Rakesh Torul
Technical Manager
Regulatory Applications
Regulatory Affairs

tel 416-495-5499
EGIRegulatoryProceedings@enbridge.com

Enbridge Gas Inc.
500 Consumers Road
North York, Ontario M2J 1P8
Canada

November 23, 2020

VIA RESS and EMAIL

Ms. Christine Long
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (Board) File No.: EB-2020-0192
London Line Replacement Project – Interrogatory Responses- Redacted

In accordance with the Procedural Order No. 1 dated October 29, 2020, enclosed please find Interrogatory Responses from Enbridge Gas in the above noted proceeding.

Enbridge Gas is not responding to the interrogatories from the Corporation of the County of Middlesex as these interrogatories are no longer relevant. As indicated in its letter filed with the Board today, the County has resolved its concerns with Enbridge Gas regarding the London Line Replacement Project, and it has withdrawn its intervenor status and the interrogatories in this proceeding.

In accordance with the Board's revised Practice Direction on Confidential Filings effective October 28, 2016, all personal information has been redacted from the following exhibits:

- Exhibit I.STAFF.2 – Attachment 1
- Exhibit I.STAFF.5 – Attachment 2
- Exhibit I.STAFF.10 – Attachment 2

Enbridge Gas is also filing corrections to the pre-filed evidence in reference to the following interrogatory responses.

- Exhibit I.APPrO.2 d)
- Exhibit I.EP.1 d)
- Exhibit I.PP.5 d)

The table below illustrates the corrections.

Exhibit	Original	Correction
Exhibit B, Tab 1, Schedule 1	Paragraph 14 "The London Lines between 2013 and 2019 had a leak rate of <u>0.43</u> leaks/km/year…"	Paragraph 14 "The London Lines between 2013 and 2019 had a leak rate of <u>0.043</u> leaks/km/year…"
Exhibit B, Tab 1, Schedule 1	Paragraph 45 "There are <u>148</u> services and 25 stations…"	Paragraph 45 "There are <u>135</u> services and 25 stations…"
Exhibit B, Tab 2, Schedule 1	Paragraph 7 "Furthermore, review of historical failures indicated that between 2013 and 2019, the London Lines had a leak rate of <u>0.43</u> leaks/km/year…"	Paragraph 7 "Furthermore, review of historical failures indicated that between 2013 and 2019, the London Lines had a leak rate of <u>0.043</u> leaks/km/year…"

Please contact the undersigned if you have any questions.

Yours truly,

(Original Digitally Signed)

Rakesh Torul
Technical Manager, Regulatory Applications

cc: Charles Keizer, Torys
EB-2020-0192 Intervenors

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 2, page 1, Location of the Project and Exhibit B, Tab 1, Schedule 1, Proposed Facilities, page 19, paragraph 48

Questions:

In addition to the replacement pipelines, the 90.5 km long Project includes a proposed new 6 inch diameter, 8.4 km long pipeline from the Strathroy Gate Station to a tie-in to the main pipeline at the intersection of Sutherland Road and Falconbridge Drive. According to Enbridge Gas the new pipeline provides a secondary feed from the Dawn to Parkway System via Strathroy Gate Station into the London Lines System. It "…provides the opportunity to install a smaller pipe size for the replacement, and provides operational flexibility in the future."

a) Please explain in more detail the need for this pipeline and the rationale for including its cost in the application as part of the Project.

b) What is the forecast capital cost of the new pipeline in relation to the total capital costs of the Project?

c) How does the new 8.4 km pipeline from the Project impact the Project's design and capacity? Please indicate the incremental capacity that the Project would provide in both absolute and relative terms.

Response:

a) This pipeline adds an additional source of gas, from the Dawn-to-Parkway system, to the customers fed from the London Lines. This adds reliability as the network is now two-way fed and adds operational flexibility to redirect flows and gas in operations and maintenance work or for emergency response. Additionally, this pipeline allows for the London Lines pipeline, from Dawn to Komoka, to be significantly downsized as a result of adding this additional source of gas.

b) The forecasted capital cost of the new pipeline is approximately $5.8 million.

c) The proposed design is for replacement capacity of the existing pipeline. The new 8.4 km pipeline was not designed to create additional capacity, but instead provide an opportunity to reduce pipe size versus a single fed system with equivalent capacity.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, page 14: System Design Criteria for Replacement of the London Lines

Question:

If the Project is approved it will result in the abandonment of 135 km of the existing London Lines, comprised of the 60 km London South Line and 75 km London Dominion Line. The abandonment is planned to start in the spring of 2022.

a) What are the applicable national and provincial regulatory standards and requirements that Enbridge Gas will have to follow for abandonment of the existing pipeline in place and for the removal of the sections of the existing pipeline from the ground?

b) Please confirm that Enbridge Gas will comply with all the applicable national and provincial requirements related to the abandonment of the London Lines.

c) Please describe any communication or consultation to date with the Technical Standards and Safety Authority (TSSA) regarding the abandonment of the London Lines. Please file copies of any correspondence with the TSSA regarding this matter. What are the next steps in communicating with the TSSA regarding the abandonment methods and plans?

Response:

a) Abandonment of pipelines whether abandoning in-place or removal requires compliance to the CSA Z662 Standard.

b) Abandonment of the London Lines shall comply to the requirements of the CSA Z662 Standard.

c) Please refer to OPCC correspondence, filed at Exhibit C, Tab 2, Schedule 2. The Application for Review of Pipeline Project form was sent the TSSA on Oct 7, 2020 to fssubmissions@tssa.org. Please see Attachment 1 for the redacted version. As the TSSA has oversight over Enbridge Gas's design and operation of its gas distribution system, the detailed design of the project will progress, following applicable national and provincial regulatory standards and requirements as noted in part a). During construction, the TSSA may visit the site to inspect and confirm compliance to these standards and requirements.

From:	[redacted]
To:	fssubmissions@tssa.org
Cc:	[redacted]
Subject:	Application for Review of Pipeline Project - London Lines EB-2020-0192
Date:	Wednesday, October 7, 2020 4:03:00 PM
Attachments:	Application-for-review-of-Pipeline-Project---FS-09563-07.18.pdf

Hello,

Please find attached the Application for Review of Pipeline Project for EB-2020-0192 – London Lines Replacement Project.

Thank you,

[redacted] **MASc, P.Eng., PMP**
Advisor
Capital Development

ENBRIDGE GAS INC.
[redacted]
101 Honda Blvd, Markham, ON, L6C 0H9

enbridge.com
Safety. Integrity. Respect.

Technical Standards and Safety Authority
345 Carlingview Drive
Toronto, Ontario M9W 6N9
Fax: 416.231.4078
Customer Service: 1.877.682.8772
Email: fssubmissions@tssa.org
www.tssa.org

Application for Review of Pipeline Project

Technical Standards and Safety Act

Fuels Safety Regulations

Please submit completed application and supporting documentation by mail, fax, or email (in pdf format).

For Office Use Only

Project Name or Title: London Line Replacement Project

Required Documentation (elig ble PDFs are acceptable)

- [x] Design and piping specifications related to the project
- [ ] Calculation of High consequence area
- [x] Project time-line related to design and construction (approximate dates are acceptable)
- [x] Length of pipeline project: 90.5 KM Diameter of Pipe: NPS 6 & 4
- [x] Pipe Material and its Standard Steel CSA Z245.1-18
- [x] Pipe wall thickness 4.8MM
- [ ] Stress level on pipe wall based on the design pressure; S/SMYS ______ %
- [x] Maximum Operating Pressure: 3447 kPa
- [ ] TSSA Transmission or Distribution license number: ______

A. APPLICANT

Company Name: Enbridge Gas Inc.		Corporation No.:
Street Name / 911 Number/Address, if applicable: 50 Keil Dr. N		
Unit/Suite:	PO Box:	
City/Town: Chatham	Province: ON	Postal Code: N7M 5J5
Telephone No.: [redacted]	Fax No.:	Cell No.: [redacted]
Email: [redacted]		
Print Name of Contact Person: [redacted]		

B. LOCATION ADDRESS: Start and end location of the pipeline project (if applicable)

Pipeline is from Dawn Compressor Station (3332 Bentpath line) to Komoka Transmission Station on Komoka Road. It also runs on Sutherland Road to Strathroy Station in Strathroy-Caradoc

C. TECHNICAL CONTACT

Same as: [x] A [ ] D

(Company should communicate regarding engineering and inspection approval on behalf of the owner.)

Company Name:		
Street Name / 911 Number/Address, if applicable:		
Unit/Suite:	PO Box:	
City/Town:	Province:	Postal Code:
Telephone No.:	Fax No.:	Cell No.:
Email:		
Print Name of Contact Person:		

Note: It is illegal to use an appliance, equipment, or work for its intended purpose unless it is approved.
Please note that this approval may be revoked or suspended if the relevant review and inspection fees are not paid in full.

Technical Standards and Safety Authority
345 Carlingview Drive
Toronto, Ontario M9W 6N9
Fax: 416.231.4078
Customer Service: 1.877.682.8772
Email: fssubmissions@tssa.org
www.tssa.org

Application for Review of Pipeline Project

Technical Standards and Safety Act

Fuels Safety Regulations

Location Address:

D. INVOICEE (Company responsible for fees invoiced for approval including engineering and inspection fees.)		
Company Name Enbridge Gas Inc.		
Street Name/911 Number/Address, if applicable 50 Keil Dr. N		
Unit/Suite:	PO Box:	
City/Town: Chatham	Province: ON	Postal Code: N7M 5J5
Telephone No:	Fax No:	Cell No: [redacted]
Email: [redacted]		
Print Name of Contact Person: [redacted]	Signature of Contact Person [redacted]	

FEES FOR ENGINEERING REVIEW AND INSPECTION

Check box to request type of service.

☒ **Regular Service:** 20-30 working days for engineering and inspection services.
Standard Fee: $169.50 (13% HST included) per hour for engineering review and inspection services.

☐ **Rush Engineering Service Only:** 5 to 10 working days.
Fee: 2 x Standard fee for engineering review.

☐ **Rush Engineering and Inspection Services:** 5 to 10 working days for each service.
Fee: 2 x Standard fee for engineering review and inspection services.

Legal Disclaimer - The owner agrees to indemnify and hold harmless the Technical Standards and Safety Authority, its employees, agents, successors and assigns from any and all damages, actions, suits, claims or loss arising from the granting of this variance. In the event of claims made against TSSA arising from the granting of this variance, the owner accepts, on demand, to defend such actions on behalf of TSSA and to assume any costs, legal or otherwise, for the defense or settlement of such claims. Failure to comply with any of the terms and conditions of the variance voids the variance.

Deposit Payment Method

Deposit of $593.25 (13% HST included) must accompany each application. Invoice will only be issued for the amount billed over and above the deposit. HST Registration No.: 891131369

Purchase Order No.__________ Purchase Order number will be reflected on invoices and TSSA will not enter into any purchasing agreements.

☐ Cheque or money order enclosed. Please make payable to: Technical Standards and Safety Authority

☒ Charge my credit card: ☐ VISA ☒ MASTERCARD

Card No. [redacted] Expiry Date Month [redacted] Year [redacted]

Name of Card Holder __________ Telephone No. __________

First Name Last Name

Signature of Card Holder X [redacted] Date: 2020.10.07 10:43:22 -04'00' Date __________ (dd-mm-yyyy)

Payment Receipts can be requested by calling our Customer Contact Centre at 1.877.682.8772 only after the payment has been processed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, page 17, paragraph 44

Question:

Enbridge Gas stated that it will adhere to the abandonment clauses set in the permanent easement agreements and will seek input from the directly affected landowners regarding the abandonment of the pipeline on their properties. Enbridge Gas also indicated that it will follow the municipal franchise agreements for the abandonment of the pipelines in municipal road allowances.

a) Please describe the nature of the abandonment clauses in the permanent easement agreements for the private properties where the abandonment will take place. What is Enbridge Gas's approach to consider these clauses when formulating the abandonment plans?

b) With respect to the abandonment of the pipelines in the municipal road allowances, please describe the requirements set in the franchise agreements with the municipalities whose road allowances will be impacted. What is Enbridge Gas's approach to implementing the abandonment requirements set in these franchise agreements?

Response:

a) In summary, the existing easement agreement states that the pipeline or pipelines may be removed at the cost of the company. Enbridge Gas will be evaluating the abandonment plans for the pipeline in easement on a case-by-case basis. When formulating abandonment plans, Enbridge Gas will consider removal of pipelines from private easements as appropriate with landowners given the physical attributes of each property and preference of the landowner.

b) The requirements set out in the '2000 Model Franchise Agreement' will be followed. Any part of Enbridge Gas's gas system on a bridge, viaduct or structure will be removed at the Company's expense. Enbridge Gas intends to cut and seal the abandoned gas main into sections; the length of these sections depends on main location and main size, and for the London Lines the sections would be up to 450m in length. If Enbridge Gas desires additional decommissioned assets on this gas system to be removed, it will be at Enbridge Gas's discretion and based on discussion/approval by the Engineer/Road Superintendent. If the Municipalities desire additional decommissioned assets be removed, the Franchise Agreement requirements (related to relocation) will be followed. Enbridge Gas is committed to working with all Municipalities and stakeholders to agreeable solutions where possible and practical.

Should third parties use decommissioned parts of the gas system for purposes other than distribution of gas, Enbridge Gas shall provide the names and addresses of third parties and the location of the associated decommissioned gas system. The third party must enter an access agreement with the Municipalities, and any decommissioned parts of the gas system used for this purpose are not subject to the provisions of the Franchise Agreement.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 1, pages 1-2

Question:

The majority of the proposed Project will be located entirely within existing municipal road allowances in the County of Middlesex, the County of Lambton, the Township of Dawn-Euphemia, the Municipality of Southwest Middlesex, the Municipality of Strathroy-Caradoc and the Municipality of Middlesex Centre.

Enbridge Gas will need to acquire approximately 0.584 acres of permanent easement and 114.9 acres of temporary land use rights for construction and storage of topsoil.

Enbridge Gas proposes to purchase five fee simple land rights for new station sites and expansion of the existing stations.

Enbridge Gas filed the form of Temporary Land Use Agreement[1] and the form of Transfer of Easement Agreement[2] which, Enbridge Gas said, were approved by the OEB in previous pipeline projects.

a) Please confirm whether the purchase of lands for new station sites required for the Project is now complete. If not, please provide an update on the negotiations with private landowners for the purchase of lands, including any concerns that have been expressed by landowners with respect to the proposed Project. Please comment on when Enbridge Gas expects these fee simple agreements to be executed.

b) Please provide an update on the status of the permanent and temporary land use rights required for the Project, including any concerns that have been expressed by landowners.

c) Please discuss any concerns that Enbridge Gas has with respect to obtaining any of the required land rights for the Project.

1 Exhibit E, Tab 2, Schedule 3
2 Exhibit E, Tab 2, Schedule 4

d) Please provide the file numbers for the OEB decisions approving the forms of permanent and temporary agreements provided in this application.

Response:

a) Negotiations for the fee purchases are ongoing. No concerns about the Project have been raised at this time. Once agreements are in place for the purchases, execution of said agreements will occur after board approval.

b) Negotiations are ongoing for the permanent and temporary land rights. No concerns about the Project have been raised at this time.

c) Enbridge Gas has no concerns at this time concerning obtaining needed land rights.

d) The current Easement Agreement has changed from the one approved in File No.EB-2018-0108 in that the terms Transferor and Transferee have been changed to Owner and Company as well as a clause has been added concerning the Planning Act to remove the need for a witness to the signing of a Declaration. This Temporary Land Use Agreement was approved in EB-2019-0172, Windsor Line Replacement.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Environmental Report, July 16,2020; Exhibit C, Tab 1, Schedule 1, page 2, paragraph 7, Exhibit C, Tab 2, Schedule 2: Summary of OPCC Comments, Environmental Report, 2.5 Input Received

Question:

Stantec Consulting Ltd (Stantec) completed an Environmental Report (ER), which assessed the existing bio-physical and socio-economic environment in the study area, the alternative routes, proposed the preferred route, conducted public consultation, conducted impacts assessment and proposed mitigation measures to minimize the impacts. The ER and the consultation process was conducted in accordance with the *OEB's Environmental Guidelines for Location, Construction and Operation of Hydrocarbon Pipelines in Ontario [7th Edition, 2016]* (OEB Environmental Guidelines).

On July 22, 2020, the ER was made available to the Ontario Pipeline Coordinating Committee (OPCC), local Conservation Authorities, and all affected municipalities for a review and comments.

Public consultation was conducted through a Virtual Open House which replaced the typical in person open house events due to the Covid-19 pandemic restrictions. Twenty five public input comments were received as of July 2020.

a) Please provide an updated summary of the comments, issues and concerns, along with Enbridge Gas actions and plans to address the concerns and resolve issues, expressed by:

   i) members of the OPCC

   ii) municipalities

   iii) local Conservation Authorities

   iv) public attending the Virtual Open House or through other consultation channels

<u>Response:</u>

a) Please see Attachment 1 for a consultation log of OPCC comments and Attachment 2 for a consultation log of non-OPCC comments.

London Lines Replacement Project
Correspondence Tracking - Post Environmental Report Submission
Ontario Pipeline Coordinating Committee (OPCC)

Final ER ciculated for review on July 23

N/A - Not Available

Comment Number	Stakeholder Group	Stakeholder Representative Name	Method of Communication	Date of Communication	Summary of Comment	Date of Response	Summary of Response
1	All OPCC contacts on the contact list	N/A	Email	7/22/2020 7/23/2020 (Conservation Authority and Municipal contacts)	Enbridge emailed a notice of the Environmental Report and a link to the report, with a request for comments to be submitted by September 3, 2020.	N/A	N/A
2	County of Middlesex	Chris Traini County Engineer	Email	July 23, 2020	Chris Traini submitted comments on the Environmental Report, noting the County of Middlesex's comments regarding the preferred route discussed during the June 17, 2020 meeting (meeting minutes were attached to the email). Mr. Traini noted that it was his understanding that further study and survey of the route and another stakeholder meeting was going to held prior to the submission of the Environmental Report. Mr. Traini requested a response and how these issues will be resolved.	July 27, 2020	Enbridge and Mr. Triani held a phone call meeting to discuss: - Last week communications triggered some excitement within the municipalities as the ER came out, request for MC for pre work, and contractors calling them for locates, etc. - He [Chris] wanted clarity on the LTC in late August. We said we hope to have the route finalized by that time - Greg Storms doesn't have too much technical background. He's concerned about the yard but Chris is supportive of it. Chris suggested when speaking to him that we come prepared with examples of other work we've done on similar roads and what specs we used to restore those roads - George won't have to many concerns except on Parkhouse (also location of yard) - Rob Cascadden has more of the technical knowledge (Middlesex Centre) - Chris stressed that in all of our communications we emphasize that it's a distribution pipeline. They are more likely to support distribution and allow room in the ROW for a distribution pipe that supports residents of Middlesex county. - Hope to have OEB approval beginning of March so that we can start construction in May. - Chris suggested that after all these on site meetings the municipalities will have an internal session to discuss outcomes of all these meetings - He asked if we were going to schedule site visits with Rob and George as well – we said we would reach out. - For the municipal consent for prework he asked that Aecon fill out the work permit application to occupy the roads etc. It can be a blanket one for a month or two, so we have ample time to do the work. - On site meeting with Chris Aug 5.
3	Ministry of Transportation (MTO)	Amanda Rodek	Email	August 25, 2020	MTO provided comments on the Environmental Report, noting conditions that are required to be met prior to any construction (i.e. permits, highway crossings installed through trenchless methods, details on the highway crossings etc.).	N/A	N/A

4	Ministry of Heritage, Sport, Tourism and Culture Industries (MHSTCI)	Katherine Kizarti	Email	August 26, 2020	MHSTCI provided comments on the Environmental Report, related to additional regulatory processes, archaeological resources, heritage resources and cultural heritage landscapes, potential impacts, mitigation and protective measures and net impacts and comments on the figures provided in Appendix A and the Stage 1 Archaeological Assessment in Appendix F.	N/A	N/A
5	Ministry of Natural Resources and Foresrty (MNRF)	Karina Cerniavskaja	Email	September 3, 2020	MNRF provided comments on the Environmental Report. The MNRF provided a copy of the Natural Heritage Information Request Guide, requested that the Ontario Oil, Gas and Salt Resources Library website be consulted, and that the Public Lands Act and Lakes and Rivers Improvement Act be reviewed. MNRF noted that once the information provided is reviewed and if none of the interests identified by MNRF are identified, there is no need to circulate any subsequent notices to the MNRF office.	N/A	N/A
6	Upper Thames River Conservation Authority (UTRCA)	Karen Winfield	Email	September 28, 2020	On behalf of Enbridge, Stantec provided the borehole locations to the Upper Thames River Conservation Authority for the geotech program.	N/A	N/A
7	St.Clair Region Conservation Authority (SCRCA)	Melissa Deisley	Email	September 28, 2020	On behalf of Enbridge, Stantec provided the borehole locations to the St.Clai Region Conservation Authority for the geotech program.	N/A	N/A

London Lines Replacement Project
Correspondence Tracking - Post Environmental Report Submission
Non-Ontario Pipeline Coordinating Committee (OPCC)

Final ER circulated for review on July 23, 2020

N/A - Not Available

Comment Number	Stakeholder Group	Stakeholder Representative Name	Method of Communication	Date of Communication	Summary of Comment	Date of Response	Summary of Response
1	Non-OPCC	Shelley-Ann [redacted]	Email	August 12, 2020	Shelley-Ann [redacted] requested a copy of the final Environmental Report	August 12, 2020	On behalf of Enbridge, Stantec provided a link to the final Environmental Report hosted on Enbridge's website. Stantec requested comments be directed to Kelsey Mills (Enbridge).
2	Non-OPCC	Shelley-Ann [redacted]	Email	August 12, 2020	Shelley-Ann [redacted] responded and noted that the interactive map hosted on the ArcGIS website as part of the virtual open house was no longer active.	August 12, 2020	On behalf of Enbridge, Stantec responded that the ArcGIS link was only active during the virtual open house and is no longer available. Stantec sent a follow-up email noting the location of the mapping used to conduct the Route Evaluation in the Environmental Report (Appendix A, Figure A-1 and A-2) and the Preferred Route (Appendix D, Figure D-1).
3	Non-OPCC	Craig M.	Phone-Call	September 29, 2020	Craig M. called the Project phone number and left a voicemail requesting a call back to discuss the Preferred Route.	September 30, 2020	On behalf of Enbridge, Stantec called Craig M. back and replied to questions regarding the Preferred Route. Stantec provided a map of the Preferred Route and provided a link to the Environmental Report hosted on Enbridge's website.
4	Non-OPCC	Lee [redacted]	Email	October 16, 2020	Lee [redacted] sent an email noting they had questions in regards to the route and the possibility of any distribution of fibre backhaul along the route.	November 18, 2020	On behalf of Enbridge, Stantec replied to Lee [redacted] and provided a PDF copy of the Preferred Route map and noted that Enbridge Gas is not partnering with other utilities including internet distribution for this project.

From: Georgopoulos, Rooly
To: Shelley-Ann
Cc: Hartwig, Emily; LondonLines; Kelsey Mills
Subject: RE: London Lines Replacement Project: Notice of Project Change
Date: Wednesday, August 12, 2020 11:55:12 AM

Hi Shelley-Ann, I have confirmed that indeed the ArcGIS site was set up for the virtual open house to show the existing pipeline route and proposed alternative segments and to gather any stakeholder information.

The mapping used to conduct the Route Evaluation in the ER can be found in appendix A, figure a-1 and a-2 and the preferred route is shown in Appendix D, figure d-1

Regards,
Rooly

From: Georgopoulos, Rooly
Sent: Wednesday, August 12, 2020 11:07 AM
To: Shelley-Ann < @gmail.com>
Cc: Hartwig, Emily <Emily.Hartwig@stantec.com>; LondonLines <LondonLines@stantec.com>; Kelsey Mills <Kelsey.Mills@enbridge.com>
Subject: RE: London Lines Replacement Project: Notice of Project Change

Hi Shelley-Ann, I believe that the arc GIS link was only active during the virtual open house and is no longer available but I will confirm and get back to you.

Regards,
Rooly

From: Shelley-Ann < @gmail.com>
Sent: Wednesday, August 12, 2020 11:03 AM
To: Georgopoulos, Rooly <Rooly.Georgopoulos@stantec.com>
Cc: Hartwig, Emily <Emily.Hartwig@stantec.com>; LondonLines <LondonLines@stantec.com>; Kelsey Mills <Kelsey.Mills@enbridge.com>
Subject: Re: London Lines Replacement Project: Notice of Project Change

Thank you, Rooly.
The following arcGIS link does not produce the interactive map, however:
https://stantec.maps.arcgis.com/apps/webappviewer/index.html?id=08cbf589324748f598206
This is part of the Route Evaluation Methodology.
S
747f7665976

On Wed, Aug 12, 2020 at 9:21 AM Georgopoulos, Rooly <Rooly.Georgopoulos@stantec.com> wrote:

> Good morning Shelley-Ann, you can access the ER at the link below and navigating to the Projects Tab and London Lines Replacement drop down.
>
> https://www.enbridgegas.com/About-Us

Comments should be directed to:

Kelsey Mills
Advisor, Environment
Enbridge Gas Inc.
101 Honda Boulevard
Markham, Ontario
L6C 0M6
Cell: 416-454-9539
Email: londonlines@stantec.com

Regards,
Rooly

Rooly Georgopoulos B.Sc.,
Senior Associate

Direct: 905-415-6367
Mobile: 416-729-2300
Fax: 905-474-9889
rooly.georgopoulos@stantec.com

Stantec
300W-675 Cochrane Drive
Markham ON L3R 0B8

Stantec

From: Shelley-Ann < @gmail.com>
Sent: Wednesday, August 12, 2020 7:41 AM
To: Hartwig, Emily <Emily.Hartwig@stantec.com>
Cc: LondonLines <LondonLines@stantec.com>; Georgopoulos, Rooly <Rooly.Georgopoulos@stantec.com>; Kelsey Mills <Kelsey.Mills@enbridge.com>
Subject: Re: London Lines Replacement Project: Notice of Project Change

Hello Emily,
I am following up to find out the status of the report which was expected in July. Could you provide me with a copy, please?
Thank you.
S

On Fri, Jun 26, 2020, 12:10 PM Hartwig, Emily, <Emily.Hartwig@stantec.com> wrote:

> Good afternoon Shelley-Ann,

Thank-you for your response. Please see the message below, sent on behalf of Rooly Georgopoulos (Project Manager, Stantec Consulting Ltd.) who is Cc'd to this email.

Good morning Shelly-Ann,

Thank you again for your comments, you have been added to the project contact list and you will be notified once the Environmental Report (ER) had been completed and posted onto the project website. We anticipate that the ER will be ready in July 2020.

Shelly-Ann I take it from your comments that you are looking for more information on the process followed for this environmental study. The following I hope provides you with the information you have requested:

Every project study area is different and local concerns are different as such there is no specific weighting assigned to criteria, we rely on regulatory and stakeholder input to identify local priorities. The routing criteria developed took into consideration routes that can be constructed at minimal cost and with minimal impact to the socio-economic and biophysical environment. Criteria included, but were not limited to:

- Minimize impact to landowners and the community.
- Minimize impacts (noise, vibration, traffic, dust, etc.) during construction.
- Maximize the constructability of the route, considering criteria that may increase technical constraints (i.e., pipeline congestion, steep side slopes, angles or entry).
- Maximize opportunities for co-location in existing utilities (railways), road or other linear public or private Rights-of-Way (RoW) and make use of overlapping easements where possible.
- Avoid potentially contaminated sites/areas of excess material management.
- Minimize length of route through natural environment areas including woodlands, natural corridors, Environmentally Sensitive Areas (ESAs), Areas of Natural and Scientific Interest (ANSIs), and areas of significant wildlife habitat and habitats of vulnerable, threatened or endangered species.
- Maximize the separation distance from sensitive receptors (i.e., commercial and institutional).
- Avoid known heritage and archaeological resource locations.

In addition to the above, the route evaluation has taken into consideration temporary workspace needs and availability. The alternative routes will take advantage of environmental and socio-economic opportunities, and, to the extent possible, avoid the following features:

- Features selected or designated for protection.
- Features recognized through local, regional, provincial, or federal policy, plan, or statute, or valued as an economic resource.
- Locations where site-specific mitigation measures would be required to minimize potential effects.

Consultation and engagement are an integral part of this environmental study. The objectives of the consultation process is to:

- Provide information to the parties on all components of the study.

- Obtain input from the parties during all phases of the study.
- Integrate information received from parties into the decision-making process

Stakeholder involvement plays a key role in the evaluation and selection of the preferred route.

If you have any other questions or concerns, please do not hesitate to contact us.
Regards,

Emily Hartwig B.Sc., EP.
Environmental Consultant, Assessment and Permitting

Direct: 519 780-8186
Mobile: 226 979-4457
Emily.Hartwig@stantec.com

Stantec
1-70 Southgate Drive
Guelph ON N1G 4P5

From: Shelley-Ann < @gmail.com>
Sent: Thursday, June 25, 2020 7:37 PM
To: Hartwig, Emily <Emily.Hartwig@stantec.com>
Subject: Re: London Lines Replacement Project: Notice of Project Change

Thank you, aEmily.
I appreciate the criteria as outlined by you; however, I am interested in the weighting of the criteria or any methodology that delineates the analysis and stakeholder engagement plan used in collecting key components of the assessment.
What is the anticipated release date for the EIA? Or, will you have a list of notification recipients to which my name can be added to ensure I become aware of the report's availability asap?
Regards,
S

On Thu, Jun 25, 2020, 1:53 PM Hartwig, Emily, <Emily.Hartwig@stantec.com> wrote:

> Good afternoon
>
> Thank-you for submitting your questions regarding the London Lines Replacement Project. This project is subject to the requirements of the Ontario Energy Board's "Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario (2016)" in the form of an Environmental Report.
>
> The criteria used to support selection of the preferred pipeline route include reviewing impacts on the natural, built, social, cultural and economic components of the environment within the study area. These criteria will include: land use planning and policies, cultural heritage resources, agricultural land, vegetation and wildlife habitat, lake and watercourse crossings, provincial parks and conservation reserves, air emissions and noise, geological features and mineral resources,

water wells and hydrology, safety considerations and social impacts. These criteria are described in the Ontario Energy Boards' Environmental Guidelines (2016), as noted above.

Under the Project List (the Physical Activities Regulation, SOR/2019-285) the following activities would require review as per the Impact Assessment Act (2019):
Electrical Transmission Lines and Pipelines

- ***39*** *The construction, operation, decommissioning and abandonment of either of the following:*

  (a) *a new international electrical transmission line with a voltage of 345 kV or more that requires a total of 75 km or more of new right of way;*

  (b) *a new interprovincial power line designated by an order under section 261 of the Canadian Energy Regulator Act.*

- ***40*** *The construction, operation, decommissioning and abandonment of a new offshore oil and gas pipeline, other than a flowline as defined in subsection 2(1) of the Canada Oil and Gas Installations Regulations.*

- ***41*** *The construction, operation, decommissioning and abandonment of a new pipeline, as defined in section 2 of the Canadian Energy Regulator Act, other than an offshore pipeline, that requires a total of 75 km or more of new right of way.*

The London Lines Replacement Project will include the construction of approximately 75 km of 8-inch high pressure natural gas pipeline, however a large portion of the pipeline will be located within existing road and easement Right of Ways. Therefore the Project does not include any of the activities as described under the Project List, and the Impact Assessment Act is not applicable.

Once the Environmental Report has been finalized, it will be submitted to the Ontario Energy Board as part of the Leave-to-Construct Application. The Ontario Pipeline Coordinating Committee, made up of provincial and municipal agencies and other affected and interested parties, are responsible for the coordination of the Ontario government agencies' review of the Application.

Once complete, the Environmental Report will be available for your review on the Project website (https://www.enbridgegas.com/About-Us) under the Projects tab, London Lines Replacement Project (LLRP).

If you have any immediate questions or concerns, please do not hesitate to reach out.

Regards,

Emily Hartwig B.Sc., EP.
Environmental Consultant, Assessment and Permitting

Direct: 519 780-8186
Mobile: 226 979-4457
Emily.Hartwig@stantec.com

Stantec
1-70 Southgate Drive
Guelph ON N1G 4P5

From: Shelley-Ann @gmail.com>
Sent: Saturday, June 20, 2020 9:07 AM
To: LondonLines <LondonLines@stantec.com>
Subject: London Lines Replacement Project: Notice of Project Change

Hello Rooly:
I am responding to your letter of May 8, 2020. I have recently purchased, last month, property In Mt. Brydges that relates to the newly proposed Alternate Route 3 and 4.
I would like to know what criteria are being used to support your decision-making regarding all the alternatives. In your letter, you indicated that the environmental study will fulfill the requirements of the Ontario Energy Board Guidelines (2016), but there is no mention of the Impact Assessment Act of 2019. I would like to know how I could acquire the report outlining the findings and conclusions of the Environmental Study as soon as it is available. Are you developing a distribution list? Additionally, I would be interested in having more information regarding the necessary environmental impacts and mitigation measures, assuming that there would have been at least some preliminary work completed in order to establish the options as set forth in your letter.
Thank you for your time.
Respectfully,
Shelley-Ann

From: Hartwig, Emily
To: @gmail.com"
Cc: "londonlines@stantec.com"
Subject: London Lines Replacement Project - Preferred Pipeline Route
Date: Wednesday, September 30, 2020 11:43:00 AM
Attachments: 160951170_ER_FigD-1_Preferred_Pipeline_Route_20200709.pdf

Good morning Craig,

Thank-you for taking the time to speak with me this morning. As discussed, I have attached a map of the preferred route for the London Lines Replacement Project. If you would like to review the final Environmental Report, a copy can be found on Enbridge's website under the "Projects" tab, located here: https://www.enbridgegas.com/About-Us.

To inquire about connecting to natural gas you can call Customer Connections at 1-866-772-1045, or complete an inquiry form online here: https://www.uniongas.com/switchtogas/.

Regards,

Emily Hartwig B.Sc., EP.
Environmental Consultant, Assessment and Permitting

Direct: 519 780-8186
Mobile: 226 979-4457
Emily.Hartwig@stantec.com

Stantec
1-70 Southgate Drive
Guelph ON N1G 4P5

From: Lee
To: LondonLines; Kelsey.mills@enbridge.com
Subject: London Lines Project.
Date: Friday, October 16, 2020 4:36:42 PM

Hi there, my name is Lee and I am located at . I just had a few questions in regards to the route and also if it would be possible to consider any distribution of fibre backhaul on this route for internet distribution to areas along the route.

If you could let me know details of the final route selection that would be greatly appreciated!

Thanks so much!
Lee

From: Hartwig, Emily
To: Lee
Cc: LondonLines; Kelsey.mills@enbridge.com
Bcc: Georgopoulos, Rooly
Subject: RE: London Lines Project.
Date: Wednesday, November 18, 2020 9:41:00 AM
Attachments: 160951170_ER_FigD-1_Pre_Preferred_Pipeline_Route_20200709.pdf

Good afternoon

Thank-you for reaching out regarding the London Lines Replacement Project. My apologies for the delayed response.

I have attached a map showing the preferred route for this project. In reference to your address, the preferred route travels southeast along Amiens Road until the intersection with Glendon Drive and does not turn down Oxbow Drive.

Enbridge Gas is not partnering with other utilities including internet distribution for this project. Please reach out to your local internet provider for specific internet service questions.

If you have any other questions or comments, please let me know.

Regards,

Emily Hartwig B.Sc., EP.
Environmental Consultant, Assessment and Permitting

Direct: 519 780-8186
Mobile: 226 979-4457
Emily.Hartwig@stantec.com

Stantec
1-70 Southgate Drive
Guelph ON N1G 4P5

From: Lee @gmail.com>
Sent: Friday, October 16, 2020 4:36 PM
To: LondonLines <LondonLines@stantec.com>; Kelsey.mills@enbridge.com
Subject: London Lines Project.

Hi there, my name is Lee and I am located at . I just had a few questions in regards to the route and also if it would be possible to consider any distribution of fibre backhaul on this route for internet distribution to areas along the route.

If you could let me know details of the final route selection that would be greatly appreciated!

Thanks so much!

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 1, Schedule 1, page 2, paragraphs 11-12 and page 4, paragraph 14

Question:

Enbridge Gas will prepare the Environmental Protection Plan (EPP) for the Project. The EPP will incorporate the mitigation measures identified in the ER and received in the consultation with the OPCC and agencies. Enbridge Gas plans to complete the EPP prior to mobilization and construction of the Project.

a) Please confirm that as part of the EPP process Enbridge Gas will develop site specific environmental management, monitoring and contingency plans in order to implement general mitigation and contingency measures identified in the ER and in the consultation process.

Response:

a) Confirmed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Environmental Report, Table 1-1: Summary of Potential Permits and Regulatory Requirements

Question:

The ER lists potential environmental permits and regulatory requirements by federal, provincial, municipal and other (i.e. Canadian National Railway, Hydro One Networks Inc.).

a) Please provide the status of each permit/approval application and expected date of acquiring each of the permits. Provide a description of causes for potential delays that may affect construction schedule for the Project.

Response:

a) Please see below for an updated table.

Permit/ Approval	Agency	Description	Expected Date of Acquisition	Causes for Potential Delays
FEDERAL PERMITS AND APPROVALS				
Clearing of Vegetation under the *Migratory Bird Convention Act* (MBCA) (1994)	Environment and Climate Change Canada (“ECCC”)	No permit is necessary; however, precautions need to be taken so that no breeding birds or their nests are harmed or destroyed during the bird nesting season (April 1 to August 31).	N/A	N/A
Review and authorization under the *Fisheries* Act (1985)	Fisheries and Oceans Canada (“DFO”)	DFO review and possible *Fisheries Act* authorization is required at watercourse crossing containing species protected under the *Species at Risk Act* (“SARA”) *(2002)*.	Q1 2021	Parties working through the approvals processes.
PROVINCIAL PERMITS AND APPROVALS				
Regulation of Development, Interference with Wetlands and Alterations to Shorelines and Watercourses), St. Clair Region Conservation Authority under O.Reg171/06	St. Clair Region Conservation Authority	Required for works within Regulated Areas, including shorelines, watercourses, wetlands and hazardous lands (flooding and erosion hazards, and unstable soils and bedrock).	Q1 2021	Parties working through the approvals processes.
Regulation of Development, Interference with	Upper Thames Conservation Authority	Required for works within Regulated Areas, including shorelines, watercourses, wetlands and hazardous lands (flooding	Q1 2021	Parties working through the approvals processes

Permit/ Approval	**Agency**	**Description**	**Expected Date of Acquisition**	**Causes for Potential Delays**
Wetlands and Alterations to Shorelines and Watercourses) Upper Thames Conservation Authority under O.Reg. 157/06		and erosion hazards, and unstable soils and bedrock).		
Regulation of Development, Interference with Wetlands and Alterations to Shorelines and Watercourses), Lower Thames Conservation Authority under O.Reg.152/06	Lower Thames Conservation Authority	Required for works within Regulated Areas, including shorelines, watercourses, wetlands and hazardous lands (flooding and erosion hazards, and unstable soils and bedrock).	Q1 2021	Parties working through the approvals processes
Permit to Take Water (“PTTW”) or Environmental Activity and Sector Registry (“EASR”) (surface and groundwater) under the *Ontario Water Resources Act (1990)*	Ministry of the Environment, Conservation and Parks (“MECP”)	Under *Ontario Regulation (O. Reg.) 64/16 and O. Reg. 63/16*, the MECP requires a PTTW for dewatering in excess of 400,000 L/day, and an EASR for dewatering between 50,000 and 400,000 L/day.	Q1 2021	Parties working through the approvals processes
Permitting or registration under the *Endangered Species Act* (“ESA”)	MECP	An ESA permit or Registration is required for activities that could impact species protected under the ESA. Consultation will	Permit may not be required based on	N/A

Permit/ Approval	**Agency**	**Description**	**Expected Date of Acquisition**	**Causes for Potential Delays**
(2007)		occur with the MECP to determine ESA permitting requirements. As indicated in Section 9 (1) a of the *ESA (2007)*, “No person shall kill, harm, harass, capture or take a living member of a species that is listed on the Species at Risk in Ontario List as an extirpated, endangered or threatened species.”	assessments and proposed mitigation measures	
Archaeological clearance under the *Ontario Heritage Act* (“OHA”)	Ministry of Heritage, Sport Tourism and Culture Industries (“MHSTCI”)	A Stage 1-2 archaeological assessment (“AA”) is required along the Right-of-Way (“RoW”) and temporary land use areas to identify areas of archaeological potential prior to any ground disturbances and/or site alterations.	MHSTCI approval Q1 2021	Stage 2 AA report expected by Q4 2020 .
Review of Built Heritage and Cultural Landscape under the OHA	MHSTCI	A Cultural Heritage Evaluation Report (“CHER”) will be completed to determine the presence of built heritage and cultural landscapes.	MHSTCI approval Q1 2021	CHER Reported expected by Q4 2020
Railway Crossing Permits	Canadian National Railway(CN) and Canadian Pacific Railway (CP)	Permission for pipeline to cross under the existing railway tracks	Q1 2021	Parties working through the approvals processes. .

Permit/ Approval	Agency	Description	Expected Date of Acquisition	Causes for Potential Delays
Encroachment Permit	Ministry of Transportation (MTO)	Permission for pipeline to cross under highway 402	Q1 2021	Parties working through the approvals processes.
Crossing Agreement	Sun-Canadian Pipe Line Co. Ltd.	Permission for pipeline to cross under Sun Canadian Pipe Line	Q1 2021	Parties working through the approvals processes.
MUNICIPAL PERMITS AND APPROVALS				
Tree By-law	TBD	Based on tree removal requirements and by-law requirements, a tree removal by-law approval may be required.	TBD	Detailed Design required to identify tree removals
Municipal Consent and municipal permits	County of Lambton, Municipality of Middlesex Centre, Municipality of Dawn-Euphemia, Municipality of Southwest Middlesex, Municipality of Strathroy-Caradoc, County of Middlesex	Municipal consent and required permits (ex. Road occupancy, entrance permits, crossing agreements) along the pipeline route within the affected municipalities	Q1 2021	Parties working through the approvals processes.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Environmental Report, section 3.4.9 Archaeological Resources and Exhibit C, Tab 1, Schedule 1, page 5, para 17

Question:

Enbridge Gas states that an archeological assessment (AA) Stage 1 has been completed for the entire route and the study area in accordance with the Ministry of Heritage, Sport, Tourism and Culture Industries (MHSTCI*) 2011 Standards and Guidelines for Consultant Archaeologists* (Government of Ontario, 2011). The ER states that a copy of the completed Stage 1 AA report will be submitted to the MHSTCI for review and inclusion into the *Ontario Public Register of Archaeological Reports*. Stage 1 AA identified areas that have archaeological potential and require Stage 2 AA.

a) Please provide details of the planned archaeological assessment, including the steps required to meet all the provincial requirements for the AA.

b) Please provide an update on status of the MHSTCI's review of the Stage 1 AA and when Enbridge Gas expects a response from the MHSTCI with respect to the Stage 1 AA

c) Please provide the planned schedule for Enbridge Gas's Stage 2 AA, indicating if the Stage 2 AA field work is underway, when this will be completed and if Enbridge Gas has submitted its Stage 2 AA to the MHSTCI for review.

d) Please indicate when Enbridge Gas anticipates a response from the MHSTCI with respect to the Stage 2 AA.

e) Please indicate the timeline by which Enbridge Gas must receive archaeological assessment approval from the MHSTCI to start the Project on time.

f) Please comment on the implications for the Project if Enbridge Gas is unable to receive approval from the MHSTCI before the timeline specified in part (e).

Response:

a) A Stage 1 Archaeological Assessment (AA) has been completed and submitted to the MHSTCI for review. A Stage 2 AA is currently being undertaken on areas of archaeological potential.

b) The Stage 1 AA was submitted to the MHSTCI for review on September 17, 2020. Enbridge did not apply for an expedited review as it was not needed. A review of the Stage 1 AA by the MHSTCI is expected to be completed prior to construction beginning.

c) The Stage 2 AA is currently being undertaken and a report is expected by the end of the year dependent on weather conditions.

d) Enbridge Gas will require a response for the Stage 2 AA prior to construction beginning on areas of archaeological potential.

e) Enbridge Gas will require a response from MHSTCI by April 1, 2021 to allow construction to proceed in areas of archaeological potential.

f) Enbridge Gas will not be able to begin ground disturbance activities in areas of archaeological potential if a response is not received by the MHSTCI.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 5, Schedule 1, page 5, paragraph 18

Question:

As part of the environmental assessment for the Project, Stantec completed a checklist of the MHSTCI *Criteria for Evaluation Potential for Built Heritage Resources and Cultural Heritage Landscapes* for the study area. Enbridge Gas has committed to complete a *Cultural Heritage Evaluation Report* prior to construction and submit it to the MHSTCI for their review and comment.

a) Please comment on the expected timeline for completion and filing with the MHSTCI of the Cultural Heritage Evaluation Report. When is the final review of the Cultural Heritage Evaluation Report expected to be completed by the MHSTCI?

Response:

a) A Cultural Heritage Evaluation Report (CHER) is in the process of being completed currently. A final report is expected by the end of 2020, Enbridge Gas expects to submit the CHER to the MHSTCI at the beginning of 2021 for review and would expect a response prior to April 1, 2021.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit G, Tab 2, Schedule 1 and Schedule 2

Question:

In accordance with the OEB's Environmental Guidelines, Enbridge Gas contacted the Ministry of Energy Northern Development and Mines (MENDM) in respect to the Crown's duty to consult related to the Project on December 9, 2019. The MENDM by way of a letter delegated the procedural aspects of the Crown's Duty to Consult for the Project to Enbridge on February 26, 2020 (Delegation Letter).

In the Delegation Letter the MENDM identified six Indigenous communities that Enbridge Gas should consult in relation to the Project:

- Oneida Nations of the Thames
- Aamjiwnaang
- Caldwell
- Chippewas of Thames
- Chippewas of Kettle and Stony Point
- Bkejwanong (Walpole Island)

Enbridge Gas provided the MENDM with its Indigenous Consultation Report for the Project and requested that the MENDM determine if the procedural aspects of the duty to consult are acceptable. The Indigenous Consultation Report includes, for each of six Indigenous communities potentially affected by the Project, the record of consultation chronology, concerns expressed, Enbridge Gas responses to questions and concerns, and information on any outstanding concerns. The information in the Indigenous Consultation Report is current of August 31, 2020.

Enbridge Gas is awaiting a letter of opinion from the MENDM regarding the adequacy of procedural aspects of the duty to consult.

a) Please provide an update on Indigenous consultation activities since August 31, 2020.

b) Please summarize all the issues and concerns raised by the Indigenous communities in the process of Indigenous consultation to date and describe Enbridge Gas's plans, actions and commitments to address these concerns and resolve the outstanding issues.

c) Please update the evidence with any correspondence between the MENDM and Enbridge Gas after August 31, 2020, regarding the MENDM's review of Enbridge Gas's consultation activities.

d) Please indicate when Enbridge Gas expects to receive a letter of opinion from the MENDM on the adequacy of procedural aspects of Indigenous consultation undertaken by Enbridge Gas for the London Lines Replacement Project.

<u>Response:</u>

a) Please see Attachment 1.

b) To date, there have been no outstanding issues or concerns from the Indigenous communities. Enbridge Gas answered all questions during the meetings and throughout consultation. Enbridge Gas is committed to continuing to engage with the six communities on an ongoing basis and will address any concerns as they come. Currently, there are no outstanding questions or concerns.

c) Please see Attachment 2.

d) MENDM is currently meeting with one of the First Nation communities this week. We are committed to working with the MENDM to ensure they have all the information necessary to make their determination.

INDIGENOUS CONSULTATION REPORT: SUMMARY TABLES
Enbridge Gas Inc - London Lines Replacement Project

As of November 16, 2020

<table>
<tr><td colspan="3">Caldwell First Nation (“CFN”)
Director of Operations
519-322-1766</td></tr>
<tr><td>Was project information provided to the community?</td><td>☒ Yes
☐ No</td><td></td></tr>
<tr><td>Was the community responsive/did you have direct contact with the community?</td><td>☒ Yes
☐ No</td><td>On September 17, a virtual meeting was held between Enbridge and CFN. The Enbridge representatives reviewed the presentation and Project map.

The Enbridge representatives explained the purpose of the Project:
Replacement Project to improve the integrity of the pipeline network and increase system flexibility.
Construction of approx. 83km of high-pressure steel natural gas pipeline.
Replaces two current pipelines
Includes construction of a new secondary pipeline into the Municipality of Strathroy-Caradoc
Proposing to install pipeline within road allowance as much as possible.
The Enbridge representative went over the environmental aspects of the project including water crossings and Species at Risk. They provided the timelines for the Project and how the OEB process works.</td></tr>
<tr><td>Did the community members or representatives have any questions or concerns?</td><td>☐ Yes
☒ No</td><td><table><tr><td>CFN Question</td><td>Enbridge Response</td></tr><tr><td>A CFN representative asked if all the pipe was being replaced and where it was located.</td><td>The Enbridge representative provided timelines for the project and discussed the environmental aspects encountered in the tabletop study.</td></tr><tr><td>A CFN representative asked how deep the pipe is currently</td><td>The Enbridge representative advised that it is usually buried at .75-1m cover. With the old pipe, due to land</td></tr></table></td></tr>
</table>

				degradation, there are currently parts that are above ground or too close to the surface. This is one of the reasons the pipe needs replacement.
			The CFN representative asked about why Enbridge would leave the old lines in place and abandon them and if there are environmental concerns about leaving the pipe in place.	The Enbridge representative advised that although the old pipe is no longer safe to carry gas, it is still safe and intact. Abandonment is a common practice and is in the TSSA guidelines.
			The CFN representative asked who monitors abandoned pipelines?	The Enbridge representative advised that there is a database to keep track of the pipe as well the pipelines are identified during locates.
			The CFN representative asked if another company needs to remove old abandoned Enbridge pipe to place their infrastructure, is it at their costs?	The Enbridge representative advised that typically companies pay to remove the other infrastructure for their own projects. During the planning of projects, utilities and municipalities work together to identify what is below the ground and work together.
			The CFN representative asked if there is a concern about layer upon layer of infrastructure in the ground. Why would Enbridge not want to remove the pipe to avoid creating problems for future generations?	The Enbridge representative advised that this is something we would need to discuss with those higher up in the company as it's a good concern. When planning the project, Enbridge works with the municipalities to try to get all infrastructure within the road allowance and keep it contained into one area. Removal of the pipe is costly, and these costs get passed back to customers due to OEB regulations.

		The CFN representative asked what type of material the pipe is made of and how long would it last?	The Enbridge representative advised that the pipe was made of steel and is externally coated to prevent exposure to water and soil. This would allow the abandoned pipe to remain intact for a very long time.
		The CFN representative asked about a Species at Risk action plan.	The Enbridge representative advised that we work with Stantec to do the field studies which will be commencing in the fall. During this time, they will be identifying mitigation necessary.
		The CFN representative asked that the information previous sent to the community be sent as they are new in the role and would like to have the background. The CFN representative thanks the Enbridge representatives for their time and letting their questions be heard.	The Enbridge representative agreed to do this.
Does the community have any outstanding concerns?	☐ Yes ☒ No	To date CFN does not have any outstanding concerns.	
Chippewas of Kettle and Stony Point First Nation ("CKSPFN") Consultation Coordinator 519-786-2125			
Was project information provided to the community?	☒ Yes ☐ No		

Was the community responsive/did you have direct contact with the community?	☒ Yes ☐ No	On September 28, 2020, the Enbridge representative sent an email to the CKSPFN representative following up on the email from MENDM. The Enbridge representative requested to have a virtual meeting to address the questions and concerns that CKSPFN might have. No response was received from CKSPFN. On October 6, 2020, the Enbridge representative sent an email to the CKSPFN representative, Chief and Band Manager with information on another project and requested a meeting to discuss both the new project and the London Lines Replacement Project. No response was received from the CKSPFN representative. On October 15, 2020, the Enbridge representative sent an email to the CKSPFN representative and Band Manager requesting a meeting to discuss the Project. No response has been received. On November 6, 2020, The Enbridge representative called the CKSPFN band office to speak with the CKSPFN representive. A message was left with a contact number asking for a return call.
Did the community members or representatives have any questions or concerns?	☐ Yes ☒ No	At this point, there are no questions or concerns.
Does the community have any outstanding concerns?	☐ Yes ☒ No	To date, CKSPFN does not have any outstanding concerns.
Chippewas of the Thames First Nation (“COTTFN”) Consultation Coordinator 519-289-5555		
Was project information provided to the community?	☒ Yes ☐ No	

Was the community responsive/did you have direct contact with the community?	☐ Yes ☒ No	On September 23, 2020, the COTTFN representative sent an email to the Enbridge representative. The email advised that the COTTFN representative had spoked to the MENDM representative and they were requesting a seeking an extension to September 30th to review the Environmental Report. The COTTFN advised that a consultation meeting would be set soon. On September 28, 2020, the Enbridge representative responded to the email to the COTTFN representative and advised them to review the ER and we can set up a call to discuss the project. On October 5, a Stantec representative, working on behalf of Enbridge, sent an email to the COTTFN representative advising that Stage 2 Archaeological Assessment would be completed in the upcoming weeks and to advise if their community was interested. The COTTFN representative responded and stated they were interested and provided their Archaeological Field Liaison contact for signature. On October 5, 2020, the COTTFN representative emailed the Enbridge representative to ask for a link to the ER as they were not able to access the report. On October 6, 2020, a link to the ER report was provided and COTTFN confirmed they were able to access the report. On October 7, 2020, the COTTFN representative emailed the Enbridge representative regarding the Project. The COTTFN representative asked that all previous correspondence be resent at they didn't recall seeing them. The COTTFN representative also advised that they were meeting with the Treaties, Lands & Environment Committee on October 9. On October 13, 2020, the Enbridge representative forwarded the signed copy of the Archaeological Field Liaison to the COTTFN representative. On October 15, 2020, the Enbridge representative emailed the COTTFN representative to follow up on a virtual meeting. The Enbridge representative reminded the COTTFN representative to send any invoices for capacity funding to review documents etc. No response from the COTTFN have been received. On October 22, 2020, the COTTFN representative emailed the Enbridge representative seeking a date to discuss the project. The COTTFN representative included a letter advising that the project identified moderate concern for the community. The parties agreed to meet on November 3, 2020 to discuss the Project.

<table>
<tr>
<td></td>
<td></td>
<td>On November 3, 2020, a virtual meeting was held between Enbridge and COTTFN. The Enbridge representatives reviewed the presentation and Project map.

The Enbridge representatives explained the purpose of the Project:

• Replacement Project to improve the integrity of the pipeline network and increase system flexibility.
• Construction of approx. 83km of high-pressure steel natural gas pipeline.
• Replaces two current pipelines
• Includes construction of a new secondary pipeline into the Municipality of Strathroy-Caradoc
• Proposing to install pipeline within road allowance as much as possible.

The Enbridge representative went over the environmental aspects of the project including water crossings and Species at Risk. They provided the timelines for the Project and how the OEB process works.</td>
</tr>
<tr>
<td>Did the community members or representatives have any questions or concerns?</td>
<td>☐ Yes

☒ No</td>
<td>
<table>
<tr><th>COTTFN Question</th><th>Enbridge Response</th></tr>
<tr><td>The COTTFN representative asked about what Enbridge does with the pipe that gets decommissioned?</td><td>The Enbridge representative explained that some parts of the old pipe will be abandoned in place in accordance with the proper procedure, and some parts will be removed depending on where the old pipe lies. Although the old pipe is no longer safe to carry gas, it is still safe and intact. Abandonment is a common practice and is in the TSSA guidelines.</td></tr>
<tr><td>The COTTFN representative raised concerns about the short time frame between project notification to filing with OEB.</td><td>The Enbridge representative recognized that times have been challenging with COVID. Enbridge is committed to ongoing consultation on all our projects and will continue to</td></tr>
</table>
</td>
</tr>
</table>

		work with the COTTFN representative on any concerns they have on this project.
Does the community have any outstanding concerns?	☐ Yes ☒ No	To date COTTFN does not have any outstanding concerns.
Oneida Nation of the Thames ("Oneida Nation") **Environment and Consultation Coordinator** **(519) 652-6922**		
Was project information provided to the community?	☒ Yes ☐ No	
Was the community responsive/did you have direct contact with the community?	☒ Yes ☐ No	On October 13, 2020, the Enbridge representative sent an email to the Oneida Nation representative requesting a date to meet with the HCCC Clan Mothers and Chief and Council. No response has been received. On November 16, 2020, the Enbridge representative sent an email to the Oneida Nation representative requesting a date to meet with the HCCC Clan Mothers if they would be interested in meeting.
Did the community members or representatives have any questions or concerns?	☐ Yes ☒ No	No confirmation of whether the HCCC Clan Mothers are interested in a presentation on the LLRP. Suggestion of presentation to the Clan Mothers had come from the Oneida Nation representative. Willing to present to the Clan Mothers if there is a confirmation of interest.
Does the community have any outstanding concerns?	☐ Yes ☒ No	

Walpole Island First Nation ("WIFN") **Chief Miskokomon** **519-628-5700**		
Was project information provided to the community?	☒ Yes ☐ No	
Was the community responsive/did you have direct contact with the community?		On September 9, 2020 a representative from WIFN sent an email cancelling the consultation meeting set for September 10, 2020. The WIFN representative requested that the meeting be held following their election. On October 1, 2020, the Enbridge representative called and spoke to the Assistant to the Chief. The WIFN representative advised the Enbridge representative to reach out to the WIFN consultation committee to set up consultation on the Project. The Enbridge representative provided all the details on the Project to the consultation committee as per the WIFN representatives request. On October 6, 2020, the WIFN representative sent an email to the Enbridge representative and provided two dates for a virtual meeting. The consultation meeting would take place on October 15, 2020. On October 15, 2020, On September 17, a virtual meeting was held between Enbridge and CFN. The Enbridge representatives reviewed the presentation and Project map. The Enbridge representatives explained the purpose of the Project: • Replacement Project to improve the integrity of the pipeline network and increase system flexibility. • Construction of approx. 83km of high-pressure steel natural gas pipeline. • Replaces two current pipelines • Includes construction of a new secondary pipeline into the Municipality of Strathroy-Caradoc • Proposing to install pipeline within road allowance as much as possible. The Enbridge representative went over the environmental aspects of the project including water crossings and Species at

<table>
<tr>
<td></td>
<td></td>
<td>Risk. They provided the timelines for the Project and how the OEB process works.

The WIFN representative provided background information on their territory and the Chenail Ecarte Reserve. They also provided information on their consultation protocol and how they operate.

On October 19, 2020, the Enbridge representative emailed the ER and OEB filing information to WIFN representative. No response received.

On November 6, 2020, the WIFN representative provided the estimate for the review of technical documents on the Project. This estimate was agreed to by Enbridge.</td>
</tr>
<tr>
<td>Did the community members or representatives have any questions or concerns?</td>
<td>☐ Yes

☒ No</td>
<td>
<table>
<tr><th>WIFN Question</th><th>Enbridge Response</th></tr>
<tr><td>The WIFN representative advised that they would need to use an outside company to review the ER and any other documents</td><td>The Enbridge representative advised that capacity funding would be provided for these costs incurred as compensate for any staff time occurred to review projects.

On October 19, the documents were forwarded to the WIFN representative.</td></tr>
<tr><td>The WIFN representative asked about mitigation on any species that might be hurt during the Project</td><td>The Enbridge representative advised that there is a process for mitigation to ensure that species are not hurt during construction.</td></tr>
<tr><td>The WIFN representative asked about employment opportunities for their community members on the Project</td><td>The Enbridge representative advised that they would reach out to the Project Construction Manager to see what can be done and how to proceed.</td></tr>
</table>
</td>
</tr>
<tr>
<td>Does the community have any outstanding concerns?</td>
<td>☐ Yes

☒ No</td>
<td>To date, there are no outstanding concerns from WIFN.</td>
</tr>
</table>

Interactions with MENDM since August 31, 2020

From: Johnston-Weiser, David (ENDM) < >
Sent: Wednesday, September 16, 2020 10:26 AM
To: Lauren Whitwham <Lauren.Whitwham@enbridge.com>
Cc: rakesh.torul@endbridge.com; Ashe, Rosalind (ENDM) <Rosalind.Ashe@ontario.ca>
Subject: [External] Request for a Short Meeting - London Lines Indigenous Consultation Report

---

Good Morning Lauren,

I am David Johnston-Weiser and I am the new Indigenous Energy Policy Intern with the Ministry of Energy, Northern Development, and Mines.

I was provided your e-mail from Rakesh (copied here) as I would like to request a short meeting with you as I have some questions regarding the Indigenous Consultation Report for the London Lines project you submitted to the ministry.

Can you let me know of a good date and time to have this short meeting in the coming days (the earlier, the better)?

I have copied my colleague Rosalind Ashe on this e-mail as she will be working with me on this.

Thank you in advance for your help with this.

David Johnston-Weiser
Indigenous Energy Policy Intern

From: Lauren Whitwham <Lauren.Whitwham@enbridge.com>
Sent: September 16, 2020 11:44 AM
To: Johnston-Weiser, David (ENDM) <David.Johnston-Weiser@ontario.ca>; Ashe, Rosalind (ENDM) <Rosalind.Ashe@ontario.ca>
Cc: [redacted]
Subject: FW: Request for a Short Meeting - London Lines Indigenous Consultation Report

CAUTION -- EXTERNAL E-MAIL - Do not click links or open attachments unless you recognize the sender.

Hi David,

Thanks for your email.

We would be happy to discuss consultation on the London Lines project with you and Roslind. Calendars are a bit busy this week but I was able to put Thursday Sept 17 from 2-3:30 on hold in our calendars. Are you able to meet during this timeframe? We could also do Friday after 3:30.

Please let me know if any of these times work for your team.

Looking forward to hearing from you,
Lauren

From:	Johnston-Weiser, David (ENDM)
To:	Lauren Whitwham; Ashe, Rosalind (ENDM)
Cc:	[redacted]
Subject:	[External] RE: Request for a Short Meeting - London Lines Indigenous Consultation Report
Date:	Wednesday, September 16, 2020 11:48:02 AM

EXTERNAL: PLEASE PROCEED WITH CAUTION.
This e-mail has originated from outside of the organization. Do not respond, click on links or open attachments unless you recognize the sender or know the content is safe.

Hi Lauren,

Yes I am available for tomorrow during that time, it should only take about a half hour maximum.

Also, just a heads up Rosalind will not be joining the meeting but I will just be advising her on the results of the meeting.

Thank you,

From: Johnston-Weiser, David (ENDM)
To: Lauren Whitwham; [redacted]
Cc: Ashe, Rosalind (ENDM)
Subject: [External] Meeting Summary - London Lines File
Date: Thursday, September 17, 2020 3:07:33 PM

EXTERNAL: PLEASE PROCEED WITH CAUTION.
This e-mail has originated from outside of the organization. Do not respond, click on links or open attachments unless you recognize the sender or know the content is safe.

Hello Everybody,

Thank you again for taking the time to meet with me today about the London Lines file.

Below is a list of the actions from today's short meeting:

1. As the meeting with Walpole Island First Nation did not occur on September 9 due to the upcoming election, Lauren to send an addendum to the London Lines Indigenous Consultation Report in approximately 2 weeks which will have the results of the meetings with Caldwell First Nation and Walpole Island First Nation.
2. Lauren to send the contact information for [redacted] Following receiving the contact information, David will reach out to the communities to see if Enbridge has the correct contact information and if they do, see why the community has been unresponsive to the requests for consultation.
3. Lauren and Kevin to continue to reach out Oneida First Nation to look for the next opportunity to speak with the Community's Clan Mothers (meetings happen approximately once per month).

Please let me know if I have missed anything or if I have recorded anything that was not said.

David Johnston-Weiser
Indigenous Energy Policy Intern

From: Lauren Whitwham <Lauren.Whitwham@enbridge.com>
Sent: September 17, 2020 2:57 PM
To: Johnston-Weiser, David (ENDM) <David.Johnston-Weiser@ontario.ca>
Cc: [redacted]
Subject: Contacts at First Nation communities - London Lines Replacement Project

Hi David,

Thanks for reaching out and having the call with us just now. We appreciate the opportunity to work with you on the review of this project.

Our contact at Kettle and Stony Point First Nation is Valerie George.

[redacted]

At Chippewa of the Thames First Nation, we work with Fallon Burch.

[redacted]

At Oneida, we work with [redacted] who is the Environmental Committee lead. [redacted] email is [redacted]

If you have any questions or would like the other names of our contact, I'm happy to provide them.

Thanks again and I will send an addendum once we have those meetings.

Lauren

Lauren Whitwham
Analyst, Indigenous, Municipal Affairs & Stakeholder Relation

From: Johnston-Weiser, David (ENDM)
To: Lauren Whitwham; [redacted]
Cc: Ashe, Rosalind (ENDM)
Subject: [External] Virtual Connection - London Lines Pipeline Project
Date: Wednesday, September 23, 2020 2:07:05 PM

EXTERNAL: PLEASE PROCEED WITH CAUTION.
This e-mail has originated from outside of the organization. Do not respond, click on links or open attachments unless you recognize the sender or know the content is safe.

Good Afternoon Everybody,

I am just making a virtual connection between the 3 of you regarding the London Lines Pipeline project as [redacted] would like to speak with Enbridge in the future regarding this project ([redacted] correct me if I am wrong regarding this).

Please advise if you require any assistance from the Ministry in the future regarding this project.

Thank you,

David Johnston-Weiser
Indigenous Energy Policy Intern

From: Lauren Whitwham <Lauren.Whitwham@enbridge.com>
Sent: September 23, 2020 3:29 PM
To: Johnston-Weiser, David (ENDM) <David.Johnston-Weiser@ontario.ca>
Subject: Meeting with Walpole

CAUTION -- EXTERNAL E-MAIL - Do not click links or open attachments unless you recognize the sender.

Hi David,

Thanks for the call today. I forgot to mention that (and you likely already saw) Walpole Island elected a new Chief on the weekend. We will be in touch with his office to set up a meeting as soon as possible.

We used to work with two communities members to do consultation (as directed by the former Chief), however, that process was changed by Chief Miskokomon in the Spring. Our hope is that the new Chief will bring in some consultation staff and we will continue to work with the community on our projects.

Our meeting with [redacted] went well and we also got to meet [redacted] who is their new consultation person. We look forward to updating them on the project as we move along. I can forward you the update on the meeting this week or hold off until we get Walpole. Please advise.

Thanks and we will be in touch soon,
Lauren

From: Johnston-Weiser, David (ENDM)
To: Lauren Whitwham
Subject: [External] RE: Meeting with Walpole
Date: Wednesday, September 23, 2020 4:33:16 PM

Hello Lauren,

I ask you to send the addendum to the ICR upon consultation with Walpole Island and perhaps after you have had discussion with Chippewas of the Thames (I would assume that this will be coming up upon recent communication with them).

I will also provide you with updates on our meeting with the Chippewas of Kettle and Stony Point and Oneida First Nation when we have them.

Thank you,

David

From: Johnston-Weiser, David (ENDM) <David.Johnston-Weiser@ontario.ca>
Sent: Thursday, September 24, 2020 3:49 PM
To: Valerie George [redacted] Lauren Whitwham <Lauren.Whitwham@enbridge.com>
Cc: Ashe, Rosalind (ENDM) <Rosalind.Ashe@ontario.ca>
Subject: [External] Virtual Connection - London Lines Project

Good Afternoon Everybody,

I am just making a virtual connection between the 2 of you regarding the London Lines Pipeline project as Valerie would like to speak with Enbridge in the future regarding this project [redacted] correct me if I am wrong regarding this).

Please advise if you require any assistance from the Ministry in the future regarding this project.

Thank you,

David Johnston-Weiser
Indigenous Energy Policy Intern

From: Johnston-Weiser, David (ENDM)
To: [redacted] Lauren Whitwham
Cc: Ashe, Rosalind (ENDM)
Subject: [External] Virtual Connection - London Lines Pipeline
Date: Thursday, October 1, 2020 2:04:32 PM

Good Afternoon [redacted] and Lauren,

This is just a virtual connection between the two of you to setup a date/time in the future for Enbridge to meet with the Clan Mothers as well as Chief and Council regarding the London Lines pipeline project.

Do not hesitate to reach out to Rosalind Ashe (copied here) and myself should you have any questions regarding this.

Thank you,

David Johnston-Weiser
Indigenous Energy Policy Intern

From: Johnston-Weiser, David (ENDM)
To: Lauren Whitwham
Cc: Ashe, Rosalind (ENDM)
Subject: [External] London Lines Consultation
Date: Friday, October 2, 2020 11:56:29 AM

EXTERNAL: PLEASE PROCEED WITH CAUTION.
This e-mail has originated from outside of the organization. Do not respond, click on links or open attachments unless you recognize the sender or know the content is safe.

Hi Lauren,

To follow-up on your call yesterday, I spoke with my colleague Rosalind Ashe (copied here) who is working with me on the file. We both suggest to continue to follow-up with Chippewas of the Thames and the Chippewas of Kettle and Stony Point regarding consultation on the London Lines project.

I understand that you have been working with Walpole Island First Nation on consulting them on this project. If possible, we would like a quick meeting with yourself and the team following consultation with Walpole Island to get an update on overall consultation regarding the London Lines project.

Do not hesitate to reach out to us if you have any questions or concerns regarding this.

Thank you,

David Johnston-Weiser
Indigenous Energy Policy Intern

From: Lauren Whitwham <Lauren.Whitwham@enbridge.com>
Sent: October 6, 2020 11:12 AM
To: Johnston-Weiser, David (ENDM) <David.Johnston-Weiser@ontario.ca>
Subject: Meeting with Walople Island Oct 15

Hi David,

Just wanted to let you know that I have a meeting set up with [redacted] at Walpole Island for October 15.

I have been back and forth with [redacted] re: ER as she was having some difficulties downloading it. I'm working on getting it over to her today. I'll continue to seek a consultation meeting with her on the project.

I have not yet heard back from [redacted] and will follow up again today or tomorrow.

Thanks,
Lauren

Lauren Whitwham
Analyst, Indigenous, Municipal Affairs & Stakeholder Relation

From: Johnston-Weiser, David (ENDM) <David.Johnston-Weiser@ontario.ca>
Sent: Monday, October 19, 2020 11:16 AM
To: Lauren Whitwham <Lauren.Whitwham@enbridge.com>
Cc: Ashe, Rosalind (ENDM) <Rosalind.Ashe@ontario.ca>
Subject: [External] Request for a Short Conversation

Good Morning Lauren,

I hope things are well on your end.

I am just writing you to see if there is a good time this Thursday or Friday for you to have a quick chat with my colleague Rosalind Ashe (copied here) and myself regarding the London Lines file.

Is there a good day and time for you to have this short conversation (it should take 15 minutes maximum)?

Thanks,

David Johnston-Weiser
Indigenous Energy Policy Intern

From: Lauren Whitwham <Lauren.Whitwham@enbridge.com>
Sent: October 19, 2020 11:31 AM
To: Johnston-Weiser, David (ENDM) <David.Johnston-Weiser@ontario.ca>

Cc: Ashe, Rosalind (ENDM) <Rosalind.Ashe@ontario.ca>
Subject: RE: Request for a Short Conversation

Hi David,

I'm available on Friday from 9-11:30 and then from 1-5. Happy to chat at any point during that timeframe.

Thanks,
Lauren

From: Johnston-Weiser, David (ENDM) <David.Johnston-Weiser@ontario.ca>
Sent: Monday, October 19, 2020 11:46 AM
To: Lauren Whitwham <Lauren.Whitwham@enbridge.com>
Cc: Ashe, Rosalind (ENDM) <Rosalind.Ashe@ontario.ca>
Subject: [External] RE: Request for a Short Conversation

EXTERNAL: PLEASE PROCEED WITH CAUTION.
This e-mail has originated from outside of the organization. Do not respond, click on links or open attachments unless you recognize the sender or know the content is safe.

Sounds good Lauren, I'll schedule something for 1030-11 on Friday.

Thanks,

David

From: Lauren Whitwham <Lauren.Whitwham@enbridge.com>
Sent: October 19, 2020 12:00 PM
To: Johnston-Weiser, David (ENDM) <David.Johnston-Weiser@ontario.ca>
Cc: Ashe, Rosalind (ENDM) <Rosalind.Ashe@ontario.ca>
Subject: RE: Request for a Short Conversation

CAUTION -- EXTERNAL E-MAIL - Do not click links or open attachments unless you recognize the sender.

Thank you.

I will provide you with a Summary update on our meetings with Walpole Island, Caldwell and correspondence with Chippewas of the Thames and Kettle and Stony Point prior to the meeting.

Thanks,
Lauren

From: Lauren Whitwham <Lauren.Whitwham@enbridge.com>
Sent: October 22, 2020 10:31 AM
To: Johnston-Weiser, David (ENDM) <David.Johnston-Weiser@ontario.ca>; Ashe, Rosalind (ENDM) <Rosalind.Ashe@ontario.ca>
Cc: [redacted]
Subject: Updated Summary for London Lines Replacement Project

CAUTION -- EXTERNAL E-MAIL - Do not click links or open attachments unless you recognize the sender.

Good morning David,

Please find attached an updated Summary for our consultation on the London Line Replacement Project.

You will note that we have a consultation meeting set up with Chippewas of the Thames on November 3.

I look forward to the call on Friday.

Many thanks,
Lauren

From:	Johnston-Weiser, David (ENDM)
To:	Lauren Whitwham; Ashe, Rosalind (ENDM)
Cc:	[redacted]
Subject:	[External] RE: Updated Summary for London Lines Replacement Project
Date:	Thursday, October 22, 2020 11:10:04 AM

EXTERNAL: PLEASE PROCEED WITH CAUTION.
This e-mail has originated from outside of the organization. Do not respond, click on links or open attachments unless you recognize the sender or know the content is safe.

Thanks for sending this Lauren.

I will have a read of this prior to our meeting tomorrow.

Thanks,

David

From: Lauren Whitwham <Lauren.Whitwham@enbridge.com>
Sent: October 23, 2020 11:26 AM
To: Johnston-Weiser, David (ENDM) <David.Johnston-Weiser@ontario.ca>; Ashe, Rosalind (ENDM) <Rosalind.Ashe@ontario.ca>
Subject: Thank you

CAUTION -- EXTERNAL E-MAIL - Do not click links or open attachments unless you recognize the sender.

Hi there,

Thank you for taking the time to reach out and talk this through. I appreciate it.

The Kimball Colynville and Payne Well was the project that received sufficiency from the Ministry in May 2020. I will continue to make outreach to Valerie and see what I can do. I appreciate your assistance in this as well.

I will update you on the meeting with Chippewas of the Thames and if I get a response from Oneida regarding a Clan Mothers meeting. Also, I will provide you with any updates that I have with the communities with questions or concerns.

Thanks again,
Lauren

From:	Johnston-Weiser, David (ENDM)
To:	Lauren Whitwham; Ashe, Rosalind (ENDM)
Subject:	[External] RE: Thank you
Date:	Friday, October 23, 2020 11:35:27 AM

EXTERNAL: PLEASE PROCEED WITH CAUTION.
This e-mail has originated from outside of the organization. Do not respond, click on links or open attachments unless you recognize the sender or know the content is safe.

Hi Lauren,

No problem, don't hesitate to reach out with any further questions or updates you have for us.

Rosalind and I will be reaching out to our manager later today to provide him with an update on this file where he will advise us on the next steps.

Thanks,

David

From: Lauren Whitwham
To: Johnston-Weiser, David (ENDM); Rosalind (ENDM
Cc: [redacted]
Subject: London Lines Replacement Project update
Date: Tuesday, November 10, 2020 12:53:00 PM

Hi David and Rosalind,

I wanted to update you on the some outreach to the communities for the London Lines Replacement Project.

Chippewas of the Thames First Nation (COTTFN)	November 3, 2020	The Enbridge representatives met virtually with Fallon Burch and Rochelle Smith to discuss the London Lines Replacement Project and the Storage Enhancement Project. The Enbridge representative provided the overview of the purpose and details of the project. The Enbridge representative went over the environmental aspects of the project including water crossings and Species at Risk. They provided the timelines for the Project and how the OEB process works. The COTTFN representative asked about what Enbridge does with the pipe that gets decommissioned? The Enbridge representative explained that some parts of the old pipe will be abandoned in place in accordance with the proper procedure, and some parts will be removed depending on where the old pipe lies. Although the old pipe is no longer safe to carry gas, it is still safe and intact. Abandonment is a common practice and is in the TSSA guidelines.

		The COTTFN representative raised concerns about the short time frame between project notification to filing with OEB. The Enbridge representative recognized that times have been challenging with COVID. Enbridge is committed to ongoing consultation on all our projects and will continue to work with the COTTFN representative on any concerns they have on this project.
Chippewas of Kettle and Stony Point First Nation	November 6, 2020	The Enbridge representative called the CKSPFN band office to speak with the CKSPFN represention. A message was left with a contact number asking for a return call.

Please let me know if you have any questions or concerns

Thanks,
Lauren

From: Johnston-Weiser, David (ENDM)
To: Lauren Whitwham
Cc: Ashe, Rosalind (ENDM)
Subject: [External] Request for Information - Oneida First Nation (OFN)
Date: Thursday, November 12, 2020 11:02:44 AM

Good Morning Lauren,

My colleague Rosalind and I have a meeting with a representative from OFN next week.

In preparation for this meeting, can you please send the following documents to Rosalind and I so that we can send it to the representative from OFN?

1. A map of the project.
2. Only OFN's section of the ICR.

Please advise if you have any questions regarding this.

Thanks,

David Johnston-Weiser
Indigenous Energy Policy Intern

From:	Lauren Whitwham
To:	Johnston-Weiser, David (ENDM); Ashe, Rosalind (ENDM)
Cc:	[redacted]
Subject:	Oneida Log
Date:	Friday, November 13, 2020 10:50:00 AM
Attachments:	Oneida First Nation Consultation Log MENDM.pdf

Hi David,

Thanks for taking my call this morning.

Please find attached the consultation log for Oneida First Nation.

Any questions, please let us know.

Thanks,
Lauren

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit F, Tab 1, Schedule 1

Question:

Enbridge Gas has provided the following capital cost estimates for the proposed Project[1]:

London Line Replacement Project
Total Estimated Project Capital Costs

Line No.	Particulars ($000's)	Mainline	Stations	Services	Abandonment (1)	Total
1	Materials	5,616	1,823	125	-	7,564
2	Construction and Labour	77,321	8,221	4,005	19,776	109,323
3	Contingencies	11,402	1,310	619	2,633	15,964
4	Interest During Construction	867	142	49	-	1,058
5	Estimated Incremental Project Capital Costs	95,206	11,496	4,798	22,409	133,909
6	Indirect Overhead	21,881	2,640	991	4,677	30,189
7	Total Estimated Project Capital Costs	117,087	14,136	5,789	27,086	164,098

Notes:
(1) Abandonment costs will not be included in Enbridge Gas's ICM request for rate recovery.

Enbridge Gas is not seeking approval for the costs of the ancillary facilities (stations and services) in this application but stated it has shown these costs in the total Project cost estimates for completeness.

A Discounted Cash Flow (DCF) analysis report has not been completed for the Project. Enbridge Gas explained that the DCF was not completed because the Project is underpinned by the integrity requirements and will not create a significant change in capacity available on the London Lines.

[1] Exhibit F, Tab 1, Schedule 1, p 1

Enbridge Gas expects the Project will meet the criteria for rate recovery during the deferred rebasing period through the use of the OEB's Incremental Capital Module (ICM) mechanism. The ICM request for the Project will form part of Phase 2 of Enbridge Gas's 2021 rates application.

Enbridge Gas stated that the abandonment costs, estimated at approximately $27 million, will not be included in the ICM request for rate recovery.

a) Please explain the rationale for not seeking approval for the costs of the ancillary facilities (stations and services) in this application. What is the mechanism for recovery of these costs?

b) Please describe the mechanism for recovery of the abandonment costs estimated at approximately $27 million and the rationale for not proposing to include these costs in the ICM request.

c) Please provide costs of comparable projects that Enbridge Gas has completed in the past and that were approved by the OEB. Please provide a breakdown of the costs for these projects showing the following information: the work year; pipe size; length; estimated costs; estimated cost per meter; actual costs; actual costs per meter; and level of contingency (in percentage of total capital costs) .

<u>Response:</u>

a) Enbridge Gas is applying for an Order granting leave to construct pursuant to Section 90 (1) of the Ontario Energy Act, 1988 (Section 90). Section 90 is applicable to the construction of hydrocarbon lines and does not include the ancillary facilities (stations and services), nor does it address the mechanism for recovery of costs. Enbridge Gas is seeking recovery of the Project costs, including ancillary facilities, in Phase 2 of its 2021 Rates Application[2] using the Incremental Capital Module mechanism (ICM) approved by the Board as part of the MAADs Decision.[3]

b) In accordance with the Uniform System of Accounts for Class A Gas Utilities, gas utilities in Ontario recover (and ratepayers pay for) the net salvage cost (or abandonment cost, or cost to retire) of a pipeline through the depreciation charged on the pipeline over its life. Depreciation allocates the service value of the plant asset over its estimated life in a systematic and rational manner. The service value

---

[2] EB-2020-0181, Filed October 15, 2020.
[3] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018. The Decision and Order was later amended by the Board on September 17, 2018 with no material changes.

of the plant, for depreciation purposes, shall be its cost less its estimated net salvage value. Net salvage value is calculated as the salvage value less removal costs. In cases where removal costs exceed salvage value, the net salvage value will be negative.

Consistent with the above guidance, Enbridge Gas has already collected/recovered a provision for the costs to retire the existing London Lines as part of depreciation expense recovered in rates over the life those assets. The accounting offset to depreciation expense is accumulated depreciation (note: for financial reporting purposes, Enbridge Gas reclasses its outstanding provision for net salvage / abandonment / costs of retirement from accumulated depreciation to a regulatory liability). Therefore, the actual cost of retirement will be charged to accumulated depreciation. To the extent that the actual retirement/abandonment cost is higher or lower than the provision/amount recovered over the life of the asset, it will either be offset by lower/higher costs incurred to retire other assets in the steel mains pool, or it will be recovered/returned through subsequent depreciation charged on assets in the steel mains pool (i.e. the depreciation rate on steel mains may need to be increased/lowered prospectively, through a depreciation study, to reflect and or compensate for a new higher or lower actual average cost to retire mains, than the current depreciation rate provides for).

c) Please see table below.

Case #	Project Name	City	Construction Year	Pipe Size (Diameter / Material)	Length (km)	Estimated Total Costs (millions)	Estimated $/meter*	Assumed Contingency	Actual Total Costs (millions)	Actual $/meter
EB-2015-0042	Sudbury NPS 10 Replacement Project	Sudbury	2015	NPS 12 Steel	0.7	$2.023	$2,890	10%	$1.023	$1,461
EB-2016-0122	2016 Sudbury Replacement Project	Sudbury	2016	NPS 12 Steel	0.85	$2.188	$2,574	13%	$3.360	$3,953
EB-2016-0222	Sudbury Maley Replacement Project	Sudbury	2016-2017	NPS 12 Steel	2.8	$6.304	$2,251	12%	$4.206	$1,502
EB-2017-0180	2018 Sudbury Replacement Project	Sudbury	2018	NPS 12 Steel	20	$74.000	$3,700	15%	$82.616	$4,131
EB-2019-0172	Windsor Line Replacement Project	Southwestern Ontario	2020	NPS 6 Steel	64	$92.744	$1,449	15%	TBD	TBD
EB-2020-0192	London Line Replacement Project	Southwestern Ontario	2021	NPS 4 & NPS 6 Steel	90.5	$133.909	$1,480	14%	TBD	TBD

*Variations in cost per metre are signficantly influenced by specific project scope parameters (such as rural or urban setting, rock excavation, local land costs, etc).

EB-2017-0180: The 2018 Sudbury Replacement Project had large proportions of rock excavation, wetland management, a specialized Cathodic Protection design and bypass installations, which are all costly activities that are not present to the same extent or not present at all in the previously approved OEB projects as indicated in the table. It is the influence of this construction scope that has increased the cost per metre for the 2018 Sudbury Replacement Project. Estimated Total Costs for this project were later increased to $83 million.

EB-2019-0172: For comparison purposes, Estimated Total Costs as indicated in the table for the Windsor Line Replacement Project represents "Estimated Incremental Project Capital Costs" (includes Stations, Services, and IDC; excludes Indirect Overheads of $14.061 million).

EB-2020-0192: For comparison purposes, Estimated Total Costs as indicated in the table for the London Line Replacement Project represents "Estimated Incremental Project Capital Costs" (includes Stations, Services, Abandonment and IDC; excludes Indirect Overheads of $30.189 million).

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, pages 1-15; Exhibit B, Tab 2, Schedule 4, page 1; Enbridge Gas Inc., EB-2020-0091, Integrated Resource Planning Proposal, Additional Evidence, October 15, 2020, Exhibit B, page 31, paragraph 68

Question:

Enbridge Gas completed a study titled "System Design Criteria for the Replacement of London Lines" to assess six physical and one non-build alternatives to address the integrity risks and to provide for the forecast growth in demand of the London Lines System.

One of the six physical alternatives is the replacement of the existing London Lines with NPS 6 and NPS 4 pipelines at 3450 kPa, reducing the proportion of NPS 6 through supplemental Demand Side Management (DSM) (Alternative 5). The cost of Alternative 5 is estimated at $130 million while the cost of the Proposed Project is estimated at $132.9 million.

Enbridge Gas's rationale for rejecting Alternative 5 is that it: "Provides capacity to serve 2021 expected demand only, while also providing reliability of supply for emergency and operational scenarios. Savings on pipeline size reduction would be exhausted by less than 2 years of supplemental DSM programming, after which continued supplemental DSM spend or pipeline reinforcement would be required.[1]"

Enbridge Gas noted that the OEB is currently holding a proceeding on the Integrated Resource Plan (IRP) Proposal[2]. The IRP Proposal includes the DSM and other programs that may be considered as part of alternatives to the pipeline projects. Enbridge Gas, in its updated IRP Proposal (EB-2020-0091), proposes that the Discounted Cash Flow (DCF) analysis method, consistent with principles underpinning the Board's Reports in E.B.O. 134 and E.B.O. 188, would be the basis for assessing the economic feasibility of IRP Alternatives (IRPA), including the DSM.

---

[1] Exhibit B, Tab 2, Schedule 5, page 1 of 1
[2] EB-2020-0091

a) Please explain in more detail the rationale for rejecting Alternative 5.

b) Please provide a Discounted Cash Flow (DCF) analysis for both the Project and Alternative 5, comparing the economics of the Project with the economics of Alternative 5.

Response:

a) The cost for Alternative 5, including the pipe and DSM costs are higher than the proposed project in 2021, $130 million in pipe, plus $4.3 million in DSM versus a Proposed Project cost of $132.9 million. These costs would be further increased in the future, as any increase in demand would require additional DSM programming, and still the critical project drivers of integrity and safety would not be addressed.

b) A DCF analysis for the Project has not been completed as the Project is underpinned by integrity requirements and will not create a significant change in capacity available. The OEB has accepted this rationale in previous applications for leave to construct. Most recently in the Windsor Line Project[3]. As explained in part a) above, costs for incremental DSM programming or incremental facilities beyond 2021 were not determined and therefore a DCF analysis for Alternative 5 has not been completed.

[3] EB-2019-0172, Decision and Order, April 1, 2020, p.13

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 4, page 1 footnote 1

Question:

Enbridge Gas proposed in the IRP application (EB-202-0091) that the OEB consider, beside DSM, other IRP Alternatives such as demand response programs, enhanced targeted energy efficiency programs, compressed natural gas, and low-carbon and non-gas solutions.

a) Please provide Enbridge Gas's rationale for not considering any additional IRP Alternatives as alternatives to the proposed Project, with the exception of Alternative 5.

Response:

The high level DSM analysis that was conducted for the proposed project was provided in order to be responsive to OEB direction in the 2015 – 2020 DSM Framework that states as part of any utility application for a leave to construct of future infrastructure projects, "the gas utilities must provide evidence of how DSM has been considered as an alternative at the preliminary stage of project development". A process is currently ongoing for the Board to develop an integrated resource planning (IRP) framework (EB-2020-0091) which would consider scope of alternatives as one item. Enbridge Gas also notes that DSM cannot address the integrity and safety drivers that underpin the need for this project.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 1

Question:

Enbridge Gas has applied for leave to construct facilities under section 90(1) of the OEB Act.

a) Please comment on the draft conditions of approval proposed by OEB staff. If Enbridge Gas does not agree with any of the draft conditions of approval, please identify the specific conditions that Enbridge Gas disagrees with. Explain the rationale for disagreement and for any proposed changes or amendments.

Leave to Construct Application under Section 90 of the OEB Act
Enbridge Gas Inc.
EB-2020-0192
DRAFT
Conditions of Approval

1. Enbridge Gas Inc. (Enbridge Gas) shall construct the facilities and restore the land in accordance with the OEB's Decision and Order in EB-2020-0192 and these Conditions of Approval.

2. Enbridge Gas shall obtain all necessary approvals, permits, licences, certificates, agreements and rights required to construct, operate and maintain the Project.

3. Enbridge Gas shall implement all the recommendations of the Environmental Report filed in the proceeding, and implement all commitments made in response the Ontario Pipeline Coordinating Committee member review.

4. Enbridge Gas shall notify the OEB and all parties in this proceeding, prior to the start of construction, of completion of each of Environmental Protection Plan (EPP) Environmental Management Plan (EMP), and Contingency Plan

documents and make a copy of the documents available to a party upon their request.

5. (a) Authorization for leave to construct shall terminate 12 months after the decision is issued, unless construction has commenced prior to that date.

   (b) Enbridge Gas shall give the OEB notice in writing of the following:

   i. The commencement of construction, at least ten days prior to the date construction commences
   ii. The planned in-service date, at least ten days prior to the date the facilities go into service
   iii. The date on which construction was completed, no later than 10 days following the completion of construction
   iv. The in-service date, no later than 10 days after the facilities go into service

6. Enbridge Gas shall advise the OEB of any proposed change in the project, including but not limited to changes in: OEB-approved construction or restoration procedures, the proposed route, construction schedule and cost, the necessary environmental assessments and approvals, and all other approvals, permits, licences, certificates and rights required to construct the proposed facilities. Except in an emergency, Enbridge Gas shall not make any such change without prior notice to and written approval of the OEB. In the event of an emergency, the OEB shall be informed immediately after the fact.

7. Concurrent with the final monitoring report referred to in Condition 8(b), Enbridge Gas shall file a Post Construction Financial Report, which shall provide a variance analysis of project cost, schedule and scope compared to the estimates filed in this proceeding, including the extent to which the project contingency was utilized. Enbridge Gas shall also file a copy of the Post Construction Financial Report in the proceeding where the actual capital costs of the project are proposed to be included in rate base or any proceeding where Enbridge Gas proposes to start collecting revenues associated with the Project, whichever is earlier.

8. Both during and after construction, Enbridge Gas shall monitor the impacts of construction, and shall file with the OEB one paper copy and one electronic (searchable PDF) version of each of the following reports:

(a) A post construction report, within three months of the in-service date, which shall:

i. Provide a certification, by a senior executive of the company of Enbridge Gas's adherence to Condition 1
ii. Describe any impacts and outstanding concerns identified during construction
iii. Describe the actions taken or planned to be taken to prevent or mitigate any identified impacts of construction
iv. Include a log of all complaints received by Enbridge Gas, including the date/time the complaint was received, a description of the complaint, any actions taken to address the complaint, the rationale for taking such actions
v. Provide a certification, by a senior executive of the company, that the company has obtained all other approvals, permits, licences, and certificates required to construct, operate and maintain the proposed project

(b) A final monitoring report, no later than fifteen months after the in-service date, or, where the deadline falls between December 1 and May 31, the following June 1, which shall:

i. Provide certification, by a senior executive of the company, of Enbridge Gas's adherence to Condition 3
ii. Describe the condition of any rehabilitated land
iii. Describe the effectiveness of any such actions taken to prevent or mitigate any identified impacts of construction
iv. Include the results of analyses and monitoring programs and any recommendations arising therefrom
v. Include a log of all complaints received by Enbridge Gas, including the date/time the complaint was received, a description of the complaint, any actions taken to address the complaint, the rationale for taking such actions

9. Enbridge Gas shall designate one of its employees as project manager who will be responsible for the fulfillment of these conditions, and shall provide the employee's name and contact information to the OEB and to all the appropriate landowners, and shall clearly post the project manager's contact information in a prominent place at the construction site.

The OEB's designated representative for the purpose of these Conditions of Approval shall be the OEB's Manager of Natural Gas Applications (or the Manager of any OEB successor department that oversees natural gas leave to construct applications).

Response:

Enbridge Gas has reviewed the draft conditions of approval proposed by Board Staff and agrees with the proposed draft conditions. All conditions set out by the Ontario Energy Board will be adhered to by Enbridge Gas.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 2, Page 1 of 1 – Map

Preamble:

None

Questions:

a) Are any customers serviced directly by the segment of “Existing London Lines” as shown in the map cited at the reference above between Dawn Compressor Station and Komoka Transmission Station? If yes, how many customers for each rate class are serviced directly by that segment of “Existing London Lines”?

b) How many customers are serviced by the London Lines downstream from the Komoka Transmission Station?

Response:

a) Yes, approximately 135 customers are served directly off the pipe indicated as the “Existing London Lines”. All of these customers are in the Union South general service rate classes (Rate M1 and Rate M2).

b) Approximately 2500 customers are served from pipe downstream of Komoka Transmission Station.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Interrogatory

Reference:

Exhibit B Tab 1 Schedule 1 Page 6 of 20

Preamble:

“The London Lines between 2013 and 2019 had a leak rate of 0.43 leaks/km/year, which is over 10 times greater than the available average leak rate for the steel main population.”

Questions:

a) We understand the London Lines consist of approximately 75km of nominal pipe size 8 and 10 inch steel natural gas main. Please provide a chart for the “steel main population” cited above for each year from 2013 to 2019, that breaks out the steel main population by each NPS (e.g. 8 inch vs 10 inch vs other diameters) as a separate row and for each row shows a column that identifies the total kilometres of steel pipe at that NPS in the Enbridge Gas Inc. system and another column that show the average leak rate (leaks/km/year) for all of steel pipes at that NPS.
b) Please provide a table showing the average leak rate (leaks/km/year) for the London Linesfor each of 2013 to 2019.
c) For the years 2013 to 2019 what actions has Enbridge taken in each year to address the leaks along the London Lines? What actions has Enbridge taken to avoid further leaks in subsequent years?
d) Please confirm that an average leak rate of 0.43 leaks/km/year for a 75km segment of line means that Enbridge encounters an average of 32.25 leaks per year along the London Lines (e.g. 75km x 0.43 leaks/km/year).

Response:

a) A breakdown of the steel main population for the London Lines is summarized below.

	Length (km)								LEGD Leak Rate
NPS	2013	2014	2015	2016	2017	2018	2019	2020	(Leaks/km/yr)
1	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.0071
2	0.34	0.34	0.34	0.31	0.31	0.31	0.31	0.31	0.0054
3	-	-	-	-	-	-	-	-	0.0605
4	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.0026
6	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.0026
8	57.19	57.19	57.19	57.19	57.17	57.11	57.11	57.11	0.0023
10	80.43	80.43	80.43	80.43	76.84	76.84	73.19	73.19	0
12	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87	0.0028
Grand Total	141.95	141.95	141.95	141.93	138.32	138.26	134.61	134.61	0.0039

For a larger network comparison only Legacy Enbridge Gas Distribution leak values were available. These leaks occurred from 2007-2017 and the 2018 active population (taken as of March 15, 2018) of steel mains were used to determine length. There is minimal (6km) of NPS 10 steel mains within the Legacy Enbridge Gas Distribution network and NPS 8 and NPS 12 are the most applicable equivalent.

NPS	Leaks (2007-2017)	Length (km)	Leak Rate (leaks/km/yr)
0.75		7	0.0000
1	79	1015	0.0071
1.25	9	199	0.0041
2	225	3765	0.0054
3	16	24	0.0605
4	96	3323	0.0026
6	54	1865	0.0026
8	36	1416	0.0023
10		6	0.0000
12	22	719	0.0028
16	1	107	0.0009
20	3	49	0.0056
24		49	0.0000
26		0	0.0000
30		51	0.0000
36	1	7	0.0129
	542	12602	0.0039

b)

	2013	2014	2015	2016	2017	2018	2019	Grandtotal
Leaks Associated with London Lines	33	0	4	0	3	0	0	40
Assumed Length (2020 active population)(km)	134	134	134	134	134	134	134	134
Leak Rate (leaks/km/yr)	0.246	0.000	0.030	0.000	0.022	0.000	0.000	0.043

c) The London Lines are monitored and managed through leak management surveys, preventive corrosion control programs, valve inspections, and plant damage prevention strategies. Plant damage prevention strategies include third party observation of external contractors when excavating in the vicinity of the pipeline system, aerial patrol of the pipeline system to observe excavation activities in the vicinity of the pipeline system, and pipeline marker placement to identify the existence of a pipeline.

Further risk mitigation measures have been implemented to minimize leak intensity, minimize small leaks from forming, minimize pull-out forces on unrestrained compressor couplings, and to increase walking of the pipeline to observe any changes to areas of concern. These measures include reducing the system operating pressure of the London Lines by approximately 25% and increasing the leak survey frequency from two (2) times per year to three (3) times per year.

d) The 0.43 leaks/km/year was a notarization error when copying the values from the main body of the DIMP Integrity Assessment. The value should have been 0.043 leaks/km/year which is included on Page 8 of the DIMP Integrity Assessment report (The value in section 6 of the DIMP report should also be 0.043 leaks/km/year). Enbridge Gas will file a correction to Exhibit B, Tab 1, Schedule 1, paragraph 14 and Exhibit B, Tab 2, Schedule 1, paragraph 7 with the interrogatory responses. The value of 0.043 leaks/km/year was calculated based upon the 40 leaks associated with the London Lines between 2013 to 2019, and a 2020 active population of length of 134 km (as shown in Table 2-1 of the DIMP Report filed as Attachment 1 to Exhibit B, Tab 2, Schedule 1).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Page 13 of 20

Preamble:

"Leak repairs are becoming more difficult due to the degradation of the pipe. For example, a Class A Leak repair in 2019 found that a first stage cut broke away from the main due to corrosion and weight of the soil as excavation was proceeding to expose the leak. Further complications arose in trying to find an adequate location to install a stopper fitting to perform the repair, as there were numerous corrosion pits preventing welding of the stopper fitting. In 2020, the Company was attempting to abandon a service when it discovered visible external corrosion pitting. Non-destructive testing analysis by a third party showed 40% wall loss."

Questions:

a) Please provide a table showing the number leaks for each Class per year on the London Lines with Class A, Class B and Class C as each row and the years 2013 to 2019 as columns.
b) We believe the OEB would benefit from a comparison of the number and severity of leaks found in the London Lines as compared to the balance of the Enbridge steel main population. Please provide a table showing the number of Class A, Class B and Class C leaks for the steel main population by NPS for each year between 2013-2019.
c) When the main broke during the Class A Leak repair in 2019, how did Enbridge adjust the flows elsewhere in its system to ensure that customers continued to receive service despite the loss of the London Lines.
d) For the other Class A and Class B leaks identified in response to the table in part (a) above, did Enbridge use the exact same approach in part (c) to ensure that customers continued to receive service despite the work being done on the London Lines. If the answer is no, please describe the alternative methods used.
e) Why could Enbridge not simply adjust its flows elsewhere in the system and otherwise decommission the London Lines?

Response:

a) Please see table below.

Leaks Associated with London Lines	2013	2014	2015	2016	2017	2018	2019	Grand Total
A Leaks	0	0	0	0	0	0	0	0
B Leaks	4	0	0	0	0	0	0	4
C Leaks	29	0	4	0	3	0	0	36
Total Leaks	33	0	4	0	3	0	0	40

This table is derived from the leak data Enbridge Gas reported to the CGA. As C leaks are not immediately repaired in all cases, the CGA reported leaks are the best source of data for the total number of leaks associated with the London Lines.

Please see Attachment 1 for a leak repair summary that provides more detailed information regarding leaks on London Lines. This summary outlines the leak repairs which were associated with the London Lines, their leak classification at the time of repair work order creation, the assigned cause of the leak, and whether the repair is associated with the London South Line or London Dominion Line. Please note that the classification of a leak can change as it is reassessed and/or mitigated. The repair summary does not include leaks that are only monitored.

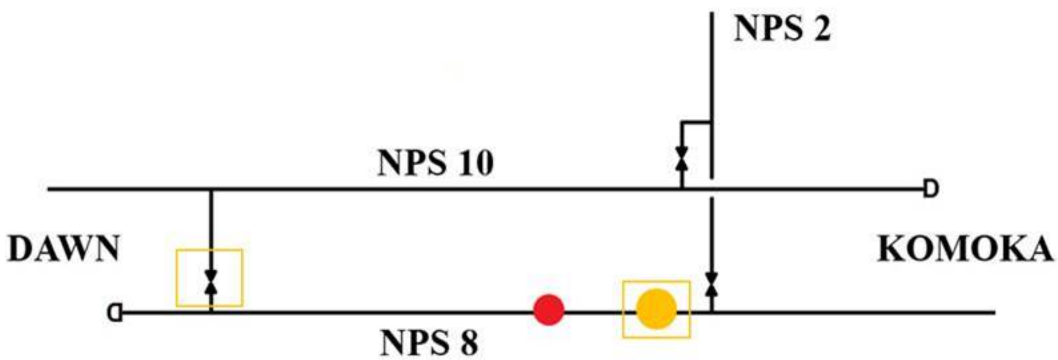
b) Please see table below.

Leaks Class	2013	2014	2015	2016	2017	2018	2019	Grand Total
A	26	26	21	30	28	15	16	162
B	69	100	40	35	64	95	86	489
C	1757	359	263	333	318	604	529	4163
Grand Total	1852	485	324	398	410	714	631	4814

This table includes all Legacy Union Gas below grade leaks associated with steel assets. This includes all pipe sizes, pressures and vintages of all steel mains, services and fittings.

c) Service to customers was maintained by isolating the leak utilizing an existing valve on the west end of the pipeline system, and the installation of a new stopper fitting on the east end of the pipeline system. This setup allowed an existing NPS 2 valve bridal that ties into the NPS 8 Dominion Line and NPS 10 London South Line to act as a bypass to maintain the operating pressure of the pipeline as shown in the figure below. This pipeline configuration was possible as Enbridge Gas determined that the NPS 2 valve bridal was suitably sized to act as a bypass based on the degree day that was forecasted during the period of time that the section of pipeline would be isolated to complete the repair.

Field employees were stationed at strategic areas on the pipeline system to monitor system pressure to confirm that the operating pressure was being maintained once the section of the pipeline was isolated.



To clarify the main pipeline did not break during the 2019 incident. The leak originated from a stub which is a short appurtenance attached to the main.

d) Enbridge Gas would implement an isolation plan that minimizes disruptions to customers, ensures the safety of employees and the public, and maintains the integrity of the pipeline system. Each isolation scenario is unique but would incorporate some, or all, of the elements as described in the response to part c).

e) The London Lines are distribution pipelines that provide the sole connection from the source, Dawn Hub, to customers and communities that are spread out along the London Lines' 82 km long project area. If the existing London Lines were decommissioned without replacement piping to connect Dawn Hub to the customers and communities, end users would lose their natural gas supply as there is no other distribution source that would be able to provide customers with gas at their sporadic spacing along the project area.

Year of Repair	Compression Coupling	Corrosion	Repair Clamp	Unknown	Valve	Weld	Grand Total
2011				1			1
London Dominion Line				1			1
2012	1		1	3			5
London Dominion Line				1			1
London South Line	1		1	2			4
2013	1	1	3	1	1		7
London Dominion Line				1	1		2
London South Line	1	1	3				5
2014	1	1	2		2		6
London South Line	1	1	2		2		6
2015		1		1			2
London Dominion Line		1					1
London South Line				1			1
2016		1					1
London South Line		1					1
2017		1	1		2	1	5
London Dominion Line		1			2	1	4
London South Line			1				1
2018				1			1
London Dominion Line				1			1
2019	1						1
London Dominion Line	1						1
Grand Total	**4**	**5**	**7**	**7**	**5**	**1**	**29**

DMWO Work Order	Date	Leak Class	Size NPS	Depth (m)	Pressure (kPa)	Street Name	Municipality	Area	Line	Component
B326712	23-May-12	B	8	0.9	HP	Bentpath Line	Dawn Twsp	Sarnia	London South Line	Repair Clamp
B368054	12-Sep-12	A	8	0.8	HP	Bentpath Line	Dawn Twsp	Sarnia	London South Line	Unknown
B391293	18-Mar-13	C	8	Unknown	HP	Bentpath Line	Dawn Twsp	Sarnia	London South Line	Compression Coupling
B101257	13-Nov-18	B	8	1.0	1900	Bentpath Line	Oakdale	Sarnia	London Dominion Line	Unknown
B383881	15-Oct-11	A	10	0.8	HP	Bentpath Line	Oakdale	Sarnia	London Dominion Line	Unknown
B065331	21-Jan-15	B	10	1.5	1380	Elviage	London	London	London South Line	Unknown
B391646	2-Dec-13	B	10	0.9	Unknown	Elviage	London	London	London South Line	Corrosion
B391646	2-Dec-13	C	10	0.9	Unknown	Elviage	London	London	London South Line	Repair Clamp
B043532	4-Sep-14	B	10	0.9	Unknown	Elviage	London	London	London South Line	Corrosion
B042000	4-Nov-14	C	Unknown	Unknown	Unknown	Elviage	Delaware	London	London South Line	Valve
B044037	5-Jun-14	C	Unknown	Unknown	Unknown	Elviage	Delaware	London	London South Line	Valve
B072149	29-Feb-16	B	10	3	Unknown	Elviage & Woodhull	London	London	London South Line	Corrosion
B042273	22-Jun-15	A	10	1.5	1200	Elviage & Woodhull	London	London	London Dominion Line	Corrosion
B355931	6-Nov-12	B	10	1.2	Unknown	Elviage Dr	London	London	London South Line	Unknown
B409993	15-Jan-14	B	10	1.2	HP	Falconbridge	Ekfrid Twsp	Sarnia	London South Line	Repair Clamp
B409994	15-Jan-14	B	10	0.9	HP	Falconbridge	Ekfrid Twsp	Sarnia	London South Line	Repair Clamp
B396148	8-Oct-13	B	8	N/A	1900	Falconbridge & Springfield.	Ekfrid Twsp	Sarnia	London Dominion Line	Unknown
B354318	24-Sep-12	A	8	Aerial	1900	Falconbridge Dr	Ekfrid Twsp	Sarnia	London Dominion Line	Unknown
B391277	9-Jan-13	B	10	0.8	HP	Falconbridge Dr	Ekfrid Twsp	Sarnia	London South Line	Repair Clamp
B391276	9-Jan-13	B	10	0.9	HP	Falconbridge Dr	Ekfrid Twsp	Sarnia	London South Line	Repair Clamp
B075017	3-Jan-17	B	10	0.6	3433	Falconbridge Dr	Ekfrid Twsp	Sarnia	London South Line	Repair Clamp
B103413	23-Mar-17	B	8	1.2	1900	Falconbridge Dr	Caradoc	London	London Dominion Line	Weld
B103414	7-Mar-17	B	8	0.9	1900	Falconbridge Dr West of Rougham	Caradoc	London	London Dominion Line	Corrosion
B408849	9-Jan-14	B	10	0.5	HP	Mosside	Euphemia	Sarnia	London South Line	Compression Coupling
B408833	27-Dec-13	Unknown	10	0.8	HP	Mosside & Dobbyn	Euphemia	Sarnia	London Dominion Line	Valve
B391282	10-Jan-12	Unknown	10	1.2	HP	Mosside Line	Euphemia	Sarnia	London South Line	Compression Coupling
03-17-624	Aug-17	A	8	Unknown	1900	Falconbridge & Springfield.	Ekfrid Twsp	Sarnia	London Dominion Line	Valve
WORK ORDER #PL02286151	6-Apr-17	B	Unknown	Unknown	HP	Gideon	Delaware	London	London Dominion Line	Valve
B101152	Jan-19	B	8	0.5	1900	Falconbridge & Glen Oak	Strathroy-Caradoc	London	London Dominion Line	Compression Coupling

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Interrogatory

Reference 1: Exhibit B, Tab 1, Schedule 1 Page 14 of 20
Reference 2: Exhibit B, Tab 2, Schedule 1, Page 5 of 6

Preamble:

Reference 1:
"The internal risk assessment performed on the London Lines shows the system has a medium risk rating on the Enbridge Standardized Operational 7X7 risk matrix when considering the lenses of the Health and Safety, Customer Loss, Financial and Reputational risks. The risk assessment also identified that some segments of the London Lines have a high risk rating for Customer Loss. This is primarily for sections where the twin pipelines cannot be isolated independently to effectively manage customer outages on the system. This risk assessment was reviewed and agreed to by the appropriate Enbridge Gas technical and management personnel for the London Lines project. Exhibit B, Tab 2, Schedule 1 shows the Integrity Assessment that was completed to explain the pipeline integrity concerns in further detail."

Reference 2:
"The London Lines were assessed primarily as a medium risk on the Enbridge Operational Risk Matrix. Several different failure modes were identified, the majority of which were assessed as a medium risk. Some sections, where the twin pipelines cannot be isolated independently to effectively manage customer outages, were assessed as a high risk for customer loss. The risk ranking results at the time of risk endorsement are shown in Table 1. This table is current at the time of risk sign-off, however some risk rankings may change over time as new information is obtained and reviewed."

Table 1

	Very High	High	Medium	Low
Financial	0	0	17	1
Health and Safety	0	0	26	0
Customer Loss	0	4	10	6
Stakeholder Concerns	0	0	10	0

Questions:

a) Table 1 shows only a 4x4 of risk ranking results, whereas Reference 1 mentions the Enbridge Standardized Operational 7x7 risk matrix. Please provide the entire 7x7 risk matrix for the London Lines.
b) For each element of the risk matrix, please explain the scenarios assessed and how the score was arrived at and why the score was categorized under Very High, High, Medium, Low risk.
c) In order for the OEB and the parties to better understand and interpret the results of the risk matrix, please provide any documentation regarding the methodology used by Enbridge to complete this type of risk assessment of the London Lines.
d) Was the risk assessment reviewed and verified by independent third party or was it done internally by Enbridge staff?
e) Please confirm that Enbridge performs a similar risk assessment as that which was performed for London Lines for all segments of its steel main population (see B-APPrO-1). If not confirmed, what criteria does Enbridge use to decide whether or not it performs a similar risk assessment on each segment.
f) With regards to the balance of the steel main population (see B-APPrO-1) please identify any other segments of the steel main population that are of medium risk or higher using the same risk assessment methodology as was used in the London Lines risk assessment cited in Table 1 above. Please provide an equivalent to Table 1 above for each such segment together with the NPS and the length of the applicable segment.
g) It would be helpful for the OEB and the parties to better understand how Enbridge prioritizes and identifies which segment of line it will replace and which can continue operating as a status quo in light of the risk assessment data provided in response to part (f) above. Please explain.
h) Please elaborate on the details of the “Stakeholder Concerns” that are identified in Table 1 above?

Response:

a) Table 1 is a summary of the results of the Risk Assessment. As noted below, Enbridge uses a 7x7 matrix to allocate risks to one of four areas on the matrix based on the likelihood and consequence. The combination of likelihood and consequence will determine if the risk is Low, Medium, High, or Very High. Please see Exhibit I.PP.4 c) for the Enbridge Standard Operational 7x7 risk matrix.

b) Please see the Risk Assessment report filed at Exhibit I.FRPO.1, Attachment 1 for further details on the risk matrix.

c) The general approach to Risk Management at Enbridge Gas is documented in the Hazard Identification and Risk Assessment Standard dated January 2020, filed at Exhibit I.PP.4 c), Attachment 1. The methodology followed to complete the Risk Assessment for the London Lines is outlined below:

- Collection of available relevant data such as pipe characteristics, leak and repair history, cathodic protection history, network analysis;
- Segmentation of the pipeline based on similar characteristics;
- Identification of people with technical knowledge required to attend the risk assessment workshop.
- Workshop:
  - Documentation (see Risk Assessment Worksheet at Exhibit I.FRPO.1, Attachment 1) of scenarios that could lead to various consequence types (see Standard Operational 7x7 at Exhibit I.PP.4, Attachment 1);
  - Documentation of the factors that could contribute to the scenarios and controls.
  - Assignment of a likelihood and consequence through a facilitated discussion and the inclusion of comments to support the ratings.
  - Assignment of a Risk Level based on the likelihood and consequence.
- Following a review period in which the workshop participants can reconsider any of the discussions at the workshop, the report is shared with the relevant Managers in Integrity, Engineering, Asset Management, and Operations.

d) The risk assessment was completed by Enbridge Gas staff.

e) Enbridge Gas does not have an established methodology to perform a systematic risk review for the 30,000km of distributions steel mains in service. Mains become identified as a potential risk to the business through several other metrics and factors, such as leak survey results, Integrity Assessments and Operational feedback.

f) There are no steel pipelines for which the risk assessment can be presented in a comparable manner at this time. Enbridge Gas uses this methodology to complete risk assessments where there is variation in factors affecting risk over the length of the pipeline for eg. Kirkland Lake, Port Stanley, Panhandle Replacement. These risk assessments are not complete at this time.

g) Please refer to Enbridge Gas's Asset Management Plan 2021-2025 Section 4.2.1 – Risk Management

h) That table entry refers to the reputation consequences identified in the risk assessment. During the risk review it was noted that lack of depth of cover and dead vegetation caused by leaks could cause stakeholder concerns. Shallow depth of cover could be an impediment to agricultural activities.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Page 12 of 15

Preamble:

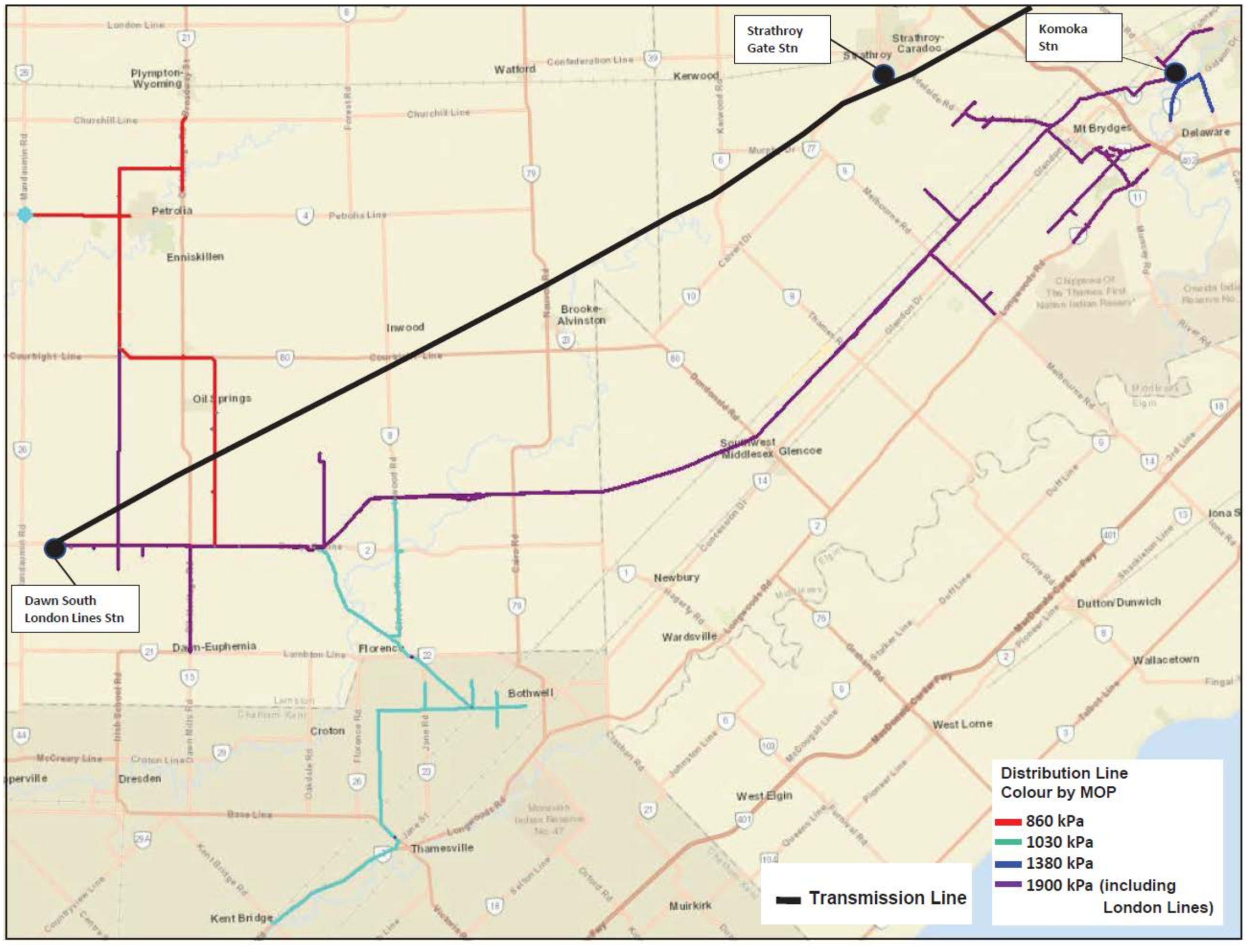
"3.5.4. Obtaining Supply from Nearby Non-Enbridge Gas Pipelines
There are currently no nearby non-Enbridge Gas pipelines to leverage as an alternative supply to the London Lines Replacement pipeline. Independent producers along this route are not large enough to support The Market, nor are they guaranteed as a source of supply; therefore, this alternative was not pursued further."

Questions:

a) Please provide a map of all existing distribution and transmission pipelines in the area the London Lines and indicate whether they are Enbridge or non-Enbridge pipelines. For each pipeline, indicate the capacity of the line and the amount of that capacity that is currently forecasted to be utilized in 2021.
b) Has Enbridge considered any non-pipeline solutions as an alternative to the London Line Replacement Project other than DSM (which is addressed in B-APPrO-6 below) or independent producers (as cited in 3.5.4 above)?
c) Has Enbridge approached any of the independent producers along the London Lines route to see if Enbridge could contract for more reliable supply with firm contractual guarantees? If no, why not?
d) Has Enbridge approached any of its gas-fired generator customers to ask them if they are willing to contract to provide demand response capacity that could be used to defer or otherwise avoid the London Lines Replacement Project? If no, why not?
e) Could a combination of independent producers, gas-fired generators and other DSM programs be used to defer the London Lines Replacement Project? If no, why not? If yes, why wasn't this alternative considered in the Application?

<u>Response:</u>

a)



The figure shows Enbridge Gas distribution lines and transmission lines. There are no non-Enbridge natural gas mains to show on this map. Based on the interdependencies and assumptions that would be required to state the capacity and forecasted utilization of each of these lines, Enbridge Gas is unable to speculate these values to be of use.

b) Enbridge Gas has not considered any non-pipeline solutions to the London Lines Replacement Project. The goal of the London Lines Replacement Project is to decommission the aging distribution pipeline and replace it while maintaining gas delivery service to the customers and communities currently served. This means solutions that Enbridge Gas could provide, such as compressed natural gas, would not be feasible as there is no common hub for customers to connect to. As indicated in response to part a) there are no alternative sources to natural gas readily available meaning that a different energy supply would be required. As the customers are spread out over the entire 82 km project length, alternative fuel sources would be cost prohibitive and therefore infeasible.

c) Section 3.5.4 of the System Design Criteria for Replacement of the London Lines included in Enbridge Gas's pre-field evidence notes that the independent producers along this route are not large enough to support the Market, nor are they a guaranteed source of supply and were not pursued further.

d) There are no customers that have gas-fired generators that can be contracted to supply natural gas in the volume required to serve the Market.

e) Even if this combination could supply the Market that the London Lines serve, as both these supplies and the customers are spread out along the 82 km length of the pipeline, a significant amount of distribution pipe would need to connect these existing customers as the existing London Lines have been fulfilling this need. As the existing Lines require replacement due to the integrity concerns/issues, alternatives sources of supply would not improve the condition of the Lines and therefore were not considered in the Application.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Page 13 of 15, 3.5.5. Implementing Demand Side Management

Preamble:

Enbridge Gas reviewed the alternative of implementing supplemental Demand Side Management (“DSM”) for customers along the London Lines in order to defer, avoid or reduce the scale of this replacement project. If Enbridge Gas were to implement supplemental DSM, it would be possible to reduce demand along the lines; however, the demand could not be eliminated altogether. Because this project is being driven by integrity concerns of the existing pipelines, the need for replacement of the London Lines cannot be deferred or eliminated by implementing DSM.

Enbridge Gas also looked at the option of implementing supplemental DSM to reduce the diameter of the pipeline required for the London Lines Replacement Project. In order to build a replacement pipeline to serve only the 2021 forecast demand, and assuming all additional future demand could be offset through supplemental DSM programs, 10.3 km of NPS 6 could be reduced to NPS 4 in the recommended design. This cost to execute a supplemental DSM program that satisfies the forecast demand, would exceed the cost savings of the downsized project design within 2 years. At that point, continual annual cost for DSM or a pipeline reinforcement project would be required. Further details on the option of implementing supplemental DSM and Integrated Resource Planning (“IRP”) can be found at Exhibit B, Tab 2, Schedule 4.

As a result of this analysis, this option was eliminated in preliminary assessment of facility and non-facility alternatives as it was determined that implementing supplemental DSM to reduce the required diameter of the pipeline is not an economically feasible alternative.

Questions:

a) Please provide a table to show the trend for actual and forecast customer demand along the London Lines for the years between 2015 and 2021.
b) Is the forecast for 2021 in part (a) above different than the 2021 forecast made when the need for the London Lines was assessed by Enbridge? Specifically, was the initial forecast for demand in 2021 conducted before the COVID-19 Pandemic?
c) How has the COVID-19 Pandemic impacted the gas flows and demands of the customers along the London Lines?
d) As the impacts of the COVID-19 pandemic may span over a long period of time, please provide a forecast of how much the pipeline capacity will be utilized through 2040.
e) Please describe at a high level what steps Enbridge has taken to monitor and track the impacts of the pandemic and business closures on its business, including the potential impact on demand for London Lines capacity. What information is Enbridge utilizing to monitor the impact on the pandemic on its business? Please provide a list of relevant metrics that are being actively monitored by Enbridge.
f) With regards to each of the metrics identified in response to question (e), please file the most current information available together with management's analysis and interpretation of what this information means for Enbridge's business.
g) Would it be prudent to update Enbridge's demand forecasts at a later date to incorporate the impacts of the pandemic and the associated business closures on this application and the associated project need? If no, why not?
h) Is the London Lines Replacement Project still needed in light of the impacts of the pandemic and associated business closures on London Lines capacity demand? If yes, then can DSM meet that need?
i) Has Enbridge only looked at implementing supplemental DSM to reduce the required diameter of the pipeline? What are the other alternatives that Enbridge has looked at that involved DSM?

Response:

a) The table below provides the peak hourly flows from Dawn South London Lines Station for 2016-2019 and the forecast for 2020-2021. The data for 2015 is not available.

   It should be noted that there are several local producers on this line that reduce the flow from Dawn when they are producing. Lack of hourly producer data makes it impossible to determine the increased flow from Dawn if these producers had not been active. Over the past few years, there has been an overall reduction in locally produced gas, as evidenced by monthly metering data available at these customers, which contributes in part to the increase in system flow from Dawn.

Year	Actual (avg hour)	Forecast
2016	13.5	-
2017	13.2	-
2018	15.8	-
2019	18.3	-
2020	-	22.4
2021	-	23.1

b) No, the forecast is not different. It was conducted before the COVID-19 pandemic.

c) There has not been any observable impact to peak gas demand on this system since COVID-19 began.

d) Please see response to part c).

e) to g)

On March 27, 2020, Enbridge Gas informed the OEB of measures it was taking to ensure the safety of its staff, contractors, customers and the general public in the wake of the COVID-19 pandemic. Please see Attachment 1.

The rapid evolution of COVID-19 prompted Enbridge Gas's Distribution Operations to re-evaluate the work performed by field employees and service providers in order to support physical distancing wherever possible, while maintaining safe and reliable operations.

The long-term impact of the COVID-19 pandemic on the demand for natural gas on the London Line system is expected to be limited. The demand forecast is expected to be the same as the forecast conducted before the COVID-19 pandemic. Please see part c) of the response. As stated in the pre-filed evidence, the London Lines have been deemed an operational risk due to the integrity concerns/issues and the proposed project is designed to replace the existing capacity of the London Lines.

h) Yes. The London Lines Replacement Project is still needed. Please see the response to part c) and d).

i) Please see Exhibit I.STAFF.13 a).

ENBRIDGE

Mark Kitchen
Director
Regulatory Affairs

tel 519-436-5275
EGIRegulatoryProceedings@enbridge.com

Enbridge Gas Inc.
50 Keil Drive N.
Chatham, Ontario N7M 5M1
Canada

VIA EMAIL

March 27, 2020

Brian Hewson
Vice President, Consumer Protection & Industry Performance
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Re: COVID-19 Impact on Service Quality Requirements ("SQRs")

Dear Mr. Hewson:

The purpose of this letter is to inform the Ontario Energy Board ("Board") of the concern of Enbridge Gas Inc.("EGI") that the COVID-19 pandemic will impact EGI's ability to meet the SQRs, as described in the *Gas Distribution Access Rule* ("GDAR"), for the year 2020. Impacts experienced to date, as well as those that may ensue in the coming weeks, are a direct result of EGI's efforts to ensure the safety of its staff, contractors, customers and the general public in the wake of the COVID-19 pandemic. Some of these measures include:

i) instituting a broad work-from-home requirement for all non-essential staff whose roles and responsibilities can be fulfilled remotely;
ii) reducing in-office call centre staff by 50% to ensure appropriate physical distancing;
iii) implementing a phased-in work-from-home program for some call centre staff;
iv) the use of health-related personal protective equipment for field staff; and
v) modifications to field work relating to SQRs, such as the suspension of indoor meter reading and the implementation of physical distancing requirements while working in the field.

As noted, some of the impacts of COVID-19 and EGI's related safety measures have begun to impact SQRs, while other impacts are either anticipated or may occur depending on the severity and duration of the COVID-19 pandemic. EGI is not seeking a GDAR exemption relating to the SQRs at this time, but rather wishes to inform the Board in advance of expected impacts. Enbridge Gas may be required to request an exemption in the future under section 1.5.1 of the GDAR.

The table provided in Attachment 1 to this letter lists the SQRs which are or may be impacted. Each SQR is accompanied by a description of the cause or possible cause underpinning EGI's challenge to meet the SQR in question.

If you have any questions, please contact me at (519) 365–0320.

Yours truly,

(Original Signed)

Mark Kitchen
Director, Regulatory Affairs

cc:
Theodore Antonopoulos (OEB)
Christine Long (OEB)
Malini Giridhar (EGI)

Attachment 1: Service Quality Requirements Impacted by COVID-19

OEB SQR Metric	SQR Definition	Target	Description of Impact
7.3.1.1 Call Answering Service Level	The percentage of all calls to the general inquiry phone number, including IVR calls that are answered within 30 seconds. This measure will track the percentage of attempted calls that are satisfied within the IVR or successfully reach a live operator within 30 seconds of reaching the distributor's general inquiry number. The operator must be ready to accept calls and to provide information.	The yearly performance standard for the Call Answering Service Level shall be 75% with a minimum monthly standard of 40%.	Reduced call centre staff and the possibility of IT-related interruptions experienced by work-from-home staff will reduce EGI's ability to manage this SQR. To the degree EGI staff are unable to work due to illness or related COVID-19 issues this will further impact EGI's ability in this area. Under current circumstances, EGI's ability to acquire and train new staff will be limited. COVID-19 is expected to result in increased call traffic as an increasing number of customers experience difficulty paying their gas bill. EGI is prioritizing emergency and other high priority work, which is expected to impact EGI's ability to handle less urgent customer requests.
7.3.1.2 Abandon Rate	The abandon rate means the percentage of callers who hang up while waiting for a live operator. This measure will track the percentage of callers that hang up before they reach a live operator.	The performance for this standard shall not exceed 10% on a yearly basis.	Reduced call centre staff and the possibility of IT-related interruptions experienced by work-from-home staff will reduce EGI's ability to manage this SQR. To the degree EGI staff are unable to work due to illness or related COVID-19 issues this will further impact EGI's ability in this area. Under current circumstances, EGI's ability to acquire and train new staff will be limited. COVID-19 may result in increased call traffic as an increasing number of customers experience difficulty paying their gas bill. Customers will be

OEB SQR Metric	SQR Definition	Target	Description of Impact
			encouraged to leverage self-service options such as myAccount and chat functions. EGI is prioritizing emergency and other high priority work, which is expected to impact EGI's ability to handle less urgent customer requests.
7.3.2 Billing Performance	The billing performance standard is a quality assurance standard. The standard requires gas distributors to have a verifiable quality assurance program in place. 7.3.2.1 Audits Distributors must audit their billing data for accuracy. Manual checks must be done to validate data when meter reads fall outside criteria, as set out in the quality assurance program, for excessively high or low usage. In addition, the quality assurance program must include random audits of data quality and billing accuracy.	No specific metric is attached to this requirement.	Reduced back office staff and the possibility of IT-related interruptions experienced by work-from-home staff will reduce EGI's ability to manage this SQR. The same restrictions may make the timely completion of audits more challenging.
7.3.3.1 Meter Reading Performance Measurement	The meter reading performance measurement requirement will measure the percentage of meters with no read for four consecutive months. Callers who call in their meter reads will be considered to have had their meters read.	This measurement shall not exceed 0.5% on a yearly basis.	EGI has suspended indoor meter reading and is experiencing an increase in missed outdoor meter reads due to physical distancing requirements. EGI's ability to meet this target is dependent on having qualified personnel and personal protective equipment (PPE). A significant loss of staff due to COVID-19 or an inability to acquire appropriate PPE may impact EGI's ability to meet this SQR.
7.3.4.1 Appointments Met Within the Designated Time Period	This measurement will identify the percentage of appointments, including meter related or other customer related work, that are met within their 4 hour scheduled time/date as arranged with the customer.	The minimum performance standard for this measurement shall be 85% averaged over a	EGI's ability to meet this target is dependent on having qualified personnel and PPE. A significant loss of staff due to COVID-19 or an inability

OEB SQR Metric	SQR Definition	Target	Description of Impact
	This includes appointments for installations, meter reads and reconnection appointments (not including those due to non-payment).	year.	to acquire appropriate PPE may impact EGI's ability to meet this SQR.
7.3.4.2 Time to Reschedule a Missed Appointment	This measurement tracks the time taken to contact the consumer to offer to reschedule a missed appointment. This includes appointments for meter related customer requests or other customer requested work such as installations, meter reads and reconnection appointments not due to non-payment. At minimum, the distributor must contact the customer to reschedule the work within 2 hours of the end of the original appointment time.	The minimum performance standard shall be that 100% of affected customers will receive a call offering to reschedule work within 2 hours of the end of the original appointment time.	EGI's ability to meet this target is dependent on having qualified personnel and technology infrastructure in place and available to call customers to reschedule a missed appointment. A significant loss of staff or technology due to COVID-19 may impact EGI's ability to meet this SQR.
7.3.5.1 Percentage of Emergency Calls Responded to Within One Hour	This measurement will track the average response time to emergencies such as gas leaks, damages and other high priority situations. The response time is calculated from the time the caller reaches a live representative from the distribution company to the time the gas representative arrives on site.	The minimum performance standard shall be that 90% of customers have received a response within 60 minutes of their call reaching a live person. The standard shall be calculated on an annual basis.	Reduced call centre staff and the possibility of IT-related interruptions experienced by work-from-home staff will reduce EGI's ability to manage this SQR. EGI's ability to meet this target is dependent on having qualified personnel and PPE. A significant loss of staff due to COVID-19 or an inability to acquire appropriate PPE may impact EGI's ability to meet this SQR.
7.3.6.1 Number of Days to Provide a Written Response	The distributor will send a substantive written response to a customer grievance within 10 days of receiving the written complaint. If the grievance needs to be investigated further and more time is required to fully respond to the complaint, an interim response will be sent until a final response can be sent. A substantive response is a response that addresses the issues raised by the complainant. If the customer wishes to have a verbal response instead of a written one, it will not be counted in this measurement.	The minimum performance standard shall be that 80% of customers will receive a written response in 10 days of the distributor receiving the complaint.	Possibility of IT-related interruptions experienced by work-from-home staff will reduce EGI's ability to manage this SQR. COVID-19 may result in an increased number of cases requiring investigation and a written response as an increasing number of customers experience difficulty paying their gas bill and EGI's ability to adhere to other SQRs is impacted by COVID-19.

OEB SQR Metric	SQR Definition	Target	Description of Impact
7.3.7.1 Number of Days to Reconnect a Customer	Once the customer is in good standing as a result of a payment made, the reconnection should be made within 2 business days.	The minimum performance standard shall be that 85% of customers are reconnected within 2 business days of bringing their accounts into good standing.	EGI's ability to meet this target is dependent on having qualified personnel and PPE. A significant loss of staff due to COVID-19 or an inability to acquire appropriate PPE may impact EGI's ability to meet this SQR. EGI has suspended disconnections related to non-payment for all residential and small commercial customers consuming less than 50,000 m^3 per year until July 31, 2020, which may mitigate impacts to this SQR.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 5, Page 1 of 1, Summary of Alternatives Table

Preamble:

None.

Questions:

a) Typically, an assessment of alternatives would start with a “do nothing” alternative. We note that this was not included in the Summary of Alternatives Table cited above. Please provide a summary of: (i) the necessary capital expenditures required to continue to operate the London Lines, (ii) the reliability of supply for emergency and operational scenarios if the existing London Lines were continued to operate, and (iii) any effects on the London Lines’ capacity to serve customers if the current London Lines continued to operate, should the OEB refuse to grant approval for the proposed London Lines Replacement Project. For an accurate comparison of this alternative to the other alternatives in the Summary of Alternatives Table cited above, please use direct capital and abandonment costs and do not include interest and indirect overhead costs when calculating the capital expenditures.
b) Rather than replacing the London Lines, is it possible to retire the pipelines and service customers using an alternative means?

Response:

a) Based on the Risk Assessment report filed at Exhibit I.FRPO.1 and management review a “do nothing” option was not considered a reasonable alternative due to the integrity concerns outlined in Enbridge Gas’s pre-filed evidence. The risks present indicate that the reliability of supply is at risk and the necessary capital expenditures required to make localized repairs would not be an efficient use of resources due to the challenge outlined in Exhibit B, Tab 1, Schedule 1, Page 14, under the section *Consequence of a Failure*.

b) It is not possible to retire the pipelines and service customers using an alternative means. Please see Exhibit I.APPrO.5 b).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Association of Power Producers of Ontario (APPrO)

Interrogatory

Reference:

Exhibit F, Tab 1, Schedule 1, Page 1 of 1

Preamble:
“Enbridge Gas expects the Project will meet the criteria for rate recovery during the deferred rebasing period using the Board’s Incremental Capital Module (“ICM”) mechanism. The ICM request for the Project will form part of Phase 2 of Enbridge Gas’s 2021 Rates application.”

Question:

If Enbridge does not receive Board approval for ICM rate recovery for the London Lines Replacement Project, will Enbridge nevertheless proceed with the replacement in 2021 if the OEB approves this application? If yes, why? If no, why not?

Response:

Enbridge Gas will consider the OEB’s 2021 Rates decision in its entirety in determining the impacts to its capital budget and how it will proceed with the London Lines Replacement Project.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Page 4 of 20, Paragraph 7

Preamble:

Compression couplings are known to provide minimal pull-out resistance, and depending on design, could cathodically isolate pipe. They are also a source of leaks especially if there is ground movement or large temperature fluctuations such as freeze/thaw cycles.

Questions:

a) What is pull-out resistance?

b) When did it become known to EGI that compression couplings provide minimal pull-out resistance?

Response:

a) Pull-out resistance is the ability of a fitting to resist thrust caused by internal pipe pressure created at points of thrust, which would then result in the pipe becoming uncoupled.

b) Enbridge Gas has known about the possibility of pull-out from unrestrained compression couplings for some time, and Enbridge Gas has addressed this risk by developing procedures for working around compression couplings. Enbridge Gas installs joint harnesses and thrust blocks to restrain new installs and has specific requirements for safely excavating around unrestrained compression couplings to ensure that pull out does not occur until the pipeline can be safely restrained.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Page 6 of 20

Preamble:

Due to the vintage, the quality of steel pipe and the general deteriorating conditions, the London Lines have not consistently operated near MOP of 1900 kPa for some time. The London Lines currently operate at a MOP of 1415 kPa to reduce the number of leaks.

Questions:

a) How long have the pipelines been operating at pressures below MOP?

b) What impact has this had on pricing and service over this period?

Response:

a) Typically, pipelines will regularly operate below Maximum Operating Pressure (MOP) due to the design, materials, and test pressure parameters. For the London Lines, Subject Matter Advisor (SMA) input confirms that the line has been running below MOP since 2013.

b) Customers have not been turned away as a result of capacity shortages on the line.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Page 19 of 20, Paragraph 48

Preamble:

A new Pipeline is also proposed to start at Strathroy Gate Station (Calvert Drive, Municipality of Strathroy-Caradoc). It will be NPS 6 and run for 8.4 km along Sutherland Road. At the intersection of Sutherland Road and Falconbridge Drive, it will tie into the NPS 6 main. This pipeline will provide a back-feed to the London Line corridor by adding a secondary feed from the Dawn to Parkway System via Strathroy Gate Station. This back-feed also provides the opportunity to install a smaller pipe size for the replacement, and provides operational flexibility in the future.

Question:

a) How does the back-feed provide the opportunity to install a smaller pipe size for the replacement and provide operational flexibility in the future?

Response:

a) Please see Exhibit I.STAFF.1 a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Building Owners and Managers Association (BOMA)

Interrogatory

Question:

a) Why have the many high risk aspects of the existing pipelines, for example, unconstrained couplings, insufficient ground cover, vulnerable aboveground crossings, excessive corrosion, and the need to operate the pipeline at pressures substantially below MOP, not been addressed for a lengthy period of time?

Response:

a) Please see Exhibit I.ED.1 a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Attachment 1, Page 3 of 10

Preamble:

The London Lines have been studied on other occasions.

Question:

a) Please provide copies of the previous reports on the London Lines:

(i) *The London Lines by Katie Hooper, 2002;*
(ii) *London Lines Report by Bob Wellington, 2004; and*
(iii) *Engineering Asset Plan – The London Lines by Jack Chen, 2016.*

Response:

a) The previous reports are attached as follows:

- Attachment 1: The London Lines by Katie Hooper, 2002;
- Attachment 2: London Lines Report by Bob Wellington, 2004
- Attachment 3: Engineering Asset Plan – The London Lines by Jack Chen, 2016

Please note that the reports created in 2002 and 2004 are several years old and will not be indicative of the current asset condition. The report from 2016 was considered in the development of the current Integrity Assessment in Exhibit B, Tab 2, Schedule 1.

THE LONDON LINES

Prepared By: Katie Hooper

Date: December 18, 2002

1.0 INTRODUCTION

The London Lines consist of two high-pressure pipelines that run parallel from the Dawn Compressor Plai to London Byron Transmission Station. The lines are one of the major feeds supplying gas to the City c London. The line that runs to the north is primarily a 10" bare steel pipeline called the London South Lin and was installed in 1935. The line that runs to the south is primarily an 8" bare steel pipeline, installed i 1952 (although records indicate that reconditioned pipe, as old as 1920 was used), called the Londoi Dominion Line. The lines have a MAOP of 1900 kPa from Dawn to Komoka Gate Station (just west c London) and 1380 kPa from Komoka Gate Station to Byron Transmission Station.

As with any pipe of this age, the quality of the pipe in certain areas is less than desirable. Several sections of both pipelines are exposed, corroded or too shallow. Both lines have a history of leakage and several sections are unweldable.

The Sarnia employees have expressed concerns over the state of the lines for several years, and out of this concern, arose the need for a comprehensive report that looked at all aspects of both lines and came to a logical conclusion for the improvement of the lines.

Over the past year, several areas have been researched, including: original installation records, repair history, depth survey, areas of exposed pipe, storage and transmission, service and laterals, corrosion, annual property tax, land issues, Ontario producers, and material properties. This report presents the findings of this research and draws conclusions from these results to suggest a possible solution to the issues surrounding the London Lines. The main purpose of this report is to justify an internal or external risk assessment on the lines to confirm a remedial course of action.

2.0 HISTORY OF THE LONDON LINES

City Gas Company was the first recognized gas distribution company serving the residents of London, Ontario, it was formed on July 6,1864. It provided manufactured gas to the City of London. City Gas remained in existence for 65 years until Union Gas purchased City Gas and took over its operation on August 1, 1930. In October 1934, Union Gas proposed a $1 million project that would see the installation of a 90 km long transmission pipeline (a combination of 4", 8" and 10") from Dawn Storage Field to the City of London. The work started on August 9, 1935 and included a new measurement station at Dawn and a new measurement/regulation station at London. The project was complete and gas flowing on October 1, 1935. This marked the introduction of natural gas into the City of London. The acceptance of this new gas supply was overwhelming and the level of demand so unexpected that in 1936 the existing line was twinned with an additional 10" line from Dawn to London. The first line would become known as the London South Line and parts of the second line would eventually be abandoned. The installation of the 8" London Dominion Line was completed in December 1952, and doubled the capacity of the pipeline systems supplying London at that time. Since then, the lines have remained an important part of Union Gas' transmission system, supplying gas to several small communities between Dawn and London, and are still a major feed into London.

3.0 AREAS OF RESEARCH

3.1 Original Installation Records

Original records were found for both the London South and London Dominion Line. The following chart summarizes the findings in these records.

Table 3.1.1

Install Date	Division	Line	Size of Job	Depth	Comments
1935	Sarnia	South	15,392.4m 8" HP	.60m	15,392m of 6" HP abandoned and recovered from Dawn to Oakdale Headers (original Dawn Field Line), no treatment, dressered. (installed from Dawn to Oakdale)
1935	Sar / Lon	South	75,199m 10" HP	.91m	Dressered line, Barrett enamel treatment (installed from Oakdale easterly to Transmission Station) from Oakdale easterly to Byron Transmission station)
1936	Sarnia	Dominion	14,867m 8" HP	.60m	Dressered line, no treatment (installed from Dawn easterly to Oakdale)
1952	Sar / Lon	Dominion	65,023m 10" HP	.91m	all welded joints, enamel coating, fiberglass wrap (installed from Oakdale to Byron Transmission station) Note: this pipe was recovered from the Windsor Line and reconditioned at Dawn before laying. Average age of pipe at time of installation ranges from 22 - 32 years old

3.2 Repair History

Gerry Box completed a comprehensive search of all maintenance records for both the London South Line and the London Dominion Line in July 2002. A summary of his findings can be found in Appendix A. For each instance of repair, the following information is recorded: division (London or Sarnia), date, line (London South or London Dominion), reason for repair, depth of line, method of repair, size of job (ex. length of main), information on materials used (fittings, coatings, grade, thickness, test pressure, welded or coupled connections, comments.

There were 85 maintenance files found for the London Lines. The following is a brief summary of the maintenance records search:

- London had 30 repairs and Sarnia had 55 repairs
- The Dominion Line had 30 repairs (7 in London and 23 in Sarnia). The reasons for maintenance are categorized as follows:
    - Corrosion – 2
    - Hit Line – 1
    - Leaks – 4
    - Miscellaneous Maintenance – 19 (10 of which were due to exposed/shallow/poor condition of the pipe)
- The South Line had 55 repairs (23 in London and 32 in Sarnia). The reasons for maintenance are categorized as follows:
    - Leaks – 18
    - Valve installation or repair – 5
    - Miscellaneous Maintenance – 36 (13 of which were due to exposed/shallow/poor condition of the pipe)

3.3 Depth Survey

A depth survey was completed in early 2000 for both the London South Line and the London Dominion Line located in the Sarnia Division (Dawn to Melbourne Rd). A depth of 24" was chosen as a safe embedment depth based on the current til depth of modern farm equipment and specifications from earliest version of the pipeline code available - the 1964 Ontario Energy Act. Therefore any pipe at a depth of less than 24" was considered shallow.

Based on the findings of this depth survey the London South Line was found to be the shallower of the two lines. Both lines were surveyed approximately every 200 m. The London South Line was found to be shallow in approximately one hundred locations, some sections as shallow as 10". One section of pipe starting at Dawn and running 4 km east was found to be shallow along it's entire length, similarly another 3.5 km long section located along Falconbridge Dr east of Dundonald was also found to be shallow along it's entire length. The total length of the London South Line in the Sarnia division is of which 15.3 km is considered to be shallow (or 27%), of this 15.3 km, 4.2 km was pipe in farmer's fields. The London Dominion Line was found to be shallow in sixteen places, but most sections were not in sequence.

A capital budget project proposal was submitted for C2002 for the removal of the shallow sections of the London South Line that ran through farmer's fields (and therefore was seen as the highest risk sections for potential damage). A total of 9.4 km of pipe run through farmer's fields with 4.2 km of pipe at a depth shallower than 24". The cost estimate for this work that was the amount of capital approved for the project was approximately $235,000. This estimate did not include any capital to pay landowners for access to their property – a cost of $132,000 was suggested by the Lands Department in head office and was based on a GAPLO Repair and Maintenance Dig Compensation Proposal used by area landowners during the replacement of a 34" pipeline a few years ago. This project was deferred until 2004.

After further investigation and driving along the length of the lines, it was discovered that farmers are cultivating the soil above some sections of pipe that run along road allowance. Therefore, it cannot be assumed that these sections pose less risk than the sections that run diagonally across the fields.

In October 2002, a depth survey was completed in the London Division for the London South Line. The length of the line is approximately 25km with 6km running though farmer's fields. The shallowest section of pipe was found on Falconbridge Rd at a depth of 10", however it was an isolated shallow section. Another isolated section of pipe was found at a depth of 22" in a farmer's field near the intersection of Glendon Drive and Komoka Road. Two longer sections of shallow pipe were also found, both along road allowance - one 30 km long and the other was 20 km long. In all, shallow pipe was found at 10 different locations. A map showing the depths and location of the depth readings can be found in Appendix B.

3.4 Exposed Pipe

In August 2002, a survey was completed to locate and document the location of exposed pipe for both the London South Line and the London Dominion Line from Byron Transmission Station to Dawn. Pictures were taken at each location as well as a description of the geometry and condition of the pipe. The complete report along with pictures and a map with the locations of the exposed pipe can be found in Appendix C. Pipe was found exposed at 30 locations (London South - 13 and London Dominion – 17). The table below summarizes the findings of the survey:

Table 3.4.1

Line	Division		Location?			Wrapped?			Corroded?	Bowed?
	London	Sarnia	Creek	Ditch	Culvert	Fully	Partially	None		
SOUTH	2	11	8	3	2	1- G	7 - G 1 - P	4 - P	12 - Y 1 - N	2 - Y 11 - N
DOMINION	2	15	11	6	0	3 - G 1 - P	8 - G 3 - P	2 - P	13 - Y 4 - N	4 - Y 13 - N

Note: G - Good; P - Poor; Y - Yes; N - No

The exposed sections of the London South Line ranged in length from 1m to 18m (average 5.1m) and the height of the pipe ranged from 0.3m to 2m (average of 1.0m). It was also noted that in one location the exposed pipe was in direct contact with water. Also, there were dressers visible at three different locations and only two were rod and lugged.

The exposed sections of the London Dominion Line ranged in length from 0.6m to 12.2m (average 4.7m) and the height of the pipe ranged from 0m to 2.7 m (average 1.0m). It was also noted that at four locations the pipe runs on top of the ground, and at two of these locations the pipe is in direct contact with the water. Also, there were dressers visible at two different locations, both of which were rod and lugged.

3.5 Storage and Transmission

Facilities Planning has verified that on a peak winter day, the current system could operate with only the London Dominion Line feeding (i.e. London South Line is abandoned) with a great deal of excess capacity left in the system. Here are the results as presented by Facilities Planning:

<u>44DD (Interruptibles Off) for 2002/2003: With Current London Lines System</u>

MAX Flow out of Dawn =	32,550 m3/hr	(270 psi)
MAX Flow through Komoka Transmission Stn =	18,470 m3/hr	(180 psi)
Extra Capacity on the System =	0 m3/hr	
If there was no feed into London, the extra capacity =	24,310 m3/hr	(100 psi MIN)

<u>44DD (IOFF) 2002/2003: Without London South Line</u>

MAX Flow out of Dawn =	16,960 m3/hr	(270 psi)
MAX Flow through Komoka Transmission Stn =	2,300 m3/hr	(180 psi)

Extra Capacity on the System = 0 m3/hr

If there was no feed into London, the extra capacity = 6570 m3/hr (100 psi MIN)

Considering there might also be an impact on the Byron Transmission Station if the London South Line were to be abandoned, it was also analyzed to ensure that the capacity was not exceeded. Again, Facilities Planning concluded that there would be no negative impacts on Byron Transmission Station if the London South Line were to be abandoned. Below is a summary of their findings:

<u>44DD (IOFF) 2002/2003: With Current System</u>

MIN Pressure into Byron Transmission Station = 612 psi

MAX Flow through Byron 500 psi regulation cut = 121,360 m3/hr

MAX Flow through Byron 200 psi regulation cut = 30,860 m3/hr (155 psi)

MAX Flow through Komoka Transmission Stn = 18,470 m3/hr (180 psi)

MAX Flow through Baseline Rd Stn 200 psi cut = 0 m3/hr (110 psi)

<u>44DD (IOFF) 2002/2003: With NO Feed from the London Lines</u>

MIN Pressure into Byron Transmission Station = 577 psi

MAX Flow through Byron 500 psi regulation cut = 139,830 m3/hr

MAX Flow through Byron 200 psi regulation cut = 36,330 m3/hr (155 psi)

MAX Flow through Komoka Transmission Stn = 0 m3/hr

MAX Flow through Baseline Rd Stn 200 psi cut = 13,000 m3/hr (110 psi)

With the current system, Baseline Rd Station (13O-206R) does not need to feed to support the London distribution system. However, if the feed from both London Lines was lost, Baseline Rd Stn would have to feed to support the City of London. The MAX Flows listed above do not exceed the capacities of the stations.

- Dawn Twp Con 8 Station (10H-201)

There is one High Pressure Plastic (HPP) outlet station off the Dominion Line:

- Downie Rd Station (11J-601)

3.6.2.2 London South Line

There are three IP outlet station off the South Line:

- Springfield Transmission Station (12L-601)
- DeJonge Take-off (11K-401)
- Forest Road Station (11J-402)

3.6.2.3 London South and London Dominion Line

There are six IP stations fed from both the South and Dominion lines:

- Mt. Brydges Station (13M-501)
- Appin Gate Station (11L-201)
- Glencoe Gate Station (11L-401)
- McAuslan Rd Station (11J-403)
- Dawn Twp Station (10J-172)
- Rutherford 1st Stage (10H-204)

There are two HP stations fed from both the South Line and the Dominion Line:

- Komoka Transmission Station (13N-401)
- Wardsville Line Station (11K-501)

3.6.3 Take-Offs

3.6.3.1 London Dominion Line

There are eight take-offs fed from the Dominion Line:

- Carriage Rd and Elviage Drive –feeds Harris Rd Station (13N-404R)
- Gideon Rd, west of Carriage Rd –feeds Delaware N Dist Station (13N-403R)
- Falconbridge Drive and Christina Rd –feeds two services
- Bentpath Line and Tramway Rd – feeds five services
- Bentpath Line and Marthaville Rd – feeds Marthaville Rd Station (10H-101R)
- Bentpath Line and Marthaville Rd – feeds Trafalgar Bentpath Compressor Station (11H-403)
- Bentpath Line and Robinson Rd – feeds one service
- Bentpath Line and Cuthbert Rd – feeds one service

3.6.3.2 London South Line

There is one take-off fed from the South Line:

- Brigham Rd and Elviage Dr (Valve Nest) – feeds seven services

3.6.3.3 London South and London Dominion Line

There are four take-offs fed from both the South and Dominion Line:

Table 3.7.1

LONDON DOMINION LINE					
Test Point	**Reading Site**	**Read Date**	**Limit**	**Reading**	**District**
2	Test Box	06/10/1996	-0.85	0	Sarnia
3	Test Box	06/10/1999	-0.85	-0.78	Sarnia
4	Test Box	01/10/1971	-0.85	-0.76	Sarnia
4	Test Box	06/10/1999	-1	-0.86	Sarnia
5	Test Box	01/10/1971	-0.85	-0.76	Sarnia
6	Test Box	01/10/1971	-0.85	-0.77	Sarnia
8	Test Box	01/10/1971	-0.85	-0.63	Sarnia
9	Test Box	01/10/1971	-0.85	-0.83	Sarnia
10	Test Box	01/10/1971	-0.85	-0.78	Sarnia
12	Test Box	01/10/1971	-0.85	-0.63	Sarnia
14	Test Box	01/10/1971	-0.85	-0.6	Sarnia
14	Test Box	01/10/1981	-0.85	-0.05	Sarnia
14	Test Box	01/05/1982	-0.85	0	Sarnia
18.01	Test Riser	16/11/1999	-1	-0.96	Sarnia
26	Test Box	01/10/1971	-1	0	Sarnia
36	Test Box	18/04/1996	-1	0	Sarnia
40	Test Box	01/07/1985	-1	-0.98	Sarnia
52	Test Box	01/11/1976	-1	0	Sarnia
65.8	Test Box	27/09/1996	-1	0	Sarnia
66	Test Box	01/04/1991	-1	-0.31	London

Table 3.7.2

LONDON SOUTH LINE					
Test Point	**Reading Site**	**Read Date**	**Limit**	**Reading**	**District**
1	Test Box	01/08/1971	-0.85	-0.76	Sarnia
3	Test Box	31/10/1995	-0.85	-0.85	Sarnia
4	Test Box	01/08/1971	-0.85	-0.81	Sarnia
4	Test Box	01/10/1971	-0.85	-0.75	Sarnia
5	Test Box	01/10/1971	-0.85	-0.76	Sarnia
7	Test Box	01/08/1971	-0.85	-0.61	Sarnia
7	Test Box	01/10/1971	-0.85	-0.6	Sarnia
8	Test Box	01/08/1971	-0.85	-0.66	Sarnia
8	Test Box	01/10/1971	-0.85	-0.63	Sarnia
9	Test Box	01/10/1971	-0.85	-0.83	Sarnia
11	Test Box	01/08/1971	-0.85	-0.64	Sarnia
11	Test Box	01/10/1971	-0.85	-0.6	Sarnia

3.8 Annual Property Tax

Based on the length, age, size and pressure of the lines, the annual property tax that Union Gas pays for the London Dominion Line is $24,200 and for the London South Line is $19,250.

3.9 Land Issues

There is only one current agreement in place that with the farmer's that have a pipeline running through their fields. Union Gas pays a farmer in Glencoe $1500 annually not to farm his land over the pipeline. This agreement expires in 2005. Other monies are paid to farmers on a case-by-case basis when Union Gas through work being done on the pipelines, damages or disrupts the farmer's crops.

3.10 Ontario Producers

There are 4 producers that tie into the London Lines. Only one ties directly into the London South Line, the remaining three producer stations tie into the London Dominion Line. Every producer has an inlet MAOP rated higher than the MAOP of the London Lines (1900 kPa), except for 10H-302, Da-Col Resources, which an inlet MAOP of 1900 kPa. Currently the lines do not run close to MAOP. The typical pressures seen in the winter at Dawn are 1380 kPa. If the London South Line were to be abandoned, this station would have to be tied over to the London Dominion Line and it is possible that the Dominion Line may need to operate closer to MAOP, therefore there could be an issue with the capacity of the station if there is not enough differential across the station.

4.0 OPTIONS AND RECOMMENDATIONS

Based upon the information from Facilities Planning, the London Lines are required to maintain gas supply to many of the towns between Dawn and London, however only one line is required to remain active to maintain this supply. The above research suggests that the London South Line is in the poorest condition of the two pipelines. It is the shallower pipeline, it is the oldest pipeline, it has a longer section of cathodically unprotected pipe, there are fewer stations and take-offs directly off of the South Line, visually the London South Line appeared to be in worse condition and there have been more repairs made to the London South Line which suggests that it is in worse condition. Therefore it is recommended that the corrective action be focused on the London South Line as opposed to the London Dominion Line.

4.1 Lower the London South Line

This is not a recommended course of action because lowering of a coupled line is very difficult and could prove to be very disruptive to the landowners and costly to Union Gas.

4.2 Replace the London South Line

Although this is a valid option, it would be extremely costly and seemingly unnecessary as the capacity of the line is not required.

4.3 Abandon the London South Line

This is the preferred option, as it is the least cost option (and it saves the cost of property taxes). It also presents the fewest landowner issues, it alleviates many of the concerns surrounding the condition and integrity of the pipeline, it doesn't put a strain on any other parts of the system as it takes advantage of the existing excess capacity in the London Dominion Line.

5.0 CONCLUSIONS

Based upon the findings of this report, it is recommended that an external or internal risk assessment be completed for the London Lines System based upon the abandonment of the London South Line.

TABLE OF CONTENTS

APPENDIX A: REPAIR HISTORY

APPENDIX B: DEPTH SURVEY

APPENDIX C: EXPOSED PIPE

1.0 SCOPE

This assessment is intended as a follow up to a report prepared by the district of London in 2002 regarding the condition of the London Dominion and London South lines. The conclusion of the report indicates that the London South line should be abandoned, as it is in the poorest condition of the two lines, is susceptible to third party damage at shallow locations, and is not required to supply the load requirements between Dawn Compressor Station and Komoka Transmission Station. $235,000 has been budgeted for this abandonment work to be completed in 2004. The report recommends that a risk assessment be performed on the London Lines to prioritize the order in which the various segments of the London South line should be abandoned. Although this document is not a true risk assessment, it is intended to fulfill the requirements of that recommendation by prioritizing the abandonment of the London South line through risk based principles.

In addition to the condition and potential failure modes of the London Lines, consideration must be given to the increased consequence that will be associated with a failure of the London Dominion line once the London South line is abandoned. As each section of the London South line is abandoned, the adjacent section of the London Dominion Line will lose its reinforcement. As a result, the consequence associated with a failure will increase, as the London Dominion will be the only feed into several townships between Dawn and London. Therefore, to manage the risk associated with the London Dominion line, the probability of a failure must be reduced. The remedial actions that will be necessary to reduce the probability of a failure of the London Dominion line are also included in this report.

2.0 BACKGROUND

Detailed descriptions for both the London Dominion and London South lines are included in the 2002 report included in Appendix A and, therefore, are omitted from this report. However, a general review of the history of each pipeline is warranted.

2.1 London South Line

The London South Line was first installed in 1935 from Dawn Compressor Station to Byron Transmission Station. The original installation consisted of approximately 15km of new, bare, NPS 8 steel pipeline between Dawn Compressor Station and Oakdale Header Station, and 70 km of new, bare, NPS 10 steel pipeline between Oakdale Header and Byron Transmission. Both segments are joined by Dresser couplings, and the nominal wall thickness and estimated grade for each, as shown in the records, are 7.0mm and 165 MPa respectively.

The MOP of the NPS 8 segment was originally rated at 2410 kPa, while the MOP of the NPS 10 segment to was rated at 1900 kPa from Oakdale to Komoka Transmission Station and 1380 kPa from Komoka to Byron Transmission Station. However, because there is no regulation or relief separating the two sections, the NPS 8 segment has never operated beyond 1900 kPa, and in 1994, it's MOP was downgraded to 1900 kPa to meet CSA standards.

Since the original installation, replacement and abandonment work has been performed on various sections of the London South line due to leakage, condition, low depth, and municipal work. A list of replacement projects and descriptions of the pipe installed under these projects are included in Appendix B. The list also identifies some of the detailed characteristics of the pipeline and its environment that will be relevant to the assessment portion of this document.

Cathodic protection was not installed on the London South line until 1965. After this the line was rectifier protected from Dawn Compressor Station to Melbourne Road in Caradoc Township. From Melbourne road to Byron Transmission Station, the line is not protected.

Segments of the London South line have already been abandoned at various locations. The schematic in Section 2.5 indicates the approximate locations where the London South line has already been abandoned. The abandoned segments are included in the quantitative assessment, but assigned an automatic relative risk value of zero, as they are no longer in service.

2.2 London Dominion Line

The London Dominion Line was first installed on 1936 and runs nearly parallel to the London South line for its entire length. The original installation consisted of roughly 15 km of new, bare, NPS 8 steel pipe from Dawn Compressor Station to Oakdale Header Station, and roughly 70 km of bare, steel, NPS 10 pipe from Oakdale Header to Byron Transmission Station, all of which was joined by Dresser couplings. The nominal wall thickness of the original pipe was 7.0mm between Dawn and Oakdale Header, and 6.4mm between Oakdale Header Station and Byron Transmission. The estimated grade for each section, as shown in the records, is 165 MPa.

In 1952, a 60 km section of the London Dominion line between Oakdale header and Komoka Transmission station was replaced with refurbished steel pipe from Windsor. The estimated vintage of the recovered pipe ranges from 1920 to 1930. This section consisted of roughly 30 km of NPS 8 and 30 km of NPS 10 with varying wall thicknesses and coatings. It was joined primarily with welds and has an estimated grade of 165 MPa, according to the records.

In addition to this large-scale project, several smaller replacement and abandonment projects have taken place, as indicated in the project list in Appendix B.

Cathodic protection was not activated on the London Dominion line until 1965. The line is rectifier protected from Dawn to Komoka Transmission and is unprotected from Komoka Transmission station to Byron Transmission Station.

The London Dominion line also has a MOP of 1900 kPa from Dawn Compressor Station to Komoka Transmission Station, and a MOP of 1380 kPa from Komoka to Byron.

2.3 Pipe Grade

Although the records for each pipeline indicated that Grade 165 pipe was used for the original installation and the replacement work done to the London Dominion line in 1952, this is not a recognized standard grade. After some discussions with Union Gas's subject matter experts and based on CSA recommendations for classifying pipe of unknown grade, the minimum grade that will be assumed for these portions of the London Lines is 172 MPa.

2.4 General Maintenance History and Depth of Cover

Each pipeline has undergone varying levels of deterioration over the years. As a result, several sections have been replaced, repaired, or abandoned; as mentioned previously. Because of the large scale replacement of the bare Dominion line with coated pipe in 1952, the London South line tends to be the more deteriorated of the two and, consequently, requires a higher level of maintenance. The collective cost of such maintenance work and concern for a potential incident associated with its condition has fuelled the proposal to abandon the South line.

In addition to concerns regarding the pipeline's condition, several sections have little to no depth of cover. In 2002, a depth survey was conducted from Dawn Compressor Station to Melbourne Drive, which covered all but the last 17 km of each pipeline from Melbourne Drive to Byron Transmission Station. In June 2004, the depth and land use for the last 17 km of each pipeline were surveyed. These depth surveys revealed several locations where each pipeline had depths of less than 60cm. TSSA requires an engineering assessment for 30% SMYS pipelines with depths less than 60cm that are located on agricultural land; and appropriate mitigation to ensure they are adequately protected from third party damage. Although the London Lines operate below 30% SMYS, there is potential for third party damage to occur where the depth of cover is less than 60cm on agricultural land. Such damage would pose more consequence than a failure associated with the condition of the pipeline, as the Assessment portion of this report will indicate. Therefore, the TSSA standard will be considered in determining appropriate mitigation for shallow locations.

Another consideration regarding the depth of the London Lines is the additional stresses endured by the pipelines where heavy vehicle loading occurs at crossings. Where public roads cross the London lines, the grade will generally be maintained by the municipality through surface pavement or pot-hole repair. However, is a privately owned gravel pit in Komoka in which London Lines are are exposed to continuous heavy vehicular loading at crossings, and the grade is not necessarily maintained by the owner. In this case, the affects of vehicular loading should be considered as the grade over the London lines and, therefore, the operating stresses in the piping may change over time.

2.5 Segmentation

A schematic for the London Lines is provided in Figure 2.5.1 on the following page. The London South line is the most northerly of the two lines. The schematic indicates key locations where the pipelines are tied together as well as those locations where the London South line is already abandoned. In addition, it indicates where existing isolation mechanisms on the London South line such as main-line valves, and stopper fittings are located. The line has been divided into 14 segments, numbered in order from Dawn Compressor Station to Byron Transmission Station. Segments have been defined between locations where there are isolation points and/or existing abandoned sections of either the London South or London Dominion Lines

Table 2.5.1 indicates the length of and number of services and take offs from each segment. The intent with the 2004 abandonment work should be to abandon as many full segments that are determined to be of high risk ranking as possible, without exceeding the budget constraints, while giving due consideration to the hydraulics of the system. The Recommendations section of this report will provide more detail as to how to manage the abandonment work.

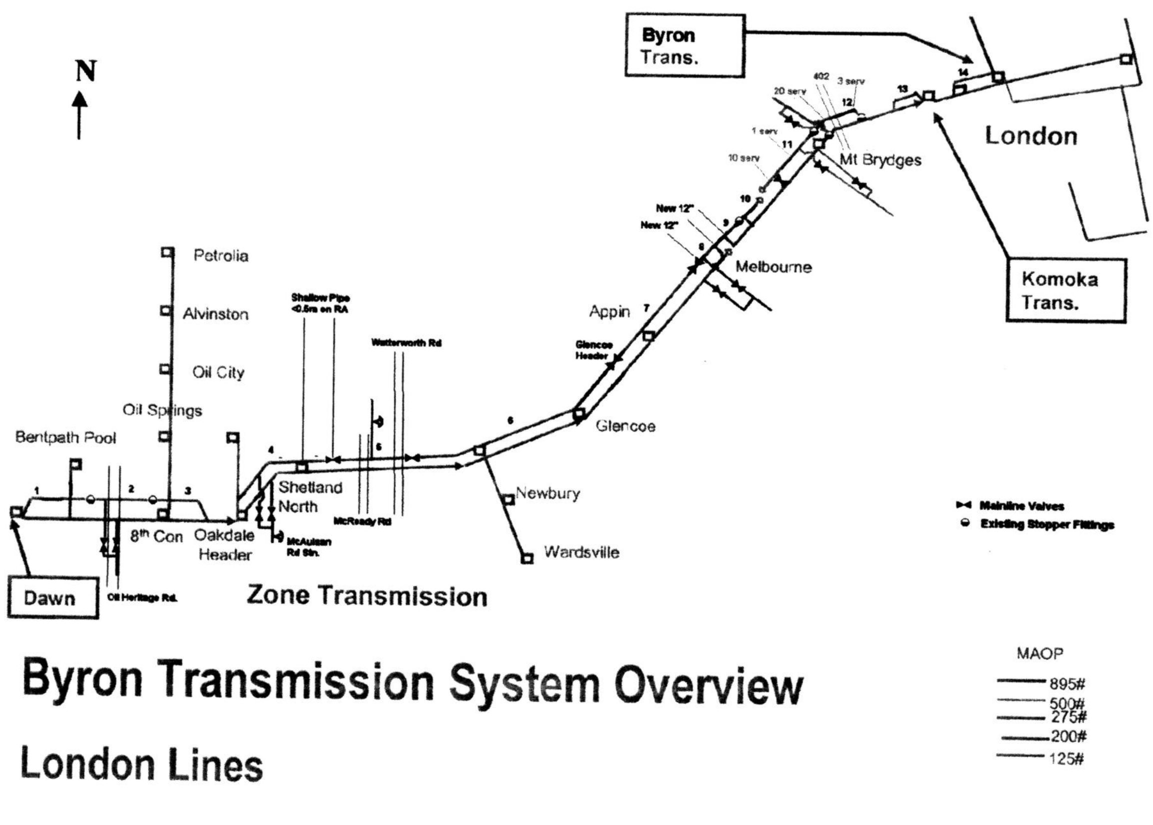


Figure 2.5.1: Segmentation of the London South Line

The length of each segment as indicated in Byers is as follows:

Segment Number	Location Description (Start and End Points)	Length (m)	Number of Services/Take-offs
1	Dawn to 219m past 3760 Bentpath Line	3194	2
2	End of Segment 1 of Huff Corners Rd and Benptath	8971	4
3*	End of Segment 2 to Oakdale Header	2575	0
4	Oakdale Header to Dobbyn Rd & Mosside Line	8495	3
5	Moside & Dobbyn to Mosside & Waterworth Rd.	9154	8
6	Mosside & Waterworth to Glencoe Header	12721	3
7	Glencoe Header to Falconbridge & Melbourne	11157	20
8**	Falconbridge & Melboure to 972m past Melbourne	972	1
9***	1100m past Melbourne to 200m past 6998 Falconbridge Drive	1152	1
10	End of Segment 9 to 7154 Falconbridge Drive (Kilns)	650	6
11	Falconbridge & Christina to Falconbridge & Adelaide	2758	14
12	Falconbridge and Adelaide to Amiens Rd. and Railway	5041	14
13	65m Past 9629 Glendon Dr. to Komoka Trans. Stn.	1536	3
14	Bringham & Elviage Rd. to Byron Transmission	3560	17

Table 2.5.1: Services off of the London South Line Segments

Notes:

* Segment 3 would require a Williamson M-Stop to be welded on the downstream end for isolation from the London Dominion Line.

** Segment 8 is composed of NPS 12 pipe that was installed between 1990 and 1996 and is of low relative risk. Therefore, it will not be considered for replacement.

*** Segment 9 is composed of NPS 12 pipe that was installed between 1990 and 1996 and is of low relative risk. Therefore, it will not be considered for replacement.

For more detailed information regarding the geographic locations of each pipeline, strip maps for each pipeline with information updated to 1994 are included in Appendix C. These maps are not consistent with Figure 2.1 due to abandonment work that has been executed in the past 10 years. However they can be used as a geographic and historic reference for the various replacement projects that were carried out on each of the London Lines before 1994. Refer to AM/FM for more recent information regarding the pipelines' geography.

3.0 ASSESSMENT

As per the EA Protocol in the Union Gas's Integrity Practices, a risk assessment should consist of two components. The first component is a qualitative assessment defining the modes of failure and potential consequences associated with a pipeline, giving due consideration to the operating and environmental conditions. Numeric values are then assigned to each of the considerations, such that the various attributes affecting probability are evaluated and weighed by likelihood, and the various factors affecting consequences of a failure are weighed based on level of contribution to the consequence. The probability and consequence values are then multiplied together to determine the relative risk values for each section. The relative risk values for each section of a pipeline are then used in a quantitative assessment to rank each one based on its relative risk value. Although this document is not a true risk assessment, the EA Protocol will be used as a guideline in prioritizing each section of both the London South and London Dominion lines for abandonment or mitigation.

3.1 Qualitative Assessment

3.1.1 Failure Modes

As mentioned in the General Maintenance History section of this report, there are three potential modes of failure for the London Lines. These are external corrosion; and third party damage, including line hits and heavy vehicle loading. Stress corrosion cracking was not considered as part of this engineering assessment because of the relatively low operating pressure of the pipelines, which is not characteristic of the pressures that are typically required for SCC to occur.

3.1.1.1 Corrosion

Although external corrosion was identified at many of the above grade locations during the 2002 leakage survey, no detailed measurements were taken to determine the amount of corroded surface at these locations or the depth of corrosion pits. Furthermore, no detailed information regarding corrosion pitting is available for any section of pipeline that is located below grade. Therefore, it is very difficult to estimate the extent of corrosion pitting that either of the pipelines has undergone, and the impact that such corrosion would have on the integrity of the pipeline.

However, information is available regarding the type of coating on each section of the pipeline, the cathodic protection history, as well as the date that each section of pipeline was installed. This information can be used to estimate which locations along the pipeline will likely have corroded more than others.

The consequence associated with a corrosion related failure is generally going to be very low. Historically, corrosion pits have caused pipelines operating at pressures similar to that of the London Lines to fail in leakage, not rupture. This is because corrosion pitting typically forms a relatively gradual void profile that does not create the same level of stress concentration as sharper imperfections, such as gouges and cracks. Therefore, the consequences of leakage need only be considered in determining the consequence associated with corrosion related failures.

Because all of the residential services tied into the London lines have first stage cuts and are relatively long in comparison to a service located in an urban residential neighbourhood, the danger of gas migrating into a customer's home and creating a hazardous atmosphere is negligible. Historically, leakage on the London lines has appeared in the form of C-leaks that can be identified through a leakage call or a yearly leakage survey. C-leaks can be monitored then mitigated once they reach B or A level, and do not generally pose any considerable danger to the public. There are, however, some commercial services being fed by the London South line (Tobacco Kilns). In these scenarios, higher pressure gas is delivered directly into, or outside of the building before the final pressure cut. In these cases, there is a potential for a hazardous atmosphere to occur within these buildings. Therefore, consideration should be given to the consequence of harming any persons who may be working in or near the commercial buildings. In order to do so, a consideration must be given to the probability of such a corrosion failure in the quantitative assessment.

3.1.1.2 Third Party Damage

3.1.1.2.1 Line Hits

The likelihood that third party damage will occur is dependent on a number of external factors including the location of the pipeline and the daily activities in that location. In addition, where the pipe is not adequately covered, it becomes more susceptible to line hits by agricultural equipment. The 2002 report in Appendix A indicates that there are a number of sections of each pipeline that are located on agricultural land and road allowance used for farming that have inadequate depth of cover to protect the pipe from being hit by agricultural equipment. In addition, there have been line hits by agricultural equipment reported in the past. Therefore, there is a probability that the London Lines will undergo third party damage at similar locations in the future.

Third party damage may lead to higher consequences than corrosion due to the nature of the failures it may cause. Where third party damage causes gouges in the pipe wall, stress concentrations are often much higher than those created by corrosion pits due to the potentially sharp geometry of the imperfection. Where such stress concentrations occur, the pipeline can become susceptible to rupture. In addition, depending on the level of impact and the condition of the pipe where the third party damage occurs, there is a potential for a line break to occur on impact. Each of these modes of failure can cause significant volumes of gas to release in a short period of time, and may pose a considerable danger to the residents in the immediate vicinity of the failure when it occurs. In addition, such failures may lead to lost customers downstream of the pipeline. So if a section of the London South line is removed, a rupture failure on the adjacent section of the London Dominion line would likely lead to a large scale outage for all customers downstream of the failure. It is for this reason that both the London South and London Dominion lines must be considered as part of the assessment, so the risk associated with the London Dominion line can be appropriately managed once the South line is abandoned. In addition to all of this, third party damage may cause an imperfection which fails in leakage and may be costly to repair, depending on the condition of the pipeline at the failure location.

Although third party damage is certainly the more consequential of the two types of failure, due consideration will be given both corrosion and third party damage, and the consequences associated with each in this assessment.

3.1.1.2.2 Heavy Vehicular Loading

Another concern that arises with respect to the 3rd party activity in the vicinity of the London Lines is vehicular loading. In particular, the last 325m of Segment 13 is located in a gravel pit in Komoka, in which gravel trucks and heavy excavating equipment are driven across both of the pipelines on a regular basis. Two depths were measured at this area for each of the London Lines. The London South line has depths measured at 0.965m and 0.585m, and the London Dominion Line has depths measured at 1.193m and 0.762m.

The MTO and Highway Traffic Act allow a maximum axle load of 10,000 kg for vehicles with dual tire axles. This is the maximum wheel load that would be expected for gravel trucks operating within the gravel pit. Vehicular loading calculations for both the London South Line and the London Dominion line based on a 5000kg (11,000 lb) wheel load (one set of dual tires), and the depths described above are included in Appendix D. The loading analyses indicate that the operating stresses in the pipelines at the all crossings are acceptable based on a Class 1 location, except for the London South line where its depth is only 0.585m. The pipe stresses in the London South line at this depth would exceed 80% SMYS.

The calculations for these loading analyses assume that the joints are welded. The London South Line, however, is joined by Dresser mechanical couplings which are not designed to withstand heavy lateral loads and can become damaged where they are subject to such loading. Therefore, additional consideration must be given to the potential for damage to the couplings which could lead to excessive leakage and potential pull-outs. In addition, because the gravel pit is on private property, the grade of the driveway may not be as closely monitored and maintained as would be the case for a public roadway. Because of the continuous heavy vehicular traffic through the gravel pit driveway and the fact that it does not have a paved surface, pot-holes and erosion can occur quite easily. Such reductions in depth of cover would result in higher stresses in the pipe wall when a vehicle crosses overtop of the pipeline. This creates concern for both the London South and London Dominion lines. Therefore, consideration will be given to both at this location in the recommendations section.

3.1.2 Leakage Model - General

Union Gas currently has a standard risk ranking model that is used to prioritize repair or replacement projects based on factors affecting their relative risk. This ranking is then used to prioritize capital budgeting for replacement work. The model has been written into an Excel program called Leakage Evaluation Model v. 2.0, and is available to all company PC users with network access to Microsoft Excel.

The leakage program consists of a range of inputs regarding the properties, condition, and environment in which the targeted pipeline operates. Relative probability and consequence values are assigned to each input based on the results of PRCI and AGA studies. Once the inputs are complete, the relative probability and consequence values associated with those inputs are multiplied together to determine the relative risk ranking for the pipeline.

The relative probability and consequence values used in the leakage model reflect Union Gas's current standards with respect to their impact on the relative risk associated with the pipeline, and give due consideration to the pipeline attributes, operating characteristics, and failure modes mentioned in the previous section. Therefore, the leakage model is an appropriate tool for the purposes of this assessment following some modifications that will be outlined in the following section.

It should be noted at this time that the leakage model is not intended to define the absolute probability that a pipeline will fail in a given period of time, nor is it intended to predict the impact of a failure. It can, however, be used to compare pipelines that have been targeted for replacement on a relative risk scale by taking into account the factors contributing to the probability that a failure will occur, and the factors contributing to the consequence associated with a failure. This comparison can then be used to prioritize the order in which the pipelines should be repaired or replaced. Therefore, if the model shows that a pipeline is in the high risk range, it does not necessarily mean the pipe is in imminent danger of a catastrophic failure. It merely indicates that the pipe should be placed higher on the list of priorities for replacement than pipelines of lower risk value.

3.1.3 Modifications to the Leakage Model

3.1.3.1 Format Changes

The leakage evaluation program is designed to evaluate a single section of pipe with continuous attributes and operating conditions. Because the London Lines consist of more than 160 km of pipeline installed under a number of different projects and having varying attributes and operating conditions, a new tool is required to perform the risk comparison for each section of each line. To satisfy this requirement a spreadsheet has been developed to accompany each of the project lists in Appendix B. This spreadsheet uses modified versions of the formulae in the Leakage Evaluation Model v. 2.0 to perform the risk ranking for each section of pipe, using varying properties of each section of pipe along the length of the London Lines.

3.1.3.2 Formula Changes

3.1.3.2.1 CP History

To better reflect current views regarding the relative risk outputs in the leakage model, and to incorporate the concerns regarding heavy vehicular traffic over the London Lines at the Komoka gravel pit, 2 formulae were changed affecting the outputs for each model.

The first is the formula for calculating the relative probability associated with the lines' cathodic protection history. In the current leakage model, the relative probability value is based entirely on the most recent pipe-to-soil voltage, not the overall CP history. The new model has been modified such that the overall downtime and in-service time prior to installation of cathodic protection are considered in determining the relative probability value associated with cathodic protection. The formula is such that the total time that a section of pipe was unprotected is taken as a percentage its service life and multiplied by the relative probability used for voltages greater than -650mV in the current leakage model. This formula is used to more accurately reflect the history of the cathodic protection, rather than the most recent performance.

3.1.3.2.2 Depth of Cover

The second modified formula is that for calculating the relative probability associated with depth of cover. Depth is considered in the leakage model for 2 reasons. The first is restraint of leakage: as depth increases, leakage intensity decreases. The second is probability of 3rd party damage.

In the current model, the possible inputs for depth of cover include <0.5m, 0.5m-1m and >1m, in order of decreasing probability. However, as mentioned, pipelines buried on agricultural land, or non-agricultural land used for agricultural activity, are susceptible to mechanical damage from farming equipment where depths are less than 60cm. Such damage can lead to ruptures, which can pose safety concerns in the immediate area of failure, as well as lost service downstream of the rupture. To address this, the risk spreadsheets are modified such that sections that have depths less than 0.6m are assigned the same relative probability values as sections with depths less than 0.5m in the current leakage model.

In addition to agricultural activity, the concerns regarding heavy vehicular traffic must also be considered in the updated leakage model for the London Lines. In particular, in the gravel pit in Komoka the London lines are between 0.5 and 1m deep at some locations, and greater than 1m deep at others. Vehicular loading analyses have shown that there is potential for the operating stresses within the London South line to exceed those allowable for a Class 1 location given its minimum depth. In addition, as the driveway surface erodes and develops potholes, there is potential for the operating stresses in both of the London lines exceed this limitation. To numerically incorporate this into the leakage model, the probability values assigned to depth of cover for the entire section of each pipeline located within the gravel pit will be equivalent to that of a pipeline in a general location with a depth less than 0.5m.

Information regarding depth has been made available from the results of the 2002 and 2004 depth surveys included in Appendix E.

3.1.4 Assumptions in Modified Leakage Model

As mentioned previously, some of the detailed environmental and operating characteristics for the pipeline are unknown. In particular, there is no detailed information available regarding the condition of the buried pipe and its coating, the soil type, the precise class location, and the number of customers downstream of each section of each pipe. To compensate, certain assumptions had to be made in filling out these attributes for the modified leakage model.

3.1.4.1 Pipe and Coating Condition

The outside wall of each pipeline is assumed to be more than 60% corroded for its entire length with pit depth reaching more than 60% of the wall thickness. Although there are several sections of pipe in each pipeline that have been installed within the last 20 years and are likely in excellent condition, there is no information with which to verify this. In addition, age and coating type are already taken into consideration in the modified leakage model, thus lowering the relative risk values for newer piping with higher quality coating. Therefore, although the assumption regarding the condition of the pipe is conservative for many of the sections being assessed, it is reasonable, given the information that is available. Furthermore, because the condition of the pipe is assumed to be the same for each section of each pipeline from start to finish, this input in the leakage model does not have any impact on the ranking of each section.

Along with the condition of the pipeline, the condition of the coating on each coated section is assumed to have undergone some sort of localized damage for the purposes of this evaluation. Again, because the same assumption was made for every section in both pipelines, the input for coating condition has no impact on the ranking for each section.

3.1.4.2 Soil Type

The original Reports of Line Change or Extensions for the replacement work on the London Dominion line in 1952 show that the soil was predominantly clay between Oakdale Header Station and Komoka Transmission Station. It is reasonable to assume that soil along the 20km of pipeline not included in the 1952 work is of the same type as that from Oakdale and Komoka. Therefore, the soil type has been assumed as clay for each section of pipeline that is being evaluated in this assessment. As such, soil type does not have any impact on the ranking of each section.

3.1.4.3 Class Location

Because the London Lines do not operate at 30% SMYS or greater, they are not surveyed for class location. As a result, there is no information regarding the class location for each section of pipe. For lack of better information, the class location has been assumed as 1 for the entire length of each pipeline. Should a class location survey reveal that certain sections have a class location greater than Class 1 in the future; the leakage model should be adjusted accordingly to reflect this. Again, the assumption that the class location is the same across the entire length of each pipeline negates any impact that this input would have on the ranking.

3.1.4.4 Security of Throughput

The Security of Throughput input in the leakage model enables the user to input ranges of customers served downstream of the section of pipe being assessed, up to 1000 customers. Beyond 1000 customers, the number of customers is generalized as 1000 or greater. Because Komoka Transmission feeds a number of customers in the Komoka area and because the population density in that area is relatively high and increasing, the number of customers served downstream of each section of pipeline along the entire length of both lines is assumed to be greater than 1000. Therefore, this input has no impact on the ranking of each section of pipe.

3.2 Quantitative Assessment

3.2.1 Results of the Risk Spreadsheets

The spreadsheets indicating the various calculated relative risk values for each section of the London Dominion and London South lines are included in Appendix F. A graphical output for the relative risk values associated for each portion of both the London Dominion line and the London South line is plotted against the chainage for each line starting at Dawn Compressor Station in Figure 3.1 on the following page.

Generally speaking the spreadsheets and the graph indicate that the highest ranking sections of each of the London Lines are those sections that less than 0.5m deep in any location, less than 0.6m deep on agricultural land, or susceptible to damage due to shallow depth and continuous, heavy vehicular loading; are bare; are joined by mechanical couplings; and have a moderate to significant downtime history.

The relative risk values associated with the London South line are generally higher than those for the London Dominion line. This validates the additional concerns that the district has with the London South line and the desire to abandon it instead of the London Dominion line.

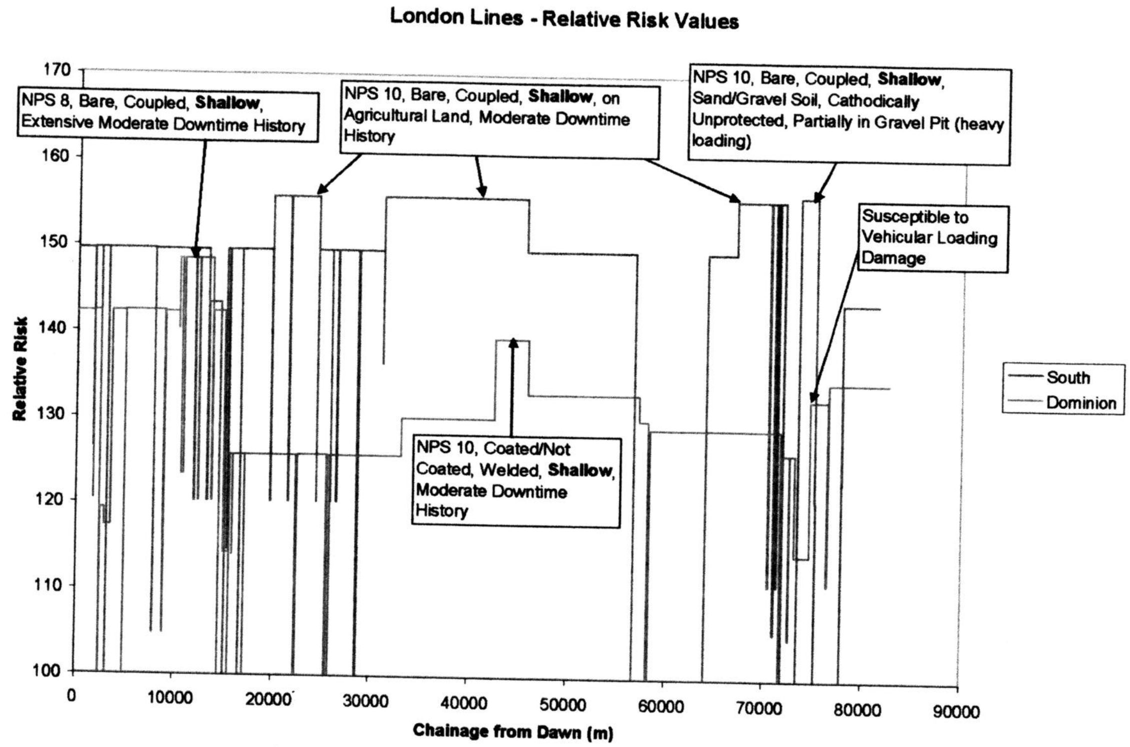


Figure 3.2.1.1: Relative Risk Plot for the London Lines

Figure 3.1 identifies the highest ranking locations associated with both of the London lines and, as well, a peak point on the London Dominion line located at about 45,000 m from Dawn, and the location of the London Dominion line where it is located within the gravel pit in Komoka. Although to locations identified on the London Dominion line are not of the highest value for the London Dominion line, and are significantly lower than most of the relative risk values associated with the London South line, they have been identified as a location where potential for 3rd party damage exists due to agricultural activity or heavy vehicular loading. As mentioned earlier, the consequence associated with such damage on the London Dominion line may increase dramatically following the abandonment of the London South line. Therefore, to manage the risk associated with the London Dominion following the abandonment work, these sections should be lowered or protected as required to prevent such damage from occurring.

It should be noted at this time that sections that are identified as shallow in Figure 3.1 are not necessarily shallow for their entire length. They may have very short or very long lengths of pipe with less than 60cm of cover. More exact locations and lengths of the shallow sections are included in Appendix E. These results can be used to more precisely determine the locations that have been identified as shallow and approximately how much pipe at each location would have to be lowered or abandoned as part of the mitigation work.

3.2.2 Segmented Risk Plot for the London South Line

In Section 2.3 of this report, the London South line was divided into segments which are identified as logical abandonment lengths based on the ability to isolate and the location of tie-ins to the London Dominion line. Figure 3.2 below divides the relative risk plot for the London South line into the identified segments to better determine which segments should be targeted first. In addition, the services tied to the London South line have also been plotted to provide some illustration of the number of services within a particular segment and, subsequently, the work required to abandon it. Where the density of service is high, consideration should be given to the cost of tying services over to the London Dominion line before making a decision to abandon the entire segment. Where the combined cost of the service tie-overs and main abandonment become cost prohibitive, only those sections of the segment fall into the highest relative risk range should be abandoned, provided the system hydraulics will allow for such segmentation.

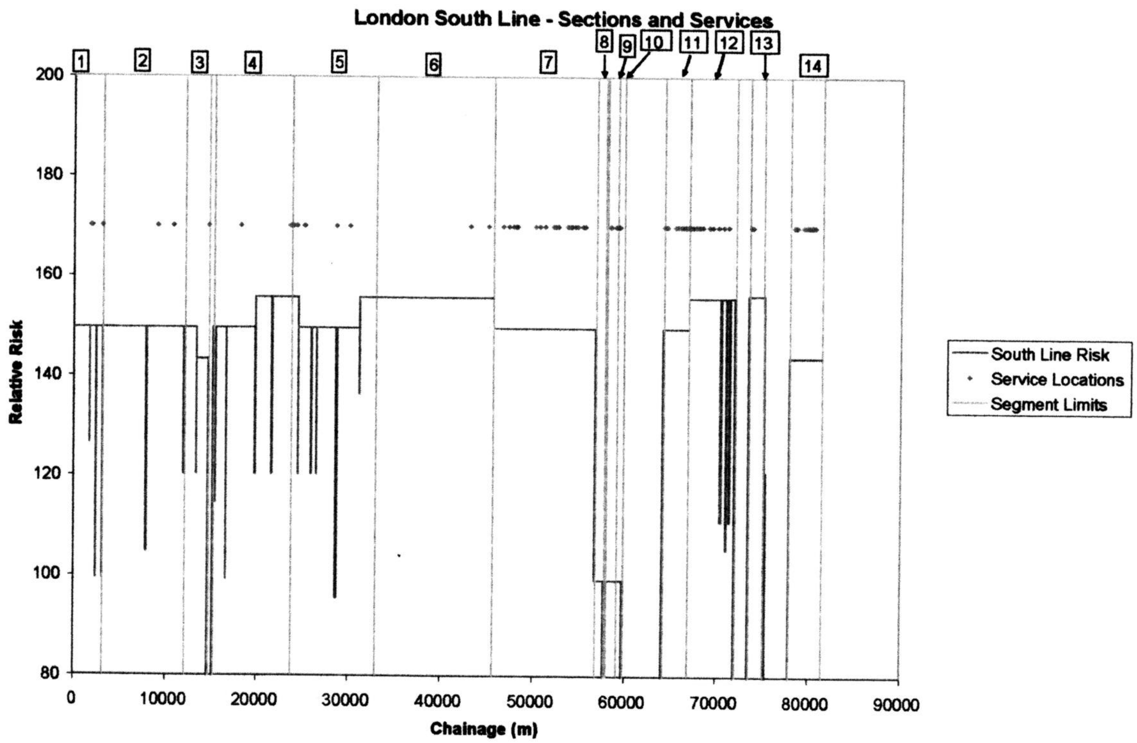


Figure 3.2.2.1: Segmented Plot for the London South line

From a ranking standpoint, Segment 13 is of the highest priority, having a relative risk value of 156.24, the last section in Segment 5 as well as Segments 6 are of the second highest priority with a risk ranking of 155.799, and the latter portion of Segment 4 and Segment 12 are of the third highest priority, each having a relative risk ranking of 155.755. Attributes affecting the risk ranking for each segment are identified in Figure 3.2.1.1.

4.0 ECONOMIC EVALUATION

In order to appropriately determine how to best spend the budgeted replacement dollars, the individual estimated cost for abandoning each segment of the London South line must be determined. This will enable the project manager to determine how to spend remaining replacement dollars once the highest ranking segments have been abandoned. In addition, this information will be useful in future abandonment work on the London South line in years to come.

The following table summarizes the high level cost estimates to abandon each segment of the London South line:

Segment Number	Length (m)	Cost to Abandon Main $42.00/m	Cost to Tie Over Services	Total Cost
1	3194	$134,148	$2,400	$137,748
2	8971	$376,782	$4,800	$381,582
3	2575	$108,150	$0	$109,950
4	8495	$356,790	$3,600	$360,280
5	**9154**	**$384,468**	**$60,000**	**$112,434**
6	**12721**	**$534,282**	**$5,400**	**$444,468**
7	11157	$468,594	$187,730.60	$86,604
8	972	$40,824	$2,000	$308,406
9	1152	$48,384	$3,900	$143,172
10	650	$27,300	$12,500	$481,094
11	2758	$115,836	$30,000	$367,042
12	**5041**	**$211,722**	**$51,271**	**$40,824**
13	**1536**	**$64,512**	**$5,000**	**$50,384**
14	3560	$149,520	$28,500	$39,300

Table 4.1.3.1: Cost of Abandonment for each Segment of the London South Line

These estimates are based on past experience with main abandonments and service tie-overs and should be refined with the assistance of the contractor before planning the scope of work for 2004.

The highest ranking segments (based on the top 3 relative risk values) have been bolded. The total estimated cost to abandon all of these segments is $248,110. The total estimated cost to abandon the entire pipeline is $3,072,288. Because these costs are far beyond what has been budgeted, further prioritizing is necessary to determine the scope of the 2004 abandonment work.

Where the London Dominion Line adjacent to each targeted Segment is determined to be shallow, the cost to lower the London Dominion Line to a depth of 60cm should be added to the cost of the abandonment. (London Dominion is shallow adjacent to Section 1, 2, 3, and 7).

5.0 CONCLUSION

The results of the qualitative and quantitative analysis indicate that those sections of each pipeline that are bare, have experienced the greatest amount of downtime, are joined by mechanical couplings, have depths of cover less than 0.6m, and are located on land used for agricultural activities or are located on land where vehicular loading creates excessive stresses in the pipe wall are of the highest relative risk value. For the case of the London South line, it is these sections that should be targeted for abandonment first, prior to any other segment of the pipeline. For the case of the London Dominion line, the segments that are less than 0.6m deep and located on agricultural land or are susceptible to damage caused by vehicular loading should be mitigated prior to removing the reinforcement provided by the London South line.

Leakage has also been identified as a problem at several locations along the London South line in the past. Although the extent of leakage did not have any significant impact on the quantitative assessment, the maintenance costs associated with such leakage is one of the driving factors behind the proposed abandonment of the London South line. Therefore, if these sites cannot be encompassed in the segments targeted for abandonment, they should be given due consideration for abandonment once the high ranking, or low depth sections along each pipeline are mitigated, if the cost to abandon them can be captured within the budget.

6.0 RECOMMENDATIONS

1. Refine the cost estimates for targeted segments or Sections of the pipeline to be replaced to ensure they are within budget constraints.

2. Segments 13, 12, and 6 should be targeted for abandonment in 2004, since Segment 5 only has a short section of piping which is shallow and located on land which, though in road allowance, may be used for agricultural activities. Subsequent segments should be prioritized based on their relative ranking and yearly budgets in future abandonment work.

3. Where the London Dominion line is shallow and located on agricultural land (or land used for agricultural activities), follow the appropriate remedial action as indicated below:

   Where the depth of cover is 480mm or greater:

   a. **Install a 150mm thick concrete barriers above the pipeline in the region of low depth of cover** – This is a viable option only where the depth of cover is greater than 480mm in locations where the land is actively tilled, and it impedes corrosion surveys. However it may be suitable for short sections where the pipe is deeper than 480mm.

Where the depth of cover is greater 180mm or greater:

b. **Improve the awareness of the pipeline and its associated depth of cover with the farmer** - If there is an opportunity for him to modify his farming practice such that a line hit will not occur, explore whether or not he is willing to modify his practices as such.

c. **Install permanent markers or warning signs in the region of low depth of cover** - If the farmer is willing to modify his farming practices such that he will not damage the pipeline, but is unaware of the location where it is shallow, increased signage will give him the awareness necessary to avoid this location.

For any depth:

d. **Install barrier fencing around the region of low depth of cover** – This can be a costly option where yearly crop damages will have to be paid. However, in areas where the pipeline is located on road allowance that is being used for agriculture, there would be no crop damages involved in which case this would be the most cost effective option.

e. **Lower the pipeline** – This is an expensive option and can be difficult and expensive in locations where the pipeline is joined by mechanical couplings. However, it will bring the relative risk values down to that associated with those sections that are not shallow.

f. **Replace the pipeline at a new lower depth of cover** – In locations where the pipeline is determined to have been hit, the resulting mechanical defects should be measured to determine whether the pipeline is suitable for continued service or whether repair or replacement is warranted. Where replacement is warranted, the replacement and lowering option will have to be selected. This may also be an economically viable option in those locations where the pipeline is joined by mechanical couplings and lowering may prove difficult.

g. **Deposit additional depth of cover above the pipeline** – Where the pipeline is shallow and the land is relatively flat, this may be a viable option provided the farmer is in agreement. Where the shallow section is located at a high point in the land, deposition will erode quickly and this will not provide a long-term solution to the problem.

Site visits should be carried out for each shallow section identified to determine which of the responses of those listed above is the most appropriate for each site. This will depend on cover, location and land owner requirements.

4. Where the London Dominion line is susceptible to excessive stresses due to vehicular loading, provide adequate protection to prevent these stresses from exceeding those allowable for the given class location.

5. Identify all sections of the London South line that are incurring additional maintenance costs due to leakage.

6. If budget permits, abandon these sections accordingly.

7. If steps 1 through 6 have been completed and funding is still available, determine the cost to replace those sections of the London South line that were identified as in poor condition as part of the above grade piping survey (See the Appendix A for the 2002 report) and abandon accordingly.

In addition to all of these recommendations, those sections of agricultural land above the London Dominion line that would be subject to more erosion (ie. high points) should be surveyed at regular intervals, to be determined by the regional SMC Manager, to monitor the changing depth of cover. As the depth begins to decrease, the risk spreadsheets should be updated to reflect this and the pipeline should be mitigated as per the above guidelines to ensure the probability for third party damage to occur is reduced.

Engineering Asset Plan

The London Lines

Union Gas, Ltd.

July 4, 2016

Performed by Jack Chen E.I.T

Pipeline Engineering

Signed: ________________

Dated: ________________

1. Executive Summary

The London Lines is a pair of high pressure distribution pipeline that connects Dawn to the City of London, and the multiple municipalities in between. The system currently operates at a Maximum Operating Pressure (MOP) of 1900 kPa and is classified as a distribution system. This assessment is being conducted in accordance with CSA Z662-15 to review system design, construction, operation and maintenance records, as well as hazards and consequences of failure.

Based on a review of the available records, the original pressure test data and NDE records are not available. There have been multiple repairs completed on the lines due to leakage, corrosion, and third part damage. In addition, there are currently multiple outstanding leaks located along the line. A report was put together in 2002 that had highlighted the conditions of the London Lines through a depth of cover survey and identifying areas of exposed piping. A new depth of cover survey should be completed to better understand the current conditions of the system.

The abandonment of the London South Line should continue due to the risks associated with this line's continuous service. Should the London South Line be completely abandoned, attention should then shift to replacing the London Dominion Line as it reaches it end of life.

2. Background

The London Lines spans approximately 80.9 km and extends from Dawn to Byron Transmission Station (13N 501) located in the London District. The London Lines consistent of 2 High Pressure (H.P) pipelines running in parallel and is considered a major feed supplying gas to the City of London and small communities between Dawn and London. The line that is located further north is known as the London South Line (Black Line) and is comprised mainly of NPS 10 steel pipeline coated in Barrett Enamel that was installed in 1935. The line that is located further south is known as the London Dominion Line (Grey Line) and is comprised mainly of NPS 8 steel pipeline coated in Durnite that was installed in 1936, which was subsequently replaced in 1952. Although the majority of the London Dominion Line was replaced in 1952, the materials used were reclaimed and refurbished steel pipe from the Windsor district with an average vintage of 1920 - 1930. The London Lines has a MOP of 1900 kPa from Dawn to Komoka Transmission Station (13N 401). Further east, the MOP from Komoka Station to Byron Station is 1380 kPa. Due to the vintage, the quality of steel pipe installed and the general deteriorating conditions, the London Lines has not operated near MOP consistently in the past 3 years.

This assessment is being conducted to identify risks to system integrity and public welfare, as well as identify opportunities for improvements in support of future growth in the London district and Union Gas's Pipeline Asset Integrity Plan. The scope of this assessment consists of the dual 80.9 km of the London Lines from Dawn to Byron Station. All H.P take-offs from the London Lines and subsequently any 420 kPa systems connected to such take-offs are out of the scope of this assessment.

This report contains the methodology that was followed and the results of an engineering assessment meeting the requirements of Clause 3.3 in accordance with the provisions of Clauses 10.3.1, 10.3.8, and 12.10.12 of CSA Z662-15.

3. Introduction

3.1 Methodology

When evaluating operating conditions, the provisions detailed in Clause 10.3.8 and 12.10.12 of the CSA Z662-15 code can be followed and an engineering assessment completed to determine whether the existing pipeline is suitable for the intended operating pressure. The guidance provided by the CSA Z662-15 code on conducting such engineering assessments is that they are to be based on factors such as consideration of the design, material, construction, operating and maintenance history, expected operating conditions, and hazards and consequences of failure as required by Clause 3.3 Engineering assessments.

The engineering assessment described in this report includes a review of design, materials, construction, operating and maintenance history, expected operating conditions, and hazards and consequences of failure to confirm whether the existing piping is in conformance with the proposed higher operating pressure as specified by the current edition of the CSA Z662 Code.

Where the engineering assessment indicates that the pipeline system would not be suitable for service at the proposed higher operating pressure, Clauses 10.3.2.3 and 10.3.8.2 requires that Union Gas implement changes to make it suitable.

Where the engineering assessment indicates that the pipeline system would be suitable for service at the proposed higher MOP, the piping will be pressure tested in accordance with Clauses 10.3.8.3 and 10.3.8.4 of the CSA Z662-15.

Information reviewed as part of assessment process included the following

- Materials and Design Information, including:
    - Material specifications including grade, diameter and wall thickness
    - Manufacturing specifications
    - Stress and pressure details
    - Service fluid and temperature range
    - Loading conditions
    - Valve spacing

- Construction Information, including:
    - Pipe depth of cover
    - Non-destructive examination
    - Pressure testing information
    - External influences

- Operating and Maintenance Information, including:
    - Leak and Failure records
    - Cathodic protection records
    - Integrity reports and records
    - Piping condition records and imperfection repairs
    - Land use analysis
    - Operating history

- Expected operating conditions

- Hazards and consequences of failure, including:
  - External corrosion
  - Internal corrosion
  - Stress corrosion cracking (SCC)
  - Manufacturing defects
  - Welding, fabrication, construction defects
  - Equipment failure
  - Third party damage
  - Geotechnical threats
  - Additional threats
  - Consequence analysis

3.2 System History and Schematic

The London Lines consists of the London South Line (1935) and the London Dominion Line (1935/52) running parallel to one another from Dawn to Byron Transmission Station.

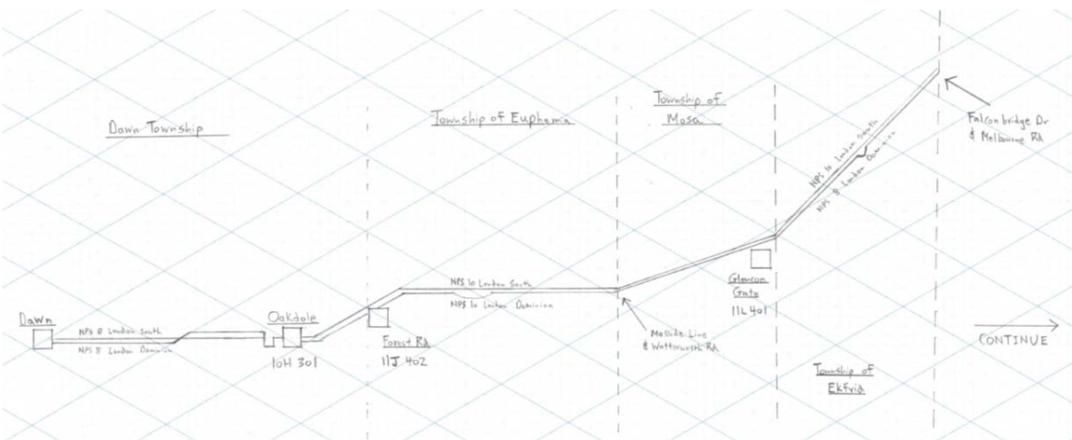


Figure 1 - Schematic of the London Lines (As per GIS) 1 of 2

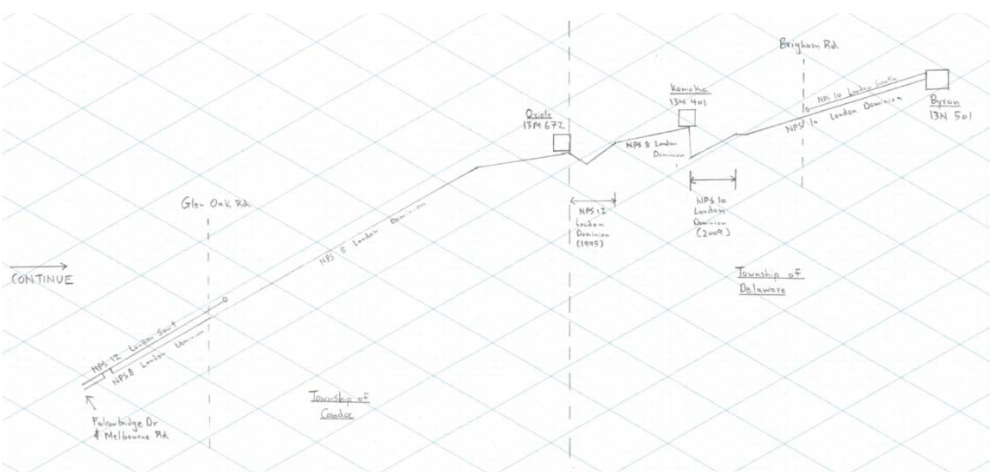


Figure 2 - Schematic of the London Lines (As per GIS) 2 of 2

London South Line

The London South line was originally installed in 1935 from Dawn to Byron Transmission Station. The first 15.3 km segment from Dawn to Oakdale Station (10H 301) consists of NPS 8 Bare pipe. The 65.5 km after Oakdale Station to Byron Station consist of NPS 10 pipe coated in Barrett Enamel. At the time of installation, the London South Line was joined together using dresser couplings. Indications of rod and lug device usage were not found. Records indicate that the grade and wall thickness of both sections are 165 MPa and 7.0mm respectively.

The London South Line was not cathodically protected until 1965. Since then, the line is cathodically protected from Dawn to the intersection of Melbourne Rd & Falconbridge Dr. As such, the line is still not protected from the intersection of Melbourne Rd & Falconbridge Dr to Byron Station. Based on the most current GIS schematic as shown in Figure 2, almost all segments of the London South Line east of Falconbridge Dr and Melbourne Rd have been abandoned. The last segmentation of the London South Line located just west of Byron Station will be abandoned this year.

Various segments of the London South Line have been replaced over the years due to leakage, deteriorating conditions and to accommodate municipal work. A list of all projects pertaining to the London South Line up to 1994 is included in Appendix B. Records of projects past 1994 was not available at the time this report was produced. Although said records were unavailable, the schematics shown in Figure 1 & 2 were produced from GIS and is an accurate representation of the current layout of the London South Line.

London Dominion Line

The London Dominion line was originally installed in 1936, 1 year after the installation of the London South Line and runs parallel to it from Dawn to Byron Station. The first 14.8 km segment from Dawn to Oakdale Station consists of NPS 8 Bare pipe. The second segment runs for 38 km, from Glencoe Station (11L 401) to Byron Transmission Station and consist of NPS 10 pipe coated in Durnite. Similar to the London South Line, at the time of installation, the London Dominion Line was joined together by dresser couplings and indications of rod and lug device use were not found. Records indicate that the grade and wall thickness of both segments are 165 MPa and 7.0mm respectively.

In 1952, a project was initiated to replace approximately 60 km of the London Dominion Line. Approximately 30.5 km of NPS 10 coated steel pipe was installed from Oakdale Station to the intersection of Melbourne Rd & Falconbridge Dr. Another 29.3 km of NPS 8 coated pipe was installed from the intersection of Melbourne Rd & Falconbridge Dr to Komoka Transmission Station (13N 401). All joints installed in this project were welded. The steel pipe used in this project was reclaimed steel pipe from the Windsor district, which was subsequently refurbished at Dawn before use. The average vintage of the pipes are 1920-1930.

The London Dominion Line was not cathodically protected until 1965. Since then, the line is cathodically protected from Dawn to Komoka Station. At present, the line is still not protected from Komoka Station to Byron Station.

Various segments of the London Dominion Line have been replaced over the years due to leakage, deteriorating conditions and to accommodate municipal work. A list of all projects pertaining to the London Dominion Line up to 1994 is included in Appendix B. Records of projects past 1994 were not available at the time this report was produced. However, the schematics shown in Figure 1 and 2 produced from GIS is an accurate representation of the current layout of the London Dominion Line.

4. Design, Materials, Construction, Operation & Maintenance, Expected Operating Conditions, and Hazards & Consequences of Failure Review

In this phase of the analysis, the design, materials, construction, operation & maintenance, expected operation conditions, and hazards & consequences of failure for the system were reviewed to confirm whether they conform to the applicable requirements of CSA Z662-15 for the proposed change to the pipeline system.

4.1 Materials Review Summary

4.1.1 Pipe

A review of records indicate that the steel pipes installed as a part of the London Line mainline system is appropriately rated for a MOP of 1900 kPa. The various combinations of Wall Thicknesses and Grades installed on the London Lines throughout the years up to 1994 are shown in Appendix C.

4.2 Design Review Summary

4.2.1 Minimum Wall Thickness Requirements

The minimum wall thickness requirements of Table 4.5 in CSA Z662-15 for NPS 8 steel pipe is 3.2mm and for NPS 10 steel pipe is 4.0 mm. Records indicate that the NPS 8 and NPS 10 steel pipes that have been installed as a part of the London Lines meet the minimum wall thickness requirements of CSA Z662-15.

4.2.2 Pressure and Stress Levels

In accordance with the requirements of CSA Z662-15 Clause 4, the design pressure shall not exceed the threshold stress levels calculated in the Table shown in Appendix C for their respective pipe size, wall thickness and grade. The maximum design pressure is calculated using the Barlow's Formula and de-rated by 0.3 corresponding to a distribution system.

It can be shown that at a MOP of 1900 kPa, the London Lines is currently operating under 30% SMYS and is considered a distribution system. As such, the existing steel pipe is adequate for the current MOP of 1900 kPa.

4.2.3 Service Fluid and Temperature

Union Gas piping is designed to service sweet natural gas at a minimum design temperature of -5°C for below-grade pipe and -30°C for above-grade pipe and a maximum temperature of 120°C for all pipes. There are no proposed changes to the service fluid or design temperature.

4.2.4 Loading Conditions

The main loading concerns of the London Lines stems from the numerous road crossings and a few rail crossings encountered in its 80.9 km span from Dawn to Byron Station. The 2002 report has highlighted the fact the London Lines has multiple depth of cover deficiencies along its span. This coupled with multiple agriculture land use along and the vintage of the steel pipe can pose concerns from vehicle loading from both a % SMYS and cyclic loading perspective.

To accurately assess the current loading conditions of the London Lines, a depth of cover survey will be required. Annual depth of cover survey is unavailable for the London Lines as it is not operating over 30% SMYS and thus is not covered over Union Gas's Depth of Cover Survey Standard operating Practices (SOP). The depth of cover survey completed in 2002 should be renewed as the depth of cover may have changed significantly over the past 14 years.

4.2.1 Valve Spacing

For distribution systems, Clause 12.4.13 requires that valves be located to limit the time required to shut down a section of the line in an emergency, with consideration given to: operating pressure, size of the distribution lines, local physical conditions, and the number and type of consumers affected.

It is believed that the existing valve spacing on the London Lines is adequate and limits the time required to shut down a particular section of the London Lines should an emergency situation occur.

4.3 Construction Review Summary

4.3.1 Minimum Depth of Cover

As per Union Gas' SOP Manual, distribution lines operating at less than 30% SMYS do not require depth of cover surveys. As such, recent records indicating depth of cover are unavailable.

As stated in CSA Z662-15, Clause 12.4.7, the minimum required depth of cover is 0.60 m for distribution lines below the travelled surface of the road or in the road right-of-way. The minimum depth of cover is 0.30 m for service lines on private property, and 0.45 m for service lines below the travelled surface of the road or in the road right-of-way.

As per the 2002 report, a depth of cover survey was conducted in 2002. The 2002 depth of cover survey, which considered 0.60m as the safe embedment depth, aligns with the current requirements as stated in Z662-15. Based on the results of the 2002 survey, multiple depths of cover deficiencies along the London Lines were identified and subsequently, a capital project was put together towards remediation in 2004. The appendix of the 2002 report has some great pictures showing sections of exposed pipes.

Given it has been 14 years since the last depth of cover survey, a new depth of cover survey would provide greater clarity as to the current depth of cover conditions on the London Lines. One can only assume that over the past 14 years, deficiencies that were identified but not addressed in 2004 may have deteriorated and new deficiencies may have appeared. In addition, the 2002 depth of cover survey did not cover the last 17 km of the London Lines from the intersection of Falconbridge Dr and Melbourne Rd to Byron Transmission Station.

4.3.2 Non-Destructive Examination (NDE)

The Ontario Gas Transmission and Distribution Pipe Line Code of 1964 required that lines intended to operate at less than 20% SMYS to only undergo visual inspection of welds. For lines intended to operate at 20% or greater, non-destructive examination is to be conducted via magnetic particle inspection, radiography or other suitable methods. At the time, the code did not require that NDE records to be maintained for the lifetime of the pipe.

Based on today's standards, pipeline operating under 30% SMYS, above 700 kPa and below 1900 kPa, Clause 12.7.4.3 of CSA Z662-15 would require all production welds be visually examined by the welder in accordance with company visual examination criteria. In addition, a minimum 5% of the production weld shall be visually inspected by visual inspection per the requirements of Clause 7.10.2 or non-destructively inspected per the requirements of Clause 7.10.4.

Given that the London Lines were installed proceeding the adoption of the Code as an official Standard, it is not known what practice was followed with regards to the inspection of welds during original construction.

For projects that took place on the mainline and involved replacement work between initial installation to 1994, NDE records were not found in their respective project files.

4.3.3 Pressure Test Review Summary

During the original 1935 London South and 1936/52 London Dominion Line installation, there were no indications that a pressure test was completed.

A project was initiated in 1956 to pressure test a large portion of the London Lines. Records of such test are incompletely at best; the only documentation speaking to such a test was an Inter-Office Communication (See Appendix D). As per the Inter-Office Communication, only the test pressure is available. It is not known what test medium was used or the duration of the pressure test. As per the Inter-Office Communication, the London Lines was pressure tested to 3450 kPa from Dawn to Oakdale station and 2758 kPa from Oakdale to Komoka. No test information exists for the London Lines from Komoka Station to Byron Station.

Subsequent projects involving replacing small sections of the London Lines do have slightly more information pertaining to pressure testing. However, for most H.P taps off the London Lines and a few ditch lowering projects, records of pressure test was not found (See Appendix B).

4.4 Operation and Maintenance Review Summary

4.4.1 Leak and Failure Records

Union Gas SOP practices require a leak survey to be conducted once every three years on lines that operate over 700 kPa and less than 30% SMYS. Water crossing do not need to be inspected if the line is buried.

At per the 2002 report, there have been 20 repairs completed on the London Dominion Line and 55 repairs completed on the London South Line up to 2002. Out of the 20 repairs completed on the London Dominion Line, 4 repairs were leak related, while 18 out of the 55 repairs completed on the London South Line were leak related.

A total of 23 leak related repairs have been completed on the London Lines in the past 5 years, and they have been mapped in Figure 5. The majority of leaks that have been repaired in the past 5 years are located west of Falconbridge Dr & Melbourne Rd and west of Byron Station.

Figure 3 – Dominion & South Line Leakage 2011-2016 June

In addition to the 23 leaks repaired in the past 5 years, there are a total of 39 outstanding leaks on the London Lines that is currently being monitored. The locations of the outstanding leaks have been mapped in Figure 4. The majority of the outstanding leaks on the London Lines also exist west of Falconbridge Dr & Melbourne Rd and west of Byron Transmission Station.

Figure 4 – London Lines Outstanding Leaks 2016

4.4.2 Cathodic Protection Records

Cathodic protection is applied to this system through a sacrificial anode system. Surveys are conducted on this pipeline to measure DC pipe-to-soil potential with an annual frequency based on Union Gas Corrosion Control SOP.

This information was unavailable at the time this report was produced.

4.4.3 Integrity Reports and Records

This pipeline has been classified as a distribution line operating below 30% SMYS and was not historically part of the >30% SMYS transmission integrity program.

4.4.4 Pipe Condition Records and Imperfection Repairs

As highlighted in the 2002 report, there have been a number of repairs completed on the London Lines due to leakage, third party damage and corrosion related issues.

As per original records from the 1952 London Dominion Line installation, the reclaimed pipe had a vintage averaging from 1920s – 1930s. Sample Daily Progress Report from the 1952 installation has multiple mentions of the steel pipe breaking off during coating processes, as such, speaks volume to the quality of the reclaimed pipe.

A Mechanical and Chemical Test was completed in 1982 on the NPS 10 pipe from the 1952 London Dominion Line installation, and from it, its grade and composition were determined (See Appendix D).

4.4.5 Land Use Analysis

Class location requirements do not apply to distribution systems provided the hoop stresses in the piping are not greater than 30% SMYS of the pipe.

The majority of the London Lines are located in rural Southwestern Ontario, where farming activities may pose a risk of injury or damage to unsuspecting individuals and the pipeline itself. Similarly, this issue has been identified in the 2002 report. The risk can be mitigated with adequate pipeline markers/signage and ensuring there is sufficient cover.

4.4.6 Operating History

The London Lines is connected to the Union Gas SCADA system at the Dawn. The past three years of operating pressure history were obtained through SCADA and the minimum/maximum daily pressures are plotted in Figure 4 below. The system typically operates between 1150 kPa and 1500 kPa, depending on season and demands.

Over the past three years, the highest and lowest pressure seen in the system is 1881 kPa and 840 kPa respectively.

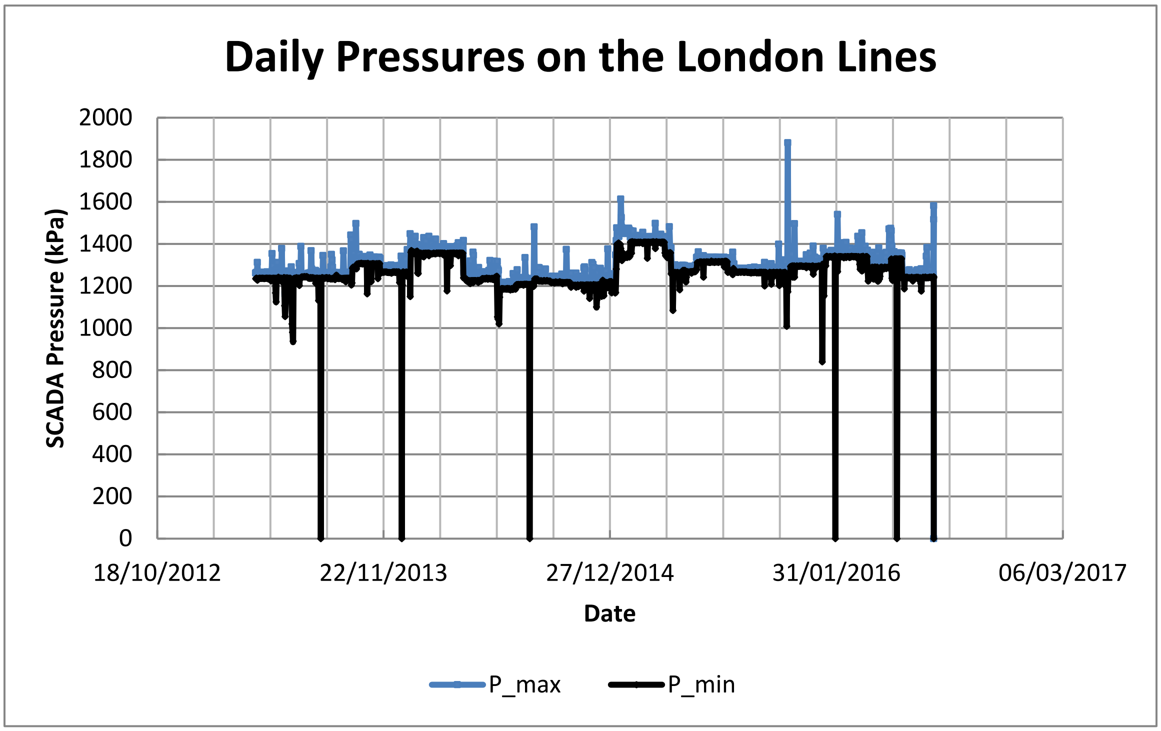


Figure 5- SCADA Maximum and Minimum Daily Pressures

4.5 Expected Operating Conditions

4.5.1 Expected Operating Conditions

Although the London Lines has a MOP of 1900 kPa, it has not been operating anywhere close to this MOP in the past few years due to its deteriorating conditions. It is suspected that an increase in established operating pressure may introduce more leaks into the system and intensify any existing leaks.

4.6 Hazards and Consequences of Failure

The following are potential time-dependent, stable, and time-independent, hazards as identified in Section 2.2 of ASME B31.8s *Managing System Integrity of Gas Pipelines* as the primary hazards associated with gas distribution / transmission systems.

4.6.1 External Corrosion

The London Lines is currently operating below 30% SMYS and therefore the failure method of this pipeline due to external corrosion is expected to tend towards leak rather than rupture. There is a possibility that longer, more complex corrosion features could fail by rupture.

The London Lines predominately runs through rural Southwestern Ontario and leaks would more likely be classified as 'B' or 'C' leak according to C&M 11.2 due to location.

The London Lines has both Wax-based coating (Coated & Wrapped C&W/ Denso) and Asphalt-based coating (Coal Tar). This coating is classified as susceptible to the threat of CP shielded corrosion according to *CEPA Stress Corrosion Cracking Recommended Practice* (2nd Edition, 2007). CP shielded corrosion occurs when the coating system breaks down adhesively (disbonds) but not cohesively (to allow the Cathodic protection system access to the pipe). This type of failure creates a shielded gap or tent after it has dissociated from the pipeline which is not protected by the Cathodic protection system. It can contain an active corrosion cell even when the Cathodic protection system is functioning properly.

Sections 4.4.3 and 4.4.4 discuss the condition of the pipe as documented through inspections. The London Lines does show a prevalence of external corrosion as per the visual inspection conducted in 2002. The prevalence of external corrosion is the result of the vintage and being exposed to above grade conditions at multiple locations, which is a contributing factor to accelerated corrosion.

4.6.2 Internal Corrosion

This pipeline system contains a service fluid of sweet distribution-quality natural gas and it has not been regularly identified as containing liquids. Internal corrosion is not identified as a threat on this pipeline system.

4.6.3 Stress Corrosion Cracking (SCC)

The coating used on the London Lines includes Wax-based coating (Coated & Wrapped C&W, Denso) and Asphalt-based coating (Coal Tar). Both of these types of coatings are considered susceptible to SCC according to *CEPA Stress Corrosion Cracking Recommended Practice* (2nd Edition, 2007). This mechanism for SCC susceptibility is through the threat of CP shielded corrosion as described in section 4.6.1.

Based on the operating stress/pressure regime (operating below 45% SMYS), the London Lines would not be considered SCC-susceptible. In addition, this pipeline is not identified on the Union Gas registry of pipelines which are SCC susceptible.

4.6.4 Manufacturing Defects

Manufacturing defects are typically considered to be stable over the conceivable life of most gas pipelines; however factors such as fluctuating operating pressures and pressurizations beyond long-standing MOP can adversely affect their stability. Industry experience has shown that a test-pressure-to-operating-pressure ratio of 1.25 or greater provides adequate assurance of stability as per *Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines* (Kiefner, 2006).

Pipelines can be subject to the following defects, imparted during manufacture; these defects would have survived a manufacturer's hydrostatic test and a field hydrostatic test and are typically considered stable / time-independent:

- Pit or rolled-in slug
- Hard spot
- Lamination

The pipeline being evaluated is considered older Electric Resistance Welded (ERW) pipe which, as pre-1980 pipe, has the potential of being low frequency ERW manufactured using an older process. This type of pipe is primarily susceptible to the following defects:

- Hook crack, immediately adjacent to ERW seam. Seldom fails at pressures below manufacturer's hydrostatic test, but subject to fatigue growth (Kiefner, 2006)
- Inadequate bonding, also called lack-of-fusion. Seldom fails at pressures below hydrostatic test. Not known to be subject to fatigue growth (Keifner, 2006)

Although manufacturing defects are typically considered stable, they can interact with other features. Laminations can link up with internal or external corrosion, pressurize, and significantly reduce wall thickness; they can also occasionally create a leak path. Defective ERW seams can be susceptible to interact with selective seam corrosion, SCC, or buckles/dents (Keifner, 2006).

Based on the operating history of this system, there has been no evidence of failures due to manufacturing anomalies.

4.6.5 Welding, Fabrication, and Construction Defects

Construction defects typically include buckles attributed to stress/strain at tie-in locations, and rock dents and backfill dents associated with improper trench preparation/padding and backfill. These defects would have passed a field hydrostatic test. Although a pressure test was not completed at the time of installation, a pressure test of the London Lines from Dawn to Komoka Station was completed on October 12th 1956 (See Appendix D).

Sections 4.4.3 and 4.4.4 discuss the condition of the pipe as documented through inspections. There is insufficient data to rule out buckles/dents on the bottom third of the pipe which are typically attributed to damage during construction. In general, the requirements for construction, sand padding and backfill in the 1930s and 1950s are less stringent than what is required today.

Stability of construction defects at girth welds is often controlled by longitudinal stress or strain rather than hoop stress (internal pressure) and accordingly seldom fail in pipelines buried in stable soils according to Kiefner, *Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines* (2006).

4.6.6 Third Party Damage

The London Lines is located both in easement and road allowance. There is typically reduced chance of third party damage in easements and higher chance of third party damage in road allowance, at utility crossings, and in areas with ongoing residential development.

The risk of third party damage is reduced with increased cover over the pipeline; section 4.3.1 of this assessment discusses the cover over the pipeline.

Higher risk locations can be compensated for with dedicated damage prevention programs to reduce likelihood of 3rd party damage strikes. The Union Gas damage prevention program includes:

- Call before you dig / Ontario One-call system advertising
  - Mail-out advertising
  - Billboard advertising
  - Website and social media advertising
  - Direct contact with contractors / constructors
- Signs along the pipeline including at road crossings

Decreased third party damage also occurs with consistently performed locates; Union Gas locating representatives follow ORCGA best practices for locating natural gas lines. For excavation around higher risk pipelines as defined in C&M 12.10 *Observation*, Union Gas representatives are required to be present to observe excavation practices, and to have a contingency plan developed in the event of a line strike. This pipeline would meet the criteria for observation as defined in C&M 12.10.

Sections 4.4.3 and 4.4.4 discuss the condition of the pipe as documented through inspections. Based on the limited data available, these sections do not show any dents on the top two thirds of the pipe or dents with metal loss which are typically attributed to third party damage. However, a new depth of cover survey may expose areas of shallow main in which third party damage is a definite a possibility.

4.7 Consequence analysis

For systems operating below 30% SMYS, consequences of failure are typically modelled as a leak with gas migration.

Based on Union Gas's risk rank categories, the London Lines was assessed on the basis of injury, regulatory compliance, loss of containment, environmental impact, financial cost, reliability of service and company reputation. The following risk ranking stems from the OMS Risk Matrix.

4.7.1 Injury

With the London Lines operating under 30% SMYS, the failure method of the line tend to lean towards leaks rather than rupture. Given that the London Lines runs predominately through rural areas. It is unlikely to cause fatality or health hazards in the event of a failure. As such, the risk of injury from this line due to failure should be classified as a C1/L2, producing a RR IV.

4.7.2 Regulatory Compliance

In the event of a pipeline failure on the London Lines, the TSSA can be expected to require significant corrective action to be completed on the London Lines. The incomplete and scattered records pertaining to the London Lines poses a non-compliance risk. The risk of regulatory repercussion on this line should be classified as C3/L2, producing a RR III.

4.7.3 Loss of containment

Loss of containment could result in either a significant leaks or rupture. In the event of an accident, there are mainline valves and/or stopper fittings available to isolate/bypass the area of concern and repair any defective pipe. Given that one of the London Lines is dressered without rod and lug devices and the vintage of both lines, the likelihood of losing containment is slightly elevated. Risk from loss of containment should be classified as C2/L3, RR III.

4.7.4 Environmental

The London Lines is expected to have a relatively low environmental impact as a result of pipeline damage. The loss of natural gas does not posed any serious and long term negative impact to nearby wildlife. As such, the classification is C1/L3, RR IV.

4.7.5 Financial

In the event of a major pipeline failure, significant financial risks may arise from the need to replace the entire London Lines distribution system. Given that it is approximately 80.9km long, with numerous road crossings, the cost of replacement would likely be between $1-5 million. As such, from a financial perspective, the London Lines will be classified as C4/L2, RR III.

4.7.6 Reliability

Based on Distribution Planning's extraction from the CMM (Customer Management Module), there are approximately 7610 customers from Dawn to Komoka Station, and 730 customers from Komoka to Byron Station. Given that the system is back fed from Byron Station (by the Trafalgars), it is unlikely that the pipeline would fail to the point of losing all of the customers on the line. Impacts from significant failure and leaks can be mitigated with stoppers and bypass fittings. As such, the classification from a reliability perspective is C5/L1, RR III.

4.7.7 Reputation

Any loss of service from potential incidents occurring on the London Lines would have public and media attention beyond the local area. Such incident may cause changes to the Z662 in subsequent revisions and how Large Distribution Companies (LDCs) operate. As such, the London Lines should be classified as C3/L2, RR III.

5. Recommendations

The London Lines distribution system is currently operating at a MOP of 1900 kPa. If this line were installed today, the mainline system would not meet the pressure test, NDE and depth of cover requirements of the current Z662-15. This may be due to the procedures and processes that were followed preceding the adaptation of the Code in Canada.

5.1 Short Term Plans

1. Given that records of the London Lines was only available up to 1994, the first action item would be to compile records pertaining to projects on the London Lines from that point onwards and storing those documents appropriately.
2. Currently, there is duplication of records throughout the London Lines repository. In order to improve accessibility, the records of the London Lines should be scanned and filed by TRIM into ProjectWise once it has been rolled out into the London district.
3. As identified by the 2002 report, the London South Line is the worst of the London Lines. This statement is echoed in the findings of this report as well. The reason behind such assertion is based on the vintage of the South Line and it being jointed together by dresser couplings with no indicate of rod and lug being used during the original installation. Abandonment on the London South Line should continue west of Falconbridge Dr and Melbourne Rd until all existing London South Line have been abandoned. This is consistent with the locations of the outstanding leaks. The section that should be tackled first based on available information is between Glencoe Station and the intersection of Falconbridge Dr and Melbourne Rd which is approximately 14.5 km.
4. Obtain detailed information with regards to CP protection on the London Lines and an updated depth of cover survey. Such information will be able to aid in prioritizing replacement/abandonment projects on the London Lines and in identifying other areas of concern.

5.2 Long Term Plans

Overall, based on the records review of the London Lines, abandonment of the London South Line and the eventual replacement of the London Dominion Line should be included in future budgets. This is in line with concerns expressed by individuals from both head office and the district with regards to the state of the lines.

The London South Line is definitely in a worst condition than the London Dominion Line and as such should be the priority. However, should the London South Line be completely abandoned, the focus should then turned onto the London Dominion Line. As aforementioned, although most of the London Dominion Line was replaced in 1952, it was replaced with refurbished steel pipe from the 1920s and 1930s. Sample Daily Progress Report from the 1952 has suggested that the refurbished steel pipe is not of great quality. As we approach the end of life for these steel pipes, they should be abandoned and replaced accordingly.

Appendix A

Past London Lines Reports

Appendix B

List of Projects

Appendix C

London Lines Main Line Pipe Listing

Appendix D

Miscellaneous Information

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Attachment 1, Page 8 of 10

Preamble:

A mechanical model was applied to model corrosion leaks using available corrosion rates. Based upon the available electronic records the majority (89%) of pipe has a wall thickness of either 4.8mm, 5.6mm or 7.0mm. Using a corrosion rate of 0.046mm/yr, which is greater than94% of the corrosion rate data points, for full wall loss the mains would have to be between 104 and 152 years of age. Based upon these calculations and corrosion rate data available we would not expect to see a significant increase in the number of corrosion leaks on this line for another 37 years. Unfortunately, due to the age, the long lengths of uncoated pipe, the large number of compression couplings and the unknown CP history there are concerns regarding the applicability of the corrosion rates.

Question:

a) Having regard to the age, the long lengths of uncoated pipe, the large number of compression couplings and the unknown CP history, when would a significant increase in the number of corrosion leaks be expected?

Response:

a) Legacy Enbridge Gas Distribution time to failure modelling shows an expected average time to first failure for individual steel main assets is approximately 100 years of age. Approximately 47% of the London Lines are composed of pipe of 1930s vintage and will be approaching 100 years of age in the next 10 years.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Page 12 of 15

Preamble:

Enbridge Gas reviewed the option of installing a combination of NPS 6 and 4 ST pipeline operating at 3447 kPa, with feeds from Dawn and Strathroy. The feed from Strathroy would be a new 8.4 km 3447 kPa pipeline from Strathroy Gate Station, which is served by the Dawn- Parkway pipeline. This alternative reduced the required size of 15 km of NPS 10 to NPS 6, 51.5 km of NPS 8 to NPS 4 and 7 km of NPS 8 to NPS 6 compared to the single fed option as a result of the additional high pressure feed. This option provided reliability of supply for emergency and operational requirements during summer and would likely be able to sustain expected loads in shoulder month temperatures such as April and October as well. Additionally, this was the least cost option of all the alternatives, and as such is the proposed design.

Questions:

a) Will this option meet the demands of the design day?

b) What occurs if the option is unable to sustain expected loads in shoulder month temperatures?

c) Why are summer and should month requirements discussed in this analysis as opposed to the design day requirements?

Response:

a) Yes.

b) If an operational or emergency scenario occurred in a shoulder month and the resultant system set up was unable to sustain expected loads, the result would be loss of gas service to customers.

c) The summer and shoulder months are discussed to further justify the need for the proposed Strathroy NPS 6 feed. The system was first designed to meet expected design day requirements, then reviewed for secondary benefit such as operational flexibility in shoulder and summer months.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

Exhibit D, Tab 1, Schedule 2, Page 1 of 2

Preamble:

The proposed pipeline will be designed as a distribution pipeline and operated at less than 30% SMYS.

Question:

a) Why will the proposed pipeline be operated at less than 30% SMYS?

Response:

a) Due to the assessed system demand, the proposed pipeline will be designed and operated as a distribution line; CSA Z662 requires distribution piping to be operated at hoop stress levels of less than 30% SMYS.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

Exhibit F, Tab 1, Schedule 1, Page 1 of 1 and Exhibit F, Tab 2, Schedule 1, Page 1 of 1

Preamble:

1. The total estimated cost of the Project is $164.1 million as shown at Exhibit F, Tab 2, Schedule 1, Line 7. This cost includes: (i) materials; (ii) construction and labour; (iii) environmental protection measures; (iv) land acquisitions; (v) abandonment of existing assets; (vi) contingencies; (vii) interest during construction; and (viii) indirect overheads. Excluding indirect overheads, the total estimated incremental cost of the Project is $133.9 million.

2. The proposed Leave to Construct ("LTC") seeks approval for the mainline costs of $95.2 million as shown at Exhibit F, Tab 2, Schedule 1, Line 5. Enbridge Gas is not seeking approval for the ancillary facilities' costs (i.e. stations, services, abandonment) in this application. These costs have been included in the total Project cost for completeness. The proposed pipeline will be designed as a distribution pipeline and operated at less than SMYS.

Questions:

(a) What is the detailed breakdown for the estimated costs set out in Exhibit F, Tab 2, Schedule 1?

(b) Are there any opportunities to reduce the total estimated $164.1 million cost of the Project?

Response:

a) Please see Exhibit I.ED.13 a).

b) The total estimated cost is based on the current scope of the project. The estimated cost presented is determined using a number of factors including historical data, costs for similar projects, and high-level quotes for the project. As detailed design progresses, these estimates will be replaced with quotes developed using more refined scopes of work and as such, Enbridge Gas will determine whether the contingency funds need to be adjusted and reallocated to known and discrete items.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Page 15

"The London Lines is on the list of prioritized projects, as identified in Enbridge Gas's Asset Management Plan."

Questions:

(a) The problems with London Lines appear to have existed for quite some time. Please explain why the replacement is a priority now and yet was not in, say, 2005?

(b) Please file a current copy of Enbridge's latest Asset Management Plan.

(c) Please file a copy of any previous versions of Enbridge's Asset Management Plan that include London Lines as a prioritized project. If it is not apparent from the face of the document, please indicate in the response the date of the document.

(d) Please file the earliest list of prioritized projects that includes London Lines.

(e) When did Enbridge first identify the London Lines as a prioritized project?

(f) Please provide a detailed timeline listing and describing the steps taken by Enbridge with respect to the identification and development of this project.

(g) There are three previous reports regarding the London Lines listed in Exhibit B, Tab 2, Schedule 1, Attachment 1, Page 3. Please file those reports. Please provide a table in the response that summarizes (a) the findings and (b) the recommendations of each report.

(h) Why were the London Lines not identified as a priority project back in 2002 to 2005 in light of the findings of the 2002 and 2004 reports prepared on the London Lines?

Response:

a) The historical approach taken was to repair leaks as they developed, however with the continuous degradation of pipe and increasing leak frequency, it was determined a more holistic approach was required to manage the risks in 2016-2017. The size and cost of this replacement project made it very difficult to manage within the company's base spend. Enbridge Gas has been addressing the highest known risks in a prioritized manner. Hence the reason why the Windsor Line Replacement project was prioritized before the London Lines project. Please see Exhibit I.FRPO.4 b).

b) Please see Attachment 1 for Enbridge Gas's current Asset Management Plan, which was filed as Exhibit C, Tab 2, Schedule 1 in Phase 2 of Enbridge Gas's 2021 Rates proceeding (EB-2020-0181).

c) Please see Attachment 2 and Attachment 3 for the prior versions of Legacy Union's Asset Management Plan.

d) to f)

The London lines were under review for several years at legacy Union. Some of the previous assessments were detailed on page 3 of the DIMP Integrity Assessment report filed at Exhibit B, Tab 2, Schedule 1, Attachment 1. Up to approximately the end of 2016, the London Lines were not under serious consideration for a specific project for full replacement. It was considered as an asset that would require significant investment to address on-going remediation. The on-going remediation would include repairing leaks, monitoring leaks, targeted repairs of sections and abandonments as necessary. In early 2017, it was identified that a full replacement may be the more preferred approach. Several reviews were held during 2017. In these reviews, options for a more targeted approach to remediate the London Lines issues were reviewed and developed. It was in legacy Union's Asset Management Plan 2018-2027, dated December 2017 where the London Lines project for a full replacement was first documented. That asset plan, filed with the Ontario Energy Board, outlines the steps taken to develop the project. Please see Attachment 3.

g) Please see Exhibit I.BOMA.5 a).

h) Please see response to part a).

EGI Asset Management Plan 2021-2025

October 5, 2020

Report

Company: Enbridge Gas Inc.
Owned by: Asset Management Department
Controlled Location: Asset Management Teamsite

EGI Asset Management Plan 2021-2025

Page intentionally left blank.

.

Table of Contents

.

Table of Figures

.

.

.

EGI Asset Management Plan 2021-2025

Page intentionally left blank.

.

1. Executive Summary

1.1 Document Purpose

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

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

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

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

1.2 Structure of the Asset Management Plan

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

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

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

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

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

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

.

- Strategy outcomes
- Capital investments to meet life cycle strategies

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

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

1.3 Company Purpose, Vision, Values and Strategic Priorities

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

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

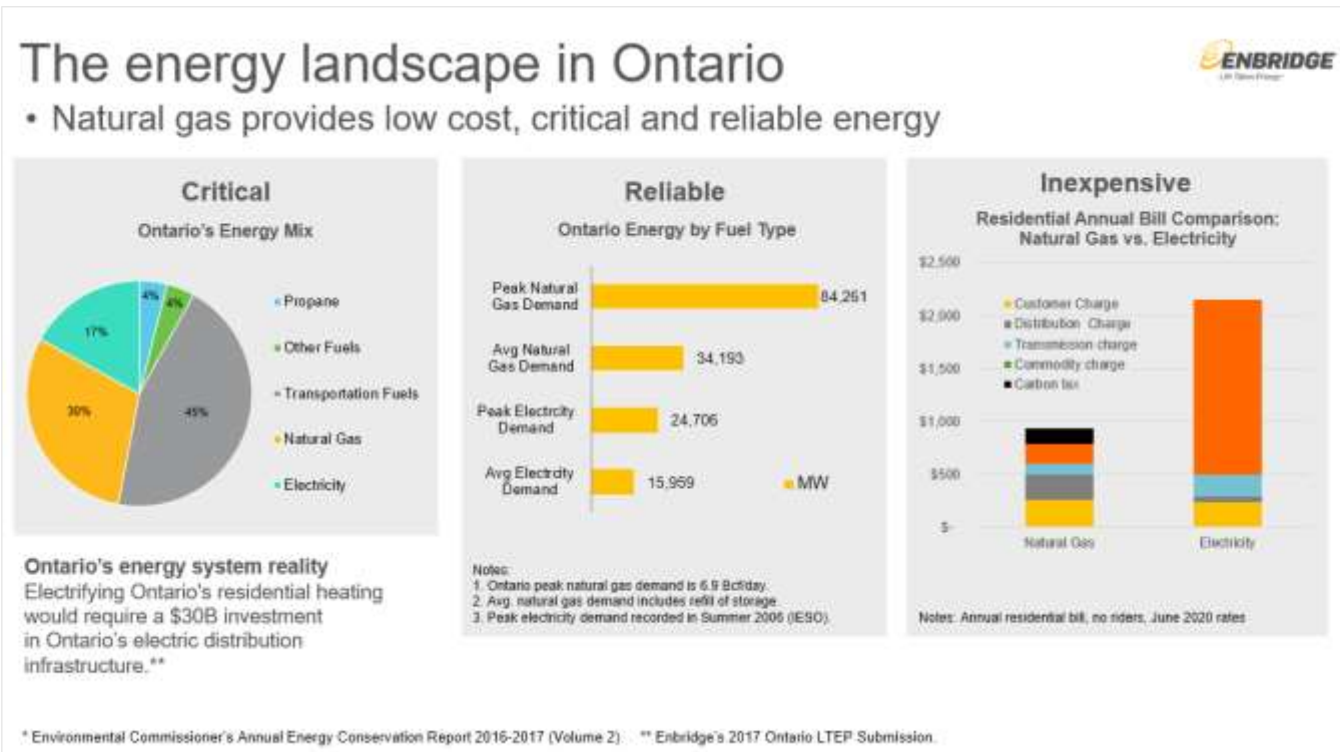


Figure 1.3-1: The Energy Landscape in Ontario

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

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

.

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

Figure 1.3-2: Enbridge Enterprise Strategic Priorities

1.4 Customer Service Area and Assets

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

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

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

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

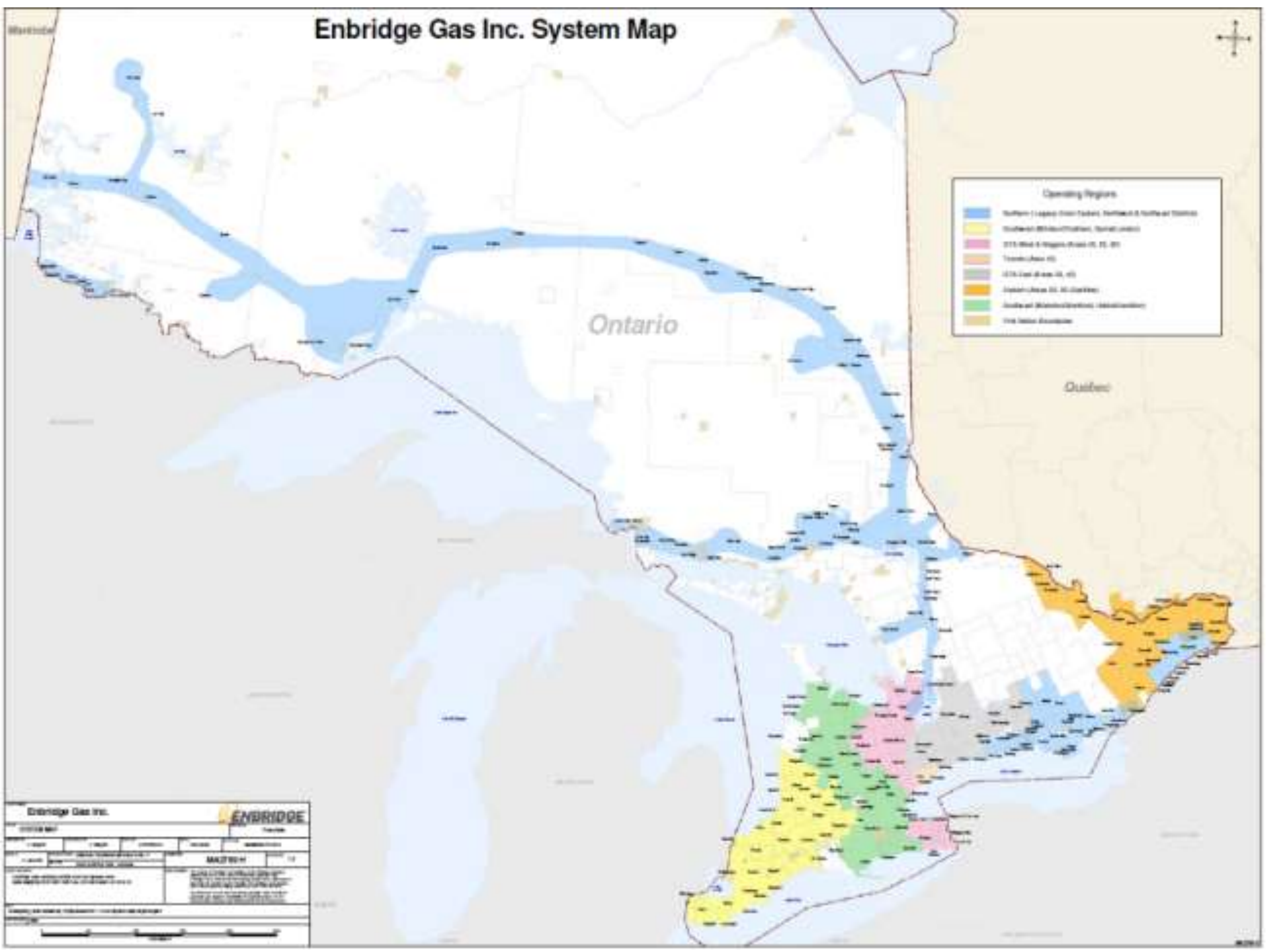


Figure 1.4-1: EGI Operating Regions

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

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

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

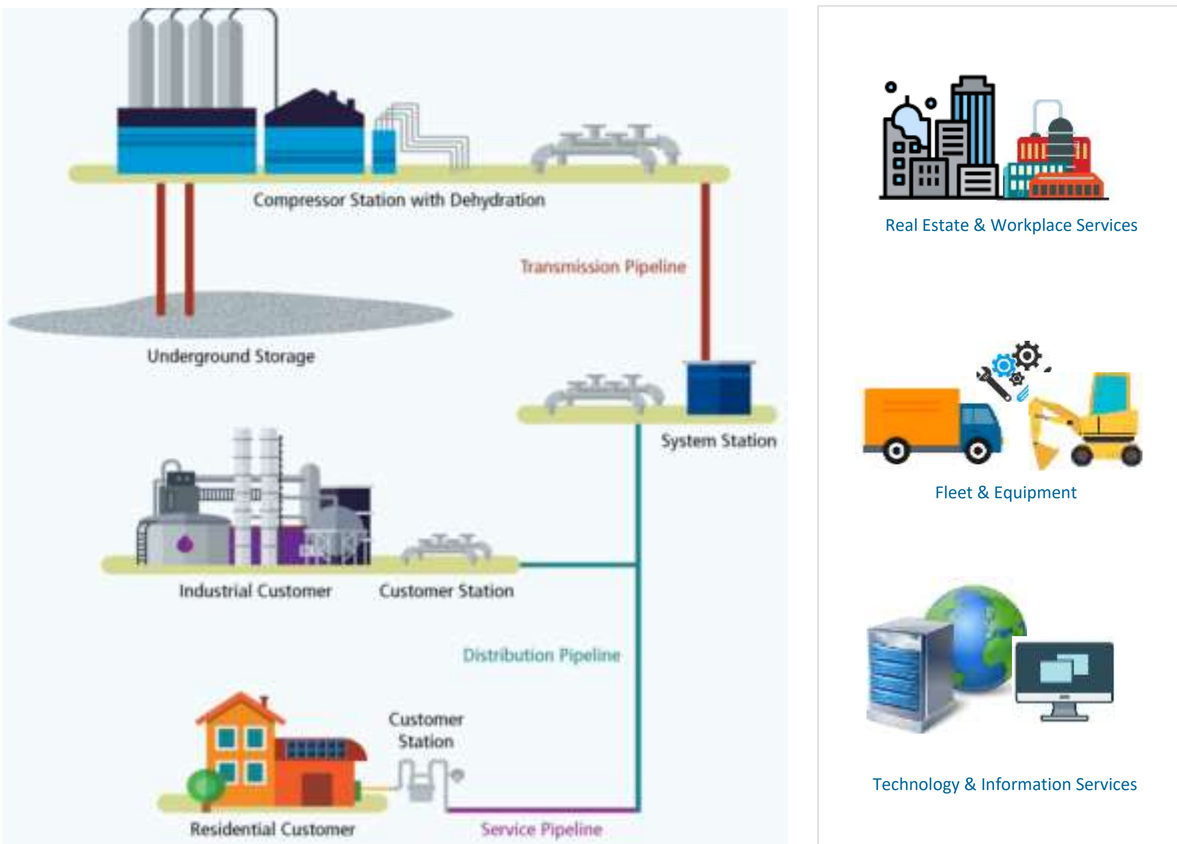


Figure 1.4-2: Components of a Natural Gas System and Supporting Assets

1.5 Advancing Asset Management

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

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

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

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

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

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

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

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

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

- **Consolidation of UGL asset data**

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

- **Evolution of asset condition and strategies**

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

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

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

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

.

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

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

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

- C55 optimization
- Asset manager input
- Stakeholder input

1.6 Asset Management

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

Figure 1.6-1: IAM Conceptual Asset Management Model

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

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

.

1.7 Asset Classes

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

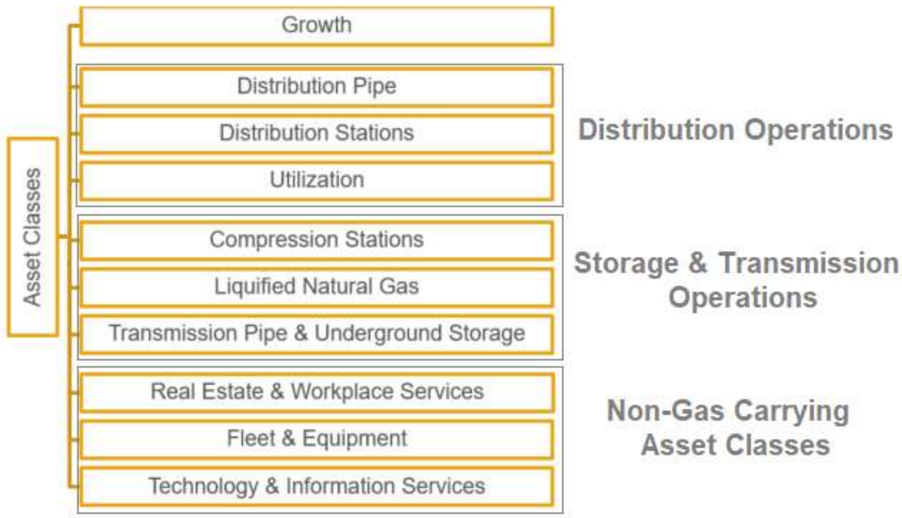


Figure 1.7-1: EGI Asset Classes

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

1.8 Condition and Strategy Overview

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

1.8.1 Growth Condition and Strategy Overview

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

1.8.2 Pipe Condition and Strategy Overview

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

1.8.3 Distribution Stations Condition and Strategy Overview

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

1.8.4 Utilization Condition and Strategy Overview

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

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

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

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

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

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

.

1.8.7 Fleet and Equipment Condition and Strategy Overview

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

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

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

.

1.9 Capital Expenditure

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

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

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

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

1.9.1 Capital Considerations

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

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

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

Table 1.9-1: Base Capital and Incremental Capital Descriptions

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

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

.

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

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

1.9.2 Optimization Results

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

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

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

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

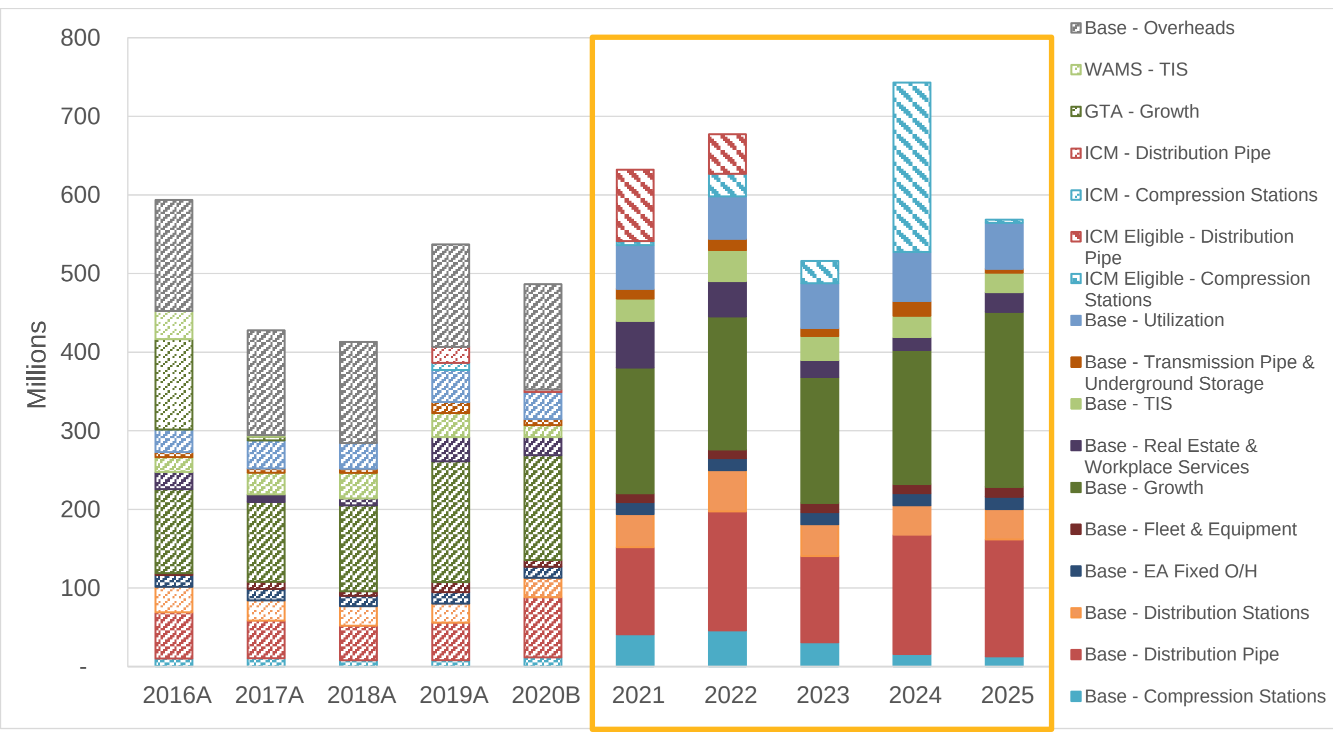


Figure 1.9-1: Final Five Year Plan by Asset Class (with ICM) – EGD Rate Zone (Capital Expenditure)

.

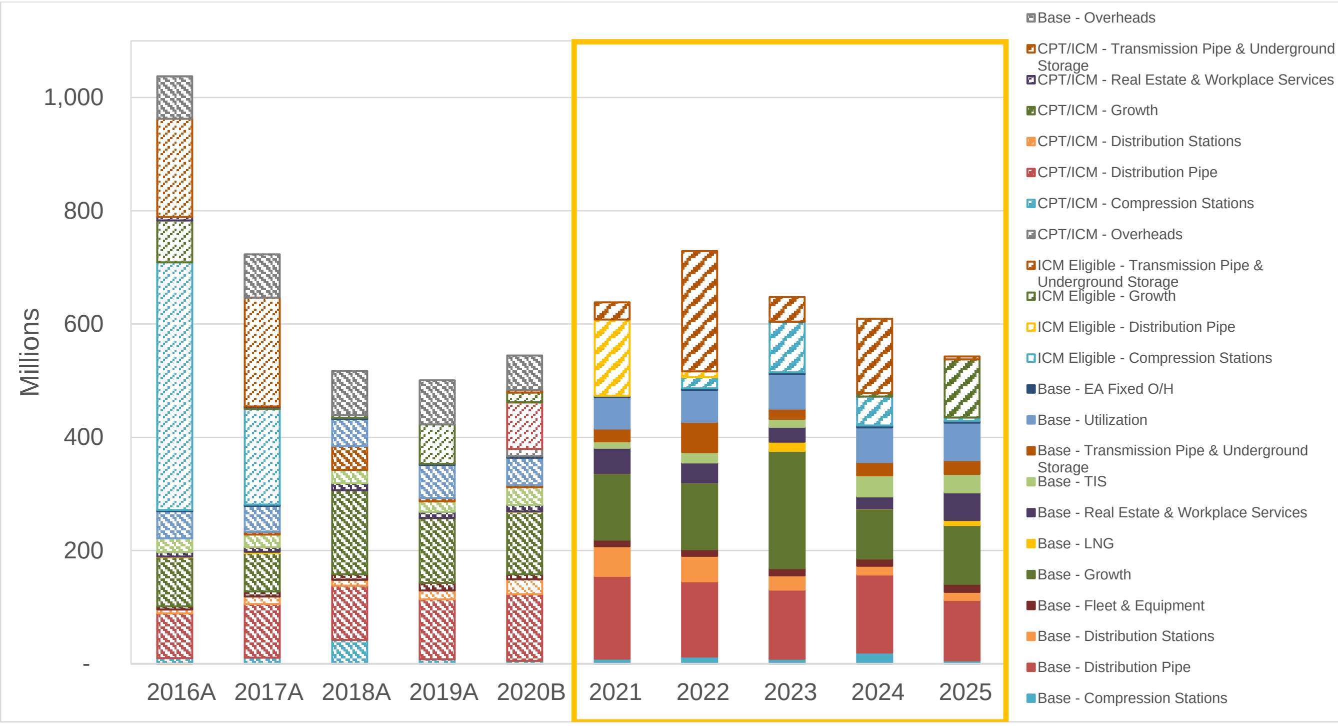


Figure 1.9-2: Final Five Year Plan by Asset Class (with ICM) – Union Rate Zones (Capital Expenditure)

.

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

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

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

[3] *The St. Laurent portfolio of work consists of four phases of work and each phase is comprised of separate projects. Phases 1 & 2 have been previously completed, with Phases 3 & 4 remaining in this forecast period. Phase 3 includes the following investments: Three PE main investments in 2021 including Lower Section, Coventry/Cummings/St Laurent and Montreal to Rockcliffe. Phase 4 includes the following investments: NPS 12 St. Laurent Aviation Pkwy and NPS 12 St. Laurent Queen Mary/Prince Albert in 2022. The investments comprising Phases 3 & 4 will be combined in a single Leave to Construct application that will be submitted in Fall 2020.*

.

Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total Net Capital ($M)	Driver
	SCOR: Meter Area-Upgrade	Ph 1 - 2021 Ph 2 - 2022	34.2	45.5	Condition
	Storage Crowland (SCRW): Station-Renewal In-Place	2025	27.9	27.9	Obsolescence
Transmission Pipe and Storage	Crowland Pool (PCRW): Wells-Upgrade	2026	1.7	11.7	Compliance, Condition
REWS	Kennedy Road Expansion	2023	15.0	26.3	Condition
	Station B New Building	2021	15.5	17.6	Condition, Function, In Progress
	SMOC/Coventry Facility Consolidation	2023	30.8	30.8	Function and Service Coverage Duplication
	Kelfield Operations Centre	2023	10.8	10.8	Condition, Function
	VPC Core and Shell	2025	20.0	20.0	Condition

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

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

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

.

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

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

.

1.10 Assumptions

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

Table 1.10-1: Assumptions for All Categories

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

Table 1.10-2: Renewal Assumptions

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

Table 1.10-3: Customer Growth Assumptions

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

Table 1.10-4: Solution Planning Assumptions

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

.

2. Introduction

2.1 Purpose of the Asset Management Plan

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

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

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

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

2.2 Company Purpose, Vision, Values and Strategic Priorities

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

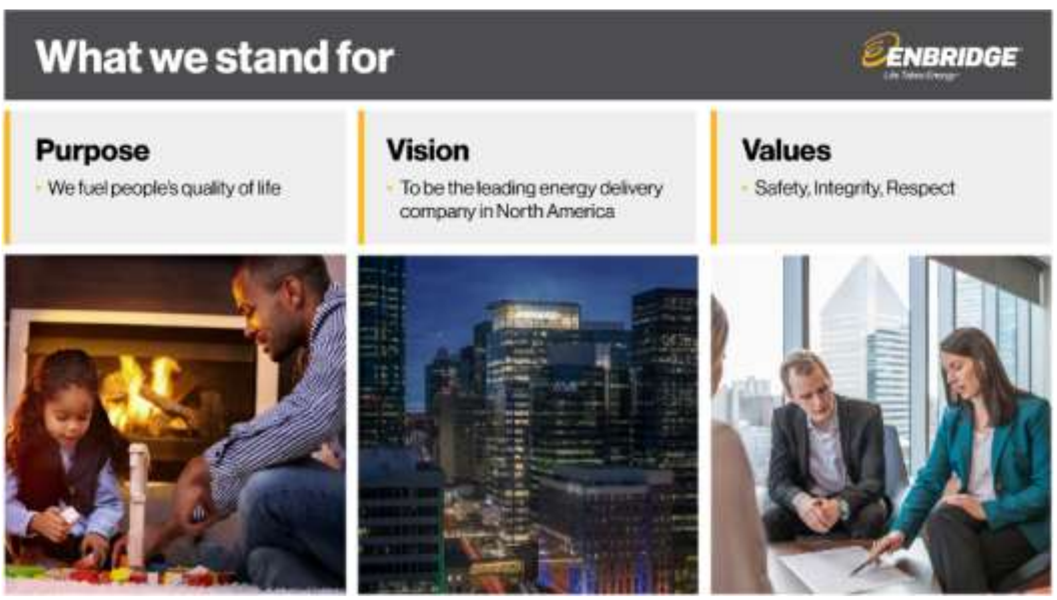


Figure 2.2-1: Enbridge Purpose, Vision and Values

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

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

.

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

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

Values: *Safety, Integrity, Respect*

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

2.2.1 Strategic Priorities

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

Figure 2.2-2: Enbridge Enterprise Strategic Priorities

2.3 Organization and Structure

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

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

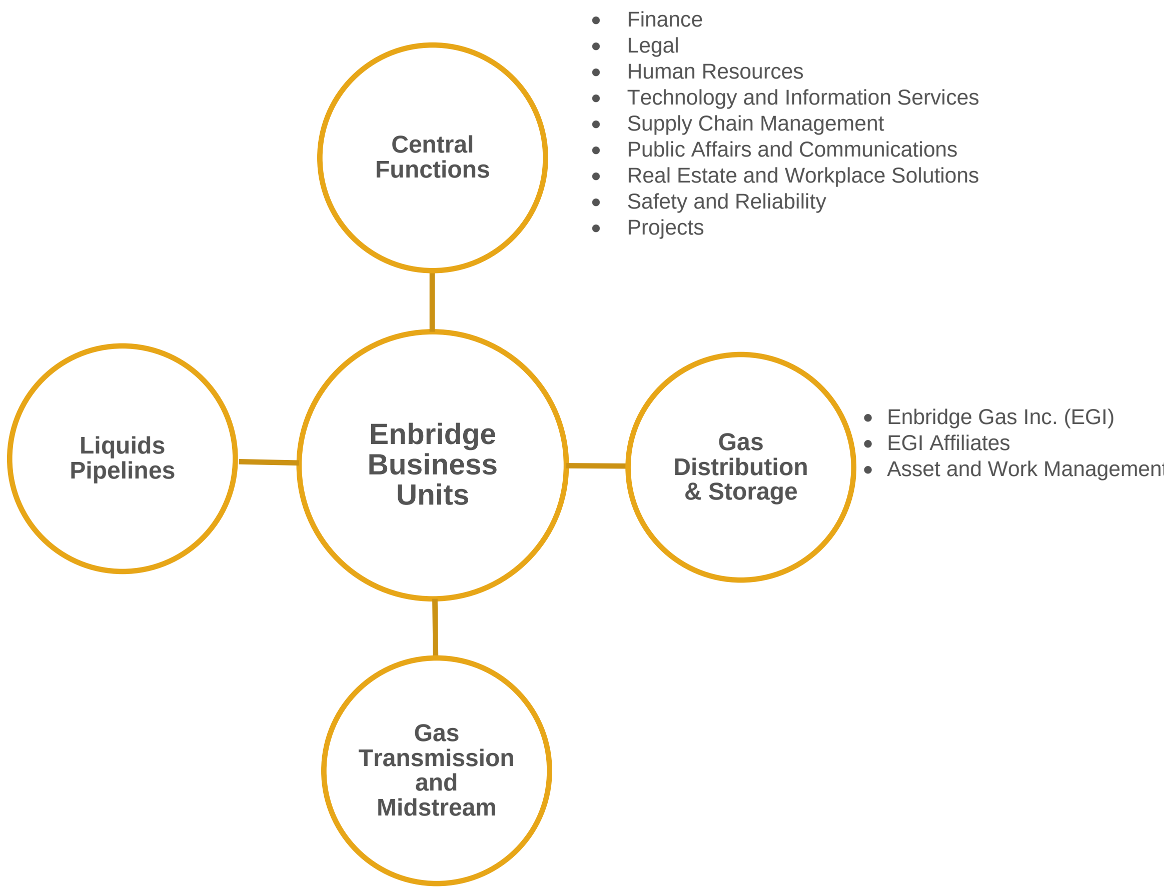


Figure 2.3-1: Enbridge Business Units

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

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

.

2.3.1 Enbridge Gas Inc.

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

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

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

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

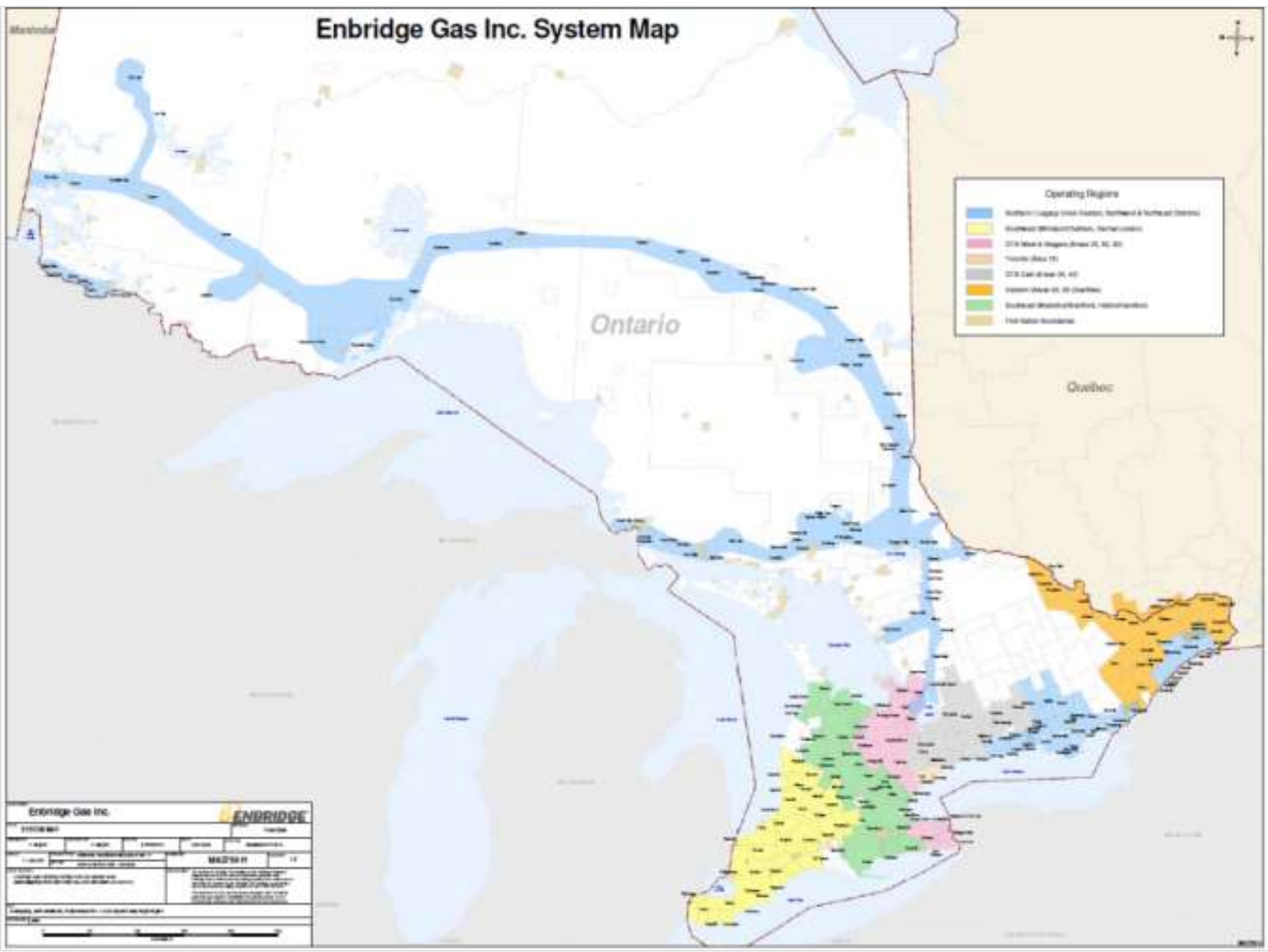


Figure 2.3-2: EGI Operating Regions

.

2.4 Stakeholder Commitment

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

2.4.1 Customer Engagement Results

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

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

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

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

- Strong majorities of both residential (88%) and business customers (77% non-contract and 79% contract) express satisfaction with the natural gas services they receive from EGI. Virtually all customers are satisfied with the safety and reliability of the natural gas service they receive to their home or business, while a majority of residential and business customers are satisfied with the value for money and customer service they receive.
- When asked if EGI should invest in improving or maintaining levels of natural gas safety, reliability and customer service, the highest proportion of residential customers would prefer that the organization focus on maintaining current levels.
- Safety, reliability and affordability are rated as being highly important customer outcomes by business and residential customers. Helping customers become more informed and community-mindedness or social responsibility are rated as the least important. When asked to rank the importance of various aspects of their natural gas service, providing stable and predictable pricing is ranked within the top four categories among all customers, while minimizing the impact on the environment is ranked third among residential customers.
- **Replacing Pipelines and Equipment (in general)**: Over half of residential customers (58%) prefer to spread costs evenly over time, even if that means higher rates now. Preferences among business customers are similar to residential customers. Contract business customers are slightly more likely to prefer to spread costs evenly over time.
- **Replacing Older Pipelines**: Half of residential customers (52%) prefer to replace older pipelines all at one time, knowing that for one project example this would translate into an increase of $3 in their natural gas bill per year. Preferences for non-contract business customers are evenly split. Contract customers are more likely to prefer to replace pipelines in phases.
- **Bare and Unprotected Pipes**: Among Union rate zone customers, slightly more than half of residential customers (58%), half of contract business customers (49%) and less than half of non-contract business customers (41%) would prefer that the replacement of bare and unprotected pipes be prioritized, which would increase customer bills. Smaller percentages prefer these pipes remain in place until they would normally be replaced.

.

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

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

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

3. Asset Management Strategic Framework

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

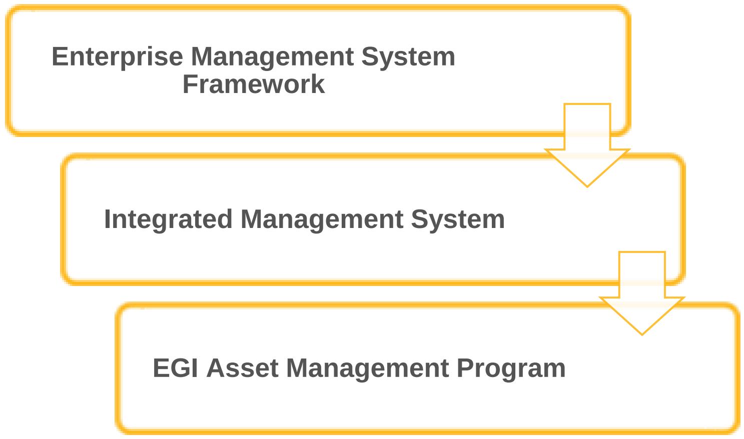


Figure 3.0-1: Alignment of Standards and Requirements

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

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

Plan-Do-Check-Act principles are:

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

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

.

3.1 Asset Management Framework

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

Figure 3.1-1: IAM Conceptual Asset Management Model

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

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

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

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

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

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

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

.

3.1.1 Enbridge Enterprise Strategic Priorities

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

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

3.1.2 Asset Management Policy

Vision and Mandate

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

Scope

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

Asset Management Program

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

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

Policy Statements

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

.

3.2 EGI Integration and Continual Improvement

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

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

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

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

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

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

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

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

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

- **Consolidation of UGL asset data**

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

- **Evolution of asset condition and strategies**

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

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

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

.

3.3 Integrated Resource Planning (IRP)

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

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

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

3.4 Structure and Scope of EGI's Asset Management Plan

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

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

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

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

---

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

.

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

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

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

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

4. Strategy, Planning and Process

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

Figure 4.0-1: Asset Management Alignment

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

4.1 Asset Management Strategies

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

Figure 4.1-1: Asset Management Strategies

Organization and People Strategies

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

Asset Information Strategies

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

Life Cycle Delivery Strategies

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

Risk and Review Strategies

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

Asset Management Decision-making Strategies

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

Strategy & Planning Strategies

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

4.1.1 Organization and People

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

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

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

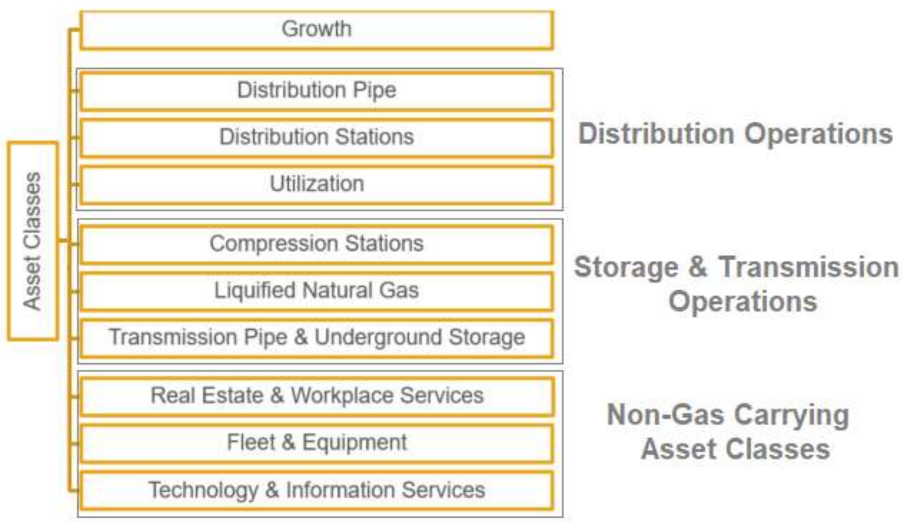


Figure 4.1-2: EGI Asset Classes

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

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

Asset Management Governance establishes and governs the following:

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

Asset Managers perform the following:

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

Functional/process departments support asset management by providing:

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

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

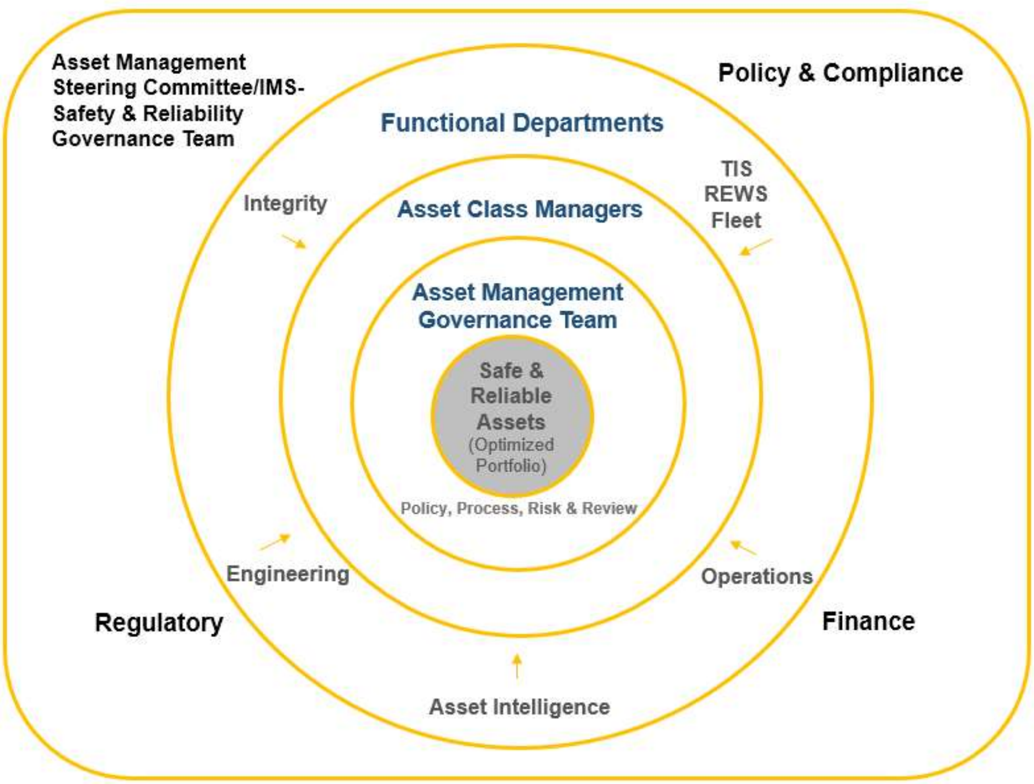


Figure 4.1-3: A Matrix Approach to Asset Management

.

4.1.2 Asset Information

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

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

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

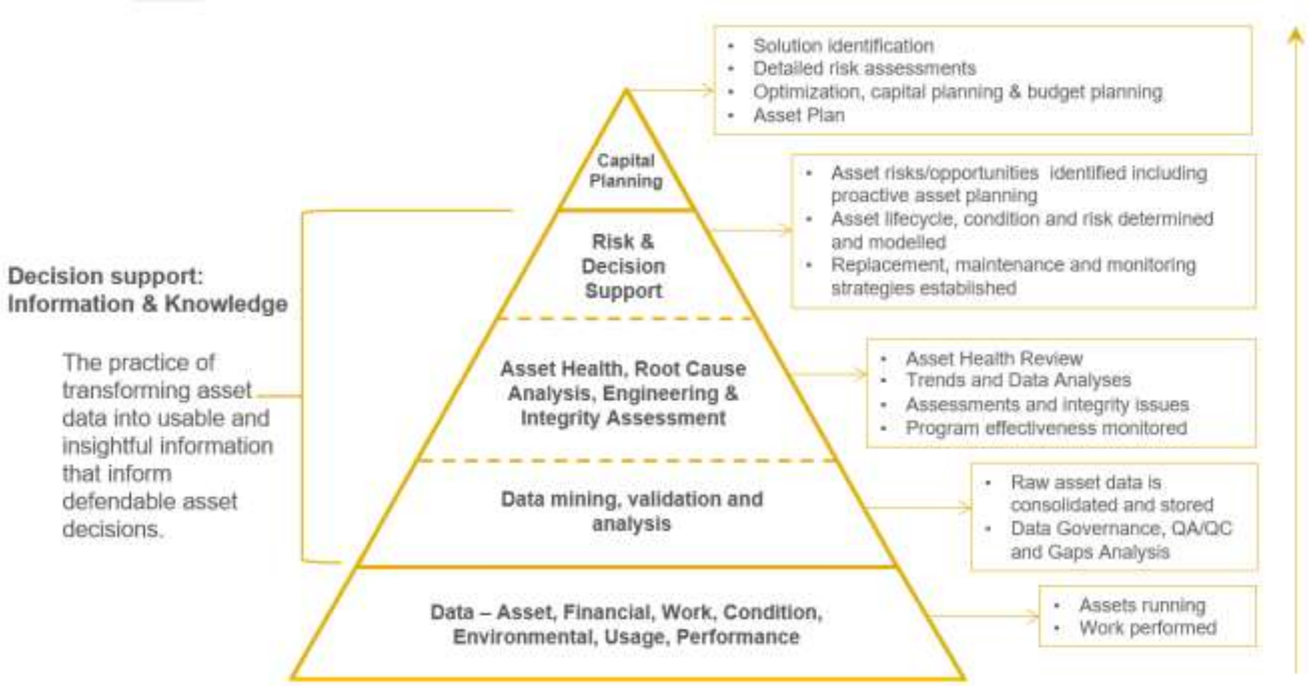


Figure 4.1-4: Asset Information and Support to Asset Investment Planning

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

4.1.3 Life Cycle Delivery

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

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

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

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

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

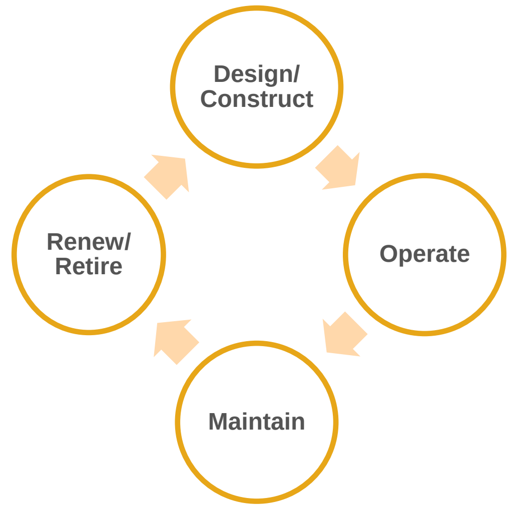


Figure 4.1-5: Asset Life Cycle Stages

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

Table 4.1-1: Life Cycle Management for Assets

Life Cycle Stage	Activities

Design/Construct	• Design new assets to:
	  ○ Ensure the safe and reliable delivery of natural gas.
	  ○ Ensure worker and public safety.
	  ○ Ensure code compliance.
	  ○ 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.
	  ○ 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.
	  ○ 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.

.

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

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

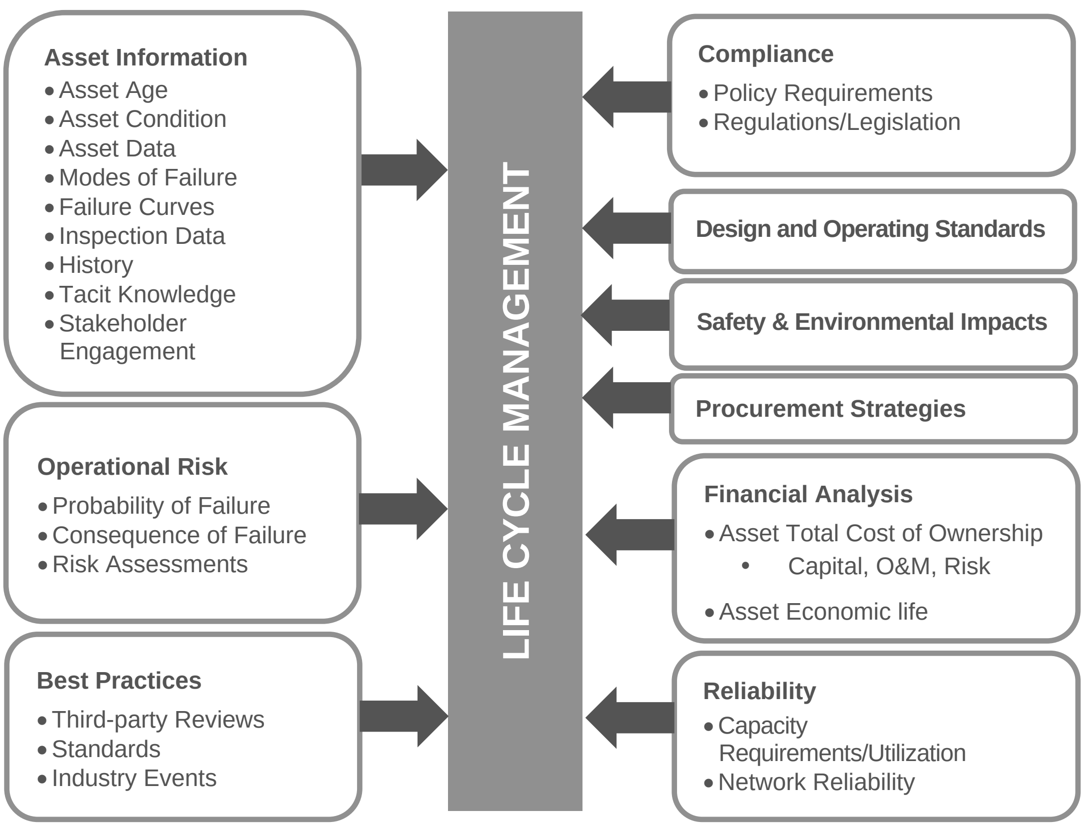


Figure 4.1-6: Life Cycle Management Inputs

.

4.1.4 Risk and Review

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

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

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

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

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

Table 4.1-2: Risk and Opportunity

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

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

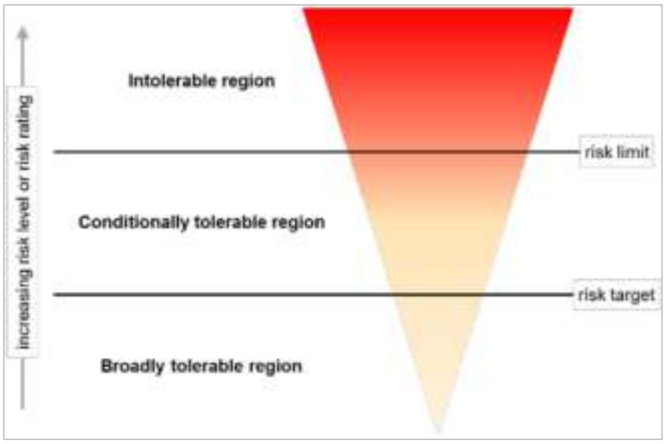
Figure 4.1-7: Enbridge Risk Matrix

.

EGI considers the following risk categories:

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

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



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

Figure 4.1-8: Enbridge Risk Tolerability Model

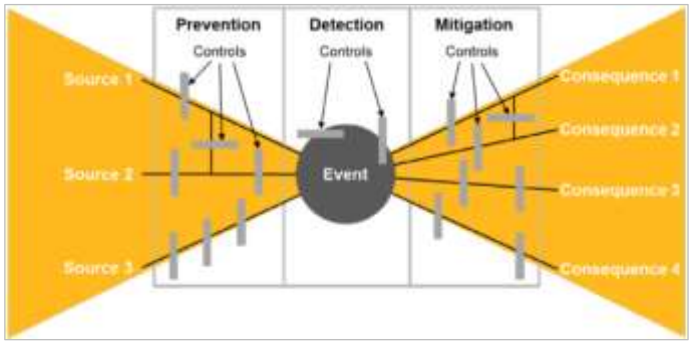
When a risk is evaluated to be in the intolerable (red) region, the project required to treat the risk is labelled as mandatory and must be addressed. Other mandatory initiatives are those driven by compliance requirements and third-party relocations (summarized in **Table 4.1-3**).

Table 4.1-3: Investments to Address Risk

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

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

.



Source: Adapted from IEC/ISO 31010 (2009)

Figure 4.1-9: Risk Bowtie Model

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

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

Table 4.1-4: EGI's Value Measures

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

.

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

4.1.5 Asset Management Decision-making

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

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

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

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

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

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

4.1.6 Strategy and Planning

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

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

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

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

4.1.6.1. Alignment of Enterprise Strategic Priorities and Asset Management Strategies

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

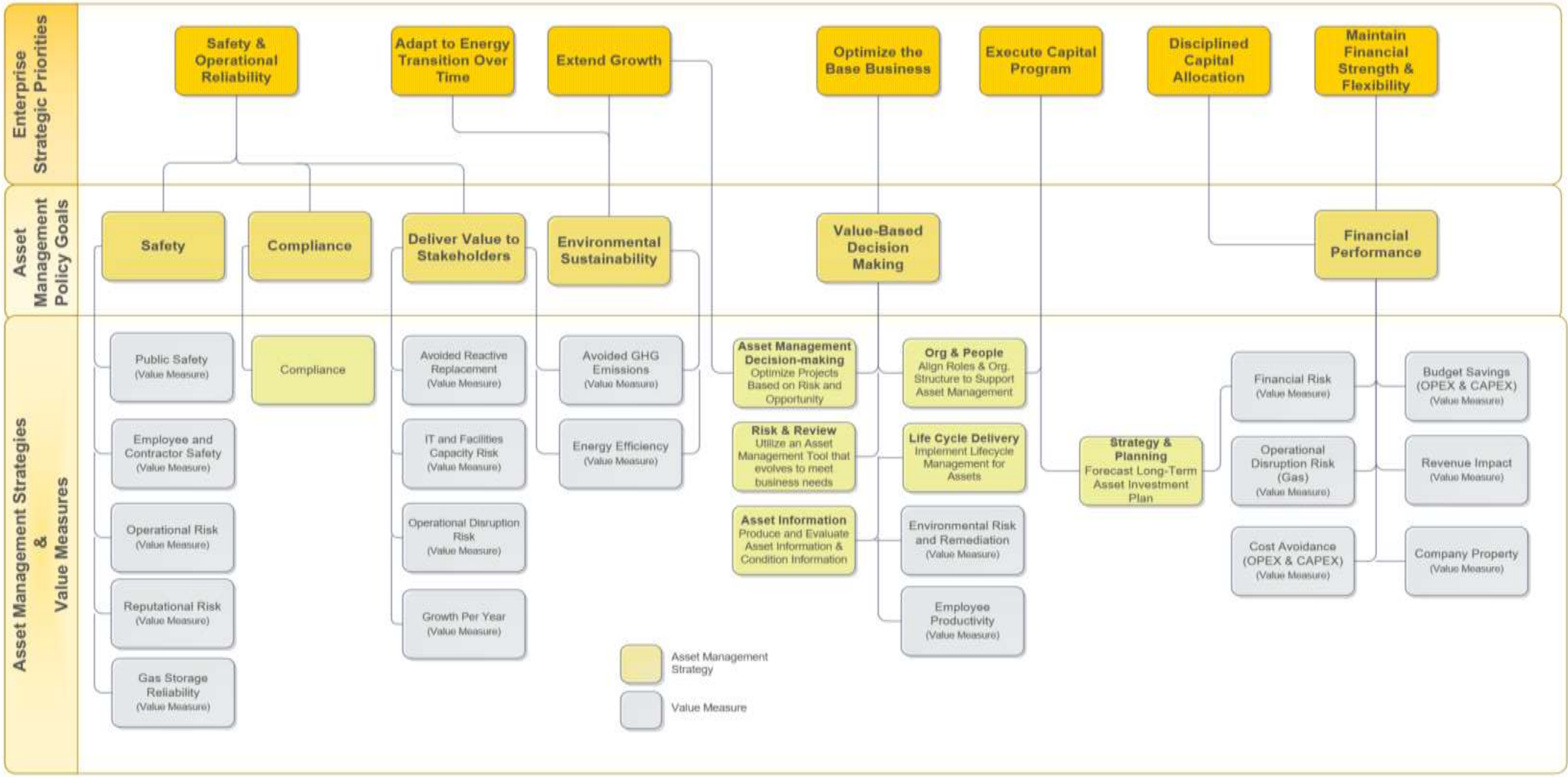


Figure 4.1-10: EGI's Alignment of Enterprise Strategic Priorities and Asset Management Strategies

4.2 Asset Management Core Process

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

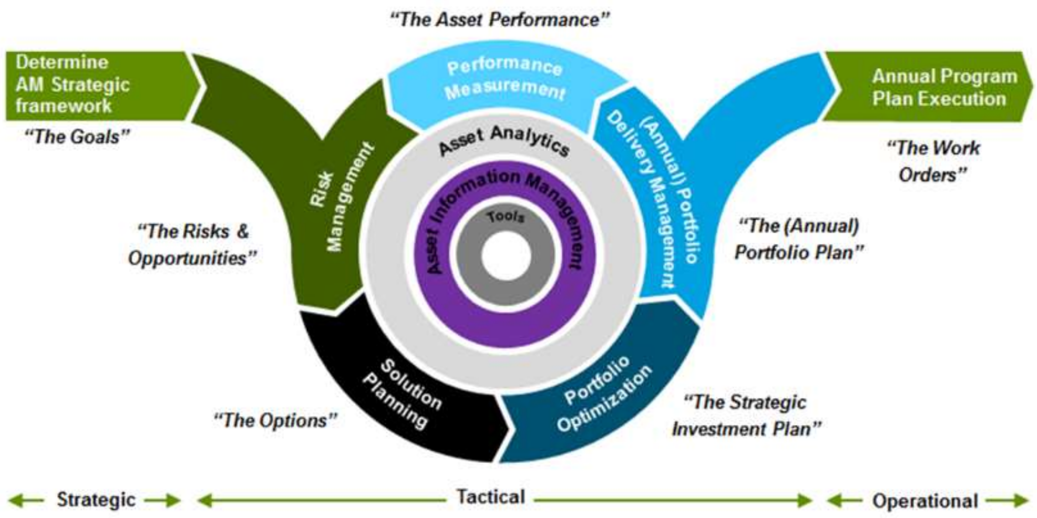


Figure 4.2-1: Value-Based Asset Management Model

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

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

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

Figure 4.2-2: EGI's Asset Investment Process

.

4.2.1 Risk Management

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

Figure 4.2-3: Enbridge Risk Management Process

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

4.2.1.1. Identify Risks

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

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

4.2.1.2. Assess Risks

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

Table 4.2-1: Risk Assessment Types

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

.

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

4.2.1.3. Treat Risks

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

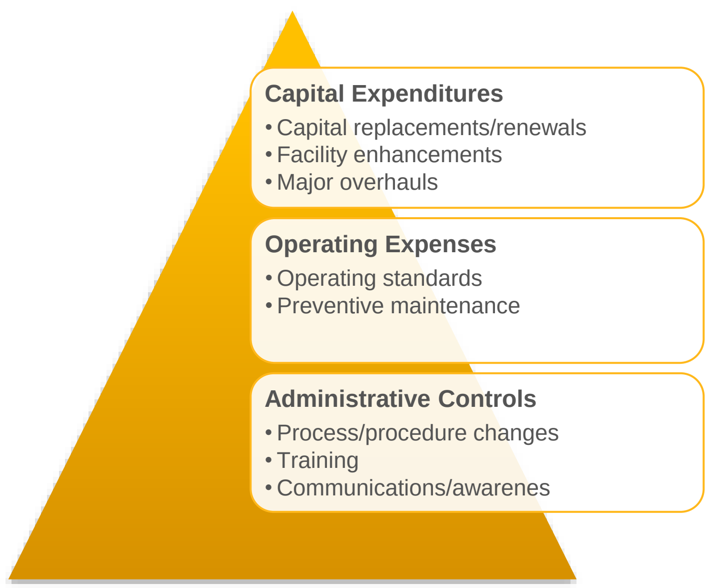


Figure 4.2-4: Spectrum of Risk Treatment Options

4.2.1.4. Monitor Risks

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

4.2.2 Solution Planning

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

Table 4.2-2: Project and Program Descriptions

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

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

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

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

Table 4.2-3: Estimate Classes

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

4.2.3 Portfolio Optimization

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

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

Once an investment is classified and verified as compliance and/or mandatory based on EGI's defined criteria in **Table 4.1-3**, portfolio optimization begins. Investments identified as mandatory and/or compliance are automatically slotted at the required time, rather than using risk and cost to determine optimal timing. Those identified as neither compliance nor mandatory are free to shift within the optimization timeframe.

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

Optimization scenarios are determined through the consideration of the following:

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

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

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

4.2.4 Portfolio Delivery Management and Annual Program Plan Execution

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

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

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

4.2.5 Performance Measurement

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

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

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

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

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

The annual budget process defines capital allocations to investments based on a review of project scope, cost, compliance requirements, risk and value.

Scope Delivery to Plan is the comparison of the approved portfolio project list to actual projects completed at the end of the fiscal year. Variances are explained to ensure the Asset Management Framework is supporting the reduction of risk and realizing optimal asset value.

Capital Budget Delivery to Plan is informed monthly by the capital forecast. This ensures the governance and controls are in place to optimize the capital plan while operating within an approved budget. It also supports continuous improvement for cost estimating, where the variance between estimate and actual costs are understood and learnings are incorporated in future planning.

Asset Class Objectives have been defined for all asset classes at EGI. These objectives, aligned with asset management goals and principles, outline asset requirements to support successful business operations. Life cycle management is applied across all asset classes to specify strategies that govern decision-making throughout the four stages of the asset life cycle: Design/Construct, Operate, Maintain and Renew/Retire. Adherence to the asset class objectives and life cycle strategies ensures consistent and holistic evaluation of risks and opportunities, setting the foundation for successful asset planning and value realization. Asset class objectives are found in Customers and Assets (**Section 5**).

The **Asset Management Scorecard** will detail specific asset management execution elements supporting the overarching asset management strategies. As asset management is a management program within EGI's Integrated Management System, the asset management programs for the legacy companies are being integrated. As part of this work, an asset management scorecard will be established. The scorecard will inform senior management of the effectiveness of the Asset Management team in maturing the asset management system.

4.2.6 Asset Information, Tools and Asset Analytics

The asset management core process relies on asset analytics, asset information management, and the tools and processes to inform decisions and activities. Like other assets, data requires processes and controls to govern its acquisition, use, maintenance and final disposition. This section outlines the methods and tools (unique to each asset class) used at EGI to manage data and use it for analysis in a fully supported and repeatable way.

One of the prominent components of the Value-Based Asset Management Model is its evidence-based decision-making capability for assets. As assets used for EGI's business functions are diverse, the analytics required to support optimal decision-making along with risk, cost and performance will vary for each asset. Asset analytics aims to use these analytical techniques to make decisions about asset acquisition, creation, utilization, maintenance and renewal/retirement, as well as establish a governance framework around data and analytics to produce consistent and reliable outputs.

The EGI analytical modelling process consists of two broad stages - input data processing and data analysis. Input data for analytical requests can come from various datasets available from internal and external sources. Raw data requires extracting attributes from different data sources, inspecting these attributes for data quality and integrity, managing data issues and transforming the cleansed data attributes to a predefined format to be used in analytics. Once raw data is processed, analyses can begin.

Two broad types of analysis are performed - **Exploratory Data Analysis** and **Analytical Modelling**. Exploratory data analysis uses graphical data displays to summarize and identify data characteristics without using complex mathematical or statistical concepts. Analytical modelling uses mathematical or statistical concepts to analyze data. Analytical modelling is different for each modelling task due to the heterogeneity of assets, data availability and analytical requirements or objectives. Four types of analytical models were used to cater to these heterogeneous modelling needs:

- **Descriptive analytics** uses analytics to provide insight into the past and to answer the question "What has happened?". An example of the type of analysis is analyzing historical work orders from the asset management system to analyze how many corrosion-related failures were observed in the distribution network.
- **Diagnostic analytics** is a form of analytics that examines data or content to answer the question "Why did it happen?". An example of this type of analytics would be identifying root cause for a regulator failure on a sales station.
- **Predictive analytics** uses a variety of techniques to make predictions about the future to answer the question "What could happen?". An example is the creation of leak projections and remaining asset life using reliability engineering and statistical concepts.
- **Prescriptive analytics** helps advise on possible outcomes and to answer the question "What should we do?". An example is the use of C55 to prescribe and optimize asset investment planning for the next five years.

Development of an analytical model is an iterative process that progresses from business understanding to consumption of results. As stated in **Section 4.1.2**, these analytical models are used to extract vital knowledge from available data and support evidence-based decision-making at EGI. Some examples of these outputs are as follows:

- Value framework
- Probability of failure and asset health indices
- Decision support tools

.

4.2.6.1. Asset Information Management

Asset information derived from structured and unstructured data, supported by EGI and industry knowledge, is leveraged for asset analytics and modelling to:

- Assess the condition of the asset
- Support and predict risk and opportunity assessments
- Inform and support asset health reviews and engineering reliability assessments
- Establish asset inventory and population over time
- Ensure compliance with EGI policy and regulatory requirements
- Make operational asset decisions, e.g., emergency response
- Ensure safe and reliable operations e.g., core work, maintenance

Data for EGI's assets is categorized as follows:

- **Master data**: Master data captures attributes and characteristics of EGI's assets. Some examples of master data include identification of the asset, location and material/equipment etc.
- **Reference data**: Material specifications and codes are used to classify asset records as they are created and updated.
- **Planning data**: Information such as preventive maintenance plans is used to plan and execute maintenance activities needed to optimize asset performance.
- **Transactional data**: Different interventions on the asset, such as inspection, repair and decommissioning etc., are captured under transactional data.

To ensure the availability of information required for operational and strategic decisions now and in the future, EGI continuously assesses the condition of its asset data through various means:

- **Data quality metrics and reporting**: EGI runs reports according to set schedules on data sets pertaining to the asset classes.
- **Data profiling**: On a periodic basis, statistical profiles of the data housed in key enterprise information systems are generated. Reviewing these results with business users allows for criticality assessments of business data usage and prioritization of data validation activities.
- **Business process evaluation**: On a periodic basis, key business processes producing and consuming asset data (whether recently created or historical) are completed. Data gaps and issues that were identified at different data management stages are ranked and prioritized for remediation based on relative impact on the processes and modelling that use the underlying data.

Generally, asset data captured is fit-for-use for operational process-related tasks (such as construction and maintenance operations), however, it requires further refinement to be used for analytics (such as a risk assessment or an asset health review). Current data management efforts include:

- **Data improvements**: Data corrections to historical records that are not fit-for-purpose are performed on a periodic basis. Data sets are prioritized for remediation according to business needs and process impacts.
- **Records management**: Ongoing efforts to capture unstructured data identifies and catalogues historical installed plant records in content management systems to achieve compliance with records management policies on retention and accessibility.
- **Data governance**: EGI has established a framework introducing policies, principles and standards to implement data governance for asset data. As a part of the framework, data stewards monitor and keep abreast of data quality issues, advise business users on the proper use of data and identify and champion data improvements.
- **Metadata compilation**: Data stewards and other SMAs are engaged in the gathering, drafting and compilation of system data dictionaries and other documentation to capture information about different data sets, improving the use of data to meet specific business needs.

Projects are currently underway or being planned to improve asset data and maintain records management compliance. Findings of these data enhancement efforts will be used to improve the entire asset data life cycle, to complete the Plan-Do-Check-Act cycle of continuous improvement.

4.2.6.2. Tools

Multiple tools are used to store, extract and analyze data, catering to evolving data needs and usage and to support this Asset Management Plan. Different technologies are used in EGI to store master and transactional data. Data extraction tools are used in extracting, transforming and loading data and information residing in different data repositories. Once data is loaded and ready, analytical models are used to support asset management decision-making. **Table 4.2-4** outlines the data systems that hold various forms of asset data (master and transactional) and the different software tools used at EGI.

Table 4.2-4: Data Systems and Tools

System	Description
SCADA	Supervisory Control and Data Acquisition system to monitor and control network operations
Click Mobile	Field mobility solution used to complete Maximo work orders and update asset information
FAST	Tool used to collect condition data at Network Operations sites, combined with other information, to prioritize stations for replacement
Maximo (Gas Distribution)	Enterprise asset management system containing master data on gas-carrying assets, related work and preventive maintenance plans
Maximo (Gas Storage)	Enterprise asset management system containing master data on gas storage assets, related work and preventive maintenance plans
Flagship Navigator, Fleet Element and Fleet Focus	Fleet management software containing information related to vehicles, heavy equipment and tools.
Cloudera, Hadoop	Data lakes used to store structured, semi-structured and unstructured data possessing the capability to store and perform analytics on big data
Oracle	Systems used by Finance to store information related to customers and finances in EGI
SAP-PM	Source of record for stations and Storage and Transmission facilities assets and associated plant maintenance Used to store station-related leak information
ServiceNow	Service management tool containing information and requests related to TIS assets
ArcGIS, Hexagon	Geographical representation of gas-carrying assets Includes modules for leak and cathodic protection surveys
SQL Server	Tool used to extract data from data repositories
Copperleaf C-55	Value framework and investment repository used for portfolio optimization
RiskMaster	System used by Claims and Insurance services to track damage incidents
SAS, Reliasoft, Matlab	Software packages that support advanced analytics and statistical data processing capabilities to perform rigorous analytical tasks
Python	Open source software tool used to automate data and execute extract, transform and load (ETL) tasks
Excel, Access	Various tools are developed on these applications before being migrated to a more robust platform.
Power-BI	Data visualization and dashboarding software tool
IBM - SPSS	Tool used to support the development of decision support tools, failure classification tools, probability of failure models and risk models
PIM - Slider (Pipeline Risk and Integrity Management)	Tool used to determine the expected remaining life of a pipe asset based on in-line inspection data and a crack propagation model
Service Suite	Tool for managing leaks and storing leak history
CORR; GL Essentials	Tool for managing corrosion survey information

.

5. Customers and Assets

This section provides details on the following for each asset class:

- EGI's customers and the customer growth projections
- Asset class objectives, risks and opportunities
- Asset inventory and condition
- Strategic plans to meet life cycle strategies

EGI delivers energy and related services to about 3.7 million residential, commercial and industrial customers, heating over 75 percent of Ontario homes.

In **Figure 5.0-1**, it can be seen that natural gas delivers a significant portion of Ontario's energy needs on both a peak and average basis. EGI is well-positioned to provide affordable energy and contribute positively to the low-carbon economy through the safe and reliable delivery of natural gas and a commitment to low-carbon alternatives such as hydrogen blending and renewable natural gas. Natural gas continues to be cost-effective when compared to electricity.

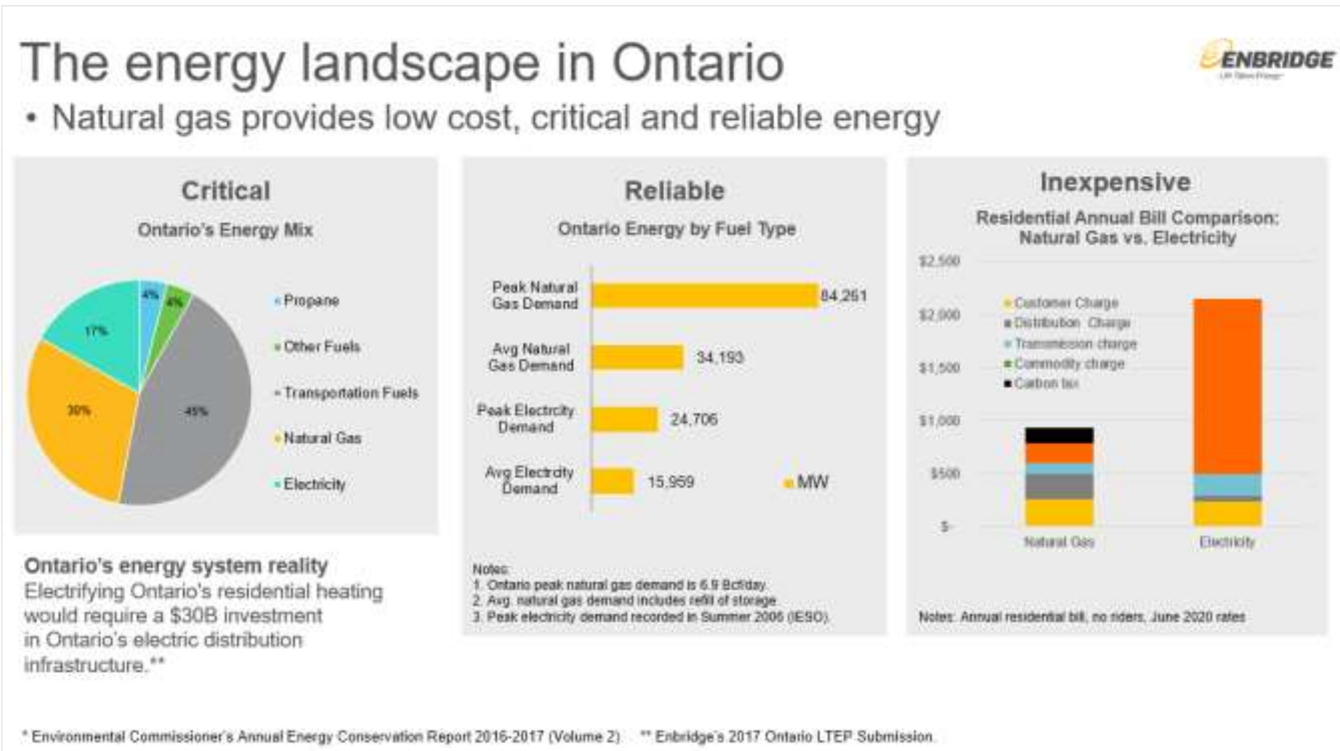


Figure 5.0-1: The Energy Landscape in Ontario

EGI also provides natural gas storage and transportation services for other utilities and energy market participants in Ontario, Quebec and the United States. EGI's storage and transmission system forms an important link in the movement of natural gas from Western Canadian and U.S. supply basins to Central Canadian and Northeast U.S. markets.

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

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

EGI has a network of natural gas assets that serve to receive, store, transport and distribute natural gas. **Figure 5.0-2** shows how these assets and those that support them are interconnected to provide safe and reliable natural gas to EGI's customers.

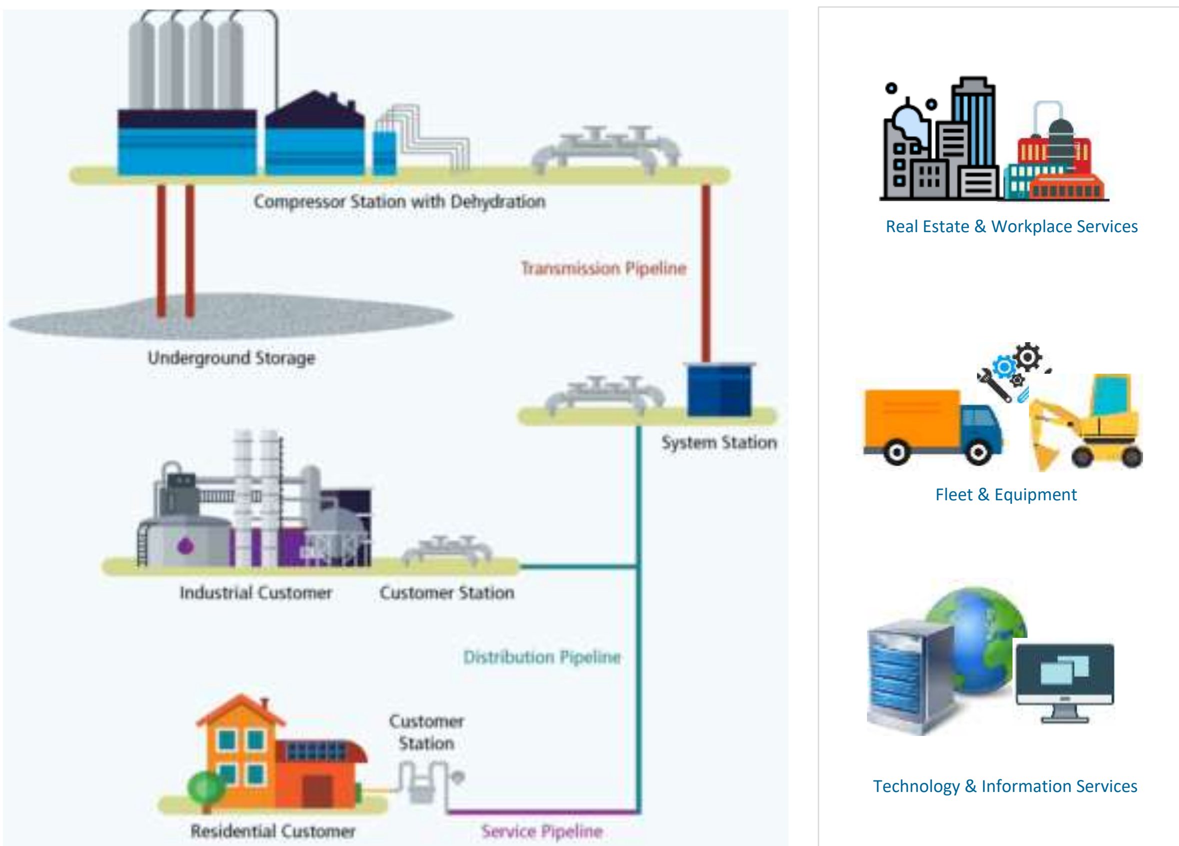


Figure 5.0-2: Components of a Natural Gas System and Supporting Assets

5.1 Growth

EGI delivers safe and reliable natural gas to over 3.7 million customers, forecasted to grow over the five-year period of this Asset Management Plan. EGI services residential, commercial/bulk-metered, multi-family/apartment and industrial customers within its franchise areas.

The Growth asset class consists of the addition of new customers based on new housing or business starts, customers converting to natural gas from another fuel source as well as equipment and service upgrades to accommodate existing customer load growth. The Growth asset class is divided into three asset subclasses:

- **Customer Connections** evaluates customers' natural gas consumption needs and ensures demands are assessed and processed in accordance with the guidelines prescribed in the *EBO 188* report. The assets and costs within this asset subclass include materials and installations of distribution mains, services, meters and regulating equipment.
- **Distribution System Reinforcement** projects involve the installation or modification of existing gas distribution assets to maintain minimum required system pressures, maintain distribution capacity and meet growing natural gas demands. These projects are primarily driven by increased customer demand, customer growth and system reliability considerations.
- **Transmission System Reinforcement** projects involve the installation or modification of existing gas transmission assets to maintain minimum required system pressures, maintain distribution capacity and meet growing natural gas demands in accordance with the *EBO 134* report. These projects are driven by increased transmission interconnect demand as well as increased franchise demand. Capital costs related to transmission system reinforcements are included in the expenditure summary for the Transmission Pipe and Underground Storage asset class (**Section 5.5.8.5**).

EGI continues to evaluate the scope of its carbon strategy and subsequent impact on customer growth forecasts, which includes the Integrated Resource Planning (IRP) initiative. Refer to **Section 3.3** for an overview of IRP activities.

EGI continues to look for ways to reduce its carbon footprint including the introduction of renewable natural gas and hydrogen blending. Risk assessments have been completed as part of project development for these new facilities. As they age, strategies for maintenance and replacement will be established. As government regulations are set and enacted, EGI will continue to respond with programs and projects to meet these requirements with its various existing assets in addition to new assets.

EGI continues to look at ways to extend the footprint of natural gas service within its franchise area, consistent with the requirements of *EBO 188*.

The Growth capital expenditure requirements for materials and asset installation is based on forecasted customer growth over the next five years. Capital expenditure requirements related to the condition of existing assets (mains, services, measurement, regulating equipment, etc.) are addressed in the **Pipe**, **Distribution Stations**, **Utilization** and **Storage and Transmission Operations** asset classes.

.

5.1.1 Growth Objectives

The Growth asset class is a key component of the Design/Construct stage of EGI's Asset Management life cycle. It supports EGI's investment in new assets related to customer growth. Growth objectives are listed in **Table 5.1-1.**

Table 5.1-1: Growth Asset Class Objectives

Asset Class Objectives	
System Growth	Ensure an engaged and positive customer experience.
	Ensure EGI provides new or upgraded natural gas services to residential, apartment, commercial, industrial and transmission customers.
	Reinforce transmission systems to economically serve short- and long-term demand requirements.
System Integrity and Reliability	Reinforce existing transmission pipeline systems and distribution networks to ensure capacity and reliably meet current and future customer demand.

The performance measures for the Growth asset class are:

- Number of networks forecasted through the long-range planning process to drop below minimum operating pressure
- Number of customer additions

To achieve the Growth asset class objectives listed in **Table 5.1-1**, asset investment decisions are governed by the life cycle management strategies outlined in **Table 4.1-1**.

5.1.2 Growth Asset Class Hierarchy

The Growth asset class hierarchy is depicted in **Figure 5.1-1**.

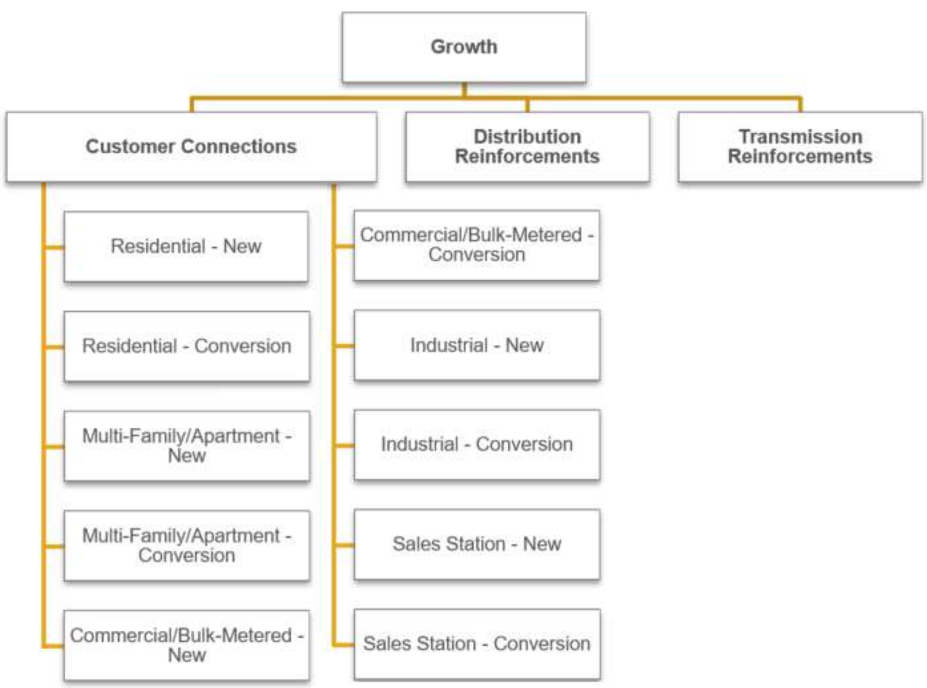


Figure 5.1-1: Growth Asset Class Hierarchy

5.1.3 Growth Inventory

Note: This section only applies the Customer Connections asset subclass.

EGI services residential, commercial, multi-family/apartment and industrial customers - **Figure 5.1-2** to **Figure 5.1-5** profiles EGI's existing customer base by type and location (see **Section 2.3.1** for a map of the EGI operating regions).

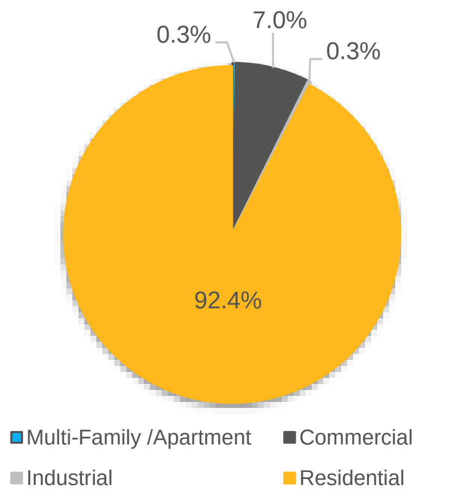


Figure 5.1-2: Customer Breakdown by Type – EGD Rate Zone

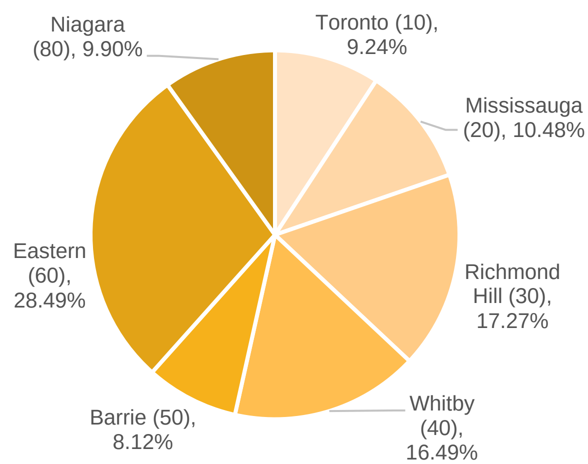


Figure 5.1-3: Customer Breakdown by Area – EGD Rate Zone

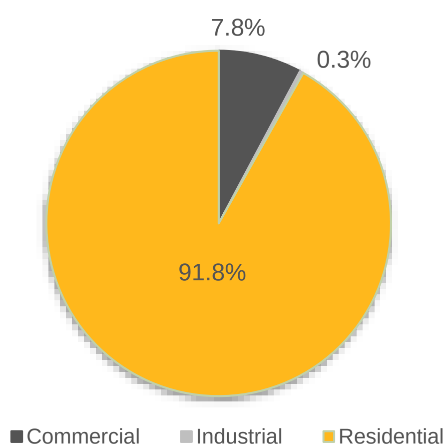


Figure 5.1-4: Customer Breakdown by Type – Union Rate Zones

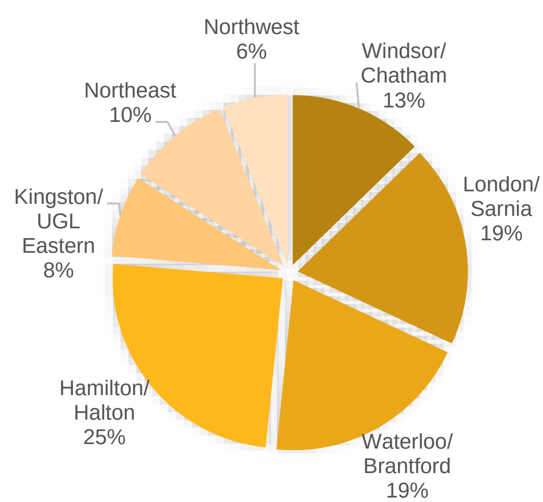


Figure 5.1-5: Customer Breakdown by Area – Union Rate Zones

For the Union rate zones, efforts are underway to recategorize multi-family/apartment customer data to align customer classifications as part of integration activities.

.

Table 5.1-2 describes EGI's customer classifications:

Table 5.1-2: Customer Definitions

Customer Type	Subtype	Customer Definition
Commercial / Bulk Metered Uses natural gas for commercial purposes, buying and selling goods or services usually for a profit.	Commercial New Construction	A customer intending to operate a commercial business (including apartment buildings with one bulk meter) in a newly-constructed building and intending to use natural gas to meet energy needs.
	Commercial Conversion	A commercial customer using a fuel other than natural gas for commercial business and is converting to natural gas.
Multi-Family / Apartment Uses natural gas for residential purposes in a large building with multiple residential suites that are individually metered.	New	A traditional apartment customer is a multi-residential dwelling containing more than six units that are metered individually.
	Conversion	A multiple unit residential building where each suite is individually metered.
Industrial Uses natural gas for commercial purposes, manufacturing or processing products.	Industrial New Construction	A customer intending to run an industrial manufacturing business in a newly-built facility and intending to use natural gas.
	Industrial Conversion	An industrial facility using a fuel other than natural gas for industrial purposes and is converting to natural gas.
Residential Uses natural gas for residential purposes.	Residential New Construction	A new residential construction development of homes constructed by a builder for domestic purposes. This includes new subdivisions.
	Residential Conversion	A residential customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.

5.1.4 Growth Condition and Strategy Overview

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

** Capital costs related to transmission system reinforcements are included in the expenditure summary for Transmission Pipe and Underground Storage (**Section 5.5.8.5**).*

.

5.1.5 Customer Connections

The Customer Connections asset subclass consists of the addition of new customers based on new housing or business starts, customers converting to natural gas from another fuel source, as well as equipment and service upgrades to accommodate load growth of existing customers. These customers are connected in accordance with the feasibility guidelines prescribed in the *EBO 188* report. The assets and costs associated with connecting these customers include materials and installations of distribution mains, services, meters and regulating equipment.

EGI expands its distribution system in accordance with the OEB's guidelines for the expansion of natural gas service. The intent of these guidelines is to facilitate the rational expansion of natural gas service while protecting existing customers from undue cross-subsidization. Factors evaluated include: the number of potential new customers, their gas consumption and the cost of extending gas mains. Details on these requirements are in **Section 5.1.5.1**.

Each year, EGI develops a customer additions forecast using a number of information sources. Details on this process and projections for each rate zone are in **Section 5.1.5.2**.

Capital investments, such as material and labour costs, are required to support new customer connections. Details on the capital investment forecast are in **Section 5.1.5.3**.

A summary of EGI's strategy for connecting new customers is in **Section 5.1.5.4**.

5.1.5.1. Customer Connections Feasibility

EGI uses a portfolio approach (Investment Portfolio and Rolling Project Portfolio) to manage system expansion activities and ensures that required profitability standards are achieved at both the individual project and the portfolio level.

- **Investment Portfolio**: This approach evaluates feasibility on all proposed new distribution customer attachments for a particular test year and ensures required portfolio profitability index (PI) thresholds are achieved. The portfolio includes the costs and revenues associated with all new distribution customers forecasted to be attached in a particular year (including new customers attaching to existing main or infill services). It also ensures there are no undue cross-subsidizations in the short term. The investment portfolio is designed to include a safety margin to mitigate the forecast risk and achieve a PI threshold greater than 1.0.
- **Rolling Project Portfolio (RPP)**: This approach maintains a portfolio of system expansion projects over a rolling 12-month period. RPP is used as a management tool for estimating the future impact of capital expenditures associated with system expansion. RPP excludes customers attaching to existing mains (infill services). RPP is required to achieve a PI threshold greater than 1.0.

The OEB's view, as set out in *EBO 188*, is that by assessing the financial viability of all potential customers as a group (using a portfolio approach), more marginal customers could be served as a result of assessing the cost of serving them together with more financially viable customers.

Feasibility analysis of individual customer connections (i.e. a project) is carried out by using the guidelines prescribed in *EBO 188*. A feasibility analysis determines whether a project meets financial requirements and ensures there is no undue cross-subsidization over the project life cycle. This is accomplished by calculating the profitability index (PI) of the project based on its future revenues versus the costs.

The profitability index is a ratio of a project's revenues against its costs. PI = 1.0 represents the value of a project's revenues being equal to the project's costs. This means that over the life of the project, project revenues will cover the entire project cost, ensuring the project will be economically feasible.

The OEB, through *EBO 188*, expects utilities to maintain a PI of 1.0 or greater at a portfolio level. Each distribution project must meet a PI of at least 0.8 in order to be included in a utility's Rolling Project Portfolio. EGI is recognizing increased costs to add customers as a result of inflation and changes to construction practices to reduce the likelihood of sewer lateral cross bores in the future.

5.1.5.1.1 Feasibility Process

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

.

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

When the present value of revenues is less than the present value of costs, customers will be asked to pay a Contribution In Aid of Construction (CIAC). The CIAC is the amount by which the project capital costs must be reduced by the customer to make the project feasible (i.e. to achieve the required PI threshold).

Feasibility Formula:

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

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

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

Costs: Direct capital costs for a project may include materials (pipe, couplings, meter sets, etc.), labour and equipment to install or construct the project and reinstatement of the surface (such as road, sidewalk, landscaping).

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

5.1.5.2. Customer Growth Forecast

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

There are important data considerations using this approach. For instance, a primary data source used in predicting growth is historical housing starts from Canadian Mortgage and Housing Corporation. For growth projections particularly in the apartment sector, housing starts are much higher than the customer additions in the sector.

Based on known applications and development projects, a consolidation of forecasts and known projects are used to determine the final customer growth forecast.

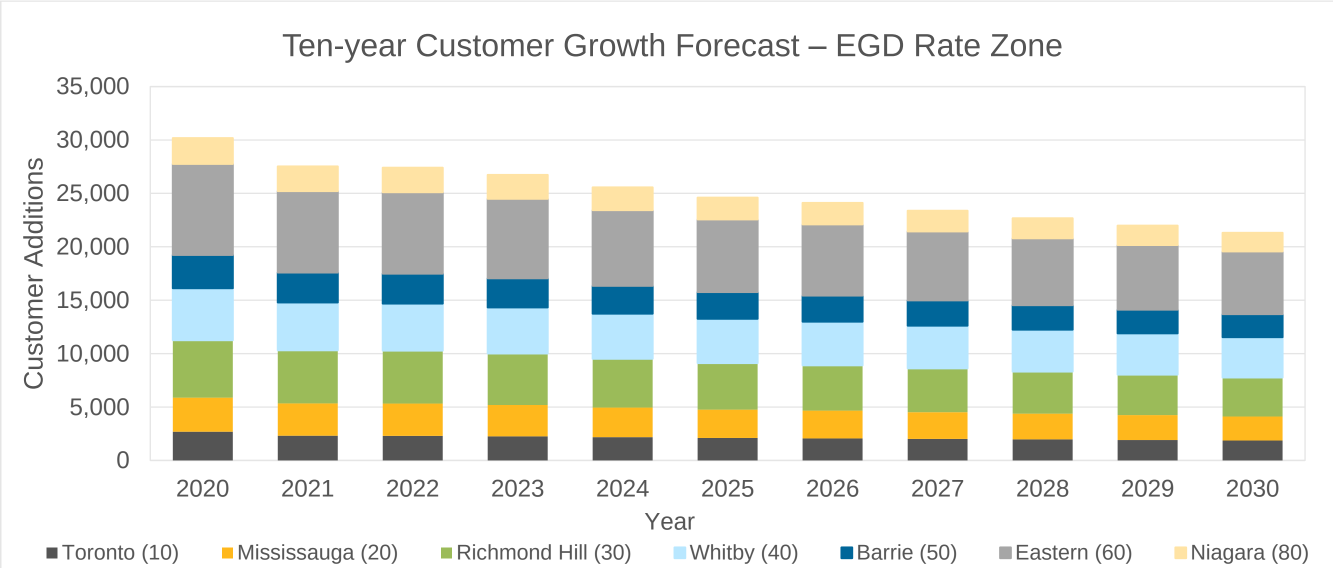


Figure 5.1-6: Ten-year Customer Growth Forecast – EGD Rate Zone

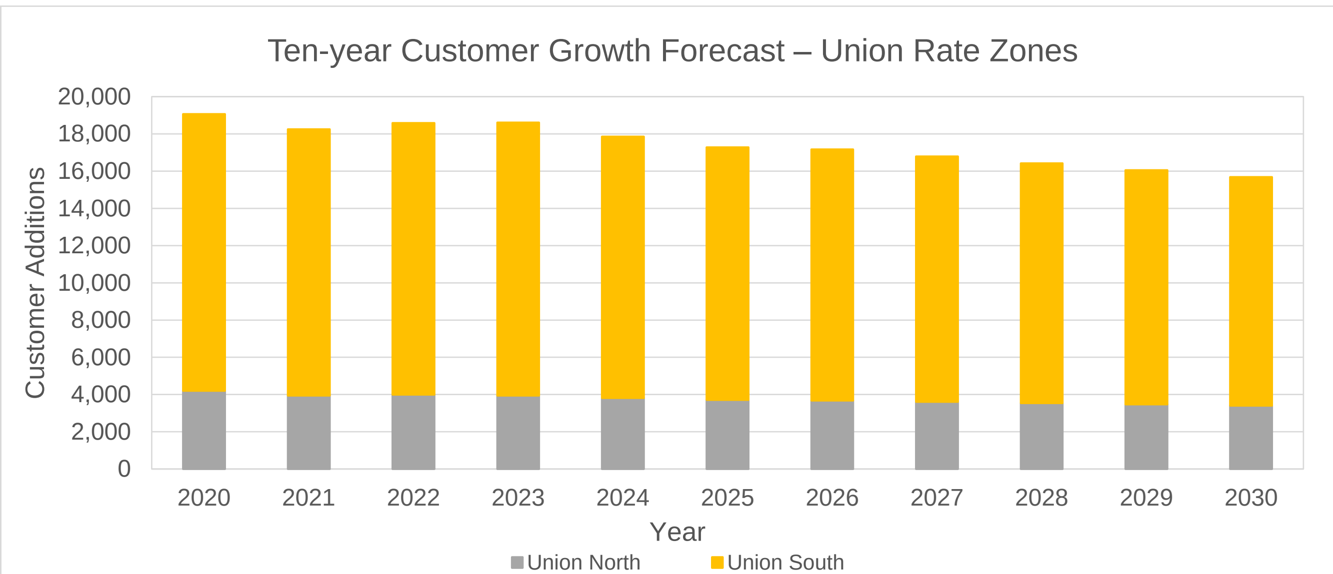


Figure 5.1-7: Ten-year Customer Growth Forecast – Union Rate Zones

In 2019, EGI's customer growth was approximately 44,200 new customers. Between 2020 and 2030, EGI's customer growth is forecasted[10] to be more than 40,000 customers annually. Key insights relating to the customer growth forecast:

- Relative to 2019, housing starts are projected to remain flat in the short term and slightly decline thereafter.
- Due to the increasing scarcity of land supply and the associated increase in housing prices in EGI's franchise areas, particularly in the Greater Toronto Area (GTA), non-apartment housing starts in the area have seen a decline.
- Urban density in EGI's franchise areas is reflected in the fact that apartments have been accounting for a larger share of total housing starts. Given that one building counts as a single customer because of the use of bulk meters, lower customer additions do not reflect lower loads served, but simply a shift in the makeup of the sectoral source of growth.

[10] *Investments based on July 2020 forecast.*

.

- Steady residential growth in the new construction sector is reflected in the strong additions in areas covering the GTA, which includes the regions of Peel and York.

Replacement (conversion to natural gas) customers have been declining over the last six years for both rate zones and this trend is expected to continue as demonstrated in **Figure 5.1-8** and **Figure 5.1-9**.

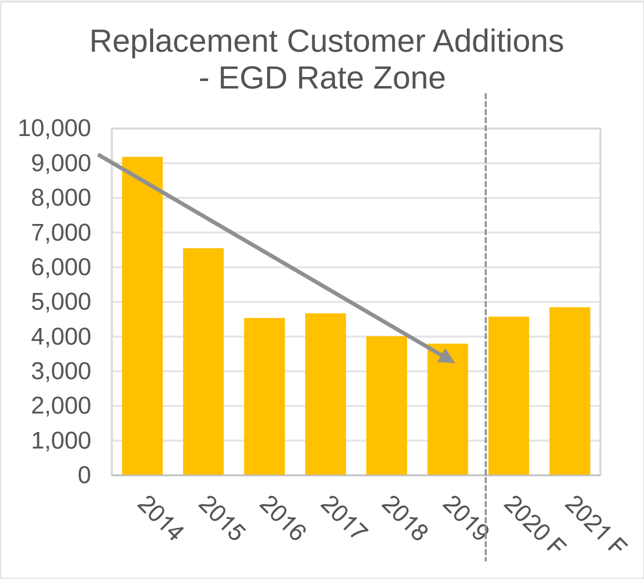


Figure 5.1-8: Replacement Customer Additions – EGD Rate Zone

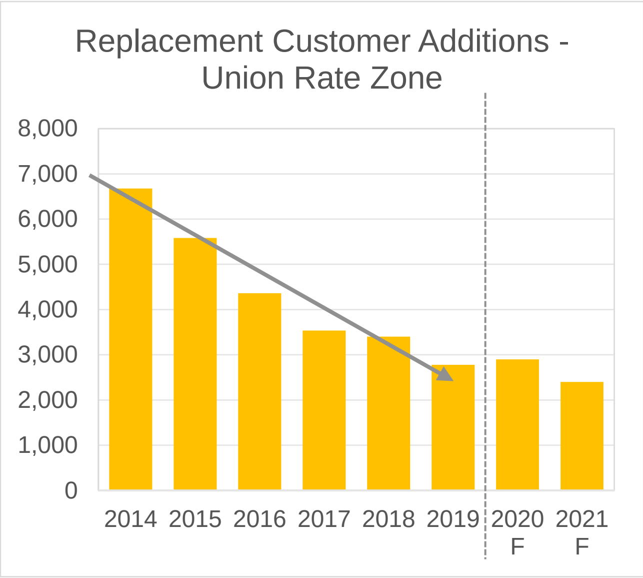


Figure 5.1-9: Replacement Customer Additions – Union Rate Zones

Based on the customer growth forecast methodology described in **Section 5.1.5.1**, **Figure 5.1-10** and **Figure 5.1-11** represent the forecasted number of customers over 10 years by sector.

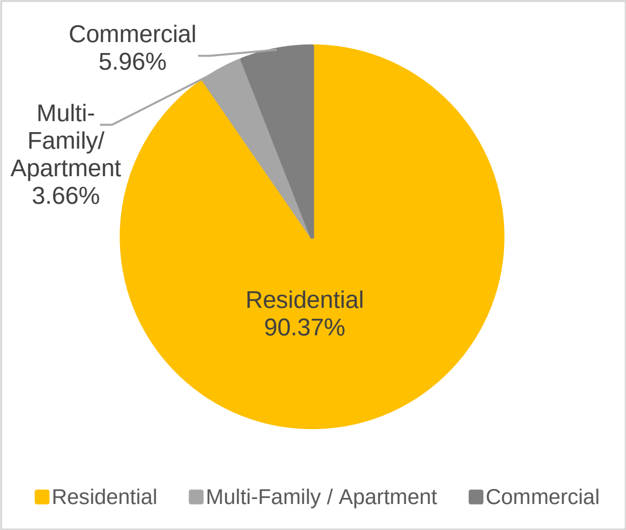


Figure 5.1-10: Ten-year Customer Growth by Sector – EGD Rate Zone

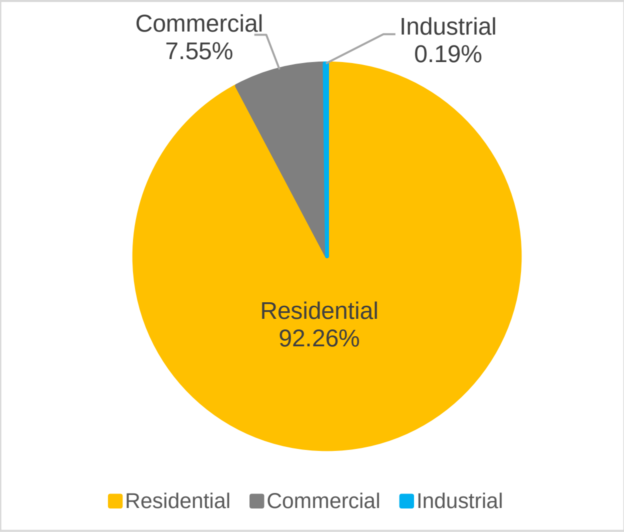


Figure 5.1-11: Ten-year Customer Growth by Sector – Union Rate Zones

The customer additions by sector reflect continued residential growth over the forecast period in both the residential subdivision and residential replacement (conversion) markets, accounting for over 90% of customer additions growth.

.

5.1.5.3. Customer Connections Capital Expenditure Forecasting Methodology

Customer Connections capital expenditure requirements include the direct costs associated with the material and installation of mains, services and regulator stations. Meter installation costs are included as part of the direct capital cost within the Customer Connections budget; however, the cost of the metering equipment/instrumentation is accounted for in the Utilization asset class.

Generally, three components of capital investments are needed to support customer addition requirements:

- Material costs related to mains, services and meters. These costs can vary according to size and type of materials.
- Installation costs related to mains, services and meters. These costs can vary according to permits, fees, land rights and construction complexity (e.g. horizontal directional drilling, sensitive environments, geo-technical considerations, proximity to existing infrastructure).
- Costs related to measurement and regulation equipment required to support customer growth.
- Improvements to construction practices to support the long-term safety and reliability of assets

The Customer Connections capital expenditure required to facilitate the connection of new gas customers include:

- Attachments from residential subdivision (Residential New)
- Residential replacement i.e., fuel conversions of existing homes (Residential Conversion)
- Commercial buildings (Commercial New and Commercial Conversion)
- Multi-family/apartment (New and Conversion)
- Industrial facilities (New and Conversion)

5.1.5.3.1 Methodology

One of the key drivers of Customer Connections capital requirements is the historical spend profile in each area. Capital spend is not uniform across all areas, as some areas have inherently higher costs (e.g., hard rock, type of joint trench agreements, densely populated areas and type of customers predominantly being attached). Based on the historical spend in each area, combined with forecast customer additions and inflation, the five-year capital expenditure forecast is determined. The capital requirement includes an allowance for some localized main extensions and operational considerations. Historically, material costs account for 17% and labor costs account for 83% of growth direct capital.

Other capital cost considerations:

- Type of customers requiring connection: each customer class has different infrastructure requirements.
- Type of connection (greenfield vs. urban infill/growth): greenfield expansions are less expensive.
- Joint Utility Trenches (JUT) in greenfield areas save costs and are safer because there is a single excavation.
- Time of year: construction costs in winter months are generally higher and carry winter premium costs.
- Environmental: system growth in conservation areas or green spaces have incremental costs.
- Long term contracts with construction partners can provide cost savings.

5.1.5.4. Strategy Outcomes

The strategy for the Customer Connections asset subclass is to continue to ensure that required infrastructure is installed for the addition of all forecasted customers that are feasible under *EBO 188* guidelines, while following current forecasting practices in each rate zone. EGI continues to monitor and update the customer additions forecast through the annual long range planning process. EGI continues to evaluate the scope of its carbon strategy and subsequent impact on customer growth forecasts, based on the outcomes of the IRP application.

Customer growth forecasts for each rate zone are similar at a high level. However, each rate zone will continue with current methods of preparing a customer growth forecast as part of integration activities. Note that at present, each rate zone maintains separate New Business Policies with a notable difference in the service connection fees, $32/metre after 20 metres for the EGD rate zone and $45/metre after 30 metres for the Union rate zones.

For the EGD rate zone, the OEB ruled in 2019 that EGI must revert back to its previously approved 2015 New Business Policy based on the 20-metre rule and fixed cost per metre thereafter. The capital budget for the EGD rate zone was increased accordingly for 2020 and thereafter to reflect a forecast reduction in the amount of CIACs being collected from customers under the old policy.

.

.

5.1.6 Distribution System Reinforcement

System reinforcements refer to asset investments required to maintain minimum system pressures, so that demand for gas can be met on design day conditions.

Distribution reinforcements refer to investments to the distribution system. These investments must meet the requirements of *EBO 188* (see **Section 5.1.5.1)** or *EBO 134* as applicable. Details on the process for identifying and planning these investments are in **Section 5.1.6.1**.

Distribution system reinforcement projects involve the installation or modification of existing gas distribution assets to maintain minimum required system pressures, maintain distribution capacity and meet growing natural gas demands. These projects are primarily driven by increased customer demand, customer growth, identification of system low pressure points, capacity constraints and other system reliability considerations.

This strategy fosters long-term system reliability and the ability to serve existing and forecasted customers during peak design temperature conditions. Failure to implement reinforcement projects in a timely manner could potentially lead to an inability to support future customer growth and the potential loss of existing customers during peak demand periods.

As part of the asset management planning process, EGI establishes reinforcement needs and timing for all operating regions, ensuring the system meets anticipated peak hourly demand. Load additions to the system are modelled based on design temperatures in **Table 5.1-3** and **Table 5.1-4** for the EGD and Union rate zones respectively.

Forecasting methodologies will be reviewed as part of integration activities.

Table 5.1-3: Temperature Criteria for Load Additions – EGD Rate Zone

Temperature Region	Design Temperature	Degree Day
Peterborough and Campbellford (Area 40)	-28 C	46
Georgian Bay and Barrie (Area 50)	-26 C	44
Ottawa Area (Area 60)	-29 C	47
Greater Toronto Area (Area 10,20,30)	-23 C	41
Niagara Area (Area 80)	-21 C	39

Table 5.1-4: Temperature Criteria for Load Additions – Union Rate Zones

Temperature Region	Design Temperature	Degree Day
Union North		
Northeast		
Zone 1 Fort Frances	-36.7 C	54.7
Zone 2 Kenora	-37.9 C	55.9
Zone 3 Thunder Bay	-33.6 C	51.6
Zone 4 Kapuskasing	-37.6 C	55.6
Zone 5 Timmins	-37.7 C	55.7
Zone 6 Earlton	-37.7 C	55.7
Northwest		
Zone 6 Earlton	-37.7 C	55.7
Zone 7 Sudbury	-33.9 C	51.9
Zone 8 Sault Ste. Marie	-30.2 C	48.2
Zone 9 North Bay	-34.5 C	52.5
Zone 10 Gravenhurst	-31.3 C	49.3
Eastern		
Zone 11 Trenton	-27.7 C	45.7
Zone 12 Kingston	-29.1 C	47.1
Zone 13 Cornwall	-31.2 C	49.2

.

Temperature Region	Design Temperature	Degree Day
Union South		
Windsor Operating Area	-25.1 C	43.1
London Operating Area	-25.1 C	43.1
Waterloo Operating Area	-25.1 C	43.1
Hamilton Operating Area	-25.1 C	43.1
Halton Operating Area	-25.1 C	43.1

5.1.6.1. Condition Methodology

Identifying Purpose, Need and Timing of Reinforcements: EGI identifies four major functions required as part of planning for reinforcements: Load Gathering and Simulation, Annual Forecasting and Long Range System Planning.

EGI builds and validates piping system models based on actual field conditions and uses pipeline simulation software to simulate pressures and flows based on customer usage data. Short- and long-term forecasted growth is incorporated into these models to predict system performance.

Load Gathering and Simulation*:* Load gathering extracts actual billed customer consumption data and matches it with locally recorded temperatures, providing EGI with a reliable, repeatable and predictable method for estimating an individual customer's peak hourly demand. Based on temperature inputs and estimated customer consumption, the base and space heating load demand for each customer is determined and assigned to selected points within the models. For large volume customers, loads are input based on measured hourly consumption and contractual parameters.

The simulation aims to compare calculated performance (pressures and flow rates) of the model versus the actual performance of the system after each winter heating season. Key system settings (i.e., station outlet pressures) in the model are adjusted to simulate actual field conditions on the selected day. The resultant pressure and flow information from the model is then compared with actual field chart or recorder readings throughout the gas distribution system.

Annual Forecasting: Based on the load gathering and simulation model, additional customer loads forecasted for the upcoming heating season are subsequently added. Overall system pressures and station flows are assessed to ensure all minimum pressures are maintained and all stations are operating within design parameters. Locations that are approaching minimum system pressure are selected for pressure monitoring - in some cases reinforcements may be required.

Long-range System Planning: The long-range system planning process considers a minimum of 10 years of customer growth to ensure the adequacy of system performance over the long term. Growth projections are based on information from builders, developers and municipalities, housing starts and other economic factors (e.g., GDP growth, employment rates etc.) as well as projections from external experts. The reliability of the system is dependent on maintaining minimum system pressures and ensuring capacity is available to support customer growth. Reinforcement solutions are considered if minimum system pressure requirements cannot be maintained with forecasted loads applied. Each reinforcement is evaluated considering any or all of the following: existing system capacity, system redundancy or looping, operating pressure, past operational history, integrity, constructability, cost, environmental impact and future expansion or development potential.

Reinforcement solutions are based on the best available information at the time long-range system planning activities are performed. Many variables may change the need, timing or scope of the reinforcement solution. For example, growth may occur earlier or later than forecasted, which may change the timing of the reinforcement.

5.1.6.2. Condition Findings

Long-range system planning activities identify a list of reinforcement projects to sustain the 10-year customer growth forecast. The forecasted customer growth is added to the distribution system provided required reinforcement infrastructure has been installed.

EGI determines the need, timing, location and scope for system reinforcement and quantifies the benefits of the reinforcement using historical and forecasted pressure and capacity at stations and at low points in the system.

Each reinforcement project is summarized in a project brief that details the following:

- **Project Purpose/Need/Timing**: Identification of key drivers affecting the need for the reinforcement, when and where forecasted pressure and capacity constraints will occur and when the solution is required.

.

- **Project Benefit**: Overall benefits (quantitative and qualitative) resulting from the proposed system reinforcement include:
  - Security of supply
  - Ability to connect future customers
  - Pressure and capacity benefits achieved
  - Length of time the reinforcement benefits will last before further reinforcement may be required
  - Benefits to system reliability
- **Identification and Evaluation of Project Alternatives**: Description of other feasible facility and non-facility alternatives that may provide similar benefit:
  - Pressure increases
  - Looping strategies that enable multiple network feeds, enhancing system reliability
  - Upsizing of existing pipe, or localized reinforcements to eliminate system bottlenecks
  - Rebuilds of existing stations or addition of new stations
  - Flow biasing
  - Project phasing over time
- **Project Risks if Not Completed:** Description of potential risks to the system if a project is not in service prior to load additions coming online (e.g., insufficient capacity, pressure drops etc.).

5.1.6.3. Risk and Opportunity

Distribution system reinforcement projects identify areas of the network where there is a potential risk of operating below minimum required pressures for safe and reliable operations. This provides EGI the opportunity to develop and manage projects that will provide service to new customers while ensuring continued reliable service to existing customers, the delivery of a low-cost energy source and efficiencies in operation. This aligns with the 2020 Customer Engagement survey results where customers are supportive of investing to maintain current levels of safety and reliability.

Reinforcement projects, which include projects being developed for security of supply and system reinforcement, are governed by the *EBO 188* report. A key principle of *EBO 188* is that existing customers should not have their rates unduly impacted by the costs of connecting new customers. **Section 5.1.5.1.1** provides further details on *EBO 188* guidelines for feasibility purposes.

To meet *EBO 188* requirements, a preliminary feasibility analysis is conducted using cost estimates, forecasted customer additions and discounted cash flow assumptions. This analysis determines the aggregate cost-benefit ratio for all reinforcement projects that are proposed as part of the Long Range Plan (for the EGD rate zone) or Facilities Business Plan (for the Union rate zones). On aggregate, the projects proposed in these plans are in the acceptable feasibility range for inclusion in this Asset Management Plan. Individual projects undergo a detailed feasibility analysis prior to construction to ensure alignment with the *EBO 188* requirements.

The value framework process in the asset investment planning tool provides additional information on risks and opportunities associated with reinforcement projects. For example, the framework can quantify risk reduced by improving system reliability through diversity of supply and quantify the forecasted financial opportunities foregone without reinforcement.

5.1.6.4. Strategy Outcomes

The strategy for the Distribution System Reinforcement asset subclass is to continue to ensure that required infrastructure is installed to enable the addition of all forecasted customers feasible under *EBO 188* guidelines, while following current forecasting practices for each rate zone. EGI continues to monitor and update the customer additions forecast through the long range planning process.

EGI continues to review the distribution system demand requirements through the long range planning process, along with continuous system monitoring. The Long Range Plan (for the EGD rate zone) and Facilities Business Plan (for the Union rate zones) are determined based on the best available information at the time and are subject to change. Changes to the forecasted number of customer additions or changes to forecasted growth locations are captured in the annual forecast review and evaluated against the long range plans. Updates are implemented as required.

Major distribution reinforcement projects reflected in the forecast include:

Rideau Reinforcement

This project will reinforce an extra-high pressure pipeline network servicing approximately 190,000 customers in the Ottawa valley and reduce volumes required from TransCanada Pipelines' pressure-reduced Ottawa lateral. The project involves approximately seven kilometres of NPS 20 pipe extending from Greenbank Road and West Hunt Club Road to Princess of Wales Drive and West Hunt Club Road.

Owen Sound Line Reinforcement

The Owen Sound area continues to grow as retirees move from the Greater Toronto Area. A current reinforcement is underway to supply increasing demands (including EPCOR) in the region - this project is the next phase in reinforcing this network to support forecasted growth. This project will install approximately 28 kilometres of NPS 16 pipe (replacing NPS 8 pipe) from Wellington Road, Harriston to the Durham gate station.

Sudbury Transmission Compressors

The Sudbury system is supported by the Liquefied Natural Gas (LNG)/compressor facility at Hagar. However, the volume of LNG available is insufficient to maintain the system in the event a historical cold winter is experienced. Higher than contracted pressures from TC Energy would be required to offset LNG utilization. This proposed reinforcement project includes the addition of two 2100 HP compressors at Marten River to increase system pressures to support Sudbury system demand. However, alternatives are continuing to be assessed - alternatives include a lift and lay pipeline project from North Bay and upgrades at the Hagar LNG plant.

5.1.7 Transmission System Reinforcement

In addition to distribution reinforcements, transmission reinforcements are required to support system-wide distribution growth, contract customer growth and depending on market conditions, ex-franchise transportation growth (specifically in Ontario, Quebec, the Maritimes and major U.S. natural gas consuming areas). The identification of the need for a capital expenditure can either be to satisfy a growth requirement or to optimize system performance of an existing asset. In either case, the process to install a new asset is the same. Capital costs related to transmission system reinforcements are included in the expenditure summary for the Transmission Pipe and Underground Storage asset class (**Section 5.5.8.5**).

5.1.7.1. Condition Methodology

EGI's transmission systems move natural gas from receipt points to delivery locations along the pipeline to meet the volumetric demands and pressure requirements of EGI's in-franchise and ex-franchise customers. The pipeline system forms the foundation for future development and provides supply capacity into many of the EGI Network Analysis models.

Transmission systems are designed to meet design day demand to ensure all firm customer demand is served on the design day. Metered data is gathered and analyzed each year to calculate demand assumptions used for system design. Although average annual consumption has been decreasing year over year, EGI has not seen a decrease in design day or peak hourly consumption.

Identifying Purpose, Need and Timing of Reinforcements: EGI completes four major activities to plan for pipeline system reinforcements: Annual Demand Development, Annual Forecast Development, Model Simulation and Short and Long Range Plans.

Annual Demand Development*:* The Load Cold process analyses daily customer consumption data and local heating degree days to estimate design day demand, providing EGI with a reliable, repeatable and predictable method for estimating customers' design day demand.

Annual Forecast Development: Incremental customer demand forecast for the upcoming winters is added to the design day demand. Various corporate growth forecasts are used including the Facilities Business Plans and the Contract Demand forecast. Customer transportation requirements (including through transportation open seasons) and Gas Supply receipts also form part of the annual forecast development. The Annual Demand and the Forecast Demand are input into simulation models to prepare the Short and Long Range Plans.

Model Simulation: EGI builds and validates the pipeline system hydraulic models used to determine short- and long-range system reinforcement plans. Models are built by extracting pipeline facility parameters from the corporate GIS system and other records. These models are validated by comparing the pressure and flow rates as calculated by the model to the actual field pressure and flow rates. Key system information such as station outlet pressures, flow rates and customer demand in the model are adjusted to match actual field conditions on the selected verification day. The resultant pressure and flow information from the model is then compared with actual field readings. The model parameters are subsequently adjusted to match the simulation to the field parameters.

Short and Long Range Plans: The Short and Long Range Plans are created to plan for the rational expansion of the system. Long Range Plans consider a minimum of 10 years of forecast customer growth to ensure EGI's ability to reliably serve customers' design day demand over the long term. The reliability of the system to serve customers on design day is dependent on maintaining minimum system pressures and ensuring system capacity is available to support customer growth. Reinforcement solutions are considered if minimum system pressure requirements cannot be maintained with forecasted demand applied. Overall system pressures and station flows are assessed to ensure all minimum pressures are maintained and all stations are operating within design parameters. Locations that are approaching minimum system pressure are selected for pressure monitoring–in some cases reinforcements may be required. Each reinforcement is evaluated considering any or all of the following: existing system capacity, system redundancy or looping, operating pressure, past operational history, integrity, constructability, cost, environmental impact and future expansion or development potential. Reinforcement solutions are based on the best available information at the time long range planning activities are performed. Many variables may change the need, timing, or scope of the reinforcement solution. For example, growth may occur earlier or later than forecasted, which may change the timing of the reinforcement.

5.1.7.2. Condition Findings

EGI determines the need, timing, location and scope for system reinforcement. Transmission system reinforcement required for in-franchise customers typically have a long planning lead time while reinforcement for ex-franchise customers can have a shorter lead time as they are driven by different factors.

.

No storage growth is forecast for the regulated asset base at this time.

The major contributing factor to EGI's recent infrastructure expansion relates to growth in natural gas production from the Marcellus and Utica shale basins (which are within 300 kilometres of Ontario) and from shippers accessing the Dawn Hub. As a result, the flow of natural gas on the Canadian and U.S. pipeline grid is changing and continuing to evolve.

EGI expects further growth along the Dawn Parkway System driven by further demand growth in the U.S. Northeast and Canadian Local Distribution Companies (LDCs).

5.1.7.3. Risk and Opportunity

The risks identified for transmission reinforcements are operational and financial risks. While the probability of risk is low, the impact–given the criticality of transmission assets to both in- and ex-franchise customers–is very high. The opportunities identified include the ability to provide gas service to meet the needs of new customers while ensuring the continued reliable service to existing customers, the delivery of a low-cost energy source and efficiencies in operation.

Two key aspects to mitigate risk are transmission system reinforcements (as required by demand) and transmission system maintenance (covered in **Section 5.5**). If reinforcements are not completed as required, there is a risk of supply shortfalls (both in- and ex-franchise) on peak operating days. A lack of supply can lead to operational and safety risks as downstream distribution systems may experience pressures below minimum to sustain operations and there could be a loss of supply to customers. As well, if interconnects are shorted, supply to other natural gas franchises can incur customer losses. The financial risks identified are potential lost revenues and possible litigation if contract commitments are not met.

5.1.7.4. Strategy Outcomes

The strategy for the Transmission System Reinforcement asset subclass is two-fold. First, to implement specific reinforcement solutions in a timely manner to enable forecasted customer growth and to support distribution growth (**Section 5.1.5**) and reinforcement (**Section 5.1.6**). Second, growth in the ex-franchise storage and transmission business is driven by economic factors such as exchange rates, interest rates and gross domestic product, but the primary driver relates to changing North American natural gas market fundamentals such as demand and supply, natural gas prices, natural gas basis differentials (the price difference between locations) and North American-wide infrastructure projects. Transmission expansion is completed in accordance with *EBO 134*.

Demand for additional long-term capacity on EGI's major transmission systems is typically met through the installation of new pipeline, station and compression facilities. Non-facility options are also considered, such as using gas supply on third-party contracts for peaking service to optimize resources. Options considered evaluate the effect on system reliability, service quality, security of supply and rates for service.

This Asset Management Plan provides an estimate of future pipeline or compression facilities and does not include any non-facility alternatives or detailed economics for alternative comparisons. If the projects identified proceed, EGI will complete a Leave to Construct (LTC) application containing detailed and rigorous examination of both facility and non-facility alternatives, including detailed costs and economics as required.

Major transmission reinforcement projects are reflected in the forecast:

2021 Sarnia Expansion Project *(EB-2019-0218)*

The 2021 Sarnia Expansion project is driven by in-franchise industrial contract rate growth. EGI filed an LTC application approved by the OEB in March 2020. This project will install 1.2 kilometres of NPS 20 pipeline from the existing Dow valve site to the Bluewater interconnect valve site and to a new LaSalle pipeline valve site. The system capacity generated will primarily serve NOVA's incremental demand and includes some future forecasted growth for the Sarnia Industrial Line (SIL) system. The targeted in-service date for this project is November 1, 2021.

Sarnia Expansion Project- Bluewater Energy Park

Based on a forecasted increase of industrial customers in the Bluewater Energy Park, additional reinforcement of the SIL system will be required. EGI plans to increase capacity through the installation of approximately seven kilometres of NPS 24 or NPS 30 pipeline from the existing LaSalle pipeline valve site to Churchill Road station, expanding customer service and station facilities and increasing SIL system connectivity to the Dawn Hub.

Sarnia Industrial Line (SIL) System

The potential aggregate volume of incremental firm demand in the Sarnia market from all customer interest received to date amounts to more than 250 terajoules per day above the demand stated in the 2021 Sarnia Expansion project (approved by the

.

OEB in March 2020). The specific volume and timing of these potential demands remains uncertain and cannot be confirmed until firm service contracts are executed with customers.

Dawn to Parkway Expansion (*EB-2019-0159*)

EGI submitted an LTC application to the OEB in November 2019 for the Kirkwall-Hamilton project, which consists of 10.2 kilometres of NPS 48 pipeline from the Kirkwall valve site to the Hamilton valve site, slated for construction in 2022. This project is required to meet increased in- and ex-franchise demands.

Dawn Parkway System

Other than the Dawn Parkway Expansion project (Kirkwall-Hamilton NPS 48) project, future Dawn Parkway System expansion projects are not included in this Asset Management Plan as expansion and timing is primarily driven by changes to North American natural gas market fundamentals. EGI will periodically conduct transportation new capacity open seasons to gauge market demand for transportation services along the Dawn Parkway System. It is anticipated that the next facilities required for expansion are at Dawn to Enniskillen and at Milton to Parkway, which will provide in- and ex-franchise customers additional access to the liquidity, storage and transportation services at the Dawn Hub to meet their market needs.

Panhandle Transmission System Reinforcement

The Panhandle System expansion is driven by in-franchise growth in Chatham-Kent, Windsor-Essex and surrounding areas, including the fast-growing greenhouse market in the Leamington/Kingsville area. Based on the current forecast for in-franchise general service and contract growth in the Panhandle Transmission System market, EGI has determined that the next Panhandle facilities for expansion will need to be in place for the 2028 winter season (construction beginning in 2027).

Panhandle Expansion

This project will install approximately 14 kilometres of NPS 30 or NPS 36 pipeline from the existing Dover transmission station, looping the existing Panhandle NPS 20 pipeline towards the Comber transmission station. Dover transmission station crossover piping will be upgraded and a new tie-in station will be required at the end of the new loop segment. Dawn measurement upgrades will also be required to accommodate gas flows into the Panhandle transmission system. Targeted for 2028.

.

5.1.8 Growth Capital Expenditure Summary

In the Growth asset class, proposed spending is organized programmatically by sector (residential, commercial and industrial) for the Customer Connections asset subclass. Distribution system reinforcements spending is organized by project. EGI has spent an average of $145M and $140M annually in the EGD and Union rate zones respectively for the Growth asset class. The total average capital spend is forecasted to be $176M (EGD RZ) and $148M (Union RZ) as summarized in **Table 5.1-5** and **Table 5.1-6.** Growth capital is further summarized as part of EGI's total five-year capital plan in **Section 6**.

Note: Community expansion spend is not included in this Asset Management Plan. Capital costs related to transmission system reinforcements are included in the expenditure summary for the Transmission Pipe and Underground Storage asset class (**Section 5.5.8.5**).

Table 5.1-5: Growth Capital Summary ($ Thousands) – EGD Rate Zone

Asset Subclass/Program	2021	2022	2023	2024	2025	Five-year Forecast
Customer Connections	**137,136**	**135,331**	**142,520**	**136,677**	**143,965**	**695,629**
Commercial	24,745	24,399	25,694	24,615	25,910	125,362
Industrial	4,865	4,797	5,051	4,839	5,094	24,645
Residential	107,527	106,135	111,775	107,223	112,962	545,621
Distribution System Reinforcements	**20,318**	**33,933**	**17,315**	**33,636**	**78,604**	**183,807**
Rideau Reinforcement	-	-	344	6,657	62,222	69,222
York Region Reinforcement	3,242	18,733	359	7,792	1,692	31,818
Amaranth System Reinforcement	244	243	-	12,316	-	12,803
Thornton Reinforcement	-	4,464	9,316	-	-	13,779
Low Carbon Energy Project: TOC Hydrogen Blending Facility	**2,667**	**-**	**-**	**-**	**-**	**2,667**
EGD Rate Zone Total	**160,122**	**169,264**	**159,835**	**170,313**	**222,569**	**882,103**

Table 5.1-6: Growth Capital Summary ($ Thousands) – Union Rate Zones

Asset Subclass/Program	2021	2022	2023	2024	2025	Five-year Forecast
Customer Connections	**75,260**	**71,699**	**76,955**	**76,640**	**82,742**	**383,295**
Commercial	-	-	-	-	-	-
Industrial	-	-	-	-	-	-
Residential	75,260	71,699	76,955	76,640	82,742	383,295
Distribution System Reinforcements	**41,688**	**45,454**	**130,447**	**16,998**	**124,272**	**358,860**
Owen Sound Line Reinforcement	-	-	181	5,757	102,718	108,656
Sudbury Transmission Compressors	-	-	66,254	-	-	66,254
Customer Stratford Reinforcement	12,595	3,651	-	-	-	16,246
NBAY: Install 12.5 km of NPS 6, Parry Sound	-	-	19,260	-	-	19,260
LOND: Goderich Transmission System, Reinforcement (11.4 km of NPS 10)	-	-	-	85	2,895	2,980
WATE - Owen Sound Reinforcement Ph 4	2,349	-	-	-	-	2,349
Union Rate Zones Total	**116,948**	**117,152**	**207,402**	**93,638**	**207,014**	**742,154**

.

5.2 Pipe

EGI's gas transmission and distribution system operates at a variety of pressures and uses a variety of specifications and materials to achieve the safe and reliable delivery of natural gas to customers. Pipe is the connection between the entry of natural gas into EGI's system and the delivery of gas to where energy is used by customers.

The distribution system takes gas from the higher-pressure transmission system and distributes it to residential, commercial and industrial customers. This is achieved through a series of pipelines of various operating pressures, regulation points that safely manage the pressure of the gas and delivery points where the gas is measured. In some cases, distribution systems are somewhat isolated, serving one or more communities from a single feed from a transmission system.

Pipe includes pipe, valves, all pipe appurtenances, services and risers installed up to Utilization components (typically, assets belonging to the Utilization asset class (**Section 5.4**) begin at the service wing-lock valve). Distribution piping can be located inside or outside of a building.

5.2.1 Pipe Objectives

Objectives of the Distribution Pipe asset class are listed **Table 5.2-1**.

Table 5.2-1: Pipe Asset Class Objectives

Asset Class Objective	Description
System Integrity and Reliability	Maintain the natural gas system to meet or exceed codes, standards and requirements of applicable governmental authorities for safety and operational effectiveness. This includes ensuring the system has the capacity to reliably meet current and future customer demand.
	Ensure the safe and reliable delivery of natural gas to end users.
	Continuously evolve the understanding of condition and risk associated with pipe assets.
	Use risk, cost and performance information to drive asset-related decisions.
Relocations	Relocate pipe assets to reduce or mitigate the impact of planned third-party work on the safe and reliable operation of the distribution system.
	Recover costs allowed by municipal franchises and other agreements for relocations initiated by third parties.

The performance measures for the Distribution Pipe asset class are as follows:

- Density of system (number of customers per kilometre of active main)
- Percentage of leaks reported by leak survey (vs. leaks reported by the public)
- Leaks per 1000 kilometres
- Percentage of cathodic protection (CP) above target
- Number of immediate digs per 100 kilometres
- Number of scheduled digs per 100 kilometres
- Bare and unprotected steel systems (kilometres)
- Pre-1970 pipeline systems (kilometres)

.

5.2.2 Pipe Asset Class Hierarchy

Pipe is categorized by material type and the asset subclass hierarchy is illustrated in **Figure 5.2-1**.

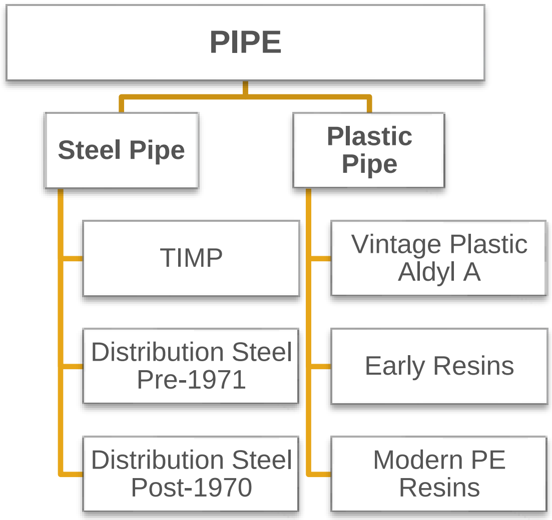


Figure 5.2-1: Pipe Asset Class Hierarchy

Notes:

- Some Pipe asset subclasses (e.g. Distribution Steel Pipe Post-1970) have programs that apply to only a portion of the assets (e.g. bare and unprotected steel).
- The TIMP (Transmission Integrity Management Program) asset subclass is a subset of steel mains that are part of the TIMP in-line inspection (ILI) program or are subject to some other periodic non-destructive assessment of integrity such as external corrosion direct assessment (ECDA). These pipelines either operate at greater than 30% SMYS or have been identified for inclusion in TIMP because of their criticality. A subset of TIMP pipe is included in the Transmission Pipe and Underground Storage asset class and a subset is included in the Pipe asset class.

5.2.3 Pipe Inventory

Table 5.2-2 lists the inventory details for each asset subclass, along with selected other component inventories relevant to certain programs.

Table 5.2-2: Pipe Inventory

Asset	EGD Rate Zone	Union Rate Zones
Mains (km)	**39,116**	**43,895**
TIMP Pipe*	533	2,983
Steel Pipe (Pre-1971)	6,810	10,252
Steel Pipe (Post-1970)	5,870	8,714
Plastic Pipe - Modern PE	20,528	11,647
Plastic Pipe - Early Resins	4,414	1,344
Plastic Pipe - Not yet categorized	N/A	7,620
Plastic Pipe - Vintage Plastic Aldyl A	979	1,335
Select additional asset inventories		
Bare unprotected pipe (km) **	0	162
Copper Services (#)	2,620	0
Copper Risers (#)	26,1973	0

**TIMP Pipe includes assets that are part of the Transmission Pipe and Underground Storage asset class and the Pipe asset class.*

***Bare unprotected pipe is a subset of Steel Pipe (Pre-1971).*

.

5.2.4 Pipe Condition and Strategy Overview

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

5.2.5 TIMP Mains

EGI has implemented an Integrity Management Program (IMP) pursuant to Technical Standards and Safety Authority (TSSA) and Canada Energy Regulator (CER) regulatory requirements.

The TIMP (Transmission Integrity Management Program) asset subclass is a subset of steel mains that are part of the TIMP in-line inspection (ILI) program or are subject to some other periodic non-destructive assessment of integrity such as external corrosion direct assessment (ECDA). These pipelines either operate at greater than 30% SMYS or have been identified for inclusion in TIMP because of their criticality. TIMP pipe is included in both the Transmission Pipe and Underground Storage and the Pipe asset classes.

Pipelines with Maximum Operating Pressures (MOPs) resulting in hoop stress levels of 30% SMYS or higher meet the technical definition of "transmission" as prescribed by the *TSSA Oil and Gas Pipeline Systems Code Adoption Document Amendment (Ref. No.: FS-220-16)*. Integrity management of TIMP pipelines represents one of the critical aspects in fulfilling the safe and reliable operation of EGI assets as these pipelines are critical infrastructure for energy markets in Ontario and beyond.

The population of TIMP pipe in the Distribution Operations TIMP portfolio consists of approximately 419 and 1676 kilometres of steel pipe for the EGD and Union rate zones respectively, for a combined length of 2095 kilometres. This includes pipelines operating at >30% SMYS and 50 kilometres of targeted lines operating at <30% SMYS.

The population of TIMP pipe in the Storage and Transmission Operations TIMP portfolio consists of approximately 114 and 1307 kilometres of steel pipe for the EGD and Union rate zones respectively, for a combined length of 1421 kilometres.

The population of TIMP pipelines by decade of installation is shown in **Figure 5.2-2**, illustrating a wide distribution of age for this group of assets. Based on length, over 40% of TIMP pipelines were installed prior to 1970. Despite increasing age, TIMP pipelines are generally in good condition because they are directly inspected and areas of poor condition are replaced or repaired.

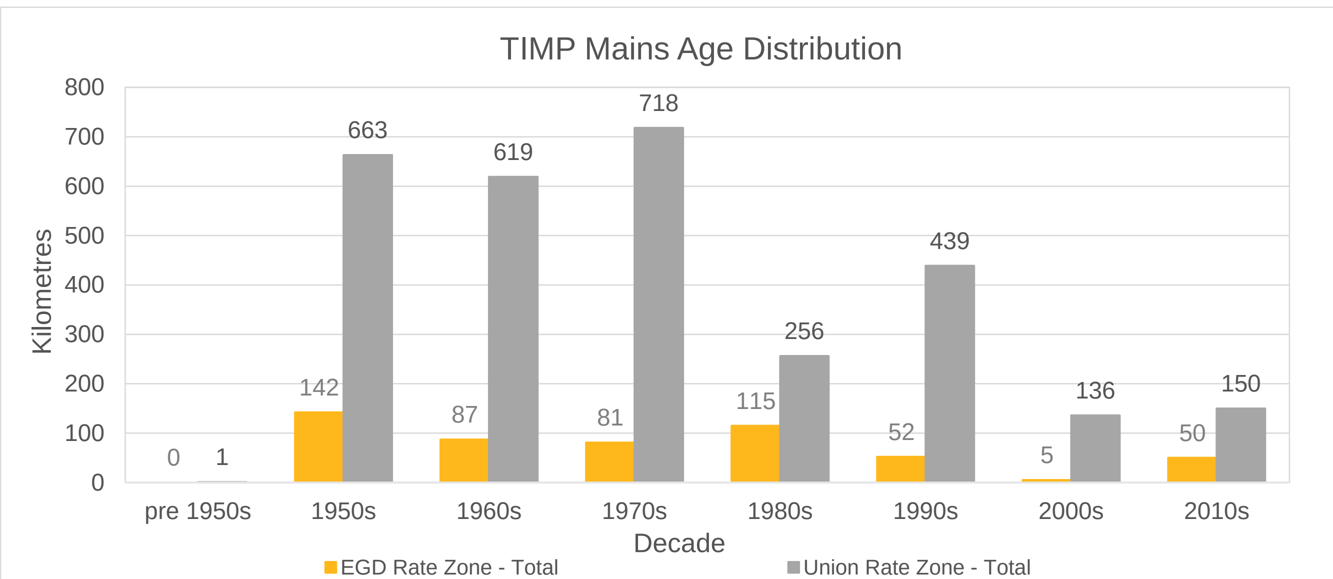


Figure 5.2-2: TIMP Pipelines Age Distribution

5.2.5.1. Condition Methodology

Using engineering analysis and a risk-based approach, the TIMP manages pipeline inspection frequencies and harmonizes inspection schedules to meet compliance requirements and industry-leading standards.

The TIMP is a systematic process for continually assessing and remediating the integrity of pipeline systems through prevention, detection and mitigation techniques. Data is compiled, assessed, validated and analyzed in a comprehensive and iterative manner. Threat mechanisms are understood and risks are assessed through data analytics that establish the

.

likelihood and consequence of various types of failures. This facilitates pipeline integrity management activities and optimizes the use of resources to control risk. Threats assessed include:

- External corrosion
- Internal corrosion
- Internal erosion
- Manufacturing-related defects
- Welding/fabrication-related defects
- Equipment failure
- Weather-related threats
- Third party/mechanical damage
- Stress corrosion cracking
- Outside forces
- Incorrect operating procedures

As threats are identified on pipelines, appropriate methods of preventing and detecting threats are used to determine the condition of the asset.

The TIMP employs a reliability-based process, using risk analysis as a tool for developing and prioritizing maintenance on anomalous pipeline features such as corrosion, cracks, mechanical damage and manufacturing defects. These features are identified using in-line inspections (ILI), direct assessments and/or other condition monitoring methods proven effective in the pipeline industry. Features meeting prescribed criteria are subject to further evaluation via direct examinations of pipeline sections through excavation (“digs”) and inspection using non-destructive test (NDT) methods. Pipeline defects found during integrity excavations are repaired before backfilling the exposed pipe.

The TIMP reduces the probability of failure through the inspection and assessment process by detecting and remediating detected pipeline defects.

5.2.5.2. Condition Findings

Many of the TIMP pipelines have been subject to two or more inspections since the inception of the Integrity Management Program. As such, the condition of these assets is generally well understood. Integrity activities on these pipelines typically result from the investigation of time-dependent (such as corrosion) and time-independent (such as third-party damage) events. Improvements in tool technologies further enable the investigation of previous undetectable threats.

In the TIMP program, EGI uses ILI data analysis and risk assessment of pipeline features along with corrosion growth modelling to project known corrosion features of the TIMP pipelines from the last ILI date to future years. This enables excavations to be scheduled prior to corrosion features reaching critical size, accounting for a factor of safety.

The number of digs depends on inspection findings and is an important part of preventing leaks on the TIMP pipeline system. As legacy practices are aligned and in-line inspection is introduced for all pipelines, it is anticipated that the number of digs may increase over the short term before settling into a more stable pattern. For reference, the number of digs over the preceding five-year period is shown in **Figure 5.2-3**.

.

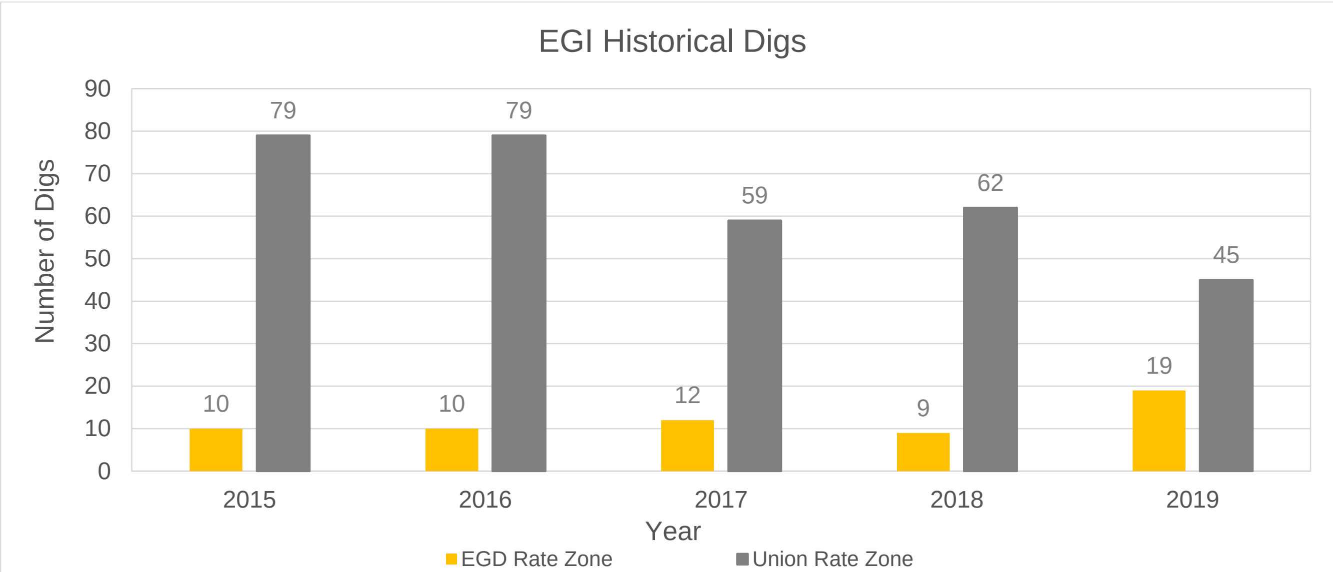


Figure 5.2-3: EGI Historical Digs

5.2.5.3. Risk and Opportunity

TIMP pipelines are critical infrastructure forming the backbone of the EGI system. These pipelines convey gas into downstream networks for distribution, supply large industrial customers (including natural gas-fired power plants) and transport natural gas to major North American markets. Some of these pipelines are located in urban areas and pass through High Consequence Areas (HCAs). Any gas release in such areas could require a substantial emergency response and a temporary shutdown of the pipeline; pipeline failures can pose a risk to public safety as well as gas supply reliability risk.

The risks associated with these pipelines are mitigated through the TIMP by identifying and remediating (as required) pipeline defects prior to failure. These inspections allow EGI to determine whether a pipeline is fit for service and provide quantitative data that can be used to forecast maintenance activities and the expected life of the asset. Understanding pipeline condition allows EGI to make informed decisions on service life extensions. By mitigating immediate and scheduled pipeline features, the TIMP reduces the probability of pipeline failures, reducing the overall public risk and helping to ensure a reliable gas supply to customers.

As a result of the potentially high consequences related to a failure on these pipelines, EGI is retrofitting pipelines with launchers and receivers so that in-line inspections can be used to assess pipeline condition as this technology provides the best data for predicting the condition of the pipeline.

5.2.5.4. Strategy Outcomes

The TIMP pipelines strategy is to continue performing in-line inspections (ILI) and to prioritize additional TIMP pipelines for inspection through retrofits to enhance the amount and quality of condition data. Capital expenditures are required throughout the five-year period to complete retrofits required to inspect previously uninspected pipelines.

Safety is the primary driver for the TIMP, which uses a strategic and long-term risk mitigation approach to ensure these pipeline assets remain fit for service. Inspection data allows EGI to assess system health and helps ensure pipeline safety.

The TIMP contributes to system longevity and is used to extend the useful life of assets by identifying condition issues prior to the occurrence of an incident. The inspections and remedial activities performed through the TIMP reduce the probability of pipeline failures and prevent large scale customer interruptions or unplanned gas releases. The information acquired through inspection is paramount to managing the balance between pipeline repairs and full replacement of TIMP pipelines.

As EGI continues to review operating standards in each rate zone and the use of various materials and fittings, plans will be developed to bring these into alignment in a way that balances risk, cost and performance. This would include but is not limited to the current approach to corrosion management and cathodic protection.

.

As EGI further develops and extends its Integrity Management Program, condition issues are identified and assessed to establish the appropriate remediation and timing. Examples that are emerging at this time include depth of cover and exposure of pipelines near watercourses, as well as pipelines that are located on bridge crossings with increased exposure to road salt.

Pipeline program management is evaluated on a continual basis using Plan-Do-Check-Act methodology. When analysis indicates that ongoing repair costs are likely to exceed capital requirements to replace the asset, the mitigation strategy is evaluated to ensure that risk is managed to the lowest practicable level.

The replacement and renewal strategies for TIMP mains are as follows:

TIMP Retrofits and Digs

Investments in TIMP retrofits and digs is mandated by the Integrity Management Program (IMP), a regulatory requirement designed to comply with all applicable codes and standards. The program manages the regular assessment and maintenance of the integrity of EGI's pipeline systems to ensure their continued safety and reliability. Investments in this program include installation costs for ILI inspection tools, retrofits to existing lines and replacement of pipeline segments with integrity issues.

A number of improvements have been implemented since the IMP was introduced in 2002. EGI developed additional criteria and processes to inspect pipelines on a risk-based frequency that considers pipeline operating characteristics and conditions and whether location has an impact on the potential consequence of a failure. EGI also continues to retrofit some pipelines initially assessed through external corrosion direct assessment (ECDA) to accommodate ILI tools and improve integrity assessment completeness. In-line inspection provides the most complete data on pipeline condition and is considered best-in-class for integrity management. Further work has also been completed to reconfigure some previously-inspected pipelines and improve data quality.

Class Location Program

Annual class location surveys are required as per *Canadian Standards Association Z662 – Oil and Gas Pipeline Systems* for pipelines greater than 30% SMYS, unless previously designed, tested, operated and maintained for a Class 4 location. Any changes in class location need to be assessed to the current standard to determine if pipeline modifications are required. Urban development which occurs in close proximity to EGI's pipelines typically triggers class location changes. An annual budget is required for EGI's pipeline system to meet current standard requirements. Remediation includes pressure testing, installation of valves, remediating depth of cover issues and pipeline replacement. This work ensures EGI is compliant and fosters the safety of the public and EGI's pipeline system.

Depth of Cover Survey Program

In compliance with *TSSA Oil and Gas Pipeline Systems Code Adoption Document Amendment - FS-238-18*, EGI has an annual depth of cover survey program for all >30% SMYS pipelines. These surveys may identify locations where remediation is required. The current cycle of depth of cover surveys will be completed in 2023, at which time a prioritized list of capital replacements will be created to plan for any identified pipelines requiring remediation.

MOP Verification Program

Maximum Operating Pressure (MOP) verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure for pipelines that are at ≥30% SMYS. While this is not currently mandated by code in Canada, it is required in the United States and is expected to become a requirement in Canada in the future. Given that EGI has over 3,500 kilometres of pipelines in this category, MOP verification continues to be a multi-year investment requiring dedicated resources. Spreading verifications over several years keeps costs down and will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements. It is also an important assurance activity to maintain a safe and reliable transmission and distribution system.

Through integration, EGI has leveraged the existing MOP Verification Program for the EGD rate zone and is shifting verification program focus to the Union rate zones which is anticipated to result in capital requirements as early as 2023. EGI does continue to use risk to evaluate the priority of the program and adjust the program scope and pacing to allow for the allocation of resources to the highest priority work. While a MOP Verification Program is not yet mandated through regulation, maintaining a balance of varying levels of priority work allows EGI to get ahead of future regulations while allowing for flexibility to reprioritize dollars to highest priority work as it is identified.

5.2.6 Distribution Steel Pipe

The Distribution Steel Pipe asset subclass includes mains (along with associated services and components) covered by the Distribution Integrity Management Program (DIMP). This population consists of approximately 13,000 and 17,000 kilometres of steel pipe for the EGD and Union rate zones respectively, for a combined steel pipe network of 30,000 kilometres. This population is further subdivided into two asset subclasses, Distribution Steel Pipe Pre-1971 and Distribution Steel Pipe Post-1970, due to differences in design, construction and maintenance practices. It is also worthwhile to note that between the early 1950s and early 1970s, steel mains were the only material used in the gas distribution system. These mains operate at different pressure classes and range in size. Note that distribution steel mains do not include pipe covered under the Transmission Integrity Management Program (TIMP). **Figure 5.2-4** and **Figure 5.2-5** illustrate the calendar age of the steel main population for the EGD and Union rate zones respectively.

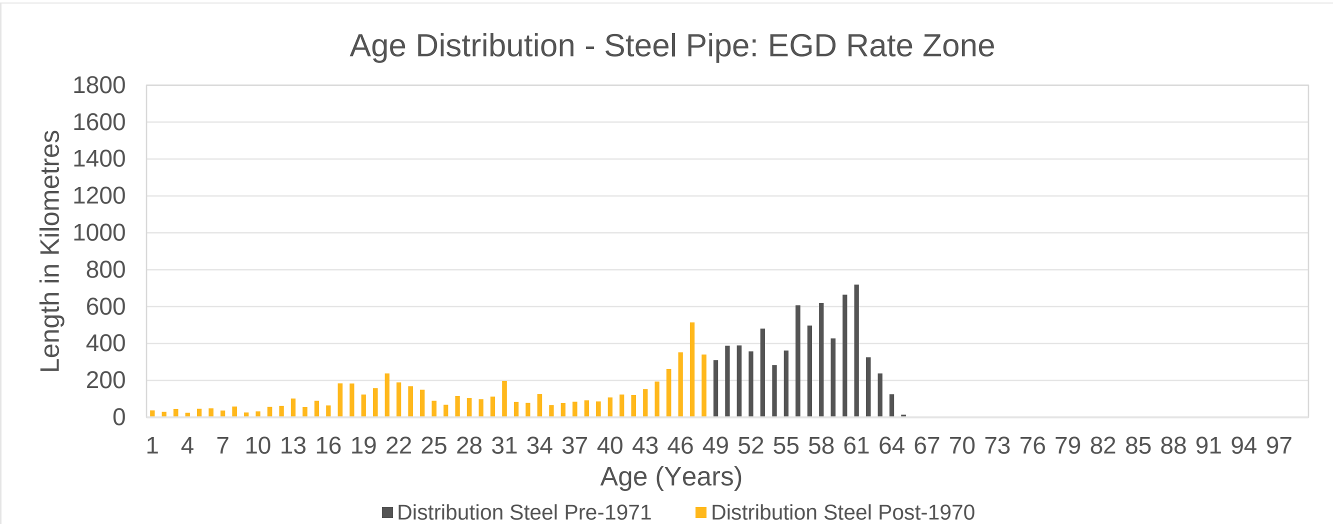


Figure 5.2-4: Age Distribution - Steel Pipe: EGD Rate Zone

In **Figure 5.2-5,** the population spike in 1958 (at age 61) is due to rapid expansion and acquisitions made by Union Gas (e.g., one major purchase was the Dominion Natural Gas Company). Unfortunately, records are not available to adequately classify the installation dates of the acquired assets.

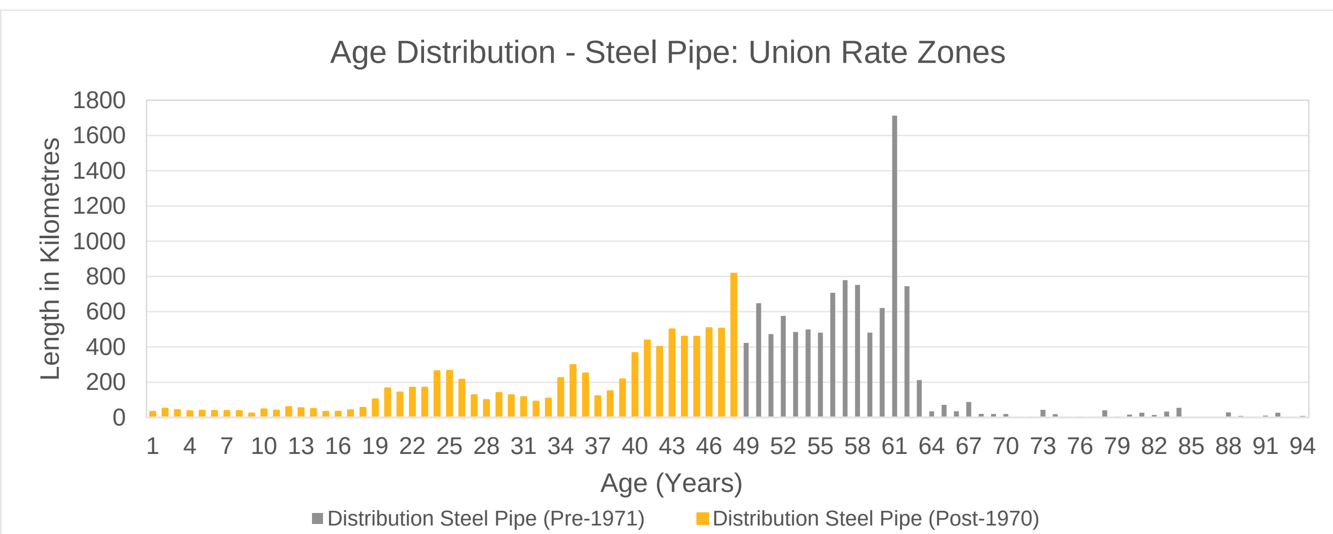


Figure 5.2-5: Age Distribution - Steel Pipe: Union Rate Zones

.

5.2.6.1. Distribution Steel Pipe Pre-1971

The Distribution Steel Pipe Pre-1971 asset subclass consists of mains (along with associated services and components) installed in 1970 or earlier and covered by the Distribution Integrity Management Program (DIMP). This asset subclass represents more than 50% of the steel pipe population (approximately 6,810 and 9,200 kilometres of pipe for the EGD and Union rate zones respectively, totaling 16,010 kilometres). These mains were installed using material, coatings, design requirements and construction practices based on standards at the time. Similarly, protection programs such as utility locate and cathodic protection procedures were different from current practices.

Distribution steel mains provide gas to some of the oldest and most populated parts of the EGI franchise area, including the downtown cores of Toronto, Hamilton, London and Ottawa. Over time, urban encroachment and infrastructure activities supporting municipal growth have impacted the condition and consequences associated with potential asset failures. In urban areas, challenges exist in ensuring adequate cathodic protection due to interference from subway, streetcar and light-rail transit systems.

5.2.6.1.1 Condition Methodology

The condition methodology of distribution steel mains is common across its asset subclasses and determined through:

- **Maintenance programs:** These programs (such as Leak Survey and Cathodic Protection) monitor asset conditions and restore assets to their functional state.
- **Condition assessment programs:** These programs (such as integrity assessments and material fault reporting) identify and assess the failure mechanisms of EGI's assets.
- **Tacit knowledge (SMA/Worker input):** Field knowledge is used to identify potential condition issues through regular meetings with subject matter advisors (SMAs).
- **Reliability modelling:** One of the major threats to steel mains is corrosion. A reliability model accounting for pipe attributes has been developed through the Asset Health Review (AHR) program under DIMP to forecast the number of corrosion leaks based on statistical analysis of corrosion leak history from the past 10 years (including factors that accelerate degradation).

5.2.6.1.2 Condition Findings

Distribution Mains

Based on the condition assessment methodologies outlined in the previous section, **Table 5.2-3** outlines the condition findings generally associated with assets in the Distribution Steel Pipe Pre-1971 asset subclass.

Table 5.2-3: Condition Findings for Distribution Steel Mains Pre-1971

Issue	Description
Corrosion	Over time, coating degradation and poor cathodic protection can cause corrosion, resulting in wall loss. Some components that are particularly susceptible to corrosion are: bare and unprotected steel mains, isolated steel mains and headers and mains with vintage coatings–for example, coal tar coatings can disbond and cause shielding. Below-grade threaded connections are also susceptible to corrosion.
Compression Couplings: Pull-Out	Compression couplings (mechanical fittings not welded onto the main) that are not properly restrained can cause a loss of containment due to exposed points of thrust. Compression couplings are held in place by the weight of the soil. When the soil is disturbed, the pipe can pull out of the fitting, resulting in gas escaping through the open pipe end. Some vintage gas mains (such as the Kipling Oshawa Loop (KOL) main) do not have sufficient records identifying the existence and location of these fittings. EGI has mitigation practices in place to address existing known compression couplings.
Compression Couplings: Corrosion	Compression couplings on steel mains can be susceptible to external corrosion and lead to an increased risk of leaks.
Depth of Cover	Reduction in the original depth of cover due to urban development or initial poor depth of cover due to construction practices at the time of installation can increase the potential for

.

Issue	Description
	damages due to excavation activities and increased external loading. A minimum depth of cover is needed to ensure the maximum weight of vehicles traversing across pipelines is not exceeded. If the depth of cover is not appropriate, excessive pipe stress and failures can result (see **Figure 5.2-6**).
Bridge Crossing: Corrosion	Continuous exposure to road salt and seasonal ground movement on bridge crossing assets can result in accelerated corrosion and external loading/stresses (see **Figure 5.2-7**).
Pipe Casing: Corrosion	Casings may cause a short with the carrier pipe if the spacers or internal integrity of the casing degrades over time. Many casings in the EGI network lack test points, preventing monitoring for shorts.
Seam Welds	Manufacturing defects associated with seam welds and fittings are weak points in the distribution system and can result in a loss of containment due to prolonged exposure to stress and corrosion (**Figure 5.2-8** and **Figure 5.2-9**). Low frequency Electric Resistance Welded (ERW) pipe (used up to the early 1970s) can also pose a hazard through the potential of cold welds, weakening bond lines and leading to brittle-like failures. Defects in low frequency ERW pipe welds have ruptured at operating pressures below 30% SMYS.
Third Party Damage: Appurtenances on Pipe	Any appurtenances which protrude from the surface of the main are susceptible to damage during excavation activities, as their depth of cover may be significantly less than that of the main. Steel drips (**Figure 5.2-10**) with a protruding drip rod that extend vertically towards the surface and shallow blow-off valve assemblies are examples.
Latent Third-Party Damage	Unreported, latent damages to pipe coatings can become active corrosion sites and can reduce the effectiveness of the corrosion protection system, resulting in accelerated corrosion and potential loss of containment.

Figure 5.2-6: Shallow and Embedded Gas Main due to Road Grade Change

Figure 5.2-7: Severe corrosion on bridge crossing pipe

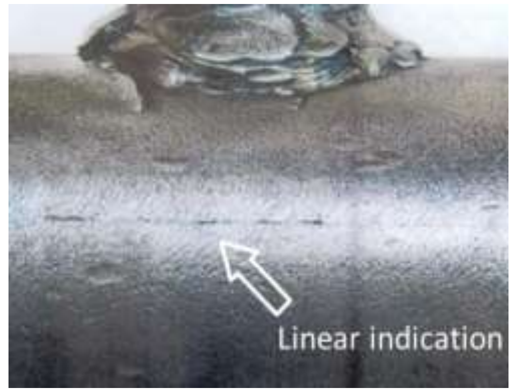


Figure 5.2-8: Vintage NPS 2 steel main with linear indication along weld seam

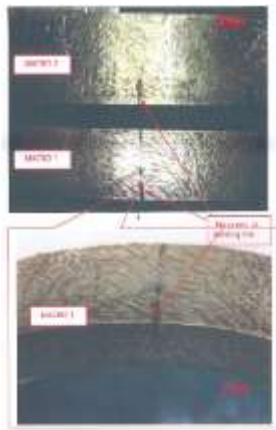


Figure 5.2-9: Inclusion at pipe weld seam on vintage NPS 2 gas main

Figure 5.2-10: Damaged drip rod on vintage NPS 2 gas main

Failure history for the Distribution Steel Pipe Pre-1971 population is shown in **Figure 5.2-11** and **Figure 5.2-12** for the EGD and Union rate zones respectively.

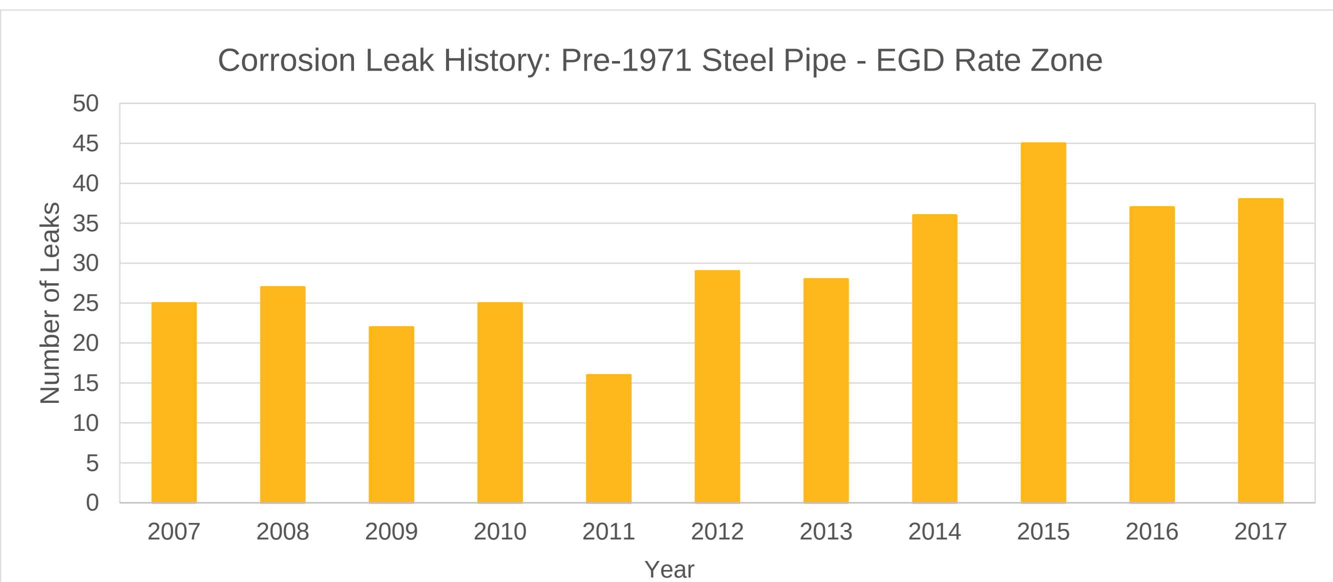


Figure 5.2-11: Corrosion Leak History: Pre-1971 Steel Pipe - EGD Rate Zone

.

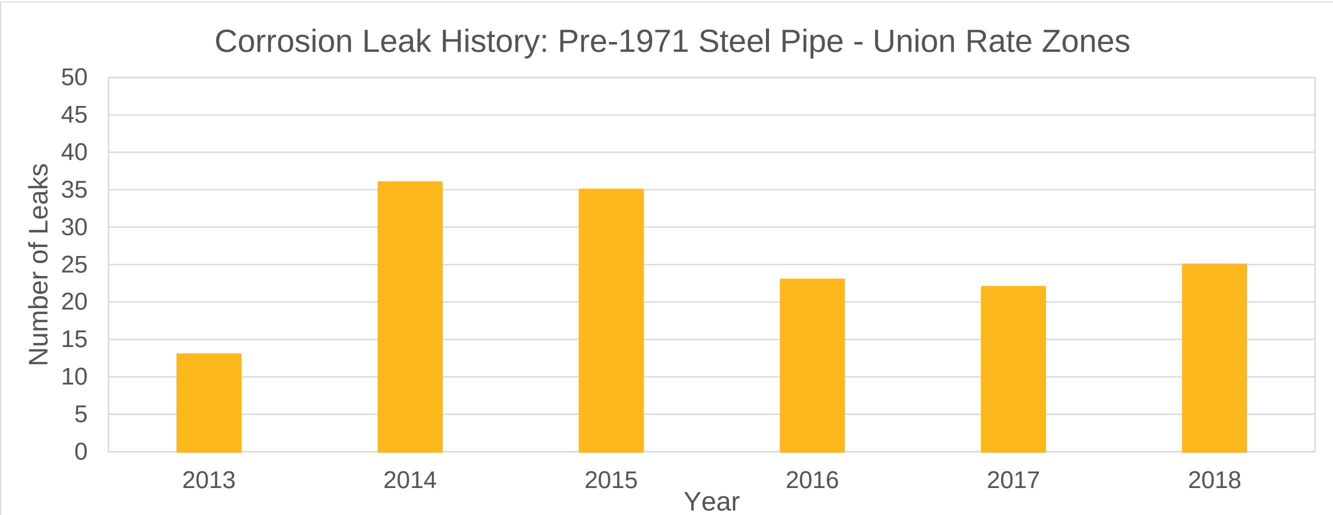


Figure 5.2-12: Corrosion Leak History: Pre-1971 Steel Pipe - Union Rate Zones

The failure history is shown over the 2007-2017 timeframe for the EGD rate zone (**Figure 5.2-11**) and between 2013-2018 for the Union rate zones (**Figure 5.2-11**). Irregularities are most likely due to the mix of assets being leak surveyed in a given year and the survey cycle (typically a five-year cycle for the EGD rate zone and a seven-year cycle for the Union rate zones, with exceptions for certain circumstances). The survey is optimized for geography and efficient execution, rather than leveling the number of leaks found. Note additional differences in the origins of these two charts:

- **EGD Rate Zone**: Leak repair data was analyzed to classify leaks to the failure type (i.e. leak), failed component (i.e. pipe) and failure cause (i.e. corrosion), as part of reliability modelling within DIMP.
- **Union Rate Zones**: Leak repair data was analyzed for location (i.e., above-grade vs below-grade), operating pressure, pipe diameter and others. Open leaks (i.e., C-leaks) are excluded from this data set.

As leaks are closed and data is further analyzed in a consistent manner across EGI, it is likely that the historical data will change. As the analytics practices are aligned for reliability modelling within DIMP, the trends and predictions will evolve and become increasingly reliable.

Reliability modelling within DIMP (currently only available for pipe assets in the EGD rate zone) is used to project the annual number of leaks on pre-1971 distribution steel mains over the next 20 years (see **Figure 5.2-13**). Projections assume no change to maintenance practices in the EGD rate zone (namely, that most steel main leaks are mitigated via repair within a relatively short period of time and a small number of leaks are eliminated when the pipe is replaced). As maintenance practices are updated as part of utility integration, these models will also be updated.

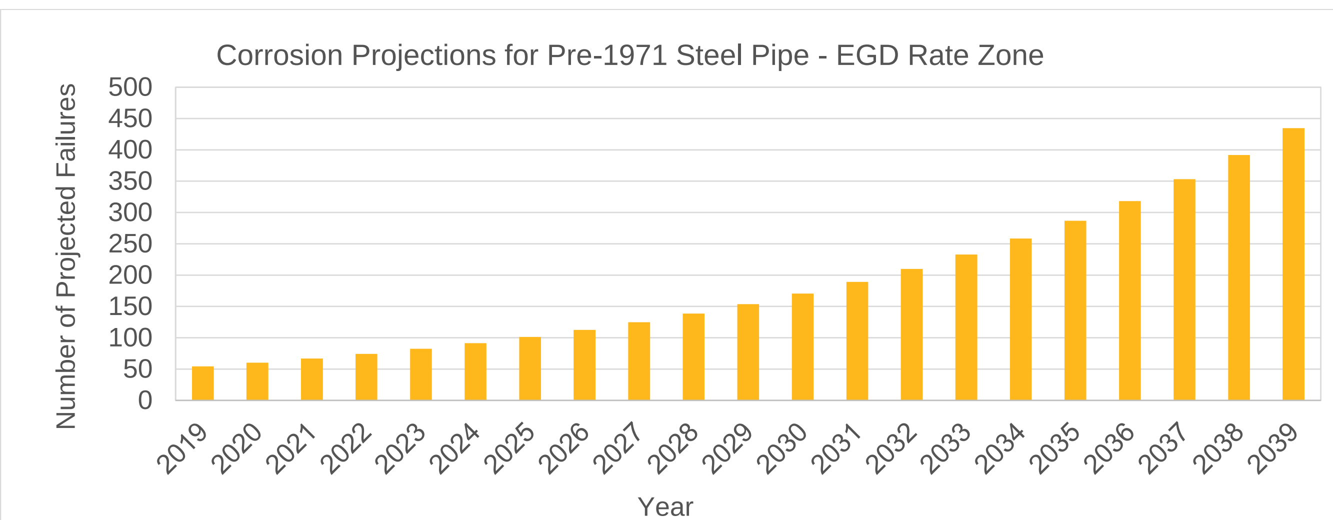


Figure 5.2-13: Corrosion Leak Projections for Pre-1971 Steel Pipe – EGD Rate Zone

.

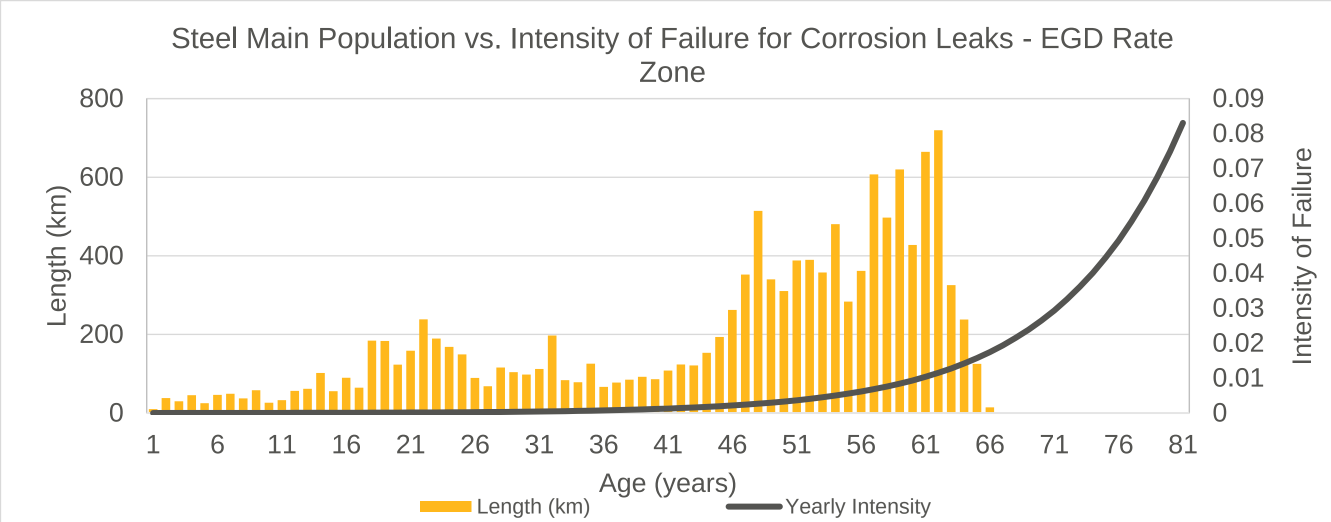


Figure 5.2-14: Steel Main Population vs. Intensity of Failure for Corrosion Leaks - EGD Rate Zone

The steel main reliability model forecasts the number of annual leaks will increase steadily over the next 20 years. **Figure 5.2-14** shows the cumulative length of pipe for a given age. By 2039, the number of leaks will have increased by approximately tenfold. This represents an exponential growth in the number of leaks. Although the above graphs represent projections specifically for the EGD rate zone, vintage steel pipe in the Union rate zones is expected to behave similarly.

The significant increase in corrosion leaks is forecasted to take place as a portion of the mains population approaches 100 years of age–this occurs between 2037 and 2057. **Figure 5.2-14** shows a sharp increase in failures per year as the mains approach 100 years of age which could be due to multiple coating defects along the pipe body and poor cathodic protection history. Coating defects can result from manufacturing defects, field applied coating anomalies, coating degradation from environmental factors or third-party damage.

To validate the reliability model, corrosion rates predicted by the model were compared to rates derived from in-line inspection (ILI) data on TIMP mains (see **Section 5.2.5**). The corrosion rates predicted that TIMP mains would experience at least one corrosion leak before reaching 100 years old if scheduled digs were not performed to mitigate defects. This result is consistent with projections of the distribution steel main reliability model. It is important to note that some steel mains could experience more severe corrosion due to exposure to multiple influencing factors, such as coating damages, poor cathodic protection and aggressive soil/ground condition, leading to the conclusion that leaks could occur well before the age of 100.

Although reliability models were not previously used to provide failure projections for Union rate zones assets, work is now underway through DIMP to include all distribution assets into the reliability modelling work, which is expected to take multiple years to complete.

Pipe coatings used on pre-1971 steel pipe (like coal tar and field-applied coatings such as mastic wrap) can get brittle over time and are susceptible to cracking and disbondment, allowing for corrosion to occur. As an example of a corrosion failure, **Figure 5.2-15** to **Figure 5.2-18** show a leak repair on a 12-inch vintage steel main located in downtown Toronto. This steel main was installed in the 1960s, showing the use of mechanical fittings (compression couplings) to join gas mains together using a fabricated fitting (steel cross).

EGI continues to monitor the asset health of steel mains and updates its reliability models with best available information to determine the appropriate mitigating action. Work is ongoing to create a proactive vintage steel mains replacement program that uses the AHR program, reliability models, tacit knowledge and Operations input to identify vintage steel mains to be considered for replacement. Failure data from repair work orders and field observations made during steel main repairs and other maintenance activities show that vintage steel mains have demonstrated faster declining health compared to steel mains installed after the 1970s. This is attributed to material specifications, construction, past damage prevention practices and latent damage (such as coating damage) from third-party construction activities near the mains.

.

Figure 5.2-15: Leak investigation on vintage NPS 12 gas main

Figure 5.2-16: Detail of fabricated fitting after removal

Figure 5.2-17: Multiple leaks due to severe corrosion on vintage NPS 12 gas main

Figure 5.2-18: Multiple leaks on vintage NPS 12 gas main

Figure 5.2-19 shows that for the EGD rate zone, about 70% of recorded steel main corrosion leaks in the past 11 years are from pipe installed before 1970. **Figure 5.2-19** also displays the failures normalized by pipe length, confirming that corrosion leaks per kilometre are disproportionately higher than those on post-1970 pipe. Similar behavior demonstrated on Union rate zone steel mains is noted through tacit knowledge–work is underway to formulate similar data analysis.

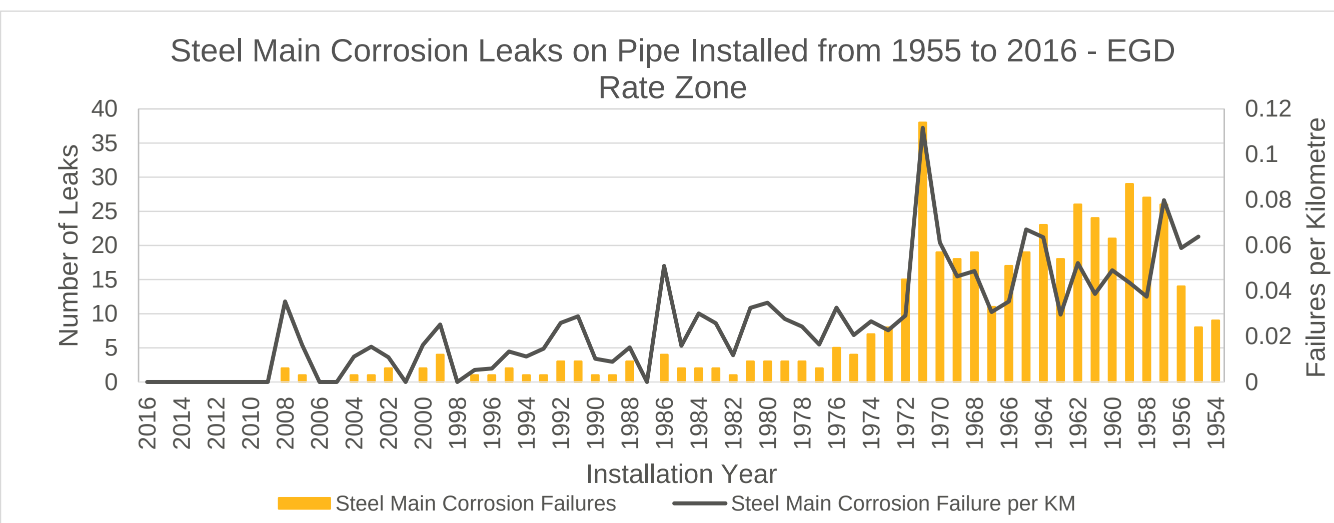


Figure 5.2-19: Steel Main Corrosion Leaks on Pipe Installed from 1955 to 2016 – EGD Rate Zone

.

Using the steel mains reliability model, the AHR program evaluates the probability of corrosion leaks for the steel main population over the next 20 years. At a macro level and given the size of its population, steel mains as a group are generally performing well at their current age and over the next 10 years. It is important to note, however, that there are individual pipelines identified to be in poor condition and requiring mitigation, as illustrated in **Figure 5.2-15** to **Figure 5.2-18**.

Aside from analytics, tacit knowledge and condition assessments have identified condition and risk issues with some of EGI's more significant distribution mains. Damages to these mains could result in significant negative impact to public and worker safety and/or significant customer outages. Condition issues and risk concerns have been identified through tacit knowledge and condition assessments on the following mains:

NPS 20 Kipling Oshawa Loop (KOL) – Cherry to Bathurst

The NPS 20 Kipling Oshawa Loop (KOL) is a vintage steel main installed in 1954 and has segments located in densely populated areas in the City of Toronto along major traffic arteries, such as the Gardiner Expressway and Lake Shore Boulevard. The NPS 20 KOL pipeline has been the main feed to the City of Toronto since it was installed and is required to maintain the security of supply to existing customers and to manage the expected customer growth from proposed developments. Given the location of this high-pressure line, in the event of a gas leak, it could require shutting down a section of the Gardiner Expressway and Lake Shore Boulevard to ensure public safety as well as to facilitate the emergency repair.

ILI and integrity dig results on approximately 1900 metres of pipe (see **Figure 5.2-21** and **Figure 5.2-21**) between Cherry Street and Bathurst Street indicate significant corrosion. The NPS 20 KOL pipeline is known to have all the characteristics of vintage steel mains as discussed in **Table 5.2-3**, including but not limited to reduced depth of cover, shallow blow-off valves, drips/siphons, lack of cathodic protection, live stubs, stray current from hydro infrastructure and possible contaminated soil. A project has been initiated to replace this portion of inspected pipe from Cherry Street west to Bathurst Street and is scheduled to be in service for 2022.

Poor soil condition is considered one of the significant factors contributing to the degradation of the Cherry to Bathurst KOL segment. The soil is man-made fill containing large particulates in the form of large stone, brick, concrete and asphalt debris (see **Figure 5.2-22**). These large particulates can damage the protective coatings of the pipe wall and lead to corrosion initiation sites.

Figure 5.2-20: NPS 20 KOL pipeline displaying 70% wall loss identified by ILI in 2016

Figure 5.2-21: NPS 20 KOL shallow cover due to road grade changes

Figure 5.2-22: Soil conditions and particulates found – Cherry Street to Bathurst Street

NPS 20 Kipling Oshawa Loop (KOL) - Bathurst to Humber River

Based on the findings of poor soil and pipe condition between Cherry Street and Bathurst Street, EGI initiated a second project to investigate the next six-kilometre segment of the NPS 20 KOL main running west from Bathurst Street to Humber River. Specifically, if similar poor soil conditions continue westward, then poor pipe conditions may be present. Six integrity digs were performed for three kilometres of pipe immediately west of Bathurst Street that concluded the poor soil conditions in fact did continue west (see **Figure 5.2-23**) and that pipe condition may be degraded similar to the Cherry to Bathurst pipe segment. Further condition inspections are being explored to gain an increased understanding of the pipe condition and to determine if further mitigation is required.

Figure 5.2-23 - Large particulates found within three kilometres immediately west of Bathurst Street

NPS 12 St. Laurent

The NPS 12 St Laurent main is a single-source system that consists of vintage steel mains installed in 1958 and is a critical supply to the cities of Ottawa and Gatineau, supplying natural gas to more than 165,000 customers. This pipeline feeds 12 distribution system stations and one header station, as well as numerous non-interruptible residential, industrial and commercial customers (including the Parliament buildings) and a natural gas-fired power plant.

The NPS 12 St. Laurent main is located in downtown Ottawa and is known to have all the characteristics of vintage steel pipe as discussed in **Table 5.2-3**. Should the NPS 12 St Laurent main experience a pipeline defect or sustain damage, EGI would have to either temporarily reduce operating pressures or shut down the line. Any pipe defects or failures that could release gas would require a significant emergency response and could have severe consequences. Shutting down the pipeline could lead to customer loss in excess of 60,000 on a cold day. **Figure 5.2-24** to **Figure 5.2-26** show areas in the St Laurent pipeline that exhibit poor condition.

Figure 5.2-24: Multiple corrosion sites on NPS 12 St. Laurent pipe

Figure 5.2-25: Gouges and dents due to latent damages

Figure 5.2-26: Coating damages

London Lines

The London Lines span approximately 83.5 kilometres and extend from Dawn to the Byron transmission station located in the London District. This major feed to the local municipalities and smaller towns consists of two single feed high pressure pipelines running in parallel. These pipelines were initially installed in 1935 and 1936 and although one was replaced in 1952, the replacement used reclaimed and refurbished materials with a vintage of 1920 to 1930. The London Lines account for a combined approximately 166 kilometres of some of the oldest pipe in the Union rate zone system.

The condition of the London Lines is generally poor, indicative of a pipeline reaching end-of-life, and is known to exhibit the characteristics of vintage steel pipe described in **Table 5.2-3**. A 2020 depth of cover survey reported that 47% of the London South main and 23% of the London Dominion line do not meet current minimum cover requirements. As well, 53 aerial crossings were identified.

Due to the condition of the London Lines, the current proposal is to complete a full replacement in one phase. A single-phase approach was based on condition, number of repaired and outstanding leaks and depth of cover issues. Project scope, costing and timing may change as additional pre-engineering is completed.

Figure 5.2-27 and **Figure 5.2-28** show areas in the London Lines that exhibit factors that can lead to poor condition and increase risk.

.

Figure 5.2-27: **Aerial Crossing**

Figure 5.2-28: Exposed Ditch Crossing

Port Stanley Line

The NPS 8 Port Stanley line was constructed in 1959 and is approximately 20 kilometres in length. This single feed system provides natural gas to Port Stanley and St. Thomas, with about 13,000 customers, including the St. Thomas hospital, a psychiatric hospital in St. Thomas and a retirement home in Port Stanley. The pipeline has unknown grade and wall thickness, is classified as bare and unprotected and is known to exhibit the characteristics of vintage steel pipe described in **Table 5.2-3**.

The pipeline has had a number of leaks which have been compounded by maintainability issues. The pipeline is difficult to access in places and extensive corrosion has made welding repairs difficult to complete.

Figure 5.2-29 to **Figure 5.2-31** show areas in the Port Stanley line exhibiting factors that can lead to difficulty in maintaining the pipeline, poor condition and increased risk.

Further risk assessment work is required to establish the timing and need for this replacement.

Figure 5.2-29: Corrosion

Figure 5.2-30: Exposed Crossings

Figure 5.2-31: Below-grade Stations

.

Copper Services

Copper services were installed from 1960 to 1979 in the EGD rate zone only (**Figure 5.2-32**). Typical issues associated with these assets include leaks, circumferential cracks and choked flow due to build-up of corrosion by-product, resulting in the interruption of gas service. Degradation mechanisms for copper services include galvanic corrosion in the vicinity of the copper service connection to the main, external corrosion at above- and below-ground transitions and internal corrosion (also known as erosion corrosion), which causes thinning of the service wall over time.

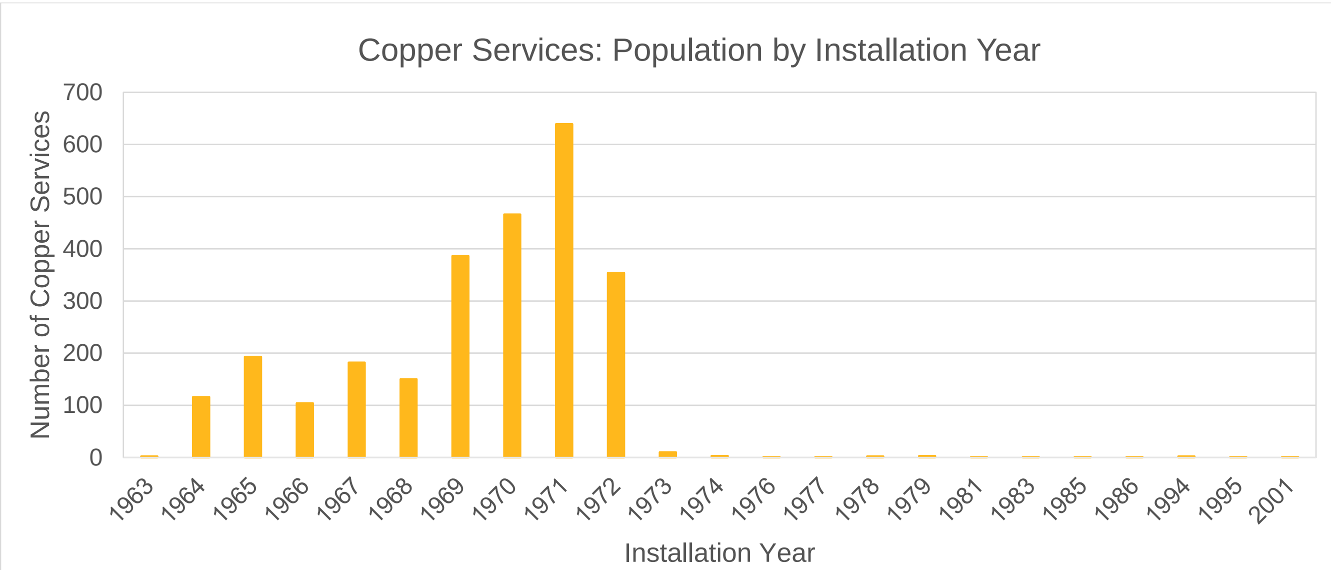


Figure 5.2-32: Copper Services: Population by Installation Year – EGD Rate Zone

Annual failure rates for copper services are steadily increasing (see **Figure 5.2-33**). Highest-risk copper services have been removed from the system and any remaining copper services now require replacement to prevent future failures.

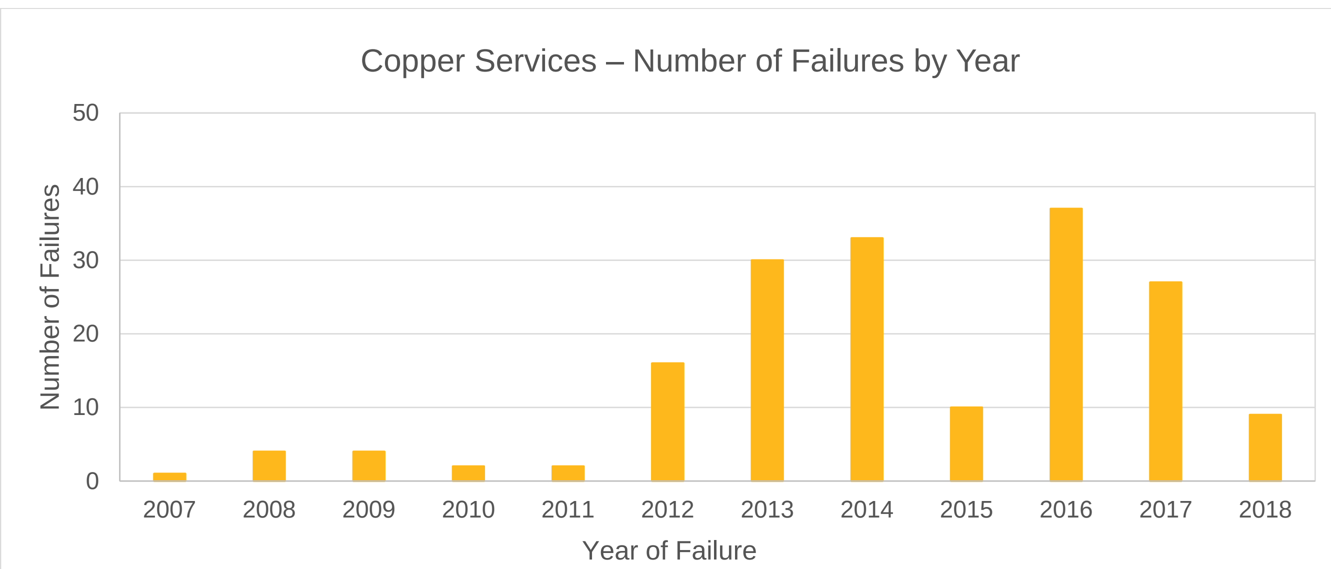


Figure 5.2-33: Copper Services – Number of Corrosion Leaks by Year

An additional failure mode is a choked service, where the internal corrosion debris from the copper pipe prevents the flow of natural gas to the customer. Loss of gas service during cold winter days for customers can cause reputational damage to EGI.

.

5.2.6.1.3 Risk and Opportunity

Steel mains are susceptible to external corrosion when barriers of pipe coatings and cathodic protection are compromised. Underground corrosion leaks can migrate to nearby structures and create gaseous environments. Leaks on steel mains in densely populated areas pose a greater risk than in suburban settings, as the ground surface is often paved across the entire width of the street, leaving no openings for escaping natural gas to vent to the atmosphere. In these cases, the path of least resistance can be underground infrastructure. Gas can migrate through these channels into buildings, creating a gaseous and potentially explosive environment for customers and the public. Corrosion leaks through pinholes are the common mode of failure for steel mains.

Health and safety risk (risks to the public, employees and contractors) represents the most aggressive risk increase over the next 40 years relative to other risk categories for steel mains. The increasing risk is driven by increasing corrosion leaks projected in the next 40 years. The current risk control strategy is not adequate to manage the accelerating risk in the next 40 years, requiring a proactive strategy to manage risk.

As illustrated in **Figure 5.2-14**, large portions of steel pipe in both rate zones are approaching the point where predicted poor condition will result in an exponential increase in leak rates. Based on reliability modelling, EGI expects that 1,300 and 1,800 kilometres of pre-1971 pipe for the EGD and Union rate zones respectively will reach this stage in less than 40 years. In order to proactively manage the anticipated increase in leaks, EGI is exploring programmatic and proactive replacement rates to manage risk, cost and performance. For example, a replacement rate of 155 kilometres per year is required to replace these 3,100 kilometres of pipe in 20 years. At the current rate of replacement (approximately 12 kilometres per year) it would take over 344 years to replace these 3,100 kilometres of pipe. Increasing the rate of replacement will likely be required to proactively manage the potential risk posed by the expected increase in leak rates.

Steel main repairs usually require more planning and resources than plastic main repairs. In many instances, specialized skill sets are needed to install isolation fittings on the steel mains and stop the flow of gas to facilitate the repair. This adds to the repair duration, causing longer service disruptions, more gas loss and higher repair costs. Additionally, with steel mains, if external corrosion exists near the leak location, welding may not be permissible for the repair work, adding additional cost and time for repairs.

By proactively replacing aging assets, savings can be achieved as planned work can be executed with less cost than emergency work once a leak has occurred. Furthermore, over 85% of the vintage steel network could be replaced with polyethylene (PE) pipe, eliminating cathodic protection and survey costs.

A proactive vintage steel replacement program will also level expenditures over time, an approach supported by EGI's rate payers based on the 2020 Customer Engagement Survey results, which showed that distribution customers prefer EGI to maintain current reliability levels. Major projects that address main replacements in a single phase rather than multiple segments and disruptions were also supported. Both objectives can be achieved if assets reaching the end of their useful life are renewed through a proactive vintage steel program.

Copper service lines (underground gas infrastructure close to a building) pose another risk– a service leak may have a more direct path to the building foundation, increasing the chance of migration. Natural gas migrating into a building has the potential of creating a gaseous and potentially explosive environment, which poses safety and property risks.

The consequences of these failures are dependent on the proximity of the service to building premises, number of linear assets in the vicinity, foundation integrity and surface structures (soft/hard street surface). These consequences are then quantified and evaluated by translating the condition and leak projection to risk. This evaluation indicates that as the failure rate increases, so does cumulative asset risk. Other risks that are associated with pipe failures are relight costs, regulatory penalties, greenhouse gas (GHG) emissions and customer outages.

5.2.6.1.4 Strategy Outcomes

The approach for the Distribution Steel Pipe Pre-1971 asset subclass consists of program work that includes condition monitoring, a reactive repair program and proactive and reactive replacement programs.

The current pipe replacement rate (mains and services) is inadequate to prevent the average age of the population from increasing, including vintage steel and vintage plastic – both of which exhibit increased failures as they age. With 16,000 kilometres of vintage steel and 8,000 kilometres of vintage plastic, EGI is developing analyses to support maintenance and replacement strategies for these assets that balance risk, cost and performance.

EGI continues to evaluate load shed zones (system isolation) as a way to manage customer outages and improve safety and operational reliability, while balancing the opportunity for performance improvements with risk and cost.

The maintenance strategies are described in **Section 1.8.2** and the resultant replacement/renewal strategies for the Distribution Steel Pipe Pre-1971 asset subclass are as follows:

Corrosion Prevention Program

This program consists of annual anode replacements to ensure steel mains have adequate cathodic protection, using pipe-to-soil survey results to determine which steel main networks require additional or replacement anodes. In addition to active steel mains, the Corrosion Prevention program also covers corrosion control on steel casings and replacement of rectifier systems.

Emergency Replacement Program

This program addresses unforeseen pipeline emergencies that are small in nature. Examples of these types of jobs include cutting out a leaking section of main/fitting, removing blow-offs that require immediate attention, ongoing municipal work that encounters an unexpected gas plant–catch basin placements, structures, temporary main cut-out to access municipal plant, water mains, etc.

Service Replacement Program

A distribution service refers to the pipe between the distribution main and the customer’s meter set. Over the years, different materials have been used for this asset, including steel, copper and varying resins of plastic, each with unique characteristics that contribute to their performance over time. Services can be repaired or replaced depending on asset condition and the nature of the issue exhibited. Generally, replacement is the preferred approach to mitigate unacceptable asset condition.

Targeted Major Replacement Projects

Where the condition or risk related to a significant pipeline has been established to be a concern, EGI will establish a project team to gather relevant information, commission additional studies to support decision-making and evaluate alternatives to address the concerns. These pipelines may require a large capital investment subject to the OEB’s Leave to Construct (LTC) process. The approach to address larger pipe projects in one phase rather than multiple smaller projects is supported by EGI’s customers as reported in the 2020 Customer Engagement Survey, where residential customers preferred to replace old pipelines all at one time. A sample of larger pipelines where condition and risk are leading EGI to evaluate replacement is provided in **Section 5.2.6.1.2**. EGI always strives to maintain safe and reliable operations while delivering projects cost-effectively.

Distribution Steel Mains Replacement Program

A long-term program targeting higher-risk pipes is required to manage the increasing number of expected leaks. This planned and proactive replacement strategy recognizes that it is not cost-efficient to perform large numbers of steel main repairs on an emergency basis and that while emergency repairs improve the condition of small sections of the affected mains, the overall system is left in generally poor condition. Planned replacements eliminate all other active corrosion sites that have not failed yet and avoid the need for multiple leak repairs along the same steel system. Planned and proactive replacements will also control the expected number of leaks, allowing EGI to manage risk and maintain reliability and customer satisfaction. This proactive program will address steel mains in the following categories known to increase the likelihood of leaks:

- **Vintage steel mains**: Refers to steel mains installed in 1970 or earlier–these mains exhibit the condition problems described in **Table 5.2-3**. The proactive vintage steel mains replacement program selects vintage steel mains for replacement based on performance, analytics such as reliability model assessments, tacit knowledge and operational identification, integrity assessments and risk assessments.
- **Isolated steel headers**: Refers to steel gas mains on private property (such as shopping malls and condominiums) that supply more than one service. The common installation configuration is to connect a header station to a gas main to reduce gas pressure and supply gas to the header network. Steel headers are isolated from the cathodic protection of the upstream steel gas main network, allowing for accelerated corrosion rates.
- **Bridge crossings**: Refers to mains installed above-ground and affixed to a bridge structure. Mains on bridges are exposed to atmospheric elements and road salt during winter months, which could accelerate corrosion on the main, casing and pipe hangers. Annual bridge crossing surveys are conducted to identify faults and issues. Issues found trigger engineering assessments, which recommend risk mitigation measures, such as the replacement of components or the entire bridge crossing if necessary.
- **Exposed mains or insufficient depth of cover**: Refers to steel mains found to have insufficient depth of cover. Municipal roadwork and city development can alter the road grade and cause gas mains to be shallower than the original installed depth. (See **Table 5.2-3** for more details.) To the extent possible, depth of cover issues will be addressed by localized mitigation. If localized mitigation is not feasible, it will be mitigated by main replacement.
- **Leaking steel mains and emergency replacements**: Throughout the year, unforeseen short main replacement projects must be expedited on short notice, such as replacing a short section of main or fittings that are leaking, removing blow-off assemblies or repairing mechanical fittings that require immediate attention.

.

Bare and Unprotected Steel Pipe Replacement Program

This program manages the replacement of all bare and unprotected steel mains in the Union rate zones. These mains are more susceptible to leaks as they have not been cathodically protected since installation. About 60% of these mains are in urban areas, approximately 5% of which are in highly-developed areas. The remainder are in rural areas. Removing these mains from service will reduce the potential for leaks due to corrosion. Some examples of bare and unprotected failures are shown in **Figure 5.2-34**. This program was part of the 2020 Customer Survey, where preferences were mixed among Union rate zone customers. More than half of residential customers would prefer that the replacement of bare and unprotected pipes be prioritized, whereas less than half of the contract and non-contract business customers would prefer the work to be prioritized.

Figure 5.2-34: Bare and unprotected steel failures

Continuous improvement of reliability models

The Distribution Steel Mains Replacement Program is paced based on projected leak rates over the next 10 years. As shown in the corrosion leak projections (**Figure 5.2-13** and **Figure 5.2-14**), at the current replacement rate, the risk will continue to increase. In the Asset Health Review program, the steel main reliability model points to an average time to first failure at approximately 100 years, where the barriers of coatings and cathodic protection break down. It is expected that based on increasing leak projections, the long-term challenge for EGI will be to manage leak acceleration in the steel main system. As stated in **Section 5.2.6**, vintage steel mains account for more than 50% of the steel pipe population.

EGI will continue to refine the program to manage this aging asset population based on advancements in the understanding of leak projections, asset age limit and resource capacity. Considerations include:

- Monitoring leak rates and improving data collection to further validate and improve steel main reliability and risk models
- Increasing understanding of other degradation factors that affect asset life such as weldability for repairs
- Evaluating potential logistics and resource constraints based on reliability modelling and current leak projections

Relocation Program

A relocation project is required when a municipality, road authority, outside agency, other utility or other third party constructs or reconstructs a road, bridge, railway, canal, building, etc. and the work is deemed in conflict with an existing gas plant.

This program aims to relocate gas-carrying assets in conflict with third-party proposed work, ensuring conflicts are resolved within the framework of various third-party agreements (in most cases by relocating the existing gas infrastructure) to ensure the continued safe and reliable delivery of natural gas to customers. Relocation renews the asset by replacing it with new pipe.

Copper Services Replacement Program

The proactive Copper Services Replacement program aims to remove all outstanding active copper services and replace these assets with new plastic services and anodeless risers as part of the Service Relay program. Additionally, EGI will be monitoring condition-based and customer-related drivers that trigger the need to replace these assets. Condition-based drivers are monitored through existing activities of the DIMP, as well as the Leak and Corrosion Survey programs. Copper services are also replaced through proactive vintage mains replacement programs and relocation projects.

5.2.6.2. Distribution Steel Pipe Post-1970

The Distribution Steel Pipe Post-1970 asset subclass consists of mains (along with associated services and components) installed after 1970 and covered by the Distribution Integrity Management Program (DIMP). In this portfolio, the steel pipeline system consists of approximately 14,500 kilometres of steel mains for EGI (see **Figure 5.2-4** and **Figure 5.2-5**). This pipe was generally constructed with improved materials and construction practices and is performing well. These mains operate at different pressure classes, ranging from low pressure to extra-high pressure.

Although post-1970 steel mains are exposed to many of the same hazards as steel mains from 1970 and earlier, their materials, coatings and construction practices have enabled the primary corrosion barriers of pipe coating and cathodic protection to be more effective, resulting in fewer corrosion-based leaks.

5.2.6.2.1 Condition Methodology

See **Section 5.2.6.1.1**.

5.2.6.2.2 Condition Findings

The condition methodology for distribution steel pipe is described in **Section 5.2.6.1**. These mains are exposed to some of the same issues as steel mains from 1970 and earlier (see **Table 5.2-3**). However, some issues (such as unrestrained compression couplings) do not apply due to different design and construction practices and other issues (such as corrosion) are better mitigated as a result of better construction practices, maintenance practices and materials. Corrosion-based leak history for the post-1970 distribution steel main population for the EGD and Union rate zones is shown in **Figure 5.2-35** and **Figure 5.2-35** respectively.

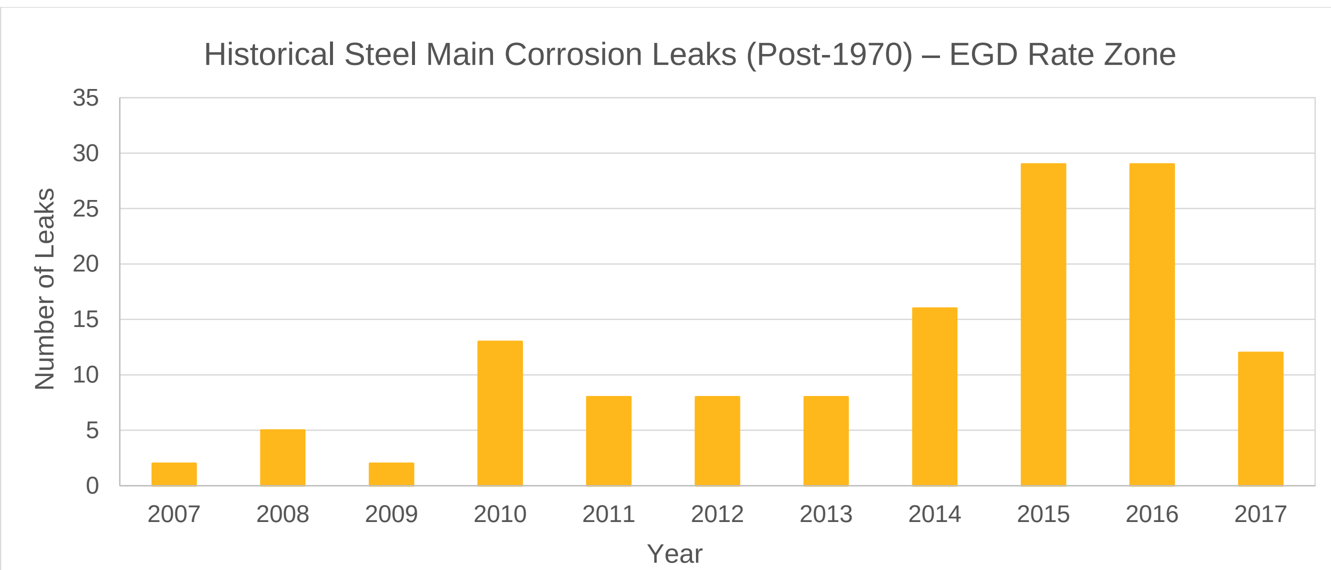


Figure 5.2-35: Historical Steel Main Corrosion Leaks (Post-1970) – EGD Rate Zone

.

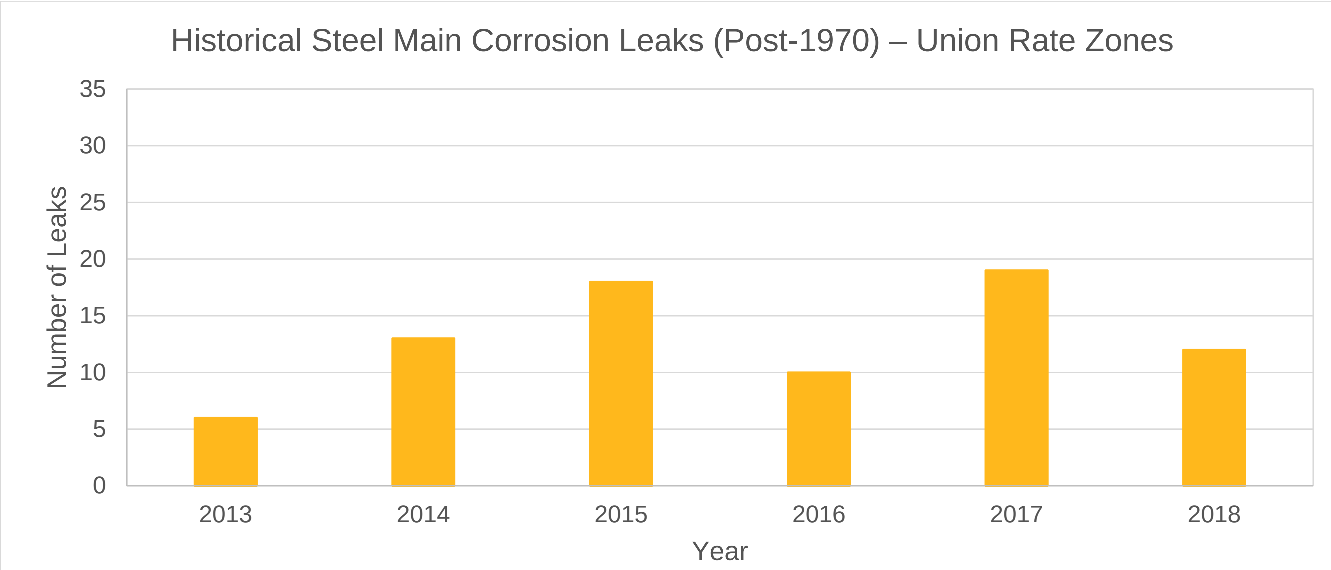


Figure 5.2-36: Historical Steel Main Corrosion Leaks (Post-1970) – Union Rate Zones

5.2.6.2.3 Risk and Opportunity

As demonstrated by the forecasted leak trends (see **Figure 5.2-37**), the post-1970 steel mains population is performing well and is expected to continue to perform well in future years, with leak rates that do not pose a significant risk. Mains are in good condition, associated with adequate cathodic protection and good coating performance. However, some hazards (third-party latent damages, environmental conditions, etc.) may accelerate degradation and result in leaks. These carry the same risks noted for pre-1971 distribution steel mains (see **Section 5.2.6.1**), including supply interruption to customers and greenhouse gas emissions associated with an uncontrolled gas release. As well, gas can migrate into buildings, creating a gaseous and potentially explosive environment for customers and the public.

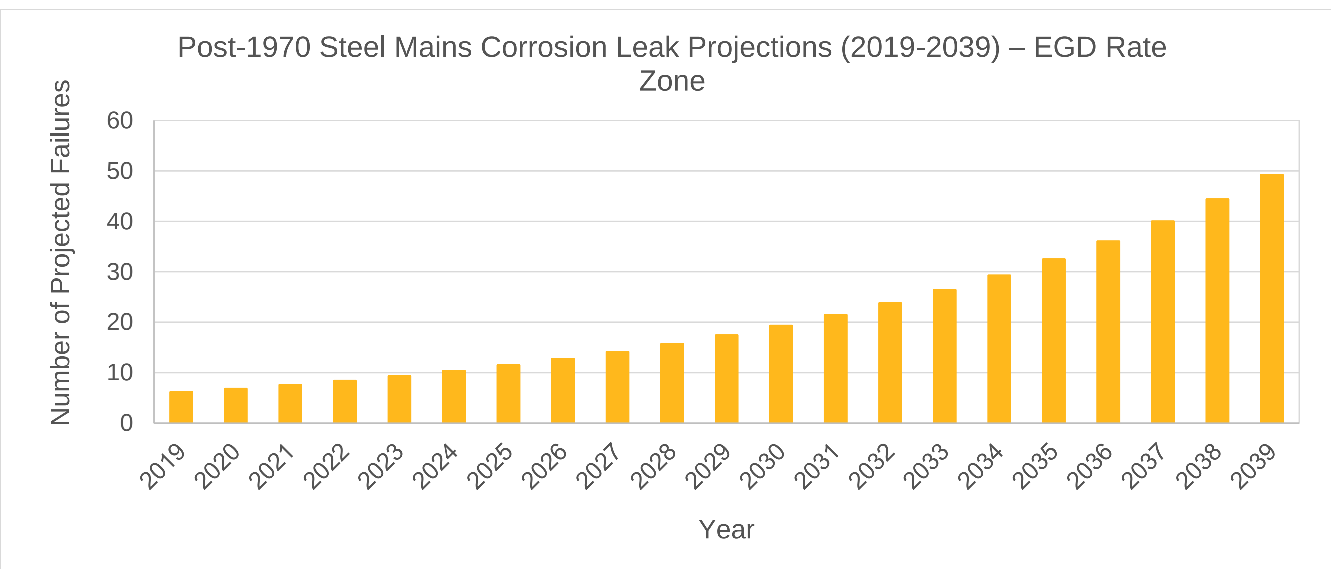


Figure 5.2-37: Post-1970 Steel Mains Corrosion Leak Projections (2019-2039) – EGD Rate Zone

.

5.2.6.2.4 Strategy Outcomes

The maintenance strategy for post-1970 distribution steel pipe is consistent with pre-1971 distribution steel pipe (see **Section 5.2.6.1**), where several condition inspection programs are in place, such as the Leak Survey and the Cathodic Protection Survey programs. The preferred life cycle approach to corrosion leaks on post-1970 distribution steel pipe is to repair them as they are discovered and perform replacements for a few select mains where condition, risk and other factors cause a repair to be not viable through the Distribution Steel Mains Replacement program. The number of failures for this asset subclass in the short term is considered manageable through existing approaches. EGI continues to monitor these failures to determine if a proactive maintenance and replacement program is required. This strategy meets the expectations of EGI's rate payers for sustaining a reliable system, based on the 2020 Customer Engagement Survey where 53% of respondents indicated that maintaining current reliability levels was a priority.

.

5.2.7 Distribution Plastic Pipe

Plastic mains were first introduced into EGI's distribution network in late 1960s on a field trial basis. Plastic mains became more widely used in the early 1970s and have since been installed across the EGI franchise area, replacing steel mains in low and intermediate pressure class systems. Plastic mains assets are divided into three subclasses: Vintage Plastic Aldyl A, Distribution Plastic Pipe Early Resins and Modern Polyethylene (PE) Resins. In some instances, records are not clear on pipe material-conservative assumptions were made to categorize the asset. In the Union rate zones, work is required to classify some pipe assets, currently grouped as To Be Categorized Plastic.

Population distributions for the EGD and Union rate zones are shown in **Figure 5.2-38** and **Figure 5.2-39** respectively.

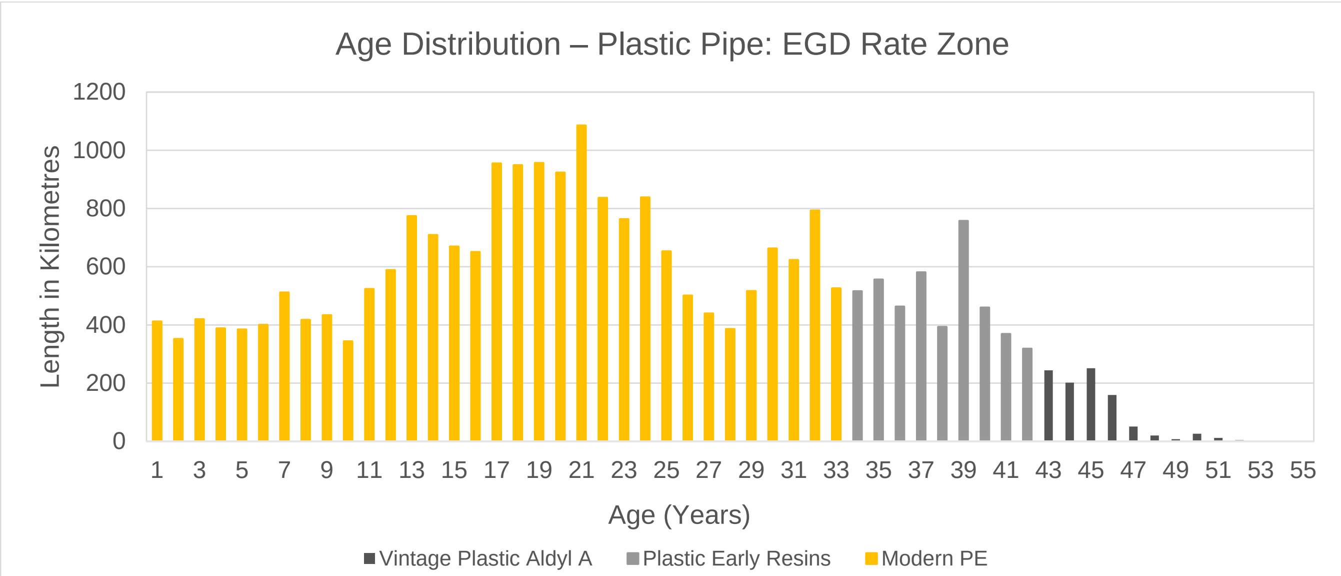


Figure 5.2-38: Age Distribution – Plastic Pipe: EGD Rate Zone

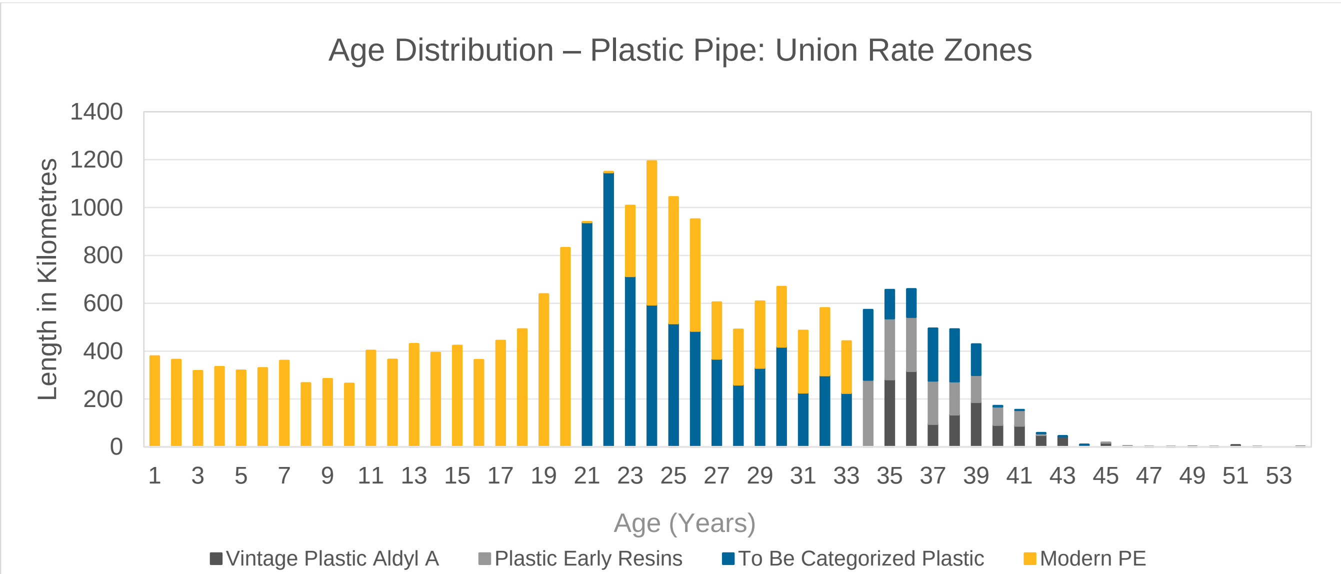


Figure 5.2-39: Age Distribution – Plastic Pipe: Union Rate Zones

Copper risers are also discussed in this section as they are primarily associated with vintage plastic Aldyl A and early resins systems. Copper risers on these systems include an AMP-fitting (a mechanical transition fitting between the plastic service

.

and the copper riser). These assets were installed between 1969 and 1984 in the EGD rate zone only. **Figure 5.2-40** illustrates the calendar age of the copper riser population for the EGD rate zone as of 2019.

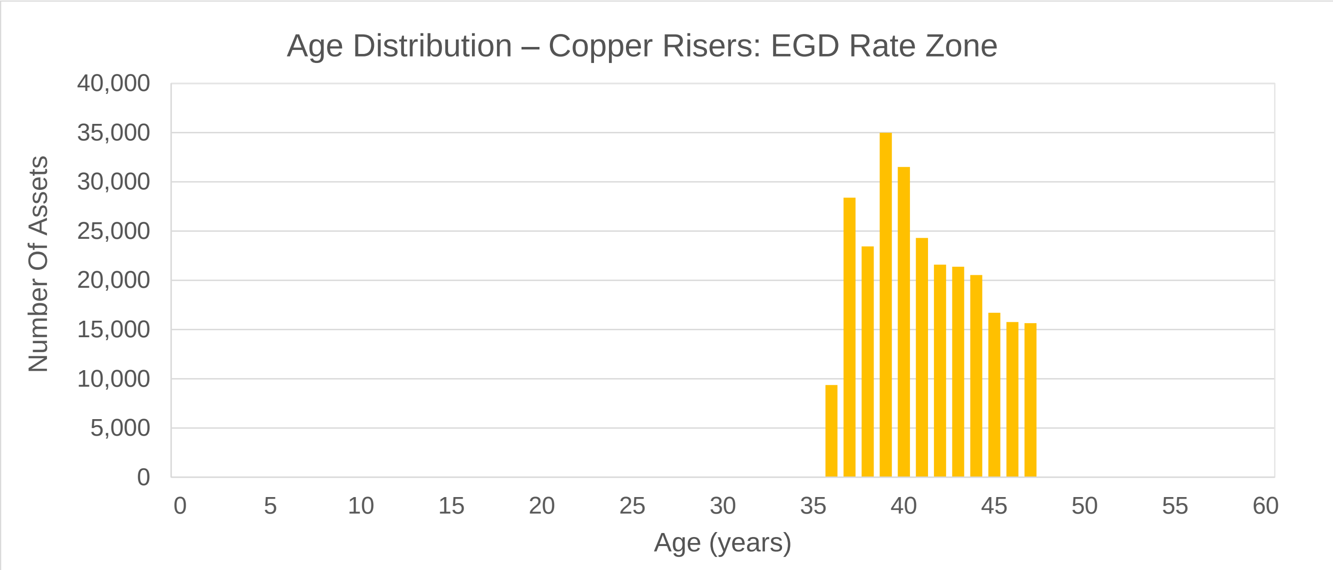


Figure 5.2-40: Age Distribution – Copper Risers: EGD Rate Zone

Note: Condition Methodology and **Risk and Opportunity** are consistent across plastic pipe assets. Asset subclasses are discussed in detail in Condition Findings only.

5.2.7.1. Condition Methodology

The condition methodology of distribution plastic mains is common across its asset subclasses. The condition of these assets is determined through:

- **Maintenance programs**: These programs (such as leak surveys) monitor asset conditions and restore assets to their functional state. Failure data from leak surveys is used to manage leaks in the short term and to build reliability models for pipe and copper services in the longer term.
- **Condition assessment programs**: These programs (such as integrity assessments and material fault reporting) identify and assess the failure mechanisms of EGI's assets. EGI has also concluded an extensive study on vintage plastic Aldyl A pipe with Gas Technology Institute (GTI) to develop data-driven predictions on the remaining useful life expectancy of plastic pipe. Studies are now being extended to Early Resins material to further enhance EGI's knowledge of this material; sampling programs and laboratory testing for TR-418 are underway with results analysis expected by 2022.
- **Tacit knowledge (SMA/Worker input)**: Field knowledge is used to identify potential condition issues through regular meetings with subject matter advisors (SMAs).
- **Reliability modelling**: A reliability model has been developed for vintage plastic Aldyl A pipe and copper risers through the Asset Health Review (AHR) program under the Distribution Integrity Management Program (DIMP). This has used a structured methodology to convert historical failure data into a statistical model that forecasts the probability of failure. Leak projections are refined with input obtained through direct assessment, internal and external industry studies and SMA input.

.

5.2.7.2. Condition Findings

The methodologies described in **Section 5.2.7.1** drive condition findings for the following subclasses: Vintage Plastic Aldyl A, Vintage Plastic Early Resins, Copper Risers and Modern PE Resins.

Vintage Plastic Aldyl A

Vintage plastic Aldyl A mains are the earliest plastic mains used within the distribution system; the installation period of Aldyl A plastics started in the late 1960s on a field trial basis and was concluded by the end of 1976 for the EGD rate zone and 1984 for the Union rate zones.

It is well known and studied in the North American gas industry that Aldyl A plastic mains have brittle-like cracking properties. The oxidation of the inner wall surface during manufacturing (also known as Low Ductile Inner Wall (LDIW)) and the large spherulites found in its microstructure causes pipe to be susceptible to cracking and premature failure in the presence of stress intensifiers such as a large number of connections, squeeze-off locations and the presence of rock impingement points caused by rocky soil types.

Many gas utilities have already started and in some cases completed, the replacement of Aldyl A pipe as a result of concerns about its brittle-like cracking properties. EGI commissioned a study through GTI to evaluate the performance of varying vintages of Aldyl A pipe used by EGI to identify failure modes over time and to determine the mean time for failure. Results of the initial sample testing showed that the LDIW property was observed and that the expected asset life of Aldyl A plastic mains is highly affected by ambient temperature and total stress intensifiers on the pipe.

Figure 5.2-41: Rapid crack propagation on Aldyl A pipe from saddle tee fusion (Mississauga, ON)

Using the failure data and statistical modelling yields a reliability model that shows a very strong correlation to asset age, although it is important to note that the model is based on a relatively small number of failures. The reliability model for vintage Aldyl A plastic mains shows a sharp increase in failure rate by age 70. Leak projections based on historic failure rates for the asset subclass are shown in **Figure 5.2-42**. At this time, factors which lead to stress intensification such as rock impingement, number of connections and squeeze-offs have not been considered in this model.

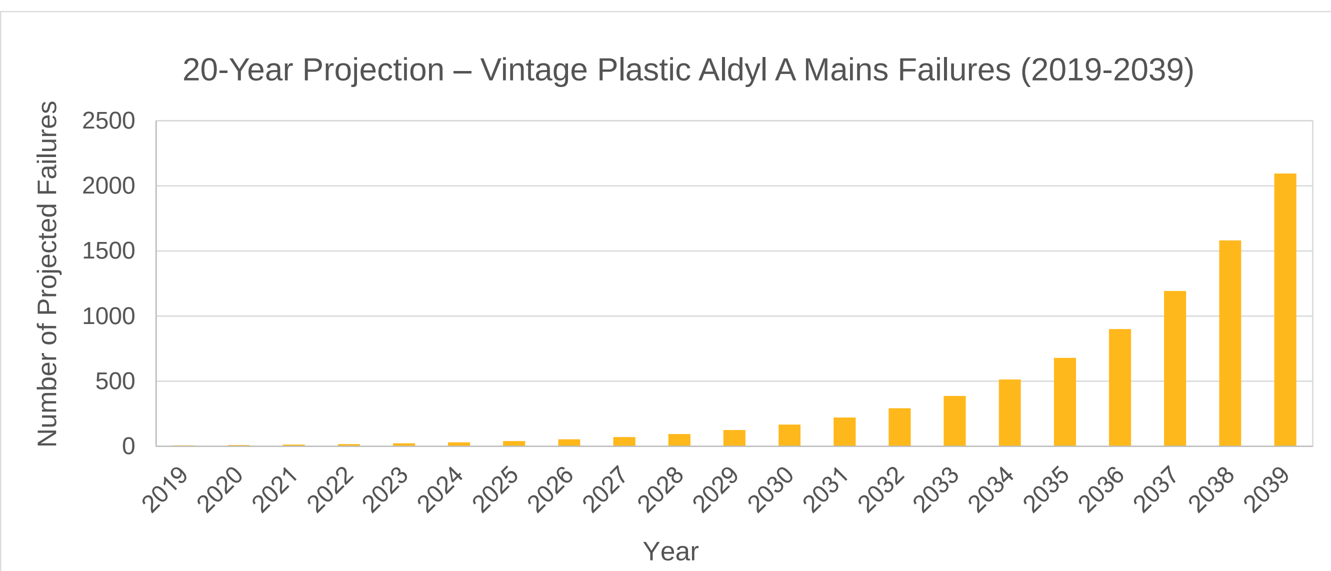


Figure 5.2-42: 20-Year Projection – Vintage Plastic Aldyl A Mains Failures (2019-2039)

.

The current population of vintage plastic Aldyl A mains is in generally good condition; however, it is important to note that the entire population is aging and will degrade quickly (see **Figure 5.2-43**). The sudden change in performance can be attributed to the LDIW property and slow crack growth (SCG) behavior, as the mains operate with additional stress intensifiers over a long period of time. This combination of material property and operating environment results in the brittle-like cracking of Aldyl A plastic mains (i.e., rapid crack propagation), a finding supported by the GTI study on Aldyl A samples supplied by EGI. The study indicated that by combining different stress factors, the asset life for vintage plastic Aldyl A mains is in the 70-year range. This implies that the residual asset life of pre-1977 plastic mains could be as short as 10 to 20 years.

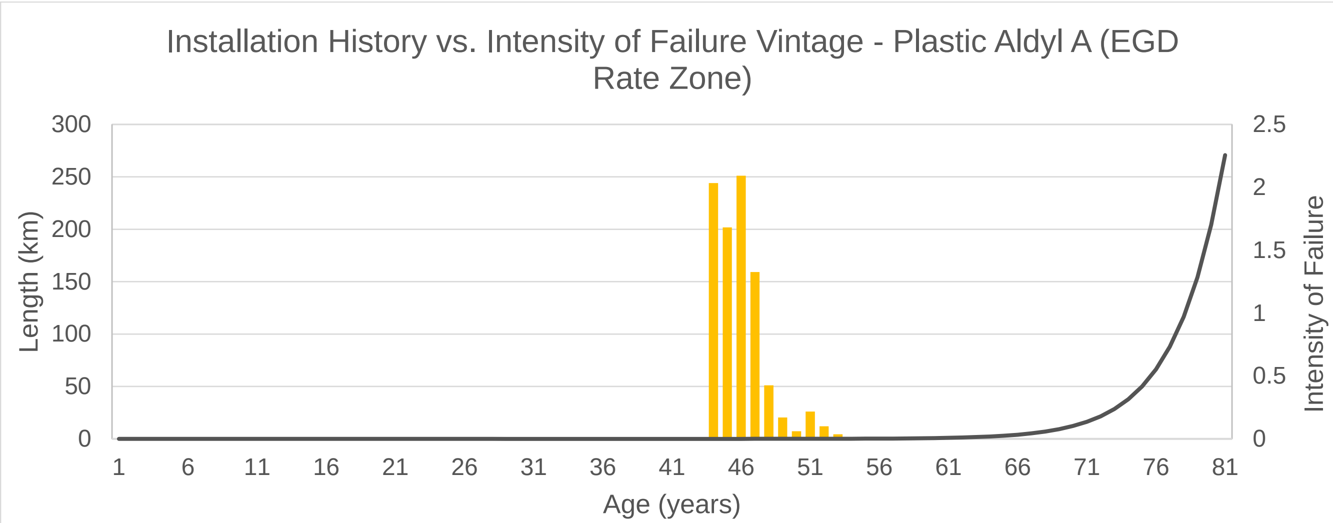


Figure 5.2-43: Installation History vs. Intensity of Failure - Vintage Plastic Aldyl A (EGD Rate Zone)

Plastic Pipe Early Resins

After using vintage plastic Aldyl A pipe, EGI transitioned to installing other resin-based plastic pipes designated as Early Resins, such as Aldyl HD and TR-418. This occurred by the end of 1976 and by 1977 for the EGD and Union rate zones respectively, with an overlap period of vintage plastic Aldyl A installations as early resins pipe was introduced.

Early resins pipe was phased out by 1985 in the EGD rate zone. For the Union rate zones, there remains a population of plastic pipe not readily classified (designated as To Be Categorized Plastic) and may include some vintage plastic Aldyl A and early resin material. The installation year for this population extends until 1998. Excluding pipe designated as To Be Categorized Plastic, the current asset age of early resins pipe ranges from 32 to 40 years and 34 to 42 years for the EGD and Union rate zones respectively.

From statistical analysis on failure data, it is predicted that early resin and vintage plastic Aldyl A mains will have very similar leak projection trends, leading to the conclusion that the asset health of early resins plastic mains will resemble the general trend of vintage plastic Aldyl A mains, but with a delay in degradation due to the later installation date. Much like the vintage plastic Aldyl A mains, this group is currently in good condition and will continue to perform over the next 20 years (**Figure 5.2-44**).The population will then start to degrade and because of its size, will result in higher leak rates (**Figure 5.2-45**).

In addition to reliability models and leak projections, multiple cases of early resins plastic main failures exhibiting similar failure modes (cracking due to extended stress exposure) as the vintage plastic Aldyl A mains were identified. Currently, there is no known industry research or investigation completed on early resin plastic mains to provide insight to its degradation and failure mechanisms. Sampling programs took place in 2019 and 2020 to extract samples from EGI pipe systems to further enhance EGI knowledge. More investigation into the failure data and research on this specific plastic pipe group is required to fully understand this modelling result (further discussed in **Section 5.2.7.3**).

.

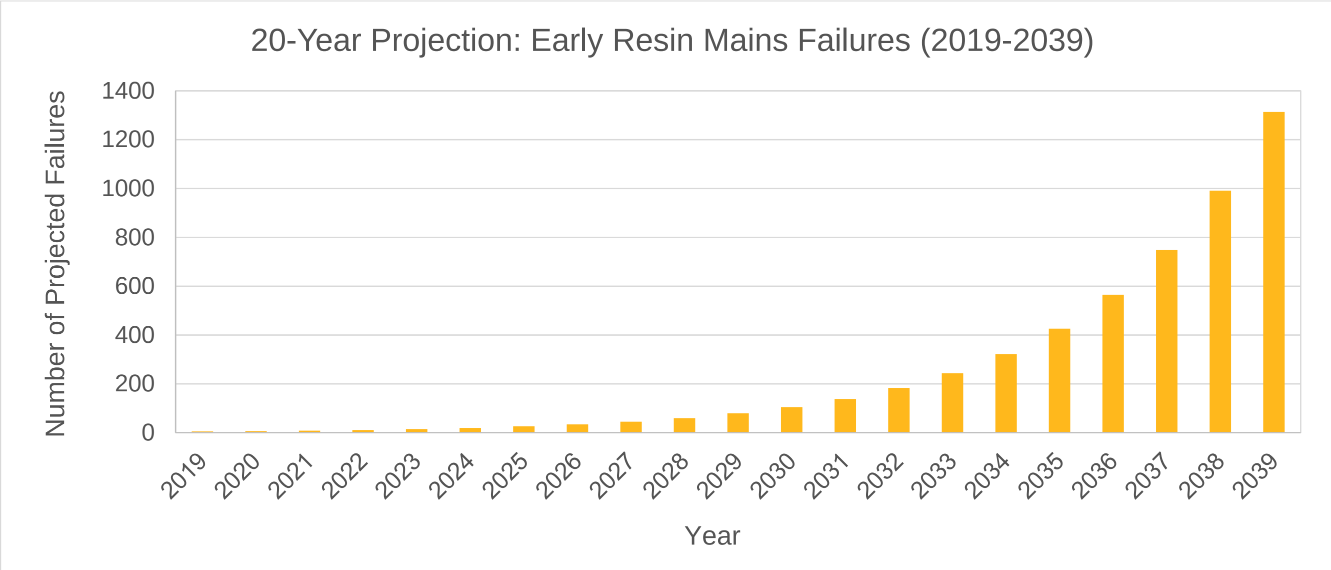


Figure 5.2-44: 20-Year Projection – Early Resin Mains Failures (2019-2039)

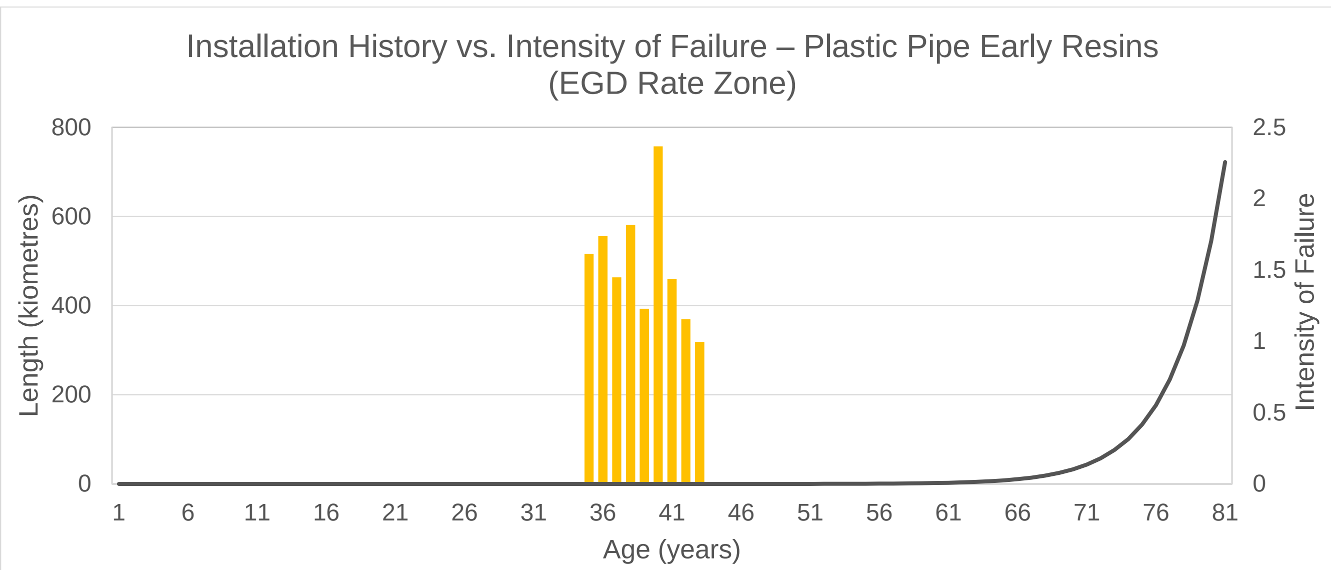


Figure 5.2-45: Installation History vs. Intensity of Failure – Plastic Pipe Early Resins (EGD Rate Zone)

Copper Risers

The copper riser's AMP-fitting causes a disturbance in the flow of gas, creating a low-pressure zone after the fitting when the gas flow becomes turbulent. This turbulence causes an erosion-corrosion failure to occur, which manifests itself into a pinhole or a circumferential crack. All sampled copper risers have shown some degree of corrosion after the AMP-fitting. Based on the sampled risers and reliability modelling, it is expected that all copper risers will corrode, causing a leak at some point in their lifetime. Subsequent sampling has confirmed these findings. The reliability modelling for copper risers has been refined to improve failure forecasts.

The predominant failure mechanism for these assets at EGI is associated with turbulent flow and is not affected by external conditions or the environment. Analysis determined the conditions (pressure and flow) that would lead to this and supported the sampling program which showed wall loss on all copper risers. The AMP-fitting assembly, typical AMP-fitting installation and localized corrosion failure are illustrated in **Figure 5.2-46**, **Figure 5.2-47** and **Figure 5.2-48**.

.

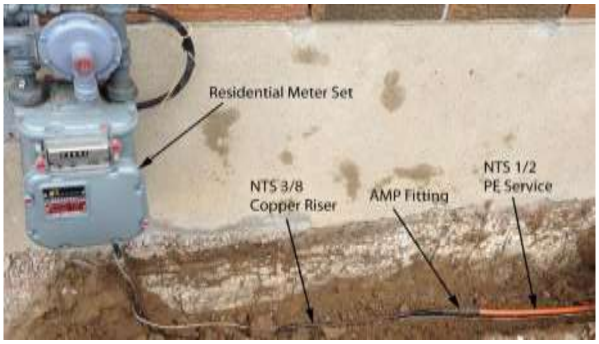


Figure 5.2-46: AMP Fitting Assembly

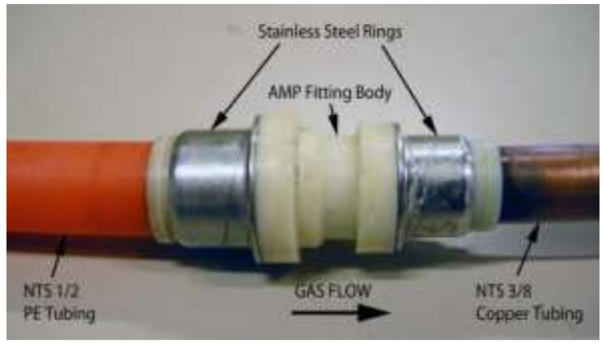


Figure 5.2-47: Typical AMP Fitting Installation

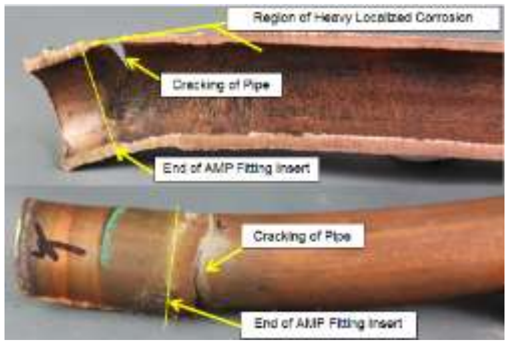


Figure 5.2-48: Localized Corrosion Failure at AMP Fitting Outlet

The condition of copper risers is expected to significantly degrade over time with a yearly increase in the number of leaks over the next 10 years as shown in a cumulative distribution function in **Figure 5.2-49.** Actual failure data has trended very closely to the statistically projected number of leaks as shown in **Figure 5.2-50**.

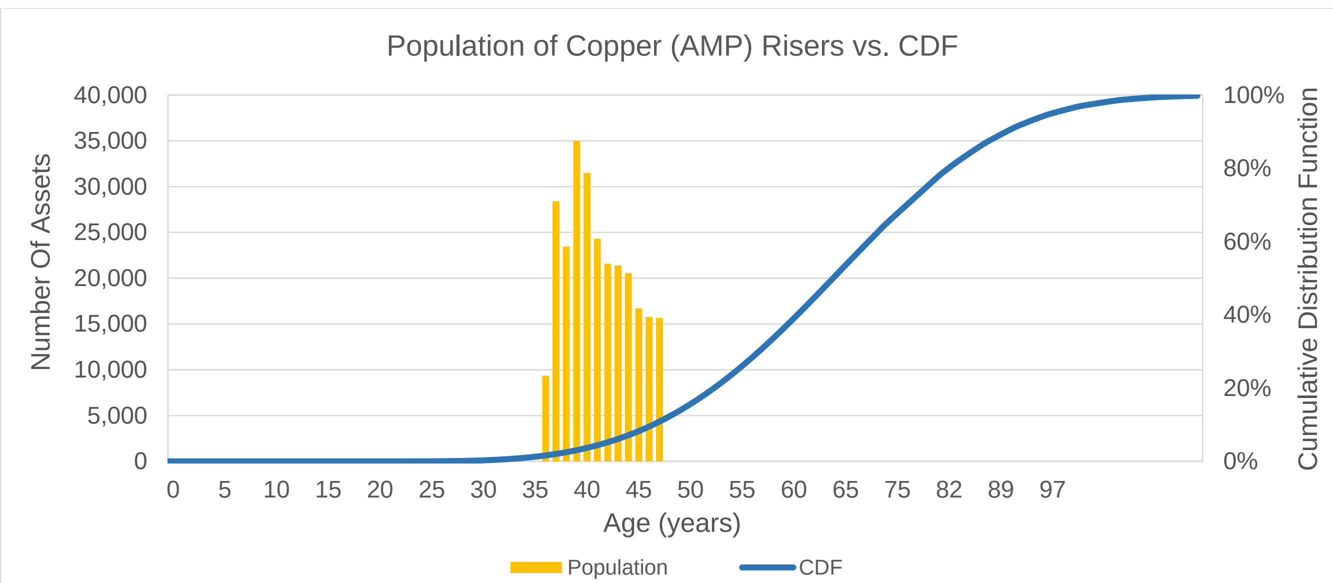


Figure 5.2-49: Population of Copper (AMP) Risers vs. CDF: EGD Rate Zone

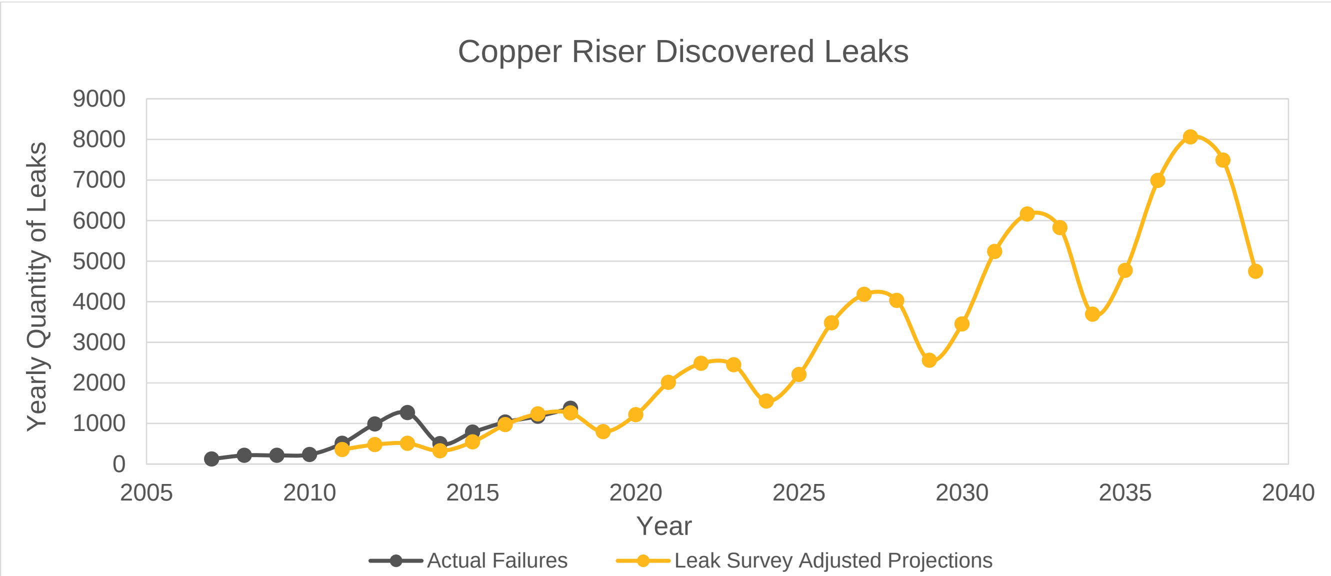


Figure 5.2-50: Copper Riser Discovered Leaks

Modern PE Resins

By the mid-1980s, EGI had started to use a different resin type, classified as Modern Polyethylene (PE) Resins. The newer generation of plastic resin and the improvement of installation practices resulted in a plastic mains asset that outperformed earlier assets of its kind. These newer resins have experienced fewer failures. EGI continues to gather data to better understand failure modes and mean time to failure.

The industry has proven that these resins do not exhibit slow crack growth (SCG) issues. These are relatively young assets and have experienced few material failures, and as such, statistical analysis to project future failures has been difficult. The entire population of this asset subclass is expected to remain in good condition for at least the next 40 years. A failure projection model is not included for this asset subclass.

5.2.7.3. Risk and Opportunity

The risks identified for distribution plastic mains apply to the entire Distribution Plastic Pipe asset subclass:

- **Safety Risk**: Gas leaks and migration through underground conduit into buildings can result in gas accumulation and explosions.
- **Financial Risk**: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties and any property damages caused by a gas leak
- **Operational Risk**: GHG emissions, environmental impact, service interruptions and reputational damages
- **Environmental Risk**: Greenhouse gas (GHG) emissions, environmental impact

For vintage plastic Aldyl A mains, slow crack growth (SCG) issues can lead to a steep failure curve, illustrating that the asset performs over time until sudden cracking occurs, accelerating the failure rate in a short period of time. This presents an opportunity to reduce failures by implementing a replacement strategy to manage the risk related to this asset subclass as a whole.

The brittle-like cracking observed on plastic mains creates a large opening on the pipe and releases a high volume of uncontrolled gas underground. If there is no way to vent to the atmosphere, gas can travel through any nearby underground infrastructure and migrate into buildings to create a potentially explosive environment. At a high volume flow rate, this accumulation could occur in a short period of time.

Copper risers have the potential for a circumferential leak and by their nature they are near building foundations. This leaves the opportunity for the gas to leak and migrate into buildings, accumulate and create a potentially explosive environment.

As the number of leaks grows over time, there is a risk to EGI's ability to respond to emergency calls and manage operational costs.

.

5.2.7.4. Strategy Outcomes

EGI evaluates asset strategies for the value that they deliver in terms of operational reliability, risk and cost over the long term. This drives a combination of reactive programs to respond to assets that have already failed and proactive programs to manage the growing number of leaks expected to occur as pipe assets approach the end of their useful life and the overall system condition degrades.

Maintenance strategies are described in **Section 5.2.4** and lead to the following replacement/renewal strategies for distribution plastic pipe:

Vintage Plastic Aldyl A Replacement Program

For this asset subclass, sufficient industry data and EGI internal failure history support the need for a replacement program. Early resins plastic mains will need to be further studied and understood through similar sampling and testing to justify a systematic asset renewal program. EGI continues to monitor all plastic mains through a leak survey program on regular cycles; leaks and other material faults with vintage plastic Aldyl A mains are addressed on a reactive basis.

The asset life of vintage plastic Aldyl A mains is estimated to be approximately 70 years. To maintain this average asset age, approximately 900 kilometres of vintage plastic mains will require replacement over the next 25 to 30 years, at an average replacement rate of 40 kilometres per year.

To identify an optimal replacement pace, an analysis was performed to identify the residual leak rate associated with different replacement rates over a 40-year period as shown in **Figure 5.2-51**.

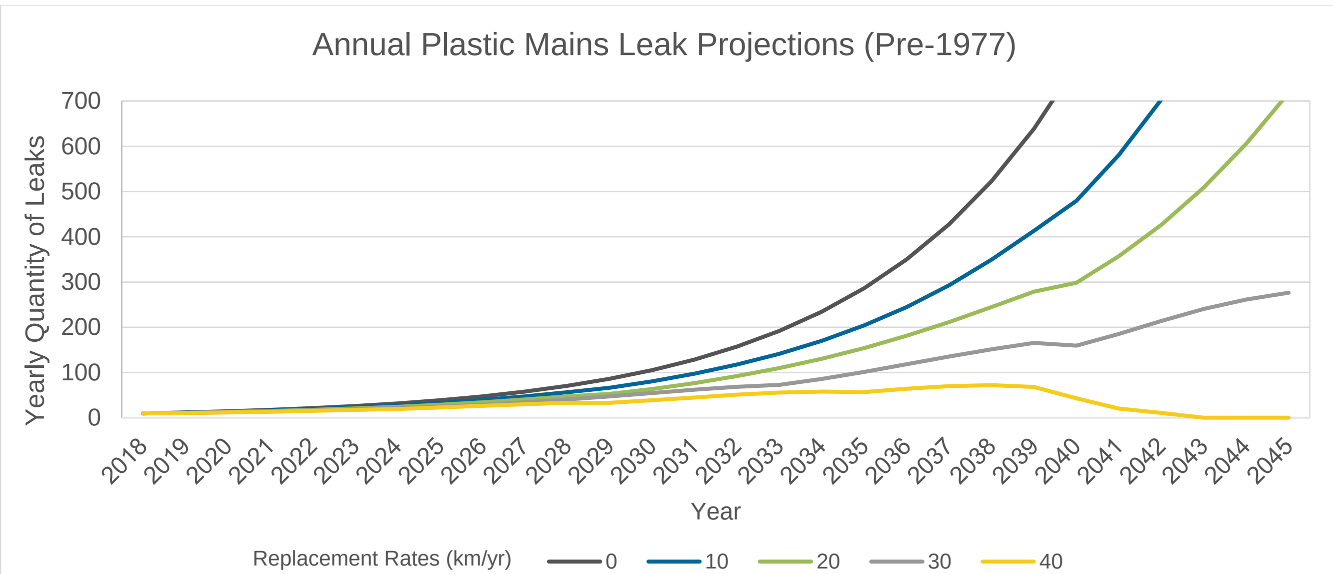


Figure 5.2-51: Annual Plastic Mains Leak Projections (Pre-1977)

Figure 5.2-51 shows the current reactive replacement approach (i.e., no proactive replacement) will result in significant increase in plastic main leaks over the next 20 years.

Because of rapid deterioration, the strategy is to increase the replacement rate to 20 kilometres per year for pre-1977 plastic mains in the next 10 years, with an immediate focus on replacing plastic mains that have experienced SCG failures due to known stress intensifiers (such as rocky soil type) and replacing early vintage field trial plastic mains pre-dating the implementation of plastic mains in the early 1970s. EGI will continue to monitor asset conditions to evaluate the asset life of pre-1977 plastic mains and determine the long-term replacement pace required to maintain the average asset age below the estimated asset life. This strategy ensures the risk is managed over the long term and replacement programs can be adequately resourced. In the short term, failing assets will be repaired or replaced as required. EGI continues to monitor asset conditions to determine if a change in pace is needed.

Emergency Replacement Program

See **Section 5.2.6.1.4**.

.

Service Replacement Program

See **Section 5.2.6.1.4**.

Relocation Program

See **Section 5.2.6.1.4**

AMP-fitting Replacement Program (Copper Risers)

Based on the Asset Health Review program and reliability models, it is expected that the majority of copper risers will fail after 2037. The degradation of the asset is significant, outpacing current leak quantities over the next 10 years. Due to the very large numbers of projected leaks, a replacement program is required to manage the risk and ensure that costs and emergency response can be managed on a year-by-year basis. The current pacing of the replacement program plans to replace increasing numbers of copper risers per year starting at 4,000 units in 2020 and increasing to 20,000 by 2026. **Figure 5.2-52** demonstrates the number of expected leaks discovered on a yearly basis.

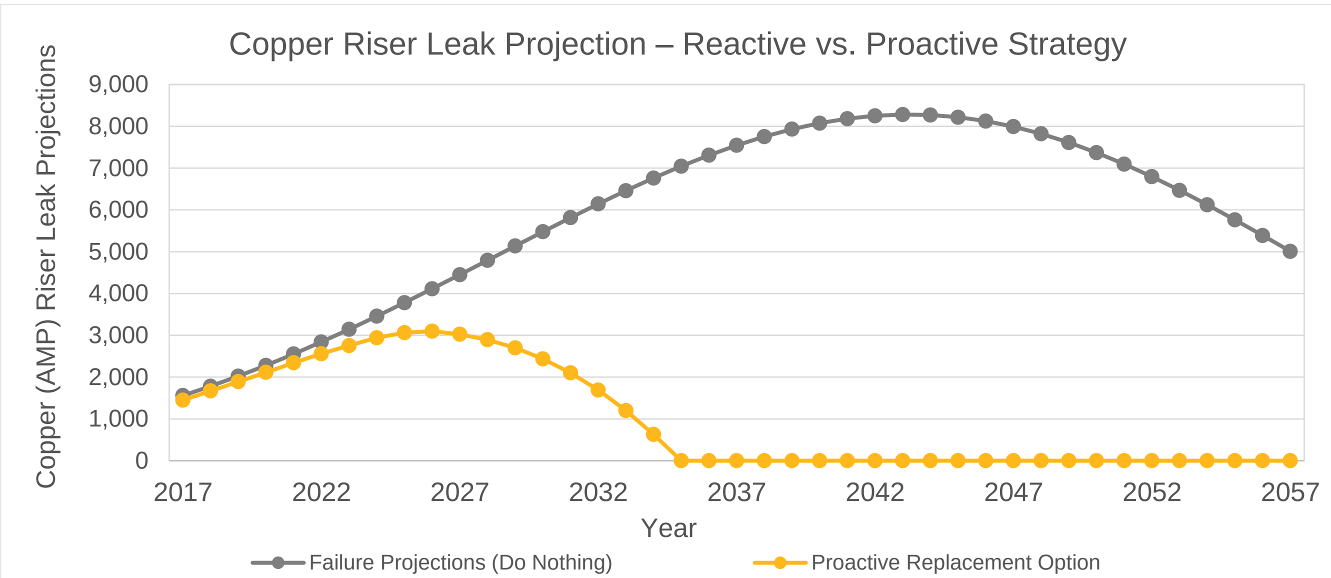


Figure 5.2-52: Copper Riser Leak Projection – Reactive vs. Proactive Strategy

EGI continues to evaluate asset condition and adjust its strategy accordingly to manage the integrity of AMP-fittings. The current annual service replacement program continues to manage the failing and non-compliant riser assets. Risers continue to be monitored under the Leak Survey and Corrosion Survey programs.

.

5.2.8 Pipe Capital Expenditure Summary

EGI has spent an average of $60M and $115M annually in the EGD and Union rate zones respectively for the Distribution Pipe asset class. The total average capital spend is forecasted to be $162M (EGD RZ) and $158M (Union RZ) as summarized in **Table 5.2-4** and

Table 5.2-5. The Distribution Pipe capital is further summarized as part of EGI's total 10-year capital plan in **Section 6.**

Table 5.2-4: Pipe Capital Summary ($ Thousands) – EGD Rate Zone

Program/Project Name	2021	2022	2023	2024	2025	Five-year Forecast
Integrity Digs and Retrofits	**16,953**	**14,590**	**2,051**	**10,157**	**6,134**	**49,884**
Corrosion Prevention Program	**3,142**	**3,069**	**3,222**	**2,195**	**2,409**	**14,037**
Main Replacements	**137,921**	**133,939**	**48,555**	**81,063**	**68,022**	**469,500**
Emergency Replacement Program	2,441	2,433	2,564	2,489	2,644	12,572
Vintage Steel Mains Replacement Program	112,138	119,615	39,143	72,500	57,566	400,962
NPS 20 Lake Shore Replacement (Cherry to Bathurst)	78,270	47,823	-	-	-	126,093
NPS 12 St. Laurent Aviation Pkwy	305	33,740	1,987	-	-	36,033
NPS 12 St. Laurent Queen Mary/Prince Albert	122	12,578	680	-	-	13,379
St. Laurent Phase 3 St. Laurent Plastic - Montreal to Rockcliffe St. Laurent Plastic - Coventry/Cummings/St Laurent St. Laurent Plastic - Lower Section	12,761	2,352	-	-	-	15,113
NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Road	-	-	512	21,524	793	22,830
NPS 10 Glenridge Avenue, St. Catharines	-	-	558	7,360	7,213	15,131
General Main Replacement Program	**1,688**	**-**	**2,320**	**-**	**-**	**4,007**
Vintage Plastic Aldyl A Replacement Program	**21,654**	**11,892**	**4,528**	**6,074**	**7,812**	**51,959**
Relocations	**6,104**	**11,799**	**12,436**	**12,074**	**12,822**	**55,235**
Service Relay Programs	**37,886**	**38,261**	**43,621**	**46,384**	**59,184**	**225,336**

.

Program/Project Name	2021	2022	2023	2024	2025	Five-year Forecast
AMP-fitting Replacement Program (Copper Risers)	12,013	11,287	13,898	16,187	25,828	79,213
Service Relay Program	25,873	26,974	29,724	30,197	33,356	146,123
EGD Rate Zone Total	**202,005**	**201,659**	**109,886**	**151,872**	**148,571**	**813,993**

Table 5.2-5: Pipe Capital Summary ($ Thousands) – Union Rate Zones

Program/Project Name	2021	2022	2023	2024	2025	Five-year Forecast
Integrity Digs and Retrofits	**38,819**	**30,370**	**30,007**	**22,595**	**20,077**	**141,868**
INTE: North Shore - Section A: Retrofit ECDA to ILI	14,674	-	-	-	-	16,674
Corrosion Prevention Program	**10,012**	**12,365**	**9,193**	**9,000**	**9,186**	**49,756**
Main Replacements	**191,743**	**63,886**	**44,293**	**67,999**	**37,017**	**404,939**
Steel Mains Replacement Program	155,154	39,138	12,949	33,016	13,472	252,567
Port Stanley Line Replacement	-	-	-	616	25,344	25,960
Kirkland Lake Lateral Replacement	733	19,715	-	-	-	20,449
London Lines Replacement	119,711	10,104	-	-	-	129,815
Windsor Line Replacement	8,802	-	-	-	-	8,802
Vintage Plastic Aldyl A Replacement Program	-	-	-	1,948	3,869	5,817
Bare and Unprotected Steel Pipe Replacement Program	15,618	14,160	12,405	14,494	-	56,678
Class Location Program	20,971	10,588	12,519	12,256	13,007	69,340
Relocations	**32,533**	**29,208**	**30,816**	**30,168**	**32,016**	**154,741**
Service Relay Program	**7,284**	**7,375**	**7,915**	**7,883**	**8,510**	**38,967**
Union Rate Zones Total	**280,391**	**143,204**	**122,225**	**137,644**	**106,807**	**790,271**

.

5.3 Distribution Stations

The Distribution Stations asset class is comprised of facilities and assets whose primary purpose is to reduce pressure from a system operating at higher pressure to a system operating at lower pressure and to provide over-pressure protection to the lower-pressure system. Depending on the facility, additional purposes may include gas metering, odourization and monitoring.

This asset class is comprised of approximately 35,000 sites throughout Ontario. This includes all natural gas entry points into the EGI distribution network, control points throughout the network and delivery points to end-use customers. Distribution Stations is organized into three subclasses based on function:

- **Stations with Auxiliary Equipment**: System and customer stations reduce upstream pressure and distribute natural gas to pipeline systems operating at lower pressures and/or customers and employ additional equipment to ensure the safe and reliable distribution of natural gas.
- **Distribution System Stations** reduce upstream pressure and distribute natural gas to a downstream gas main.
- **Customer Stations** reduce upstream pressure and deliver to a downstream customer that consumes the natural gas with a total connected load greater than 12 m^3/h and with a delivery pressure to the customer of 14 kPa or greater.

EGI monitors the industry for incidents that may be relevant to EGI's assets. As such, EGI has assessed the potential for an incident on a low-pressure system such as that which occurred in Merrimack Valley, Mass. where a distribution system was over-pressured. EGI took some immediate measures to review procedures and records and ensure that sense lines were inside the perimeter of regulation stations. EGI is continuing to evaluate the risk in each of these installations and determine whether additional layers of protection are required to bring the risk to broadly tolerable or as low as reasonably practicable.

The current station rebuild and replacement rate is inadequate to prevent the average age of the population from increasing. With more than 34,000 stations of varying degrees of complexity and criticality, EGI is developing analytics to establish age, condition and risk so as to develop maintenance and replacement strategies that balance risk, cost and performance.

As EGI continues to review operating standards in each rate zone and the use of various equipment and fittings, plans will be developed to bring these into alignment in a way that balances risk, cost and performance. An example would be the addition of fire suppression systems at gate stations to ensure compliance with applicable codes and standards.

.

5.3.1 Distribution Stations Objectives

Objectives of the Distribution Stations asset class are listed in **Table 5.3-1.**

Table 5.3-1: Distribution Stations Asset Class Objectives

Asset Class Objective	
System Integrity and Reliability	Maintain distribution stations to meet or exceed codes, standards and the requirements of applicable governmental authorities for safety and operational effectiveness. This includes ensuring the system has the capacity to reliably meet current and future customer demand.
	Ensure the safe and reliable delivery of natural gas to end users.
	Use cost, risk and performance information to drive asset-related decisions.
	Continuously evolve the understanding of condition and risk associated with station assets.

The performance measures for the Distribution Stations asset class are as follows:

- Number of unscheduled visits per station
- Number of events where pressure is controlled via Over Pressure Protection (OPP) device
- Number of service disruptions
- Number of over-pressure events (failure to control pressure above OPP set point)

To achieve the Distribution Stations asset class objectives listed in **Table 5.3-1**, asset investment decisions are governed by the life cycle management strategies outlined in **Table 4.1-1**.

5.3.2 Distribution Stations Hierarchy

The asset subclass hierarchy for the Distribution Stations asset class is illustrated in **Figure 5.3-1**.

- **DISTRIBUTION STATIONS**
  - Stations with Auxillary Equipment
  - System Stations
  - Customer Stations

Figure 5.3-1: Distribution Stations Hierarchy

Figure 5.3-2 shows the station hierarchy by station type. Note that there are many possible configurations of distribution station assets downstream of the entry point into the distribution system. **Figure 5.3-2** is for illustrative purposes only and is not meant to display all possible configurations.

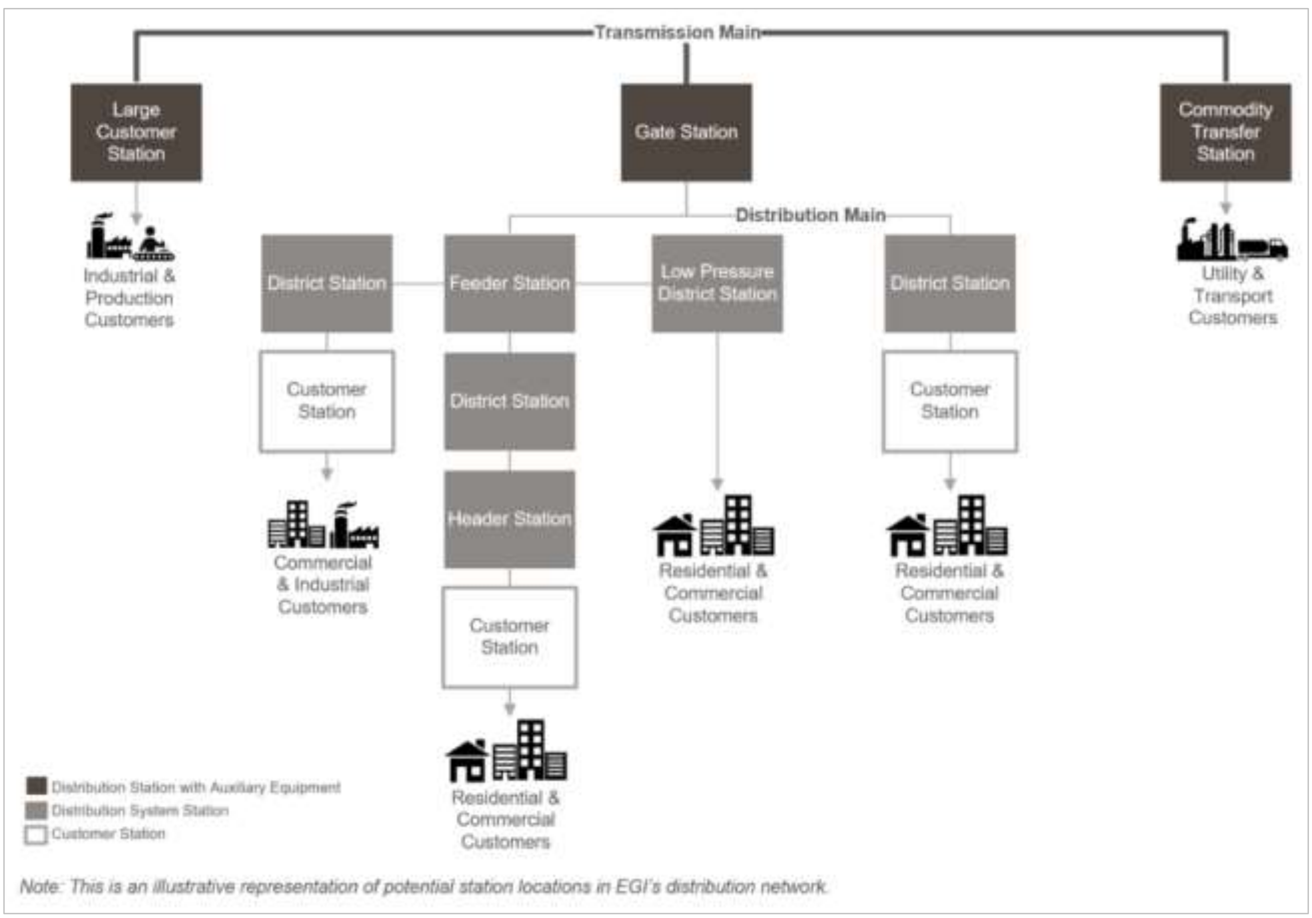


Figure 5.3-2: Station Hierarchy by Type

The Distribution Stations asset class includes the following asset component sub-systems:

- Pressure control
- Station valves
- Strainers and filters
- Piping systems
- Heating system (boilers and heat exchangers)
- Telemetry system
- Odourization system
- Measurement system
- Civil and site assets

Figure 5.3-3 depicts the typical schema and interconnection of systems associated with distribution stations. Station components and layout will vary based on the design, type and function of the station. A typical example of a station in the Station with Auxiliary Equipment subclass consists of the following system components: the inlet valve assembly for isolating and/or bypassing the station, the measurement system to accurately track the gas flow or volume, the heating, pressure control and odourization systems, the outlet/supply valve assembly and the outlet piping. These systems are interconnected through the telemetry system, which monitors and controls the operation and performance of each station component.

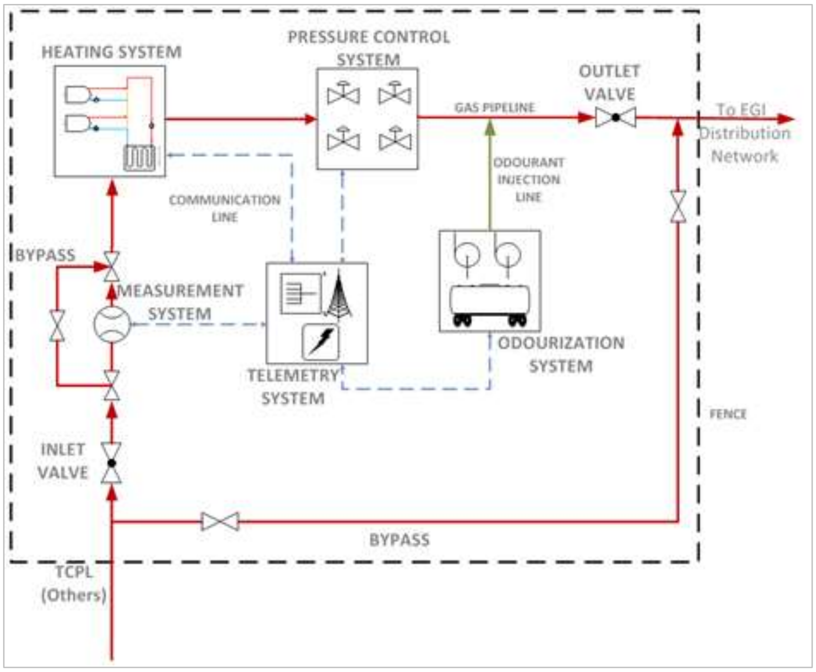


Figure 5.3-3: Station Components

The **pressure control** components control and regulate gas pressure from a higher pressure (inlet pressure) to a set lower pressure (outlet pressure). Pressure control equipment typically consists of operator regulators, monitor regulators, relief valves and slam-shut devices. Operator regulators control pressures while monitor regulators, relief valves or slam shut devices provide over-pressure protection in the event the operator regulator fails. Regulators are classified into four types: pilot-operated boot, pilot-operated non-boot, spring type regulators and pilot-operated control valves. Relief valves provide an audible and odor notification in the event of operator regulator malfunction.

The **station valve** components control the flow of gas through the station and include all inlet valves, outlet valves, bypass valves and component isolation and process valves. Station valves are used to direct flow, isolate station components and shut down gas supply for planned or unplanned events.

Strainers and filters are applied to remove particles of dirt from the gas before they can damage downstream system components such as regulators, pilots, meters or other equipment.

The **piping system** within stations is comprised of the pipe connecting each of the component groups, as well as ancillary piping and tubing. Ancillary piping includes glycol piping for the heating system, tubing for pressure control and piping and tubing for the odourization system. Piping may be installed below- or above-grade with pipe supports and may be insulated to

.

retain heat or for noise attenuation. Protection of the piping system consists of underground corrosion control systems and above-ground high performance coating and paint.

The **heating system** components ensure that gas temperatures within the distribution system remain above a site-specific targeted setpoint, as the reduction in temperature caused by pressure regulation can have detrimental effects on equipment performance. The heating system is comprised of two sub-components–the boiler and the heat exchanger. The pressurized boiler heats and circulates glycol through a glycol loop to the heat exchanger, which transfers heat to the gas prior to pressure control reduction. Heating systems may also be comprised of small component heaters or heat trace systems that are used for thermal protection of critical components such as regulators and pilots.

The **telemetry system** connects station equipment to a network that remotely transmits station performance information to centralized gas control management for monitoring and control. Information such as inlet and outlet pressures and temperature, gas flow rate, odourant injection rate and other critical characteristics of station performance are monitored in real time. Typical sub-components include:

- Programmable Logic Controller (PLC) / Remote Terminal Unit (RTU) as the central processor
- Pressure and temperature sensors and transmitters
- Gas monitors
- Communications devices and antenna towers
- Power supply, UPS and backup generators and other electrical assets
- Weather systems

The **odourization system** components are responsible for the introduction of odourant into the gas stream to ensure gas is detectable at low concentrations as natural gas is odourless in its basic state. Odourant injection is automated at all stations at the entry point to the gas distribution network. Sub-components of the odourization system include:

- Odourant tank
- Odourant pumps
- Injection point with sight glass
- Odourant containment
- Meters, valves, tubing, controllers
- Atmospheric monitoring devices
- PLCs

The **measurement system** components provide a corrected volumetric measure of the amount of natural gas flowing through a particular site. Measurement devices are used in customer stations as a custody transfer point between EGI and the customer, subject to the MXGI program in **Section 5.4.5.1**. EGI uses many different meter types and electronic volume correcting equipment to calculate pressure and temperature compensation factors in real time. At customer or system stations where the design requires, EGI incorporates measurement devices to measure the rate of gas flow through its system. These measurement devices are critical for calculating the demand requirements (rate of odourant flow, heating system temperature requirements, etc.) for other station components.

Civil assets in the Stations with Auxiliary Equipment subclass can include individual buildings for housing telemetry assets, heating/boiler equipment, the odourization system, the pressure control system and other miscellaneous equipment. Civil assets also include fencing, property lighting, security systems, piping supports and barriers, water management systems such as culverts and ditches and general property.

.

5.3.3 Distribution Stations Inventory

Table 5.3-2 lists the inventory details for the Distribution Stations asset class.

Table 5.3-2: Distribution Stations Asset Class Inventory

Asset Subclass	EGD Rate Zone	Union Rate Zones
Stations with Auxiliary Equipment	**168 Stations**	**389 Stations**
Pressure Control	550	1,787
Valves	989	5,964
Filter	N/A	413
Flow Meters	114	295
Heating System - Boilers	143	554
Heating System - Exchangers	59	277
Odorization	194	147
Telemetry	1,083	1,055
Distribution System Stations	**4,928 Stations**	**2,646 Stations**
Pressure Control	14,527	5,077
Valves	3,224	8,405
Filter	N/A	734
Flow Meters	20	133
Telemetry	161	125
Customer Stations	**12,056 Stations**	**14,594 Stations**
Pressure Control	29,753	18,899
Valves	2,871	2092
Filter	N/A	2,700
Flow Meters	11,785	24,691
Telemetry	49	47
Rental Refueling – Large and Mobile	10	1
Refueling – Small (VRA)	210	N/A
Utility Refueling	19	3

Note: The inventory for meters and regulators (discussed in **Section 5.4.3**) also includes meters and regulators located at customer stations and included in the inventory figures above (EGD rate zone only).

In the Union rate zones, some subclass inventories (Local First Cut Regulator Sets, Remote First Cut Regulator Sets, and Below-ground and Internal Piping Systems) are not currently available. As part of integration activities, inventory tracking processes will be harmonized over time.

.

5.3.4 Distribution Stations Condition and Strategy Overview

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

5.3.5 Stations with Auxiliary Equipment

The assets in the Stations with Auxiliary Equipment subclass are the most complex distribution stations within EGI - most are uniquely configured and involve the highest pressures and volumes. These stations include entry points into the gas distribution system and require additional equipment, which are not required in other stations downstream of the network.

Station components can vary greatly depending on the station's purpose and design complexity. Stations with auxiliary equipment have components that consist of piping, meters, regulators, valves, filters, separators, heaters, odourant, controls, and in some cases, structures. These stations are grouped according to function:

- **Gate and Transmission Stations** accept gas from a transmission company's pipeline (EGI or other) and supply gas to the distribution system, acting as the custody transfer and entry points of natural gas into the network. Station components included in these stations are pressure control, odourization, measurement, station valves, heating and telemetry. Gate stations typically accept incoming gas pressures from the transmission company at high pressures and regulate to distribution pressures. In a particular location, a single gate station can supply gas to over 600,000 customers.
- **Feeder Stations** are large regulator stations within the gas distribution system. Station components included in feeder stations are pressure control, measurement, gas pre-heating and telemetry. Feeder stations typically accept incoming high pressures and regulate to distribution pressures. This type of station is traditionally located within the Greater Toronto Area.
- **Commodity Transfer Stations** are stations where gas is bought from or sold to another utility or transporter.
- **Large Customer Stations** refer to a commercial or industrial station where the downstream system served is a single service.

The majority of station sites have above-ground components, with some piping and operating equipment located below ground. All gate and transmission, feeder, commodity transfer and large customer station sites are located on EGI-owned property within fenced and controlled access compounds. The additional station equipment (i.e. filtration, heating systems and/or odourization) at these sites present increased hazards that require enhanced attention. These sites are the custody transfer point and critical pressure control location from the transmission company's pipelines into the EGI distribution network or to a large customer site.

Table 5.3-3 represents the age of the various systems components and life expectancy at all station sites for this subclass. The expected lifespan for each system was based on evaluations and Subject Matter Advisor (SMA) interviews and is aligned with the current asset population and historical replacement strategy.

The age of individual systems is used for evaluation, rather than the age of the original activation of the station site, as individual station components are replaced based on their condition. Typically, the oldest assets tend to be the pressure control components, which have the longest expected life span.

Table 5.3-3: Estimated Life Expectancy for Stations with Auxiliary Equipment

Station Component	Expected Life (SMA input)		Average Asset Age (Years)		Maximum Asset Age (Years)	
	EGD RZ	Union RZ	EGD RZ	Union RZ	EGD RZ	Union RZ
Pressure Control	37 to 45	Up to 37	16	17	57	52
Odourization	19 to 28	20 to 25	13	14	23	29
Heating System	18 to 24	10 to 38	12	12	22	47
Telemetry	14 to 23	9 to 20	13	7	33	38

Table 5.3-3 shows both rate zones have differences in the expected life of station components, the actual average age and the maximum asset age. This is expected due to different design standards and maintenance strategies. As part of integration activities, best practices for engineering design and operating standards are being applied to the combined station asset population to better understand asset condition.

5.3.5.1. Condition Methodology

EGI station assets are inspected and maintained on a regular basis in accordance with operating standards. For example, the pressure control system is inspected on a frequency that considers inlet maximum operating pressure (MOP), inlet pipe size, station type and regulator type. This can be as frequent as a weekly inspection for stations with a higher inlet MOP and inlet pipe size. Inspection results and trouble call history are recorded and analyzed to understand asset performance, condition and health.

.

EGI is enhancing the Facilities Integrity Management Program (FIMP), which provides the framework to identify threats, monitor facility conditions and manage Integrity data. FIMP applies to stations that meet the following criteria:

- Any station interconnected between EGI and any other gas transmission company, distribution utility or production facility that supplies gas into or receives gas from the EGI network and is not the final point of use.
- All facilities connected to or including pipe operating at or above 30% SMYS based on MOP and not currently inspected by the Transmission Integrity Management Program (TIMP). If these stations do not have auxiliary equipment, they are considered to belong in the Distribution System Stations asset class (see **Section 5.3.6**).
- Facilities where the following equipment is used in the direct conditioning of gas that is being used further downstream.
    - Heat exchangers as part of a boiler system
    - Equipment containing glycol used to directly heat gas
    - Liquid separation equipment (excluding separation used for control or fuel gas)
    - Filters (excluding single cartridge/element filters)
    - Control valves
    - Odourization

Approximately 92% of the assets in the Stations with Auxiliary Equipment subclass are within the scope of the FIMP. The FIMP will provide direct evidence in the form of quantifiable data on assets to supplement existing condition information. The remainder of the population condition will be assessed through routine maintenance and visual condition inspections.

5.3.5.2. Condition Findings

The condition at each station is unique (in terms of asset condition, obsolescence and compliance). Station components may vary in age due to the replacement history of the site. Historically, station issues have been identified when existing maintenance procedures are executed. A list of typical findings can be found in **Table 5.3-4**.

Table 5.3-4: Typical Station Issues

Issue	Description
Construction and Configuration	Station configurations are not in compliance with current design standards. Electrical configurations not in compliance with current design standards may result in a higher potential for electrical supply failures, employee safety concerns and violation of ESA standards. Lack of adequate backup power contributes to a high probability of station power loss during hydro outages, resulting in system and monitoring failures. Leak containment issues contribute to potential code compliance violations and potential high cleanup costs in the event of loss of containment for glycol, odourant, etc.
Function	The asset is unable to deliver the required demand (i.e., insufficient gas supply, heating requirements, over-working components, etc.) and can result in loss of supply to customers. Equipment inaccuracy results in incorrect gas measurement systems and potential revenue loss. Sealing issues increase the probability of asset failure and downstream over-pressure situations.
Operability	Operating difficulties contribute to increased maintenance costs and potential employee safety concerns.
Maintainability	The asset requires frequent maintenance calls and adjustments. Component accessibility issues contribute to increased maintenance costs, potential asset failures and employee safety concerns.
Components	Parts are no longer available, repairs result in long downtime, or repair costs are excessive. Glycol conditioning issues indicate the degradation of heating system internal components, which result in higher maintenance costs and decreased component reliability Communication issues contribute to electronic component failures, loss of remote monitoring, alarming and control. Recurring component issues contribute to increased failures and component reliability concerns. Corrosion is an indication of component degradation and less reliable assets Insulation damage promotes rapid corrosion growth on piping.

.

Issue	Description
	Building issues can result in leaks and lack of component protection, causing premature failure and less reliable assets.
External Factors	Dirt and debris increase the probability of failure and downstream over-pressure situations. Damaged components contribute to increased maintenance costs and potential employee safety concerns. Pipe heaving occurs due to inadequate heating supply or improper construction methods, resulting in undue stress to piping and other components. Improper support can result in movement or settlement, causing undue stress to piping and components. A sinking foundation causes stress in piping and other critical components. Damages to fences or other physical security equipment could result in vulnerability threats.

In addition to maintenance inspection results, the condition and health of station components may be subject to further engineering analysis and future FIMP inspections. These stations are evaluated based on the following:

- The age of critical components, such as regulators, boilers, RTU, etc.
- The performance of the asset, such as known operational problems
- Asset history and the evaluation of failure events
- SMA input

To better understand asset condition, the FIMP will provide direct assessment data as described in **Section 5.3.5.1**.

5.3.5.3. Risk and Opportunity

Assets in the Stations with Auxiliary Equipment subclass are a vital part of the distribution network; as such, failures have significant consequences and must be avoided. Mitigation strategies to reduce risk to the lowest practicable level include redundancy of critical systems and a comprehensive inspection and maintenance program.

When station components are not maintained, the following are types of failures and the likely consequences (failure scenarios) are observed for this asset subclass:

- **Loss of Pressure Control**: Pressure control failures could cause an over-pressure or under pressure scenario.
    - **Over-pressure Event**: Stations are the delineation between different operating network pressures. Failures causing over-pressure situations result in the upstream higher pressure network interacting with the downstream lower pressure network. In this scenario, the pressure of the downstream network increases to levels beyond which it is rated. Over-pressure could lead to component failure in the downstream network, over-stressing pipe or fittings, loss of containment and gas entering customer premises if the customer regulator fails. The potential for fire or explosion is increased in an over-pressure situation.
      The frequency of pressure control failure is dependent on the configuration of the station. A station with a single regulator and single run will fail more frequently than a station with double regulators and double runs. Each of these could result in a release to the environment, leading to potential ignition or explosions.

      The consequence of an overpressure event from a financial impact includes commodity loss, service disruptions, increased network leak surveys and system checks, repairs or replacement of company-owned property or damages to public, commercial or industrial property. Pressure control failures may lead to unintended GHG emissions of natural gas to the environment, impact EGI's reputation and fail to meet the expected high levels of operational reliability.
    - **Under-pressure Event**: Under-pressure at a station can lead to loss of service for customers. This is of particular concern for industrial customers, who expect a reliable natural gas supply for processes, as well as for heating needs during colder periods. Stations approaching design capacity could experience under-pressure situations, loss of service to customers and station equipment performing beyond recommended operating limits.

  Typically, the pressure control design includes redundancy with a method of over-pressure protection to reduce the likelihood of a pressure control failure.
- **Loss of Measurement System Function:** Measurement equipment can be used to accurately inject odourant into the pipeline. Loss of measurement functionality could lead to improper odourant levels (undetectable gas leaks), inaccuracy of gas measurement and inaccurate billings of commodity transfer which could result in volume billings or purchase disputes.

.

- **Loss of Odourant System Function**: The odourant system adds the odour in natural gas so that it is detectable in the event of a release. Failure of the odourant injection system could result in leaks not being readily detectable which could lead to service disruption implications, commodity losses from undetected leaks, public property damages or fines from the technical regulatory authority. Reputational and financial risk may result from the reduction in emergency and unplanned callouts to unreliable odourant injection systems. Inoperable odourant systems would lead to a failure to maintain proper odourant levels as mandated by code requirements, potentially impacting the safety and reliability of the gas distribution network.
- **Loss of Heating System Function**: Loss of the heating system function could result in two scenarios (frost heave or pressure control failure due to the freezing of station components) that could result in the loss of pressure control and potentially leading to an over-pressure or under-pressure situation. Frost heave occurs when cooling of the gas due to the pressure reduction causes an upwards swelling of soil around public or private property near the gas main. The financial impact includes commodity loss, service disruptions, increased network leak surveys and system checks, repairs or replacement of company-owned property, or damages caused to public, commercial or industrial property. Inoperable systems will lead to a failure to maintain operational supply to customers.
- **Valve System Malfunction**: The frequency of a valve malfunction is low. Inoperable station valves prevent isolating gas flow within the station. This would lead to isolation of the station where available (up and/or downstream of the location), increased maintenance and potentially lead to higher response times.
- **Loss of Telemetry System Function**: Failure of real-time monitoring would cause a delay in responding to system operation problems or emergencies. Stations with an older telemetry system have a higher failure frequency. Without the telemetry system, there is no visibility to the performance and operation of EGI's system, causing increased callouts, emergency system repairs and greater patrols. Failures of the telemetry system could also be caused by cybersecurity attacks into the communications network.
- **Loss of Electrical System Function**: Loss of the electrical system function will impact the odourant, telemetry and heating systems as all rely on electrical power or backup power systems to function properly. Without a power supply, the failures described for each station component can exist. The frequency of losing power at a station depends on the frequency of electricity outages in the area, third-party damage and backup power system failures.

Equipment failures can occur in any asset subclass component and its impact is dependent on site location and redundancy, which could affect response times if a failure occurs. The impact of each system failure is different; however, there are some interdependencies between system failures. The extent of impact is dependent on the station location (i.e., whether the station is in a populated or remote area), the number of customers serviced by the station and whether the station is a single-feed or multi-feed system. The subsystems within these stations have interdependencies which may impact the reliability and performance of other systems. Therefore, the complexity of failures in one subsystem may lead to potential failures of other subsystems. For example, the measurement system is used to both measure gas flow and calculate the proper odourant injection rate. The response times to address equipment failure can vary depending on the location of EGI's response team, reinforcing the design strategy to include redundancy where appropriate.

The risk for assets in the Stations with Auxiliary Equipment subclass is dominated by financial risk, which may require fixing any damages to public property, relights due to service disruption, commodity loss, replacing and repairing company property and any regulatory penalties. Failures at these stations could impact gas supply to EGI's customers, leading to decreased operational reliability and reputational impacts. The public safety and employee and contractor health and safety risks for these assets are higher if the station is located in an urban or developed area due to a high potential impact on the surrounding population. Operational risks identified include GHG emissions and loss of service to customers.

5.3.5.4. Strategy Outcomes

The strategies for the Stations with Auxiliary Equipment asset subclass support the proactive replacement of stations based on obsolescence and condition:

Stations with Auxiliary Equipment Replacement Strategy

This strategy targets the replacement and/or rebuild of station components at sites prioritized based on condition, age and observations identified through site inspections and SMA reviews. Station investments are selected based on value framework assessment results and compliance/design standards. The goal of this strategy is to proactively replace or rebuild station components prior to end-of-life to reduce risk and maintain a safe and reliable distribution system. This is aligned with 2020 Customer Engagement survey results where customers are supportive of investing to maintain current levels of safety and reliability. Despite this strategy, there may be instances where reactive replacement occurs.

This strategy includes considerations to leverage resources and plan capital replacements in a thoughtful manner that can vary by site. Some considerations include:

- Replacement of components based on expected failure. For example, if the entire boiler system is in poor condition with a high expectation of system failure, the entire system is replaced (proactive).
- Multiple component rebuilds to benefit from combined resources and project scope. For example, if the boiler system is in poor condition with a high expectation of failure and the telemetry and odourization systems are currently approaching poor condition, all three systems are replaced (proactive).
- Replacement and upgrade of components evaluated to be at or approaching capacity, based on projected forecast demands. For example, if regulators are evaluated to be approaching capacity in the upcoming year, components will be upsized to handle the appropriate projected system demands (proactive).
- Replacement of individual component assets as they fail. For example, a failure of one of the pumps within the boiler system results in the pump being replaced (reactive).

Compliance Remediation Strategy

This strategy targets the elimination of compliance concerns at stations identified through engineering assessments and Process Hazard Analyses (PHAs), using a managed approach to monitor and address identified code compliance issues. The strategy targets individual station sites found to have compliance deficiency issues such as issues on access/egress, building codes and fire codes, venting and site security vulnerabilities, as well as environmental compliance approvals.

Obsolete Heating Equipment Strategy

This strategy targets stations with heating equipment that have reached end-of-life, with a focus on systems where there is a risk of a glycol spill. Natural gas heating equipment is used in many system and customer stations to help mitigate failure of equipment due to the freezing of liquids in the gas stream and moisture surrounding buried piping. Over many years of operation, a variety of heating systems have been used, resulting in varying equipment age and ultimately, equipment obsolescence. This work will maintain system reliability, ensure operating costs for heating systems are minimized and reduce the potential for glycol spills.

Odourization System Strategy

This strategy targets stations with older odourization systems, specifically those with compliance issues. The expenditures in this portfolio include investments to upgrade odourant systems to ensure compliance to current codes, such as replacing old tanks and painting rusted containment pans and tank stands. Additionally, performance capability will be added by installing heat tracer lines, heated cabinets, improved tank valves and indoor regulator panels. This work will help to ensure safe, compliant and continuous odourization and will help mitigate the risk of tank rupture, frequent freeze offs and nuisance odour calls.

Telemetry Strategy

This strategy aims to maintain reliable telemetry equipment and will focus on component replacements as these have a much shorter anticipated life span than other station equipment. Telemetry components have varying life expectancies and are upgraded to address obsolescence, communication issues, electrical configurations and backup power. Obsolete equipment cannot be replaced like-for-like if it is damaged and may compound communication issues. The scope of the Telemetry Strategy includes:

- Replacement and upgrade of telemetry instrumentation, electrical and power generation assets and telemetry communications assets
- Replacement and upgrade of servers and network devices such as firewalls, modems, routers, etc.
- Supply and installation of security assets (swipe card access, video surveillance and intrusion detection assets)
- Tower network expansion as required to augment communication pathways
- Computer terminal and server expansion to support central logbook repository, data analytics and data historians

.

- Continued development of the maintenance layer at major stations and the implementation of capabilities to backhaul data from remote sites to enable video surveillance, swipe card access at all compounds and buildings and a central logbook repository for all sites

Stations Retrofit Strategy for TIMP Mains

The Stations Retrofit Strategy for pipelines covered under TIMP targets adding permanent in-line inspection assets (launchers and receivers) to existing stations upstream and downstream of pipelines operating at >30% SMYS. See **Section 5.2.5** for more details on the assets within the TIMP Mains asset subclass.

Stations Capital Upgrade Program

This program includes a number of risk remediation programs and general upgrade activities that are part of the core system and customer station work:

- **Obsolete Equipment**: As station facilities age, regulators and relief valves can become obsolete due to vendors no longer supporting specific types of equipment or may present maintenance and reliability concerns due to age. This initiative remediates all currently identified obsolete station equipment in the Union rate zones, improving system reliability and generating field efficiencies due to the reduced equipment variability and simplified maintenance procedures.
- **Regulator Freeze-offs**: As natural gas supplies into the pipeline systems change, natural gas quality can also change. Existing system stations that experience significant pressure cuts combined with elevated moisture content in the natural gas stream can cause freezing of regulators and loss of downstream customers. Sites of concern will continue to be addressed as needed.
- **Station Blankets**: Spend is also allocated to each region to ensure capital is available for unforeseen maintenance challenges, such as leaks or failures that require short turnaround times for remediation, particularly if no specific project is identified for the affected assets.
- **Frost Heave Mitigation**: This initiative targets stations presenting issues due to frost formation in below-grade soil. Mitigation techniques can include the addition of station heaters, or where frost heaving is less severe, the excavation and leveling of station sites. This program ensures the risk of leaks and piping failures are reduced to maintain system reliability. It also ensures maintenance challenges are reduced, such as when piping can spring out of place due to stresses imparted from frost heave.

Using these factors as a guide, work is ongoing to identify stations that will require replacement in the later years of the asset plan (2024-2045).

Facilities Integrity Management Program

See **Section 5.3.5.1**.

.

5.3.6 Distribution System Stations

The assets within the Distribution System Stations subclass reduce gas pressure from a network operating at a higher pressure to a network operating at a lower pressure depending on the needs of downstream natural gas main. These types of stations are typically located above-ground, with or without an enclosure and differ in size, operating pressure conditions, number of downstream connected customers and gas volume delivered. System station components consist of piping, meters, regulators, valves, and in some cases, limited pressure monitoring. System station function and components vary greatly depending on use and design complexity:

- **District Stations** operate within the gas distribution network and regulate the flow of gas from a higher pressure to a lower pressure. District stations are primarily used for pressure control and may have basic pressure monitoring capabilities (district stations with a gas pre-heating system are included in the Stations with Auxiliary Equipment subclass). District stations are typically located within roadway allowances and can be housed within a box enclosure, located above-ground without an enclosure or buried below-grade in a vault.
- **Header Stations** accept gas from any EGI pipeline system and feed a header service (a network of pipe on private property). Header stations are primarily used for pressure control. These stations are typically located above-ground and on private property. While header stations are a class in the EGD rate zone, it is not an identified class in the Union rate zones.
- **Commodity Transfer Station Without Auxiliary Equipment**: these stations mark the change of gas ownership from EGI and another party.
- **Ontario Producer Stations** are located at gas production wells within EGI's franchise area where gas enters the distribution system.

Distribution system stations consist of mechanical components with shorter lifespans relative to other gas-carrying assets (see **Table 5.3-5**). Based on Subject Matter Advisor (SMA) experience, this is broadly aligned with preliminary models predicting the useful life of regulators.

Table 5.3-5: Estimated Life Expectancy for Distribution System Stations

System Station Rate Zone	Expected Life (SMA Input)	Average Asset Age (Years)	Max. Asset Age (Years)
EGD Rate Zone	27 to 37	18	51
Union Rate Zones	27 to 36	21	60

Based on SMA input for a station's expected life, both rate zones have differences in the expected life of these assets compared to the actual average asset age and the maximum age of the current population. This is expected due to the different design standards and maintenance strategies employed. Integration activities are ongoing to harmonize best practices for engineering design and operating standards in both rate zones.

Although age is not the only factor in evaluating station asset condition, an increase in failure is seen as the asset approaches the end of its life. **Figure 5.3-4** displays the distribution system station population age demographics for the EGD rate zone.

.

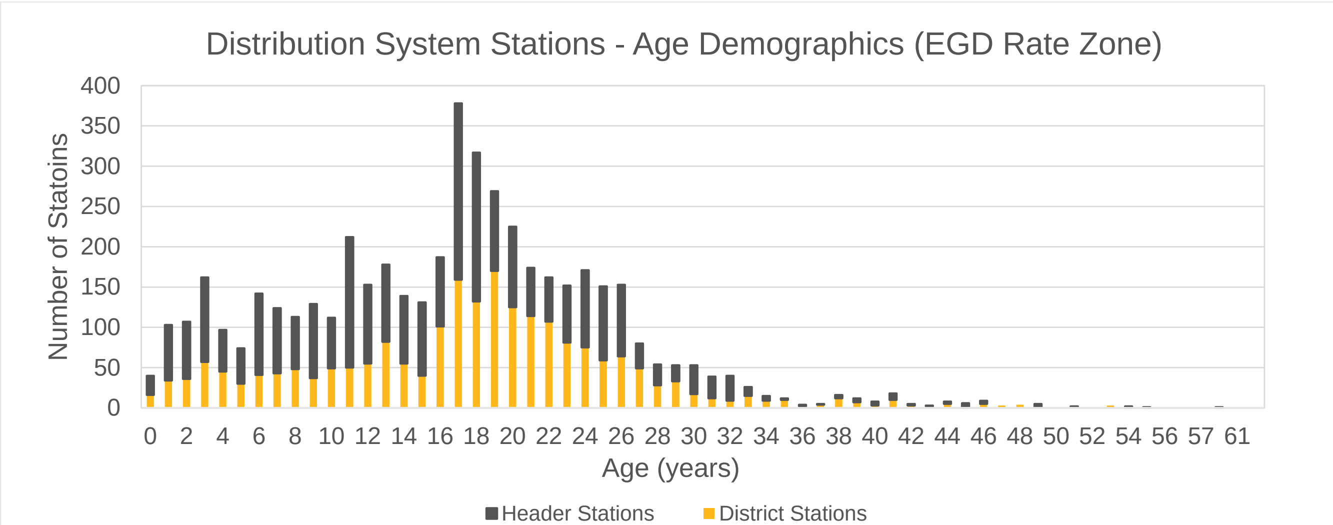


Figure 5.3-4: Distribution System Stations - Age Demographics (EGD Rate Zone)

Figure 5.3-5 displays the age demographics for distribution system stations in the Union rate zones. Two outliers in the number of stations at 19 and 30 years can be attributed to the integration of legacy asset information systems. The age data represents when the last asset was installed and may not reflect situations where existing assets remained within the station (i.e. pipe or valves that typically have longer lives). Work continues to understand the demographics of Union rate zone stations as part of integration activities.

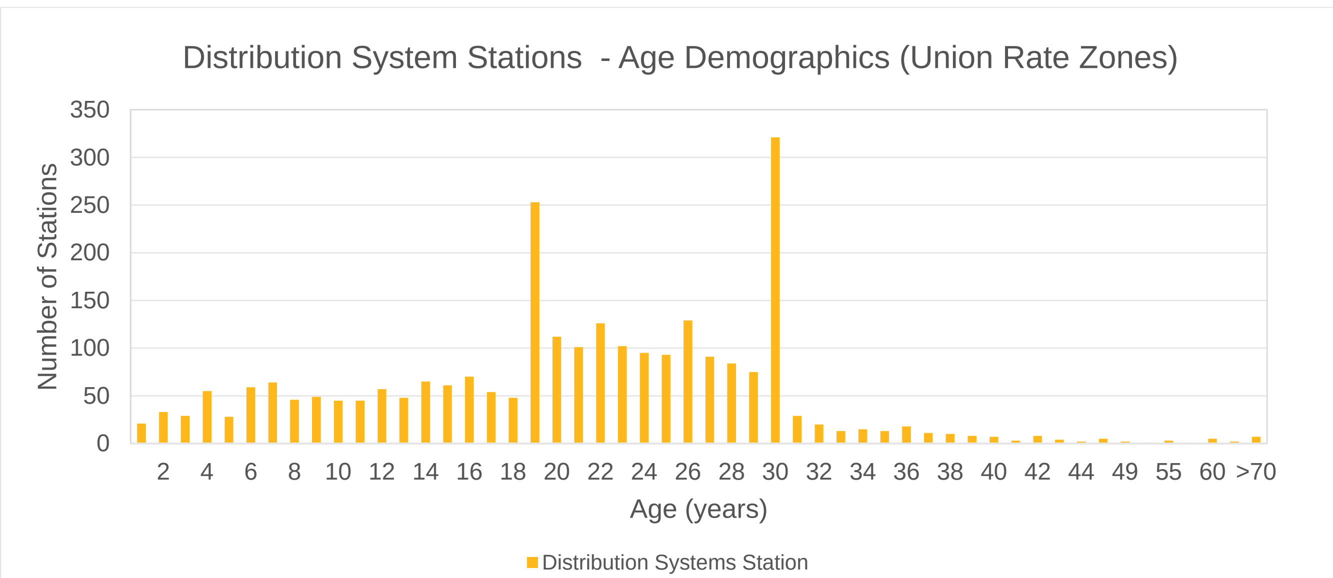


Figure 5.3-5: Distribution System Stations - Age Demographics (Union Rate Zones)

Distribution system stations are generally installed either above-ground or below-ground in a vault (see **Figure 5.3-6**) and typically installed on public right-of-way but can also be on private property or easements. Above-ground, they may be protected from the elements within a box enclosure or exposed to the elements. Below-ground vault locations can experience aggressive condition degradation from a wet environment, flooding or sidewalk/road runoff and may create confined spaces requiring specific procedures for safe entry. These assets can experience pipe coating degradation which can lead to corrosion. Flooding could impact the mechanical operation of the pressure control and valve systems.

.

Figure 5.3-6: Examples of Distribution System Stations

5.3.6.1. Condition Methodology

The methodology for determining the condition of distribution system stations assets uses a combination of data analysis of the asset's failure and event history and a qualitative on-site condition assessment. These methods provide an understanding of the station asset age, past performance and future projected reliability. This methodology is also applied to customer stations assets (see **Section 5.3.7**).

The Distribution Integrity Management Program (DIMP) uses data analysis to make predictions about the life of distribution system station assets using widely-accepted and applied statistical principles. Reliability models are developed to understand the failure behavior and reliability of station assets. These models employ recurrent data analyses for repairable assets by fitting a statistical distribution or function to the data for the population. For repairable assets, the function for the data set can then be used to estimate important life characteristics of the asset such as reliability, conditional probability, intensity of failure at a specific time, its mean life and failure rate.

The calculated reliability for individual sites can be adjusted to reflect assets that are in worse condition than anticipated by the reliability models. **Figure 5.3-7** provides a visual representation of how evaluation from the field condition assessment is applied to adjust the reliability for the individual site.

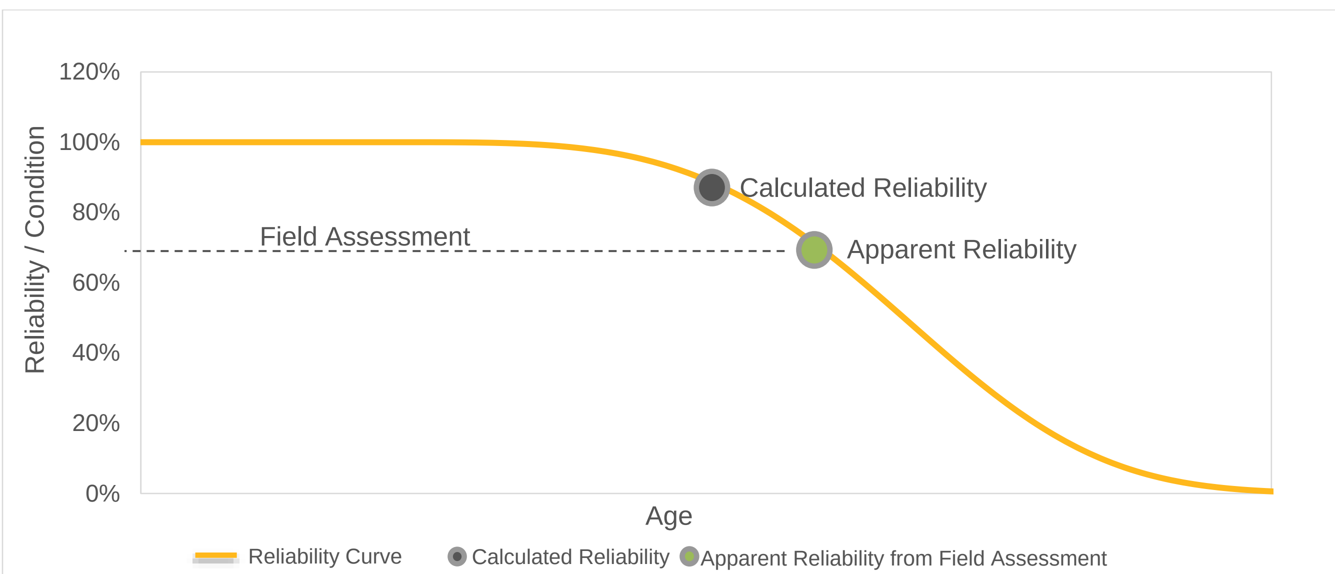


Figure 5.3-7: Station Reliability and Condition Assessment

On-site condition assessments are conducted to assess, classify and further understand condition details that cannot be determined through data analysis alone. **Table 5.3-5** outlines the specific condition evaluation criteria used to assess station components. These assessments inform the priority of individual stations for station replacement programs.

.

Table 5.3-6: Evaluation Criteria for Station Components

Station Component	Condition Evaluation
Pressure Control	• Operating parameters for each regulator are correct (i.e., outlet pressure matches the correct set point) • Ability to lock up under zero flow condition • Responds appropriately to changes in outlet pressures and flows • Over-pressure protection device operates at its specified set point and capacity is adequate • Obsolete equipment and/or parts not available • Improper/non-standard configuration
Station Valves	• Difficult to operate/move freely • Leak to atmosphere • Damaged or inaccessible • Will not seal completely and gas flow cannot be isolated
Piping	• Presence of corrosion indicators • Damage to insulation or coating • Pipe heaving or movement
Other issues	• Level of corrosion • Signage or station protection • Issues impacting safety and the ability to perform maintenance inspections • Condition of paint and pipe coating • Performance of the components • Level of heaving or piping alignment • Overall site safety condition • Obsolete equipment no longer supported by product manufacturers

Other factors to be assessed by other groups (not on-site) include:

- Station capacity verification (to ensure the reliability of supply to EGI's growing customer base)
- Compliance with relevant codes and standards

5.3.6.2. Condition Findings

As assets age and degrade, they typically begin to fail at an increasing rate and the accumulation of those failures over time will begin to account for a greater proportion of the total population. Using historical failure event rates to model the projected failure events, **Figure 5.3-8** helps to illustrate this relationship over time and provides insight into the impact of projected future failure events on the asset population with the current replacement program applied.

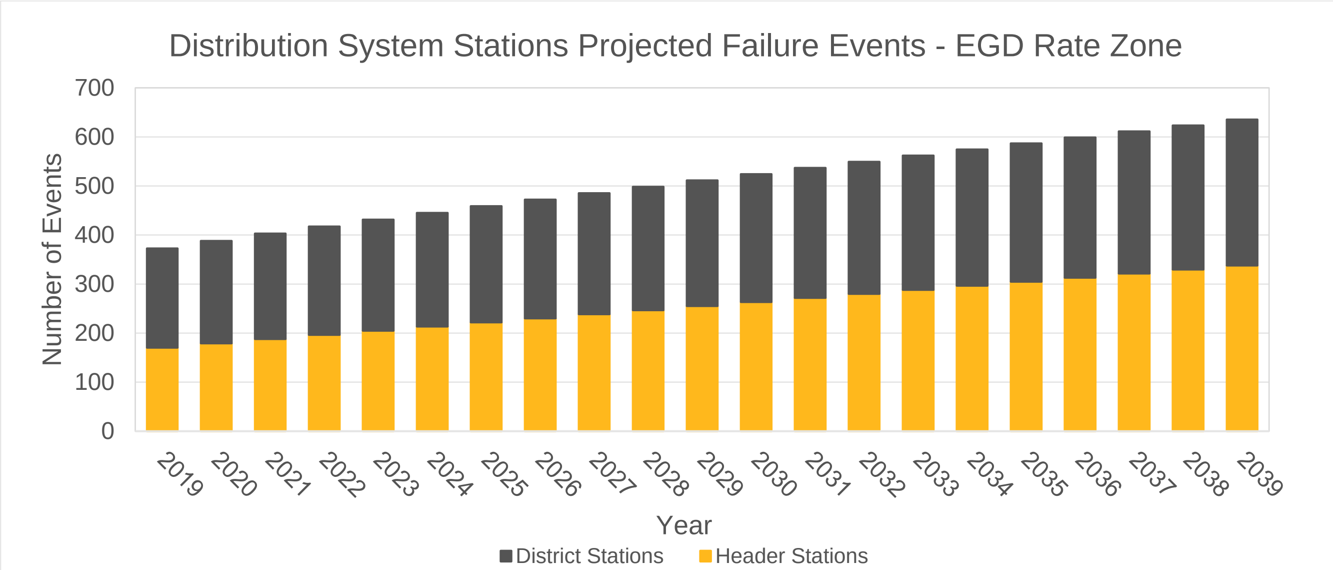


Figure 5.3-8: Distribution System Stations Projected Failure Events - EGD Rate Zone

Figure 5.3-8 reveals that distribution system stations have a relatively constant and low growth rate in failure events over the next 20 years under the historical and current replacement and renewal programs. At this time, Union rate zone assets have not been incorporated in the Asset Health Review (AHR) program. A detailed plan is being developed for their inclusion.

On-site condition assessments continue to be collected on an ongoing basis to thoroughly understand the condition of distribution system station assets. Results of the surveys (issues have been identified in the valve, pressure control or piping component groups) are actively addressed through reactive repairs or through replacement programs where appropriate.

The system station replacement programs are informed by condition surveys to reduce the risk of any issues observed. For example, boot-style regulators which use a combination of a flexible “boot” element and gas pressure to regulate downstream flow and pressure may be more susceptible to higher failure rates due to their design. This type of regulator station design has demonstrated susceptibility to failures caused by debris, particulates, hydrates and sulfur deposits. Adopting a new design philosophy to use alternative regulator models or including filtration minimizes the potential for downstream over-pressure events.

Another example of issues from field reviews of distribution system station sites have found non-conforming configurations or locations deemed to be potential hazards to safe site operation, such as clearance issues or potential threats from third-party damage. It is anticipated that these potential hazards may exist across the distribution system station population of certain vintages, when construction practices and standards were not consistently applied. It is also expected, in some cases, that local area development over time has encroached on the facilities resulting in higher risk of station damage from external influences, such as vehicle traffic or debris from above or compromised station supports.

Figure 5.3-9: The Joule-Thomson Effect on a District Station

Distribution system stations that experience a high differential pressure reduction from inlet to outlet pressure are associated with a higher risk of failure. For instance, as natural gas passes through the pressure control device, the gas temperature decreases approximately 4°C for each 700 kPa of pressure reduction (the Joule-Thomson Effect). High differential pressure control significantly decreases gas temperature (from high inlet pressure to lower outlet pressure). Stations where a high pressure reduction occurs can be subject to freezing of its station components, which may cause a loss of pressure control if there is moisture in the gas, heaving of the station piping if there is moisture in the ground surrounding the station, or the temperature reduction of the gas could cool the downstream piping and impact the surrounding grounds, including the potential to damage roads. The effects of the Joule-Thomson Effect are illustrated in **Figure 5.3-9**. Ice build-up is visible on the downstream components and the station assembly is misaligned due to heaving.

.

5.3.6.3. Risk and Opportunity

The risks identified for distribution system stations are operational risk, financial risk, employee and contractor safety risk and public safety risk, which may lead to the following consequences:

- Public impact, threat to over-pressuring customer piping
- Repair and high maintenance costs, customer supply impact
- Loss of service to customers

These risks are also applicable to the Customer Stations asset subclass (**Section 5.3.7**). Risks are dependent on station design and location:

- **Over-pressure Event**: In an over-pressure event, the downstream network is operating above the designed maximum pressure. In addition to the risks discussed in **Section 5.3.5.3**, distribution system stations feeding low-pressure networks have additional safety consequences, as these networks are designed without individual regulators at customer meter sets, normally considered a second line of defense against potential piping over-pressure inside the customer's premises.
- **Loss of Pressure Control (Lock Up)**: A regulator locks up when it cannot completely shut off gas flow in low flow conditions. Pressure control failures could cause the unplanned release of natural gas, a pipeline rupture or over-pressure delivery to customers. The impact and frequency of a pressure control failure varies - the frequency of a pressure control failure causing a minor impact, such as a repair, is higher than the frequency of over-pressure delivery to a customer due to the multiple layers of protection within the gas distribution network.
- **Loss of Containment (Leaks)**: A leak is an unplanned release of gas from the gas distribution system. The risk of a leak leading to a fire or explosion has the potential to cause injury to members of the public. The risk of an over-pressure event at the station could similarly lead to a leak in the downstream system, including inside the customer's premises if other safeguards fail. Financial loss is possible due to total repair costs, commodity loss, relighting customer gas appliances and any property damages caused by a gas leak. Risks identified are potential GHG emissions, environmental impact, service interruptions, over- or under-pressure events and reputational damages associated with reduced public confidence.
- **Under-pressure Event**: In an under-pressure event, the downstream network is operating below the designed minimum pressure. See **Section 5.3.5.3** for risks associated with under-pressure events.
- **Valve System Malfunction**: A valve malfunctions when it no longer provides isolation of the gas as intended. See **Section 5.3.5.3** for risks associated with valve system malfunctions.

Additional issues that were considered in the risk assessments were obsolete regulators, single-run stations and stations with non-compliance issues. When obsolete regulators fail, they cannot be easily replaced as the existing station configuration may not have replacement parts available. When this occurs, the station must be replaced in its entirety, leading to a disruption in service and gas delivery impact. Single-run configurations are stations without a standby run available. A standby run can take over control to provide the required capacity and pressure of gas to a system in the event that maintenance of the station is required. Exposure to under-pressure risk is greater in the absence of a standby run. Non-compliant stations are typically locations where surrounding developments have encroached within the hazardous zone, causing clearance concerns.

Distribution system stations that are installed below-grade in a vault were evaluated to consider risks such as additional maintenance requirements, increased replacement cost and potential for worker injury. It is expected that the projected reliability for these below-ground assets will be lower and will degrade faster than other above-ground assets.

5.3.6.4. Strategy Outcomes

The renewal strategies for assets in the Distribution System Stations subclass support proactive replacements targeting stations based on obsolescence, condition and age:

Distribution System Station Replacement Strategy

This strategy mitigates risks associated with station condition and legacy station designs. Risks can be significant; one station may supply gas to hundreds of customers, and accordingly, all downstream mains and services can be affected by a failure. Stations are identified through regular inspections, information collection and condition methodology. This strategy will maintain the station population's current average condition and operational reliability, ensure operational capacity to meet current demands and minimize process safety risk. The program targets stations with the following issues:

- Below-ground boxes
- Boot-style regulators
- Capacity issues
- Poor performance and poor condition

.

- Low pressure control
- Obsolete components

Condition assessment reviews, Subject Matter Advisor (SMA) consultation and risk assessments are all used to prioritize stations for replacement. Since these stations are small and pre-fabricated off site, the scope of the investment includes replacing the entire station (pressure control, overpressure protection, valves) and as necessary, associated inlet and outlet piping below ground.

The replacement pace for distribution system stations is approximately 20 to 30 stations per year in the EGD rate zone. This pace is aligned with the historical replacement rate. Models indicate this pace will maintain the reliability of the station population at a relatively consistent level over the next 20 years. This aligns with the feedback from the 2020 Customer Engagement Survey on replacing pipelines and equipment as the majority of customers indicated a preference for EGI to assess long-term system health system and to spread out costs over time (even if that means higher rates now). **Figure 5.3-10**: 20-Year illustrates the projected failure events of the population by maintaining the current replacement rate.

In the Union rate zones, condition assessments and operational issues are also used to identify stations for replacement - a programmatic approach that includes analysis will be developed to address the needs of these assets going forward.

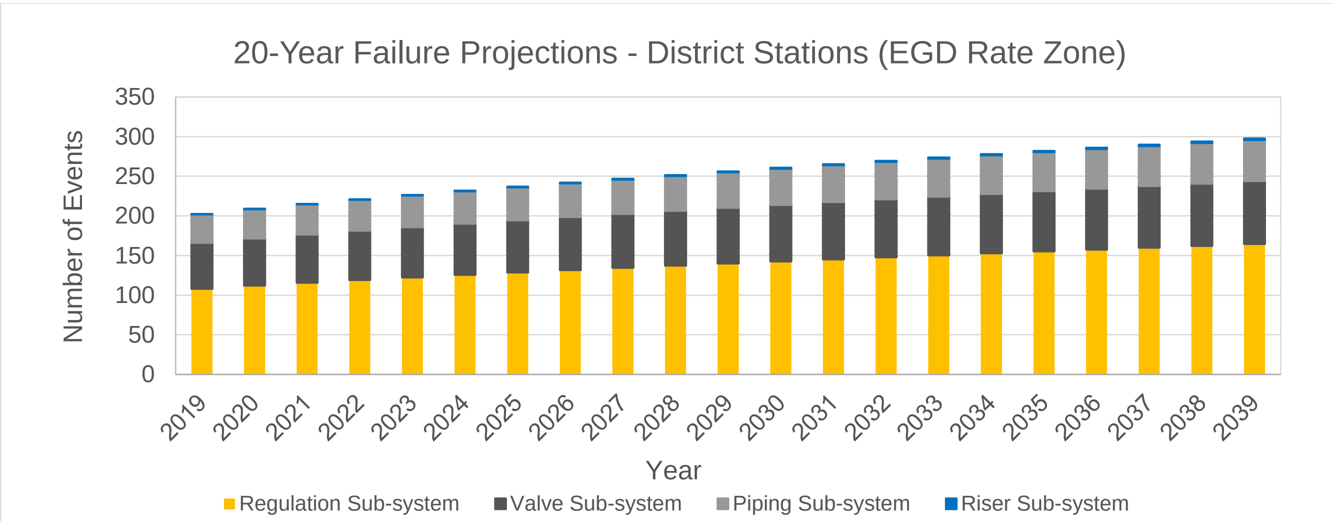


Figure 5.3-10: 20-Year Failure Projections – District Stations (EGD Rate Zone)

Header Station Replacement Program

This strategy targets header stations that require replacement due to the following issues: unsafe installation locations, poorly performing components, poor condition, obsolete components, non-standard configurations and other issues identified in **Section 5.3.6.2**. Stations are evaluated to validate downstream customer impact, asset condition and workers' health and safety to ensure maximum risk reduction and benefit for each replacement.

For the EGD rate zone, the strategy for header stations is to replace approximately 25 header stations per year, based on condition assessments, component age and obsolescence. **Figure 5.3-11** illustrates the projected failure events of the population by maintaining the current replacement rate.

Header stations in the Union rate zones are covered under the **Distribution System Station Replacement Strategy**.

.

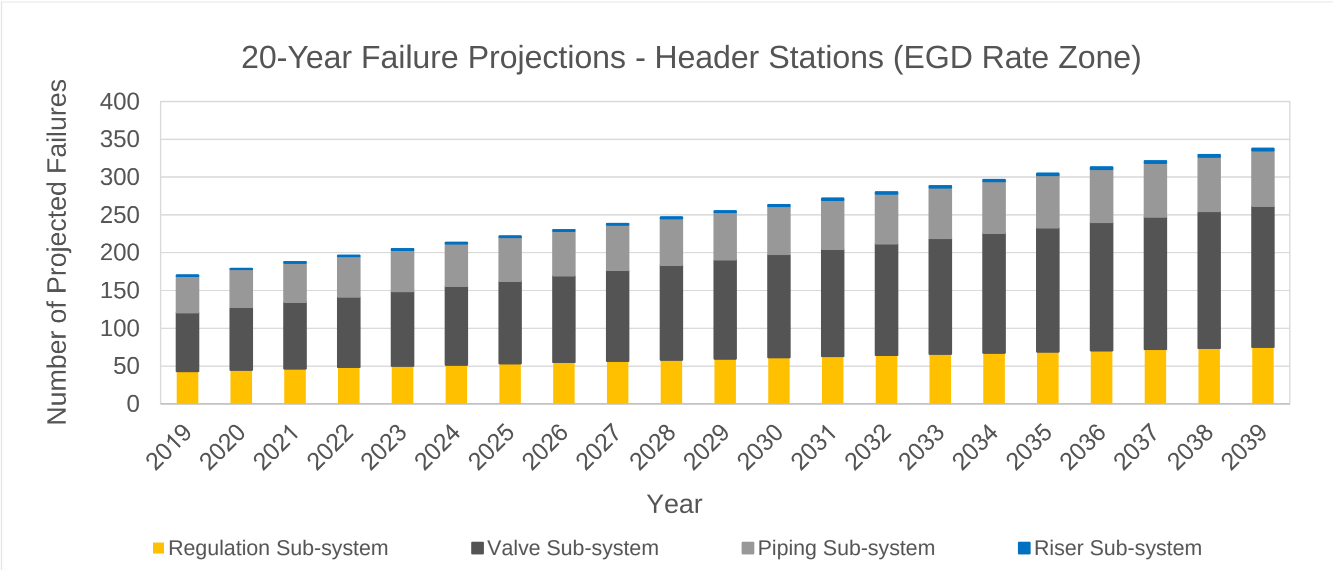


Figure 5.3-11: 20-Year Failure Projections - Header Stations (EGD Rate Zone)

Vaulted Stations Replacement Program

This program targets a subset of distribution system stations installed in below-grade vaults. The scope of this program includes replacing all remaining vaulted stations with above-grade facilities, reducing the risk of equipment failure. These stations are advanced in age and present significant maintenance challenges due to their confined nature and risks related to asset deterioration and equipment failure. The vault design is prone to water ingress that can cause frost heave, accelerated corrosion of assets and of the vault itself and can interfere with the proper equipment operation. All of these factors have a negative effect on reliability and worker safety. Solutions for each asset are developed considering either a typical system station design with land purchase or an above-grade enclosure station if land purchase is impractical. This program will decrease the risk of equipment failure, improve system reliability and result in stations being more safely and efficiently maintained.

Stations Painting Program

This program is a centrally-managed initiative to apply high-performance paint to mitigate corrosion of station assets. This program targets stations where existing paint has begun to fail or wear off, ensuring the safety and reliability of stations by reducing the probability of leaks and piping/equipment failure due to significant corrosion. This program is specific to the Union rate zones only.

Stations Capital Upgrade Program

See **Section 5.3.5.4** > **Stations Capital Upgrade Program**.

.

5.3.7 Customer Stations

Customer stations reduce upstream pressure and deliver gas to a downstream customer with a total connected load greater than 12 m³/hour and with a delivery pressure of 14 kPa or greater (with a limited number of exceptions). Customer pressure and volume requirements are driven by their natural-gas-fired equipment requirements. Typical delivery pressures can vary up to 1,380 kPa or higher depending on individual customer needs. The estimated life expectancy for customer stations is shown in **Table 5.3-7**.

Typical components of customer stations can vary greatly based on customer delivery requirements (e.g. gas volume, delivery pressure). The smallest customer stations are typically comprised of small diameter piping, a single regulator, meter and shut-off valve. Larger customer stations can be comprised of multiple regulators and meters, large-diameter piping and headers, an electrical system, controls and telemetry and multiple valves. EGI's largest in-franchise customer station facilities typically supply natural gas to major electric power producers, major steel mills, chemical plants, smelters and other process-based industrial plants. Note that all customer stations that have filters/strainers, odourant and heating equipment are considered part of the Stations with Auxiliary Equipment asset subclass (see **Section 5.3.5**).

Table 5.3-7: Estimated Life Expectancy for Customer Stations

Rate Zone	Expected Life (SMA Input)	Average Asset Age (Years)	Max. Asset Age (Years)
EGD Rate Zone	25 to 38	17	59
Union Rate Zones	27 to 37	16	62

Although age is not the only factor in evaluating station asset conditions, an increase in failure is seen as the asset approaches the end of its useful life. **Figure 5.3-12** displays the age demographics in the EGD rate zone for the customer stations population.

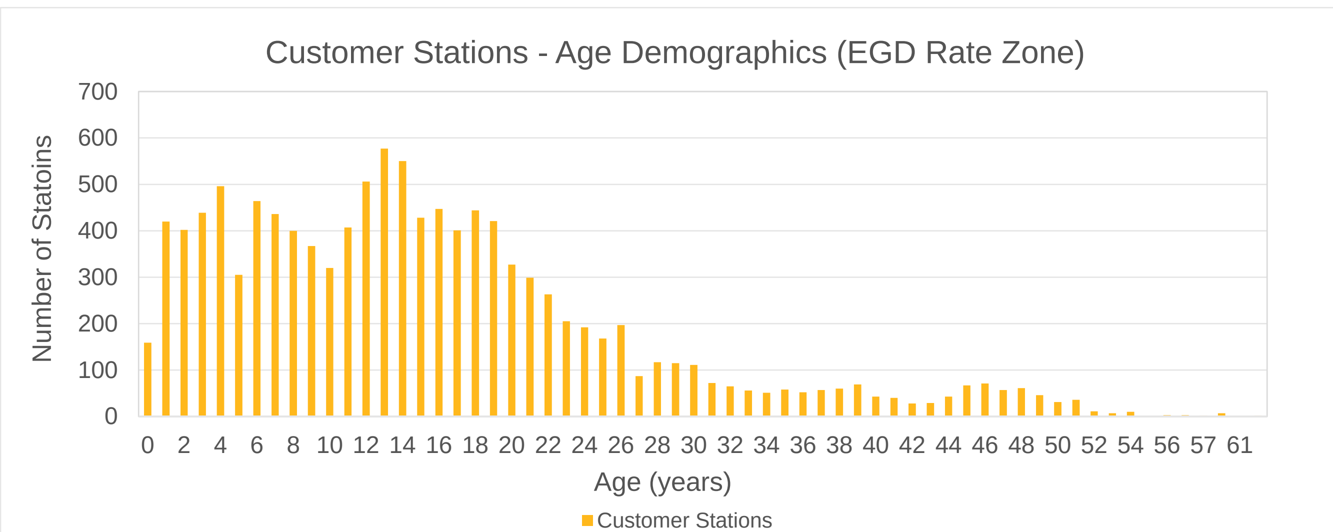


Figure 5.3-12: Customer Stations - Age Demographics (EGD Rate Zone)

Figure 5.3-13 displays the population age demographics for customer stations in the Union rate zones. An outlier in the number of stations at 30 years can be attributed to the integration of legacy asset information systems. The age data represents when the last asset was installed and may not reflect situations where existing assets remained within the station (i.e. pipe or valves that typically have longer lives). As systems and asset management practices are further aligned, data and analytics will become more consistent for the rate zones.

.

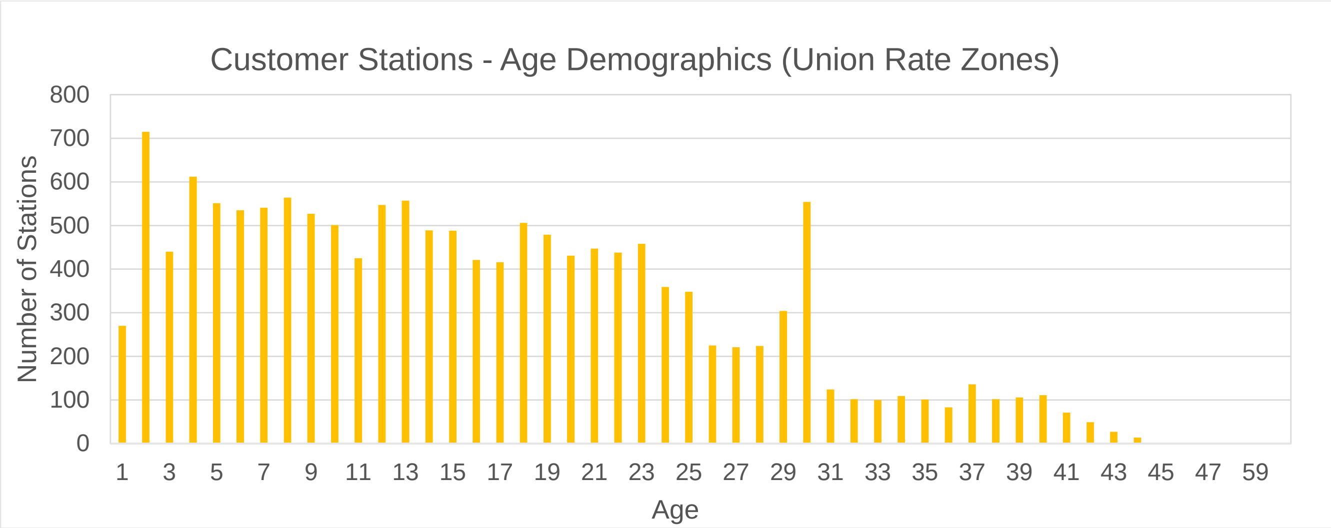


Figure 5.3-13: Customer Stations - Age Demographics (Union Rate Zones)

5.3.7.1. Condition Methodology

The condition methodology for customer stations is the same as for distribution system stations (see **Section 5.3.6.1**).

5.3.7.2. Condition Findings

Customer stations experience failures similar to distribution system stations (see **Section 5.3.6**).

As assets degrade over time, they typically begin to fail at an increasing rate and the accumulation of those failures over time will begin to account for a greater proportion of the total population. Using historical failure event rates to model the projected failure events, **Figure 5.3-14** helps to illustrate this relationship over time and provides useful insight into the impact of projected future failure events on customer stations with the current replacement program applied.

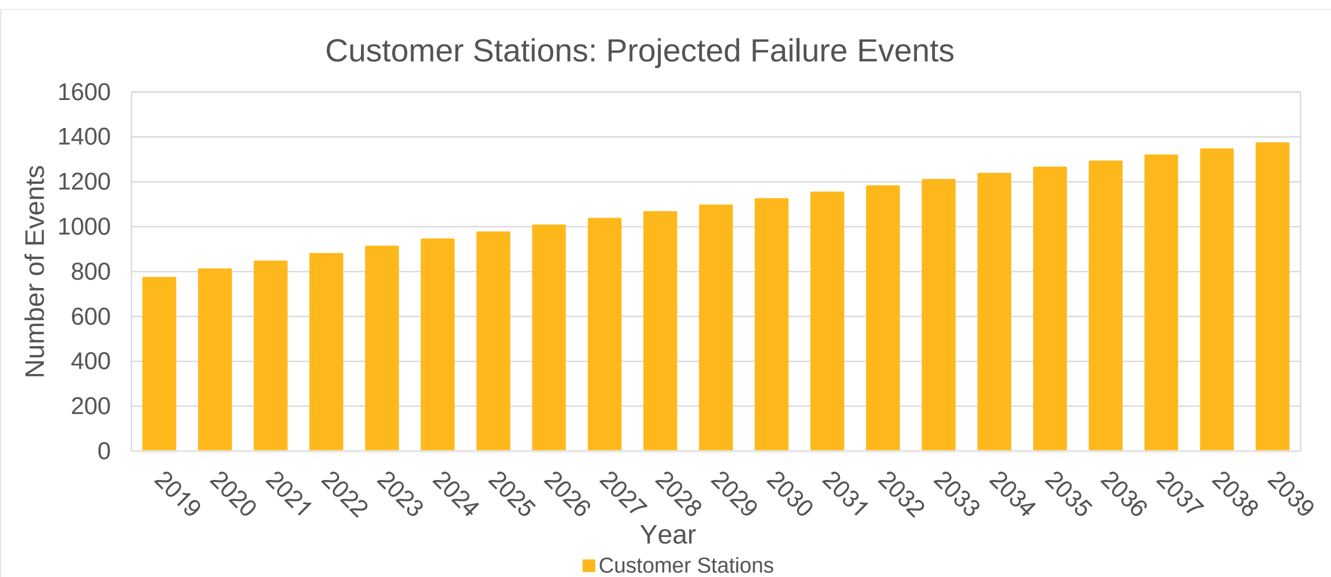


Figure 5.3-14: Customer Stations: Projected Failure Events

.

Figure 5.3-14 illustrates that customer stations are forecasted to have a slight increase in failure events with the current replacement pace over a 20-year projection.

5.3.7.3. Risk and Opportunity

The risks identified for the Customer Stations asset class are similar to risks for distribution system stations (see **Section 5.3.6.3**) The hazards identified include:

- Over-pressure of non-boot style regulators
- Non-conforming station configurations
- Stations with compliance related issues
- Stations experiencing loss of containment (leaks)

The risk assessment on these conditions determines the potential failure of the asset: pressure control failure, valve system malfunction and loss of containment (leaks), discussed in **Section 5.3.6.3**.

Customer stations are the final pressure control point prior to entering into a customer's building. Leaks or loss of containment at a customer station can lead to an explosion or fire. Some factors included in this risk category are damage to property, injuries to members of the public and the cost to repair the damaged assets.

Another concern with a subset of these assets is the design or configuration of some customer stations, which does not allow for required maintenance work (compliance work) to be completed without customer interruptions.

5.3.7.4. Strategy Outcomes

The strategy for the Customer Stations asset subclass support proactive replacements targeting stations based on obsolescence, condition and age:

Customer Station Replacement Program

This program targets stations that have issues and concerns identified through regular inspections and will be based on condition, age and obsolescence. Issues targeted include non-standard configuration, unsafe installation locations, poor performing components, poor condition and obsolete components. Execution of this program will maintain reliable gas supply to customers, address sites with non-conforming configurations (i.e. legacy designs) and minimize impacts to businesses and customers.

Condition assessment reviews, SMA consultation, AHR projections and risk assessments are used to prioritize stations for replacement. Since these stations are small and pre-fabricated off site, the scope of the investment includes replacing the entire station (pressure control, overpressure protection, valves) and as necessary, associated inlet/outlet piping below ground. Customer stations are the direct supply and control to commercial and industrial customers and the consequence of a station failure can be significant. Prior to replacement, all stations are evaluated to validate customer impact, asset condition and worker health & safety to ensure maximum risk reduction and benefit.

Figure 5.3-15 illustrates the projected failure events of the customer station population in the EGD rate zone by maintaining the current condition and reliability of existing station assets. Analysis suggests customer stations failure events are projected to increase slightly over time with the historical replacement strategy in place.

Based on the historical replacement rate of the customer station population and comparing to the condition assessment findings, it is expected that the replacement rate should increase as part of the Asset Management Plan.

Customer stations in the Union rate zones are replaced based on condition and operational issues. As systems and asset management practices are further aligned, data and analytics will become more consistent for the rate zones.

.

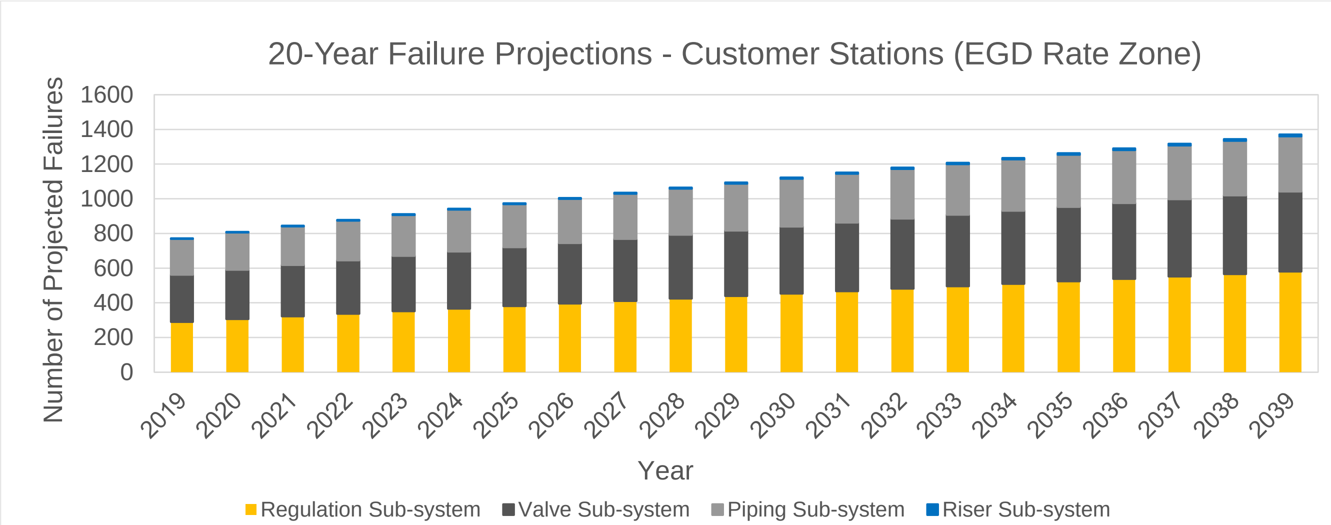


Figure 5.3-15: 20-Year Failure Projections – Customer Stations (EGD Rate Zone)

The conditions and risks associated with customer stations assets continue to be monitored and assessed to determine if the current replacement rate is adequate in maintaining the operational reliability and risks associated with these assets.

External Regulator Room Program

This program aims to reduce the risks associated with the installation of pressure-reducing regulators inside a building by relocating the regulator to a lower-risk location (at the exterior of the building envelope). An external regulator room is an enclosed room with adequate ventilation that has not been specifically designed and approved to house EGI regulators or stations. The scope of work involves remediating the room enclosure to ensure adequate ventilation to the exterior and to modify enclosing walls to be air-sealed from the building to prevent gas migration. This program is specific to the EGD rate zone only. A review of Union rate zone assets that are considered as inside regulators is ongoing and may have capital requirements in future years.

Stations Painting Program

See **Section 5.3.6.4** > **Stations Painting Program**

Stations Capital Upgrade Program

See **Section 5.3.6.4 > Stations Capital Upgrade Program**

5.3.8 Distribution Stations Capital Expenditure Summary

EGI has spent an average of $26M and $15M annually in the EGD and Union rate zones respectively for the Distribution Stations asset class. The total average capital spend is forecasted to be $42M (EGD RZ) and $30M (Union RZ) as summarized in **Table 5.3-8** and **Table 5.3-9**. Distribution Stations capital is further summarized as part of EGD's total 10-year capital plan in **Section 6.**

Table 5.3-8: Distribution Stations Capital Summary ($ Thousands) – EGD Rate Zone

Program/Project Name	2021	2022	2023	2024	2025	Five-Year Forecast
Compressed Natural Gas (CNG)	**1,135**	**1,255**	**926**	**914**	**988**	**5,218**
Stations with Auxiliary Equipment Replacement	**22,918**	**21,193**	**21,941**	**20,336**	**19,025**	**105,412**
Compliance Remediation Program	244	243	256	249	264	1,257
Telemetry Program	1,709	1,703	1,795	1,743	1,851	8,800
Inside Regulator and ERR Program	**610**	**608**	**641**	**622**	**661**	**3,143**
Distribution System Station Replacement	**15,926**	**27,730**	**15,195**	**13,860**	**16,482**	**89,192**
Harmer District Station	-	15,909	-	-	-	15,909
Stations Capital Upgrade Program	7,212	11,261	11,356	11,849	13,969	55,649
Integrity Initiatives	**1,416**	**1,411**	**1,487**	**1,444**	**1,533**	**7,292**
FIMP Inspections	1,416	1,411	1,487	1,444	1,533	7,292
EGD Rate Zone Total	**42,077**	**52,197**	**40,190**	**37,176**	**38,689**	**210,329**

Table 5.3-9: Distribution Stations Capital Summary ($ Thousands) – Union Rate Zones

Program/Project Name	2021	2022	2023	2024	2025	Five-Year Forecast
Compressed Natural Gas (CNG)	917	913	963	-	-	2,793
Stations with Auxiliary Equipment Replacement	**23,223**	**23,207**	**4,893**	**2,514**	**2,668**	**56,505**
Telemetry Program	3,729	3,043	2,568	2,514	2,668	14,522
Stations Capital Upgrade Program	19,493	20,164	2,325	-	-	41,983
Distribution System Station Replacement	**22,795**	**16,395**	**14,931**	**8,580**	**6,988**	**69,688**
Odorization System Program	1,234	1,228	1,118	1,095	1,162	5,837
Station Painting Program	2,446	2,434	2,568	2,514	2,668	12,630
Integrity Initiatives	**5,346**	**4,223**	**4,455**	**4,362**	**4,629**	**23,015**
FIMP Inspections	4,243	4,223	4,455	4,362	4,629	21,912
Union Rate Zones Total	**52,280**	**44,737**	**25,242**	**15,456**	**14,285**	**152,001**

.

5.4 Utilization

Utilization assets are the components of the distribution system that regulate system pressure, ensure low pressure delivery to the customer and measure gas consumption. Safety is the paramount role of these assets, as the regulation system within it is the last line of defense for over-pressure to the customer. Unlike customer stations described in **Section 5.3.7**, these assets support the delivery of gas primarily to customers consuming volumes less than 17.0 m^3/h at a typical pressures of 7"wc.

Each Utilization asset subclass has unique characteristics and the management of each is tailored to ensure the safe and reliable delivery of natural gas. Utilization is comprised of three asset subclasses–measurement systems, pressure regulation and over-protection systems and below-ground and internal piping systems.

5.4.1 Utilization Objectives

The objectives for the Utilization asset class are listed in **Table 5.4-1**.

Table 5.4-1: Utilization Asset Class Objectives

Asset Class Objective	
System Integrity and Reliability	Maintain the natural gas system to meet or exceed codes, standards and requirements of applicable governmental authorities for safety and operational effectiveness. This includes ensuring the system has the capacity to reliably meet current and future customer demand.
	Ensure the safe and reliable delivery of natural gas to end users.
	Use cost, risk and performance information to drive asset-related decisions.
	Continuously evolve the understanding of condition and risk associated with Utilization assets.
	Ensure accurate metering of customer gas consumption.

The performance measures for the Utilization asset class are:

- Completion of Government Inspection Meter Exchange (MXGI) program
- Percentage of failed meters within sampling program
- Number of doubtful meters (EGD rate zone only)
- Number of above-ground leaks
- Number of non-program failures and explanations
- Work management process conformance

To achieve the Utilization asset class objectives listed in **Table 5.4-1**, asset investment decisions are governed by the life cycle management strategies outlined in **Table 4.1-1**.

.

5.4.2 Utilization Hierarchy

The asset class hierarchy for the Utilization asset class is summarized in **Figure 5.4-1**.

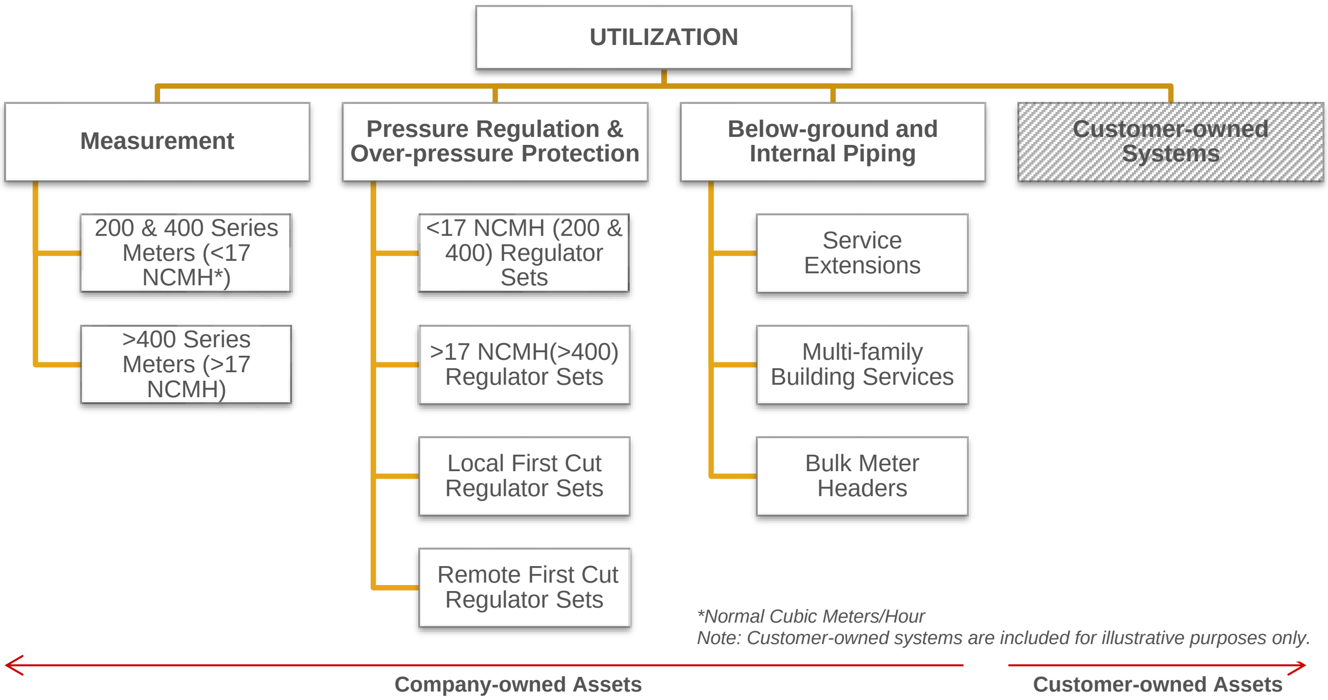


Figure 5.4-1: Utilization Asset Class Hierarchy

Measurement Systems (natural gas meters and electronic volume correctors (EVCs)) track customer gas consumption. These systems directly link to customer billing and are subject to a stringent replacement program overseen by Measurement Canada. Measurement assets allow the safe operation of the natural gas network, provide accurate and timely measurement and monitor and control the flow of natural gas in real time.

Natural Gas Meters are devices used in measuring the quantity of natural gas delivered. Meters are classified as custody transfer or non-custody transfer. The former are billing meters for gas purchased from suppliers or sold to customers and must meet the legal requirements of the *Electricity and Gas Inspection Act*. The latter are used for internal accounting of gas inventories. EGI uses a variety of gas meter types to fit different applications and requirements:

- **Diaphragm meters** use positive displacement technology and internal mechanical temperature compensation to calculate delivered natural gas volumes at base temperature and pressure. The 200 series meter is the most common meter type in use. The 400 series meters are used for commercial and large residential loads and have incrementally more capacity than a 200 series meter. The 800/1000 series meters are used for large commercial, small industrial and estate residential loads.
- **Commercial ultrasonic meters** are used as a direct substitute for 800/1000 series diaphragm meters. These meters use inferential ultrasonic flow measurement, electronic temperature correction and consumption recording.
- **Rotary meters** are positive displacement devices comprised of a meter body with an EVC and are used in commercial and industrial applications.
- **Large turbine meters** are inferential metering devices used at large commercial and industrial customer stations for high-volume metering. They are also used for volumetric measurement at interconnect sites between EGI and other pipeline companies.
- **Large ultrasonic meters** are sophisticated multi-path inferential measurement devices directly connected to remote terminal units (RTUs) for measurement of large volumes of gas at high pressures.

.

Electronic Volume Correctors (**EVC**) typically receive volume measurement inputs from a meter. EVCs measure the temperature and pressure and corrects the measured volume for both. EVCs store measurement information and are capable of doing detailed calculations, if provided with various factors, to give a corrected volume.

Pressure Regulation and Over-pressure Protection Systems regulate the delivery of gas at a pressure appropriate for customer-owned gas-firing appliances and are the last line of defense for over-pressure protection. Three typical safety devices used in the Utilization asset class–internal relief valves, external relief valves and over-pressure cut-offs.

With the exception of customers off low pressure mains, each customer location has at least one regulator and one over-pressure safety device installed to prevent unsafe pressures from entering the premises in the event of a malfunction. These systems include above-ground piping between the wing-lock and meter and the components required for regulation.

This asset subclass is comprised of the following components:

- **Regulators** reduce natural gas pressure to safe operating limits and control its flow based on customer demand. Regulators typically have an internal relief valve designed to be closed but will open if the primary regulation function is malfunctioning. Regulators in the Utilization asset class are regulated to deliver low pressure, typically at 7” wc.
- **Safety devices** prevent downstream over-pressure and are the last line of defense to prevent potentially hazardous conditions.
- **Piping on regulator sets** refers to any of the above-ground piping between the winglock and the meter outlet.

Below-ground and Internal Piping Systems: These systems are located upstream of inside meters and refer to piping running below grade or piping running inside a building.

EGI owns a type of below-ground asset called a service extension. Service extensions are below-ground pipe between the regulator outlet and the meter inlet (not to be confused with jumpers owned by the customer since they are downstream of the meter set). Within this asset class, EGI takes all reasonable efforts to avoid below-ground piping since this type of configuration has inherent hazards and requires costly maintenance. Internal piping is typically found in multi-family buildings. This piping runs between the regulation and piping system located outside to meters inside the garage or in individual units.

Customer-owned Systems: Piping and assets downstream of the meter are customer-owned. Although EGI does not own these assets, *O. Reg. 212/01* requires an inspection of all installations upon initial connection to the gas supply or during the reintroduction of gas. In addition, EGI continues to inspect customer assets as part of a quality management program. By meeting these requirements, EGI helps to ensure the safe delivery of natural gas. As a last resort, EGI can terminate the natural gas supply if the customer fails to remediate any identified critical safety issues. As customer-owned systems are not part of EGI’s assets, they are included in this discussion for illustrative purposes only (see **Figure 5.4-2**).

Figure 5.4-2: Utilization Assets Illustration

.

5.4.3 Utilization Inventory

Utilization assets include all assets downstream of the wing-lock valve and upstream of the meter outlet. These assets serve customers grouped into the following categories based on similar characteristics:

- Multi-family/Apartment
- Commercial/Bulk Meter
- Industrial
- Residential (low density)

Over 90% of customers are residential, with the remaining being mostly commercial. With 2.2 million customers in the EGD rate zone and 1.5 million customers in the Union rate zones requiring low pressure delivery, understanding and maintaining the health of these assets is a critical part of providing safe and reliable gas delivery.

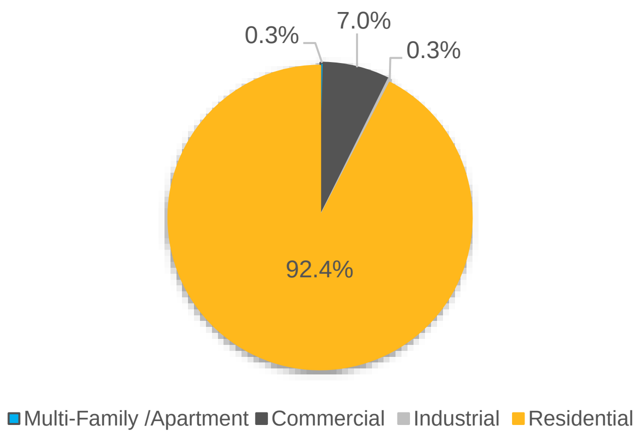


Figure 5.4-3: Customer Breakdown by Type – EGD Rate Zone

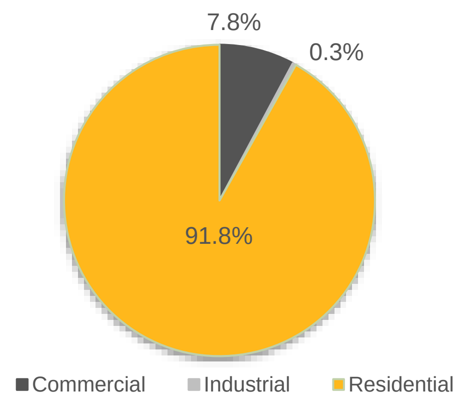


Figure 5.4-4: Customer Breakdown by Type – Union Rate Zones

For the Union rate zones, efforts are underway to recategorize multi-family/apartment customer data to align customer classifications as part of integration activities.

.

Table 5.4-2 lists the inventory details for the Utilization asset class.

Table 5.4-2: Utilization Asset Class Inventory

Asset Subclass	EGD Rate Zone	Union Rate Zones
Measurement Systems		
200 and 400 Series Meters (<17 NCMH*)	2,190,131	1,463,833
>400 Series Meters (>17 NCMH)	65,999	24,658
Regulation, Safety Devices and Piping Systems		
<17 NCMH (200 and 400) Regulator Sets	1,986,323	1,012,464
>17 NCMH (>400) Regulator Sets	103,566	42,475
Local First Cut Regulator Sets	25,964	N/A
Remote First Cut Regulator Sets	10,495	N/A
Below-ground And Internal Piping Systems		
Service Extensions	13,666	N/A
Multi-Family Building Services	3,002	N/A
Bulk Meter Headers	39	N/A

***Normal Cubic Meters/Hour*

The number of meters and regulators in the EGD rate zone includes those at customer stations (excluded in the Union rate zones).

For the Union rate zones, inventories for local first cut regulator sets, remote first cut regulator sets and below-ground and internal piping systems are not currently available. As part of integration activities, inventory tracking processes will be harmonized over time.

5.4.4 Utilization Condition and Strategy Overview

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

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

Asset Subclass	Avg. Age (Year)	Condition	Risk / Opportunity	Maintenance Strategy	Replacement / Renewal Strategy
Customer Owned Systems: **Customer-owned Piping and Appliances**	N/A	EGI inspects customer-owned assets at the time of initial installation and after conducting relights. Customers are issued A-tags if unacceptable conditions that present an immediate hazard are identified.	Improperly identifying customer-owned assets for maintenance can lead to the following risks: **Employee and Contractor Safety Risk and Public Safety Risk**: Loss of containment **Financial Risk**: Emergency response costs	The maintenance strategy for customer-owned assets is to continue to perform existing operating standards at initial installation. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	The current strategy for customer-owned systems is to continue existing practices at initial installation. For any subsequent issues, the customer is responsible to take corrective action.

.

5.4.5 Measurement Systems

Meters represent the largest group of assets within the Utilization asset class. Meters measure gas flow to the customer premises. Different measurement devices are used to measure customer consumption:

200 and 400 Series Meters have a capacity 17.0 m^3/h or less. All meters in this subclass are diaphragm meters.

>400 Series Meters have a capacity 17.0 m^3/h or greater and can be comprised of the following meter types:

- Diaphragm meters
- Rotary meters
- Ultrasonic meters
- Turbine meters

Certain meters have instruments (electronic volume correctors) that perform compensation to accurately measure gas flow. Instruments are components of 800 series rotary meters and 800 series ultrasonic meters, used for environmental temperature and/or pressure compensation.

Meters are managed through a well-established program detailing the performance testing, repair and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate identifying the meter as compliant with *Electricity and Gas Specification S-EG-02*, which specifies meter tolerance. EGI must ensure all measurement devices remain in compliance for annual Measurement Canada audits and must demonstrate all aspects of its meter sampling, maintenance and replacement activities are compliant to receive Measurement Canada accreditation as an authorized service provider and to adhere to *Measurement Canada Accreditation Standard S-A-01*.

5.4.5.1. Condition Methodology

The replacement of the meter population is prescribed by Measurement Canada requirements and fulfilled by System Measurement programs. Government Inspection Meter Exchange (MXGI) volumes are driven by a sampling program. Based on the failure rate of sampled meter groups, groups are either given in-service extensions or are fully replaced, ensuring the health and accuracy of the asset. Groups of meters that have short seal life extensions available to them are also replaced. This approach optimizes sampling and meter group replacement costs, to stabilize workload and meter purchases as some years have larger populations to survey. Sample results and corresponding extension durations are used to indicate meter group health.

The methodology for determining meter replacement is developed by Measurement Canada and varies by meter type:

200 And 400 Series Meters (<17 NCMH): The pace and methodology of diaphragm meter replacements is set by Measurement Canada's *S-S-06 Standard Sampling Plans*. Annual sampling is carried out on meter groups. Meters are due for replacement originally based on their initial span (10 years for most 200 series meters, seven years for 400 series meters). Meters are grouped homogenously–in the year before first expiry (typically at Year 9 for 200 series meters), samples are pulled from each group for testing. If the sample meters pass, then a life extension of 8, 6, 4, or 2 years (based on the meters' initial span) is given to the meter group. If the sample meters fail (0), the meters are removed from service. Meter groups that pass require further testing after their next extended life span expires (i.e., 6, 4, or 2 years).

>400 Series Meters (>17 NCMH): Rotary meters, turbine meters and instruments (electronic volume correctors) do not qualify for sample inspection. The life cycle management for these meters is to renew and replace prior to seal expiry, as 100% of these assets are exchanged a year before their seal expires. Rotary meters expire after 16 to 20 years, ultrasonic meters at 10 years, turbine meters at six years and instruments at 7 to 12 years.

>1000 Series Meters: Meters are exchanged based on expiry year.

Exchanged meters are processed at the meter shops on EGI premises, as one of the facilities is accredited by Measurement Canada. Processing includes labelling, cleaning and performance testing. Meters are also sent offsite to accredited meter inspections facilities as required

In addition to the MXGI program, meters are also exchanged when malfunctioning, when customer load changes, or if involved in billing investigations.

.

5.4.5.2. Condition Findings

The MXGI program is designed to keep the in-service meter population healthy. The length of extensions is dependent on sample group performance. In addition, the maximum achievable extension decreases as sampling of a group increases. For 200 and 400 series meters, the typical in-service life for meter groups is 18 to 24 years. As manufacturing and handling processes have evolved over time, meter groups frequently reach 24 years and beyond. The historical quantity of program-exchanged meters and non-program exchanged meters is shown in **Table 5.4-3**.

Table 5.4-3: Meter Replacements (Historical)

Year	MXGI Program Meter Exchanges	Non-Program Meter Exchanges	MXGI Program Meter Exchanges	Non-Program Meter Exchanges
	EGD Rate Zone		Union Rate Zones	
2016	63,425	17,222	54,900	12,501
2017	26,965	15,729	54,559	13,609
2018	46,651	17,796	55,603	13,240
2019	40,839	17,271	53,948	11,326

Non-program meter exchanges are attributed to the reasons listed in **Figure 5.4-5** and **Figure 5.4-6**. As reporting and analytics for the asset class are integrated, naming conventions will be aligned to clearly identify the reasons for the meter exchange, which will allow for maintenance strategies to be refined.
Meters exchanged due to leaks are low.

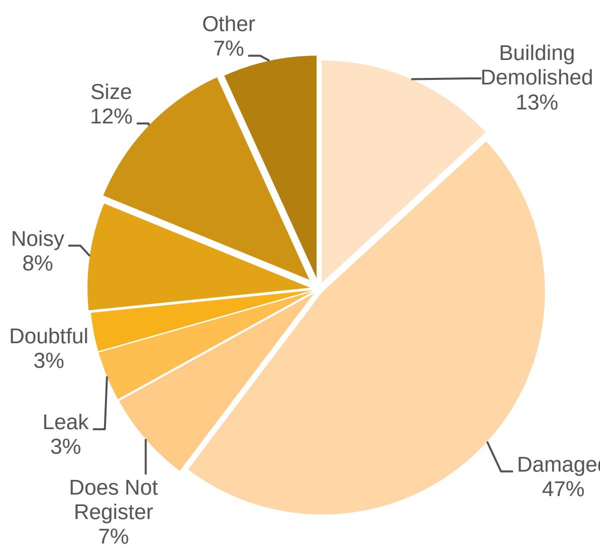


Figure 5.4-5: Causes of Non-Program Meter Exchanges (2017) – EGD Rate Zone

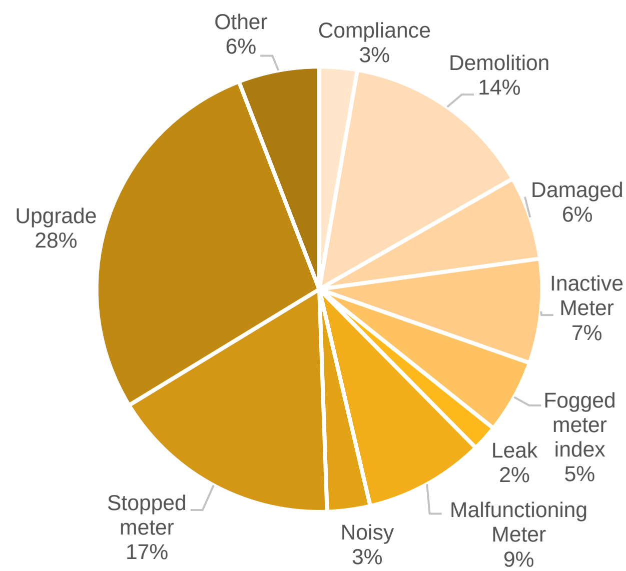


Figure 5.4-6: Causes of Non-Program Meter Exchanges (2019) – Union Rate Zones

5.4.5.3. Risk and Opportunity

MXGI Risk

Failing to remove expired meters from service carries penalties under the *Electricity and Gas Inspection Act*. Penalties could eventually lead to EGI's loss of accreditation, leading to higher meter replacement program costs. Therefore, maintaining Measurement Canada accreditation is critical for resealing meters, which allows for an extension to the life of meter assets that would otherwise need replacement. The financial risk would be a monetary penalty to EGI for not removing failed and overdue meters if the MXGI program was not executed, as well as the financial impacts of a reduced asset life cycle.

.

Non-MXGI Program Meter Exchange Risk

Non-MXGI program meter exchanges target leaking meters, damaged meters and meters that do not flow gas. Hazards associated with leaks could result in migration and gas accumulation. However, the health and safety risk associated with meters is minimal, as meters leak very infrequently and majority are located outside customer premises. Very few meters are returned due to leaks (approximately 0.007% of the population annually). The financial risk of failed or leaking meters may lead to financial loss due to repair costs, relighting customer gas appliances and any property damages. As well, EGI may lose revenue from stopped meters. These risks can result in damage to the EGI brand which promotes the core values of safety and reliability.

In addition, there is a financial opportunity to remove groups of meters that have been sampled multiple times with the availability of short extensions remaining.

5.4.5.4. Strategy Outcomes

The maintenance strategy for these assets is to continue with current practices at each rate zone until procedures and processes are aligned, targeted over the next two years. The joint Measurement Canada accreditation for both rate zones is targeted for 2022.

The renewal strategy for measurement assets are as follows:

- For 200, 400 and >400 series meters covered under the MXGI program, the renewal strategy is to maintain current practices at each rate zone until policies are aligned (i.e., sampling vs. exchanging groups with only short extensions available).
- For >1000 series meters, meter exchanges will be conducted in the year of expiry or one year prior to expiry (if warranted) as there is no sampling program in place. The typical lifespan of >1000 series meters vary by type:
  - Rotary meters: 16-20 years
  - Modules: 10-12 years
  - Turbine meters: 6 years
  - Instruments: 7-12 years
- EGI reactively responds to customer leak or other service interruption calls for non-program related meter exchanges.

In addition, EGI continues to use data to project MXGI replacement volumes with a focus on leveling volumes over future years. Meters have a complete set of data that includes quantity, age, make, size, location and historical performance. The completeness of this data enhances the optimization of the life cycle strategy.

The replacement program for these assets is mandated by Measurement Canada, which maximizes asset life through sampling and testing, to ensure the required level of metering accuracy. The effectiveness of this program is a result of complete asset data, appropriate data management systems and statistically sound testing methodologies representative of larger population groups. EGI currently forecasts future budgets based on historical results. The projections for 2021-2030 are shown in **Table 5.4-4** and **Table 5.4-5** for the EGD and Union rate zones respectively.

Table 5.4-4: Meter Replacements (Projected) – EGD Rate Zone

Year	MXGI Meter Exchanges	Non-Program Meter Exchanges
2021	48,572	18,980
2022	53,308	19,019
2023	64,266	19,027
2024	59,247	19,113
2025	41,163	19,642
2026	58,071	20,000
2027	55,848	19,967
2028	41,534	20,267
2029	58,203	19,868
2030	58,203	19,868

.

Table 5.4-5: Meter Replacements (Projected) – Union Rate Zones

Year	MXGI Meter Exchanges	Non-Program Meter Exchanges
2021	52,299	9,659
2022	52,882	9,783
2023	53,510	9,908
2024	53,400	10,035
2025	54,012	10,163
2026	54,684	10,293
2027	55,337	10,425
2028	55,998	10,558
2029	56,668	10,694
2030	57,347	10,830

MXGI quantities are influenced by historical customer addition patterns and group performance of sampled meters. Previous year sampling results inform a given year's budget. An average of the meter exchanges over the past 10 years were used to project averages for the next 10 years. To further refine longer term forecasting of MXGI quantities, a predictive failure model is being built based on historical extension and failure results of meter groups.

Consistent with the majority of utilities, EGI is considering the deployment of Advanced Metering Infrastructure (AMI). This initiative would modernize and allow two-way communication with the meters by way of a network. It will provide significant benefits to customers–reducing meter reading and call centre costs and eliminating estimated bills while providing customers insight into their gas usage at a granular level so they can make informed decisions. With access to granular usage information, EGI gains needed insights into peak usage. This in turn will support EGI's implementation of IRP plans and may allow the deferral of reinforcement projects.

As EGI continues to review operating standards in each rate zone and the use of various equipment and fittings, plans will be developed to bring these into alignment in a way that balances risk, cost and performance. Examples could include EGI's approach to meter location in high-density townhomes, the standards and maintenance practices for multi-unit buildings, or the installation and maintenance strategies for remote first cut regulators.

.

5.4.6 Pressure Regulation and Over-pressure Protection Systems

EGI is accountable for managing 3.2 million regulator sets that deliver low-pressure natural gas to customers. These critical assets act as the last line of defense against over-pressure. A regulator set is comprised of the following components: a regulator that reduces distribution gas pressure to delivery pressure, piping and over-pressure protection devices. Proper performance of these assets is vital for the health and safety of customers, the public and employees. **Table 5.4-6** describes the four subsets of this asset subclass:

Table 5.4-6: Regulator Set Descriptions

Regulator Set	Description
< 17 NCMH (200 and 400 Series Regulator Sets)	These regulator sets provide low pressure delivery (typically 7"wc) to primarily residential customers. Associated with meters having capacities of 17.0 m^3/h or less.
>17 NCMH (>400 Series Regulator Sets)	These regulator sets provide low pressure delivery (typically 7" to 10"wc) to high-volume regulator sets. Associated with meters having capacities greater than 17.0 m^3/h.
Local First Cut Regulator Sets	These regulator sets are associated with services connected to higher-pressure mains and have two regulators in series (both installed adjacent to the building). The first-cut regulator reduces pressure from a higher pressure to an intermediate pressure and the service-cut regulator reduces pressure from intermediate to low pressure.
Remote First Cut Regulator Sets	These regulator sets (also known as farm taps) are associated with services connected to higher-pressure mains (typically in rural areas) and have two regulators in series. The first-cut regulator reduces pressure from a higher pressure to an intermediate pressure and is typically located close to the property line (remote from the premises). The service continues below grade to the service-cut regulator, located adjacent to the premises.

5.4.6.1. 200 and 400 Series Regulator Sets

The 200 and 400 series regulator sets account for the majority (approximately 95%) of all regulator sets. Currently, regulators with single meters are replaced at the same time as meters exchanged through the Government Inspection Meter Exchange (MXGI) program. Based on MXGI program requirements, replacements can happen as soon as after 10 years of service. EGI has begun to collect regulator data as part of the MXGI program–a survey of 6,785 regulator sets in the EGD rate zone confirmed that most regulators have the same age as the meter set. A similar initiative is underway for the Union rate zones.

Using the service installation date as a proxy for the age of the regulator set, **Figure 5.4-7** shows that for the EGD rate zone, 0.002% of 200 and 400 series regulator sets are older than 40 years and 16% are older than 20 years.

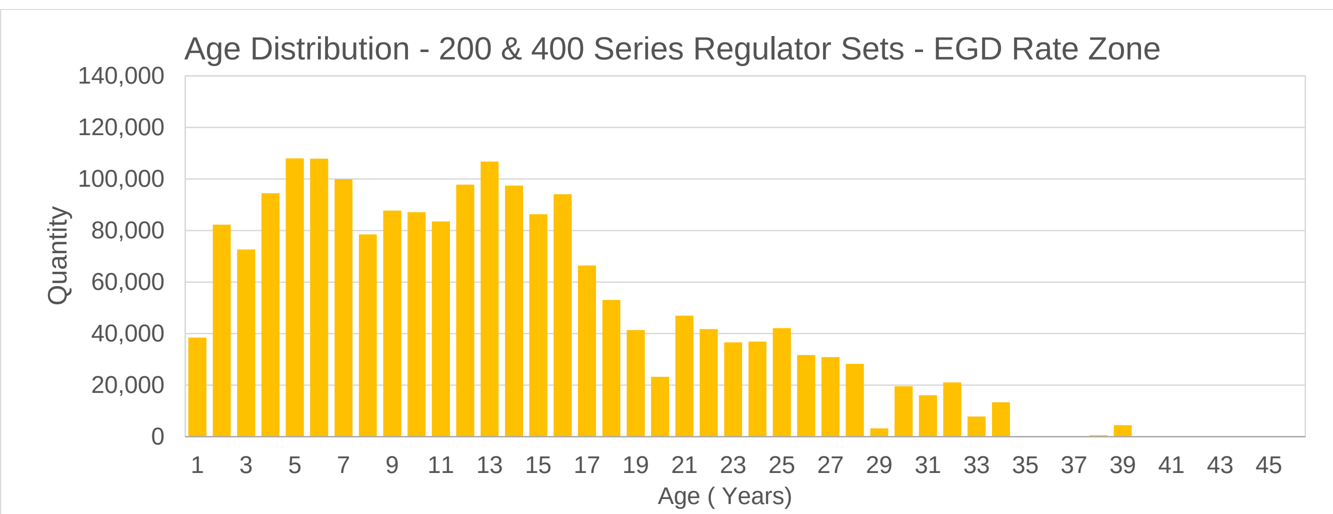


Figure 5.4-7: Age Distribution of 200 and 400 Series Regulator Sets – EGD Rate Zone

.

5.4.6.1.1 Condition Methodology

Regulator set condition is determined by performance, corrosion of piping and regulators and adherence to installation specifications:

- **Regulator performance** is influenced by the age of the asset (mechanical wear and tear) and its physical environment, potentially affecting its ability to lock up in abnormal conditions (to prevent over-pressure) and its ability to contain gas (absence of leaks). Assessment is determined through failure data, laboratory testing and age of the asset.
- **Corrosion of piping and regulators** can lead to loss of containment and faulty regulator performance. This is determined through an on-site visual assessment.
- **Adherence to installation specifications** is affected by a number of external factors which can affect failure rates and consequences. These include physical changes in site condition made by the customer after the initial installation of the set, such as new building openings/vents, increased grade and unreported damage, as well as regulatory specifications and codes that have changed since installation. This is determined by an on-site visual assessment.

Issues and outcomes affecting regulator sets, safety devices and piping systems are summarized in **Table 5.4-7**:

Table 5.4-7: Component Issues and Outcomes Summary

Component	Issue	Outcome
Regulator	Incorrect delivery pressure	Undesirable downstream effects can cause an emergency response and potentially higher severity consequences.
External reliefs	External relief missing on downstream regulator	Absence or failure of this component removes over-pressure protection, which is critical in the event of a regulator failure.
Regulator cap	Damaged or missing	A damaged or missing regulator cap can allow water or debris to enter the regulator housing, resulting in faulty performance and compromised pressure control.
Vent	Orientation not downwards	The vent must point downwards to reduce the probability of water or debris entering regulator control components and compromising pressure control.
	Missing or incorrectly sized vent screen	Missing or incorrectly sized regulator vent screens can allow insects and/or debris to block vent openings, impeding regulator diaphragm movement and compromising pressure control.
	Presence of vent shields	Vent shields are legacy components that were in place to protect vents. Debris or ice can build up on the vent shield, causing blockage and compromising pressure control.
	Vent too close to grade	Vents that are too close to grade can experience splashing and freeze-up of the opening, or can be covered with snow/ice, compromising pressure control.
	Insufficient vent clearance to building openings	Vents must comply with minimum distances to building openings to prevent gas migration.
Regulator	Regulator touching customer supply lines	Regulators touching customer supply lines can cause electrical continuity of below- and above-ground systems. This can promote migration of corrosion between below- and above-ground piping.
	Regulator too close to ground	Regulators that touch the ground are more susceptible to corrosion.
Fittings	Buried fittings	Fittings, typically wing-locks, must be above-ground to shut off gas in emergencies and avoid corrosion.
Regulator, Piping, Fitting, External Reliefs	Corrosion	Severe corrosion and pitting can lead to a loss of containment or abnormal operating condition.
All	Damaged by third party or environmental factors	Damages can lead to a loss of containment or abnormal operating condition.

.

These issues can contribute to failure of the regulation system and can cause pressured gas to enter the customer's supply piping, resulting in the potential failure of gas equipment, loss of containment, gas accumulation and/or potential incidents.

5.4.6.1.2 Condition Findings

Failure history and trending indicates that the wear-out phase for regulators associated with 200 and 400 series meters is unlikely to occur before 30 years of age. The current failure rate is 0.14% of the total population. EGI replaces regulators before they fail and are exchanged at the same time as the meter–meters are managed through the MXGI program and is based on sampling and testing to ensure Measurement Canada specifications are maintained.

Non-program regulators that fail before the manufacturer's recommended maximum service life are discovered during emergency calls or customer-initiated work. In most years, the number of regulators exchanged outside of the program is very minimal (less than 1% of the population).

Three condition categories evaluated for 200 and 400 series regulator sets are regulator performance, corrosion and adherence to installation specifications:

Regulator Performance: Regulator performance is affected by wear-out due to a combination of internal mechanical cycling and field operating conditions such as the presence of debris in the gas or atmosphere, ice or snow load and regulator set location. Additional layers of protection that are part of EGI's installation standard (e.g., over-pressure protection) can mitigate regulator failure incidents. EGI uses actual regulator failure and exchange data where possible to establish failure modes and frequencies.

For regulators exchanged outside the MXGI program, the historical data does not indicate the reasons for regulator exchanges. A conservative approach for the reliability study assumed that all exchanges were due to some type of failure. Failures may include a relieving regulator, regulator creeping, under-pressure, over-pressure or gas escapes. Non-failure replacements may be due to handling issues, customer load changes, changes to building openings, obsolete regulators, corrosion and damages. In a study completed in the EGD rate zone on regulator exchanges between 2005-2014, it was found that approximately 2800 regulators (0.14% of the population of 2.1 million) were exchanged independent of meter exchanges each year. As part of integration activities, an initiative to obtain similar data for the Union rate zones is underway.

The quantity of regulator exchanges independent of meter exchanges is relatively low. Analysis will be done to distinguish failure and non-failure exchanges within this data set. Going forward, failure classifications in the work and asset management system will improve root cause identification for regulator replacements.

Corrosion: A survey to investigate regulator corrosion on regulator sets was carried out across a population of 20,700 in the EGD rate zone. Corrosion distribution by age is shown in **Figure 5.4-8**.

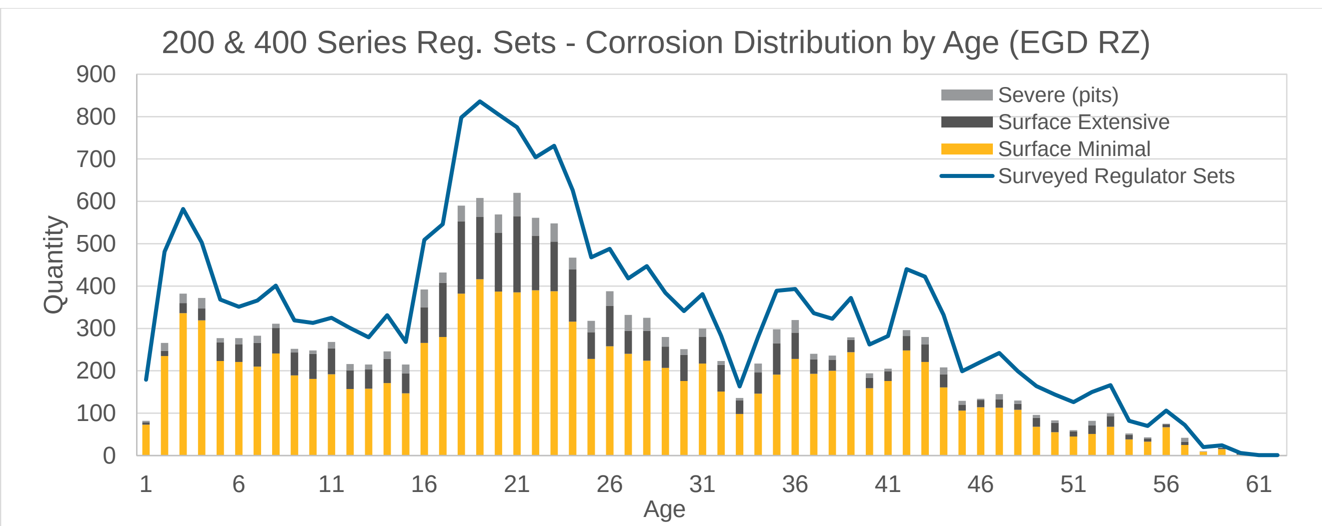


Figure 5.4-8: 200 and 400 Series Regulator Sets - Corrosion Distribution by Age – EGD Rate Zone

Results for the EGD rate zone show that 73% of the surveyed regulator sets have varying degrees of corrosion. Each vintage has at least 50% of the population of regulator sets with signs of corrosion. However, **Figure 5.4-8** shows that the majority of regulator sets have minimal surface corrosion and only 5% was categorized as severe. As part of integration activities, an initiative to obtain similar data for the Union rate zones is underway.

.

Adherence to Installation Specifications: It has been observed that regulator sets can have deviations from current installation specifications. This can occur when site conditions change over time, such as buildup of grade level, addition of new vents/building openings and building structures, as well as broken/missing components. In addition, installation specifications have changed over time and legacy specifications and components may still exist in some of these sets. These issues are rectified as part of MXGI program work.

5.4.6.1.3 Risk and Opportunity

200 and 400 series regulator sets in poor condition expose EGI to financial and safety risk. Poor condition can result in the regulator not delivering gas to the premises as designed for the downstream piping and equipment. In turn, this can result in a loss of containment within the building (including gas migration). Delivery pressures outside of normal operating conditions (under- or over-pressure) can also negatively affect appliance performance. If appliance safeguards fail, building occupants may be potentially exposed to carbon monoxide.

The most likely risk is financial risk associated with failure of these assets, which includes emergency response, commodity loss, repair costs and the costs of relighting customers' gas appliances. More severe incidents may also include costs associated with property damage and personal injury due to a gas leak. Regulator failure and customer service disruptions resulting from these failures may also result in reduced customer satisfaction.

The probability of a safety risk is low due to the MXGI program governing these assets. Regulator exchanges through the MXGI program and the policy to remove regulators older than 20 years (as found through service calls) ensure the safety risk is managed.

5.4.6.1.4 Strategy Outcomes

The strategy for 200 and 400 series regulator sets is to continue exchanging regulators and correct other compliance issues as part of the MXGI program, as these critical assets serve the majority of customers in the EGI franchise area.

Run-to-failure is not an acceptable practice for this asset, as the over pressure protection devices associated with the regulators are the last line of defense to protect customers from over-pressure events. The over pressure protection device is usually a part of the regulator set itself. Exchanging the regulators as part of the MXGI program mitigates the population from reaching the wear-out phase and ensures optimum regulator performance and safety.

By exchanging the regulator proactively as part of the MXGI program, the health and safety risk is managed and remains broadly tolerable because compliance issues are resolved before regulator failure. Financial risk is also managed by replacing regulators during MXGI program exchanges. By proactively replacing regulators nearing end-of-life, the financial impact of responding to emergency calls is minimized. A proactive strategy ensures that failures are minimized, reducing customer outages and maintaining high customer confidence in EGI as a gas provider.

This strategy applies a planned and controlled spend of capital dollars, while maintaining the current level of operational reliability. The continuous collection of failure data will help support improvements.

The Regulators and Relief program (specific to the Union rate zones) manages the cost of purchasing and stocking of natural gas regulators and relief valves to support replacement work. As regulators and relief valves fail or require replacement due to age or obsolescence (whether it be at the time of meter exchange or in conjunction with other maintenance projects), regulators are purchased and stocked to help maintain the high reliability of EGI's station assets.

5.4.6.2. >400 Series Regulator Sets

The >400 series regulator sets are primarily used by commercial, industrial and high-density residential customers and account for approximately 4.6% of all regulator sets. Failure of these regulator sets has the potential to cause over-pressure to a customer's supply line and appliances. Over-pressure can result in a loss of containment within the building, potentially allowing gas migration. The current policy states commercial regulators are exchanged if found to be 20 years or older.

Figure 5.4-9 shows that for the EGD rate zone, 20% of the population were installed over 40 years ago and 58% were installed over 20 years ago.

.

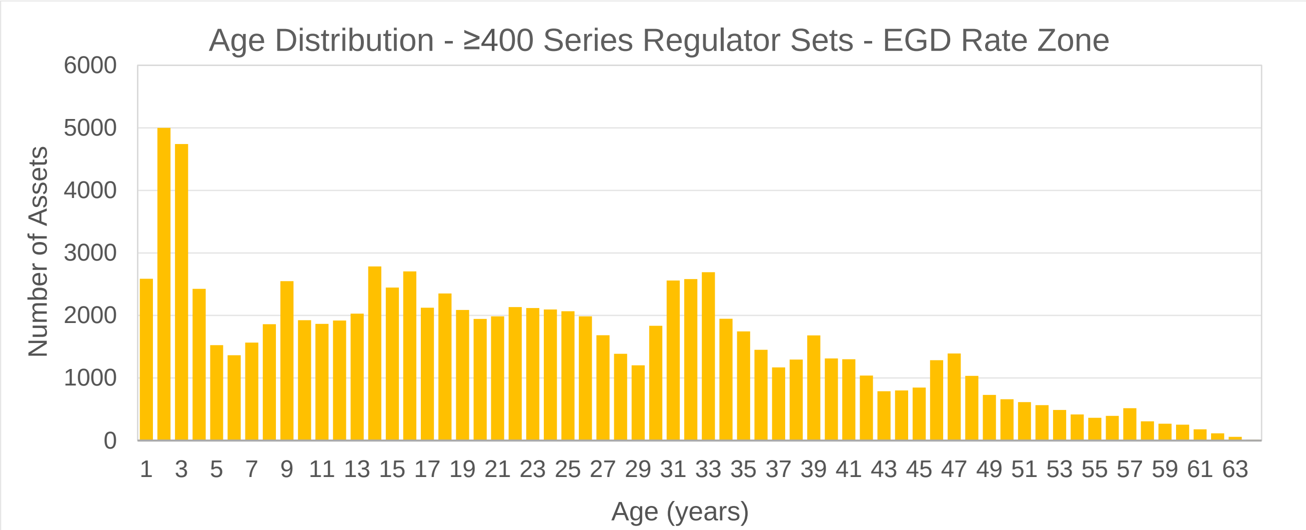


Figure 5.4-9: Age Distribution of >400 Series Regulator Sets – EGD Rate Zone

Commercial Meter Manifolds are a subset of >400 series regulator sets. These installations of multiple banked meters are typically located in commercial plazas. An EGD rate zone survey found this type of >400 series regulator set is more prone to condition issues and non-adherence to installation specifications, as EGI has not historically provided specifications on the addition of new meters to existing manifolds and criteria required for regulator set rebuilds. A risk assessment of this asset class is scheduled, which will assist in the development of an integrated program.

5.4.6.2.1 Condition Methodology

The condition methodology for >400 series regulator sets is the same as for the 200 and 400 series regulator sets. Refer to **Section 5.4.6.1.1**.

5.4.6.2.2 Condition Findings

Three main condition categories were evaluated for >400 series regulator sets: regulator performance, corrosion and adherence to installation specifications.

Regulator performance: **Figure 5.4-9** shows that for the EGD rate zone, more than half of these regulator sets are older than 20 years. Without failure data for these assets, EGI used station regulator failure data as a proxy to determine the probability of failure due to external leaks and ability to lock up. While a regulator used in a station may be the same as a >400 series or local first cut regulator, there are some differences. Using SMA input, a multiplier was developed and applied to the probability of failure to adjust for these differences.

A DIMP program to review the asset health of >400 series regulators not located at a customer station is being proposed to better understand the condition of this population.

External Corrosion: A preliminary visual integrity survey on a small sample population in the EGD rate zone identified issues related to corrosion and adherence to installation specifications. Sixteen percent (16%) of sites had severe corrosion or non-adherence to installation specifications. Thirty-seven percent (37%) of >400 regulator sets had corrosion of some extent. **Figure 5.4-10** shows that light corrosion was most frequently found on these regulator sets across all ages. Heavy corrosion was only found on regulator sets 29 years and older, showing a variation in corrosion across the age population. External corrosion does not affect the engineering design and safe operation of the >400 regulator assets.

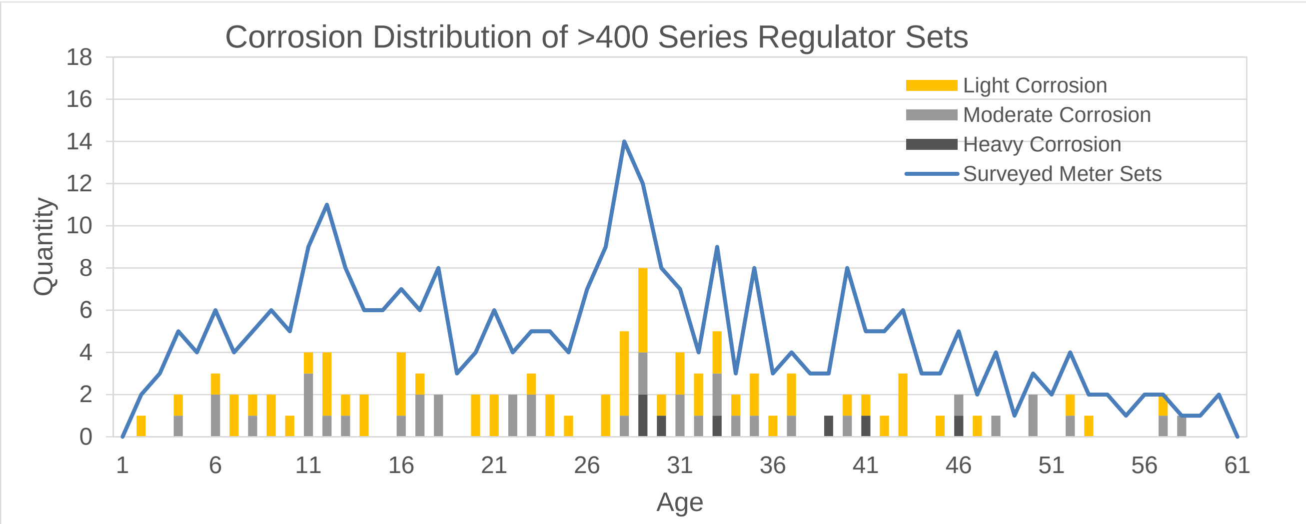


Figure 5.4-10: Corrosion Distribution of >400 Series Sets – EGD Rate Zone

Adherence to Installation Specifications*:* The sample survey also identified sites not adhering to current installation specifications. Results show that non-adherence to installation specifications is not specific to a certain age of >400 series regulator. The most prevalent issues found include:

- Issues with vent clearances and other components
- Regulator touching pipe
- Vent not pointing downward
- Missing vent screen
- Improper valve distance from ground

All installation specification issues are scheduled to be corrected/remediated and the development of a >400 series regulator set sampling program is planned to better understand the condition of this asset population.

As part of integration activities, an initiative to obtain similar data for the Union rate zones is anticipated.

5.4.6.2.3 Risk and Opportunity

Based on historical failure data, the probability of a >400 series regulator failure is low. These assets account for 4.6% of all regulator sets and are predominantly used in commercial, industrial or higher-density residential premises, which typically serve a larger number of end-users than single-family residential premises. An abnormal operating condition for one of these assets puts a larger number of end-users at risk. As well, >400 series regulators have higher delivery flow rates than residential (200 and 400 series regulators) services. This results in potentially more severe consequences for safety and financial risks when compared to smaller flow regulator sets.

EGI may be exposed to a safety risk due to a loss of containment if the regulator cannot control the gas pressure to the premises, leading to an over-pressure event that may damage downstream equipment and property and migrate gas into the customers' premises, resulting in gas accumulation and a potential incident.

Failure of these assets exposes EGI to financial risk. A loss of containment triggers emergency calls which may result in repair costs, commodity loss, relighting customers' gas appliances, property damage and personal injury due to a gas leak. Regulator failure and customer service disruptions resulting from these failures may also negatively impact EGI customer satisfaction.

The most likely risk for >400 series regulator sets is financial, due to the likely outcome of a failure only requiring remediation. The probability of a safety risk is low due to engineering policies governing these assets. Regulator exchanges through the MXGI program and the protocol to remove regulators older than 20 years (as found through service calls) help manage this risk.

.

5.4.6.2.4 Strategy Outcomes

The strategy for >400 series regulator sets is to replace assets older than 20 years through the MXGI program. Additionally, there are strategies in place through DIMP to collect information on the failure rates of these assets, informing future policy decisions on replacement frequency. The associated services are surveyed for leaks every five years and surveyed for corrosion every year.

>400 series regulator sets typically serve higher-usage and higher-density customers. The safety and reliability impacts of an incident could be high. A risk assessment will be completed for these assets to determine mitigation strategies. By proactively inspecting and remediating issues on a priority basis, the risk of an in-service failure will be reduced. If these regulator sets are allowed to run to failure, there will be inconvenience to the customer, a financial impact due to emergency call responses and the possibility of a health and safety incident.

This strategy manages safety risk by remediating all discovered compliance and integrity issues before they turn into failures, minimizing the risk to the safety of customers, employees and the public. Remediation may entail a full replacement of the regulator, meter and riser, as well as adjustments to bring the regulator set to current installation specifications. The planned and controlled spend of capital dollars minimizes the financial impact of responding to emergency calls. The strategy supports operational reliability by ensuring that failures continue to be very minimal, minimizing customer outages and maintaining high customer confidence in EGI as a gas provider.

In 2017, a sample survey was completed for this asset class in the EGD rate zone. Similar to the assets in Measurement Systems, the continuous improvement strategy for this program is made possible through data collection. Data will be used to optimize the renewal schedule and potentially change the program pace. Data will continue to be collected on regulator sets that become part of the MXGI program. Data such as condition, adherence to installation specifications, regulator attributes and failure classifications will be collected to iterate data models. Refinements include validating criteria that assist in prioritizing high risk locations and analyze asset life cycle and risk assessments.

As part of the integration activities, programs to assess the >400 series regulator sets are being developed to better understand the condition of the broader population in both rate zones and to determine if further proactive processes or programs are required to ensure safe and efficient operations.

5.4.6.3. Local First Cut Regulator Sets

When gas is delivered from a higher-pressure (>100 psig) gas main, the regulator set will have two regulators installed in series (i.e. two pressure cuts). This configuration is not common and represents an estimated less than 2% of the total 3.2 million EGI services. In the local first cut regulator set configuration, the first regulator reduces gas pressure from higher-pressure gas main to intermediate pressure (typically in the range of 60 psig) and the second regulator reduces pressure from intermediate pressure to the delivery pressure (up to 14” WC). The regulator set may also include additional components, such as external relief valves.

The entire local first cut regulator set population for the EGD rate zone was surveyed in 2015 and 2016 to identify and remediate any immediate concerns (e.g. missing first cuts, leaks, improper relief vents, etc.) and to assess the asset population’s fitness for service. The age distribution of these regulator sets is shown in **Figure 5.4-11**. Programs to assess this asset subclass are being developed to better understand the condition of the broader population for both rate zones.

.

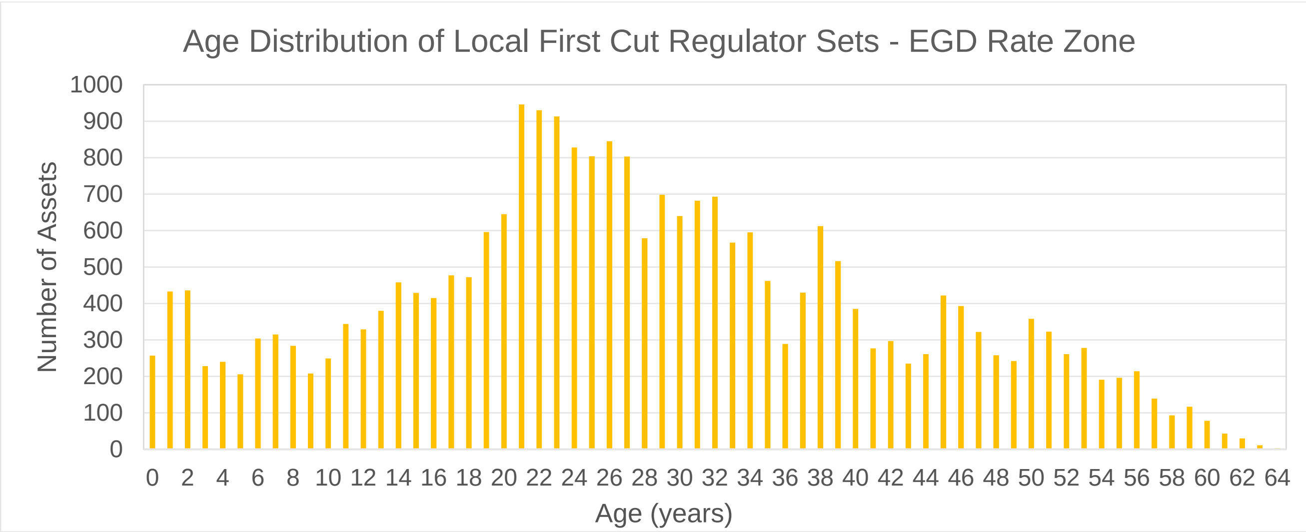


Figure 5.4-11: Age Distribution of Local First Cut Regulator Sets - EGD Rate Zone

5.4.6.3.1 Condition Methodology

The condition methodology for local first cut regulator sets is the same as for the 200 and 400 series regulator sets. See **Section 5.4.6.1.1**.

5.4.6.3.2 Condition Findings

Three main condition categories were evaluated for local first cut regulator sets in the EGD rate zone: regulator performance, corrosion and adherence to installation specifications.

Regulator Performance: Failure data specific to local first cut regulators has not historically been categorized. Station regulator data was used as a proxy in determining the probability of failure due to external leaks and the ability to lock up.

Corrosion of piping and regulators: A survey of local first cut regulators in the EGD rate zone was conducted to identify corrosion and issues with adherence to installation specifications. Seventy-eight percent (78%) of the total population was found to have some minimal degree of corrosion. **Figure 5.4-12** shows that most sites with signs of corrosion have minimal surface corrosion. All sites with severe corrosion have been remediated.

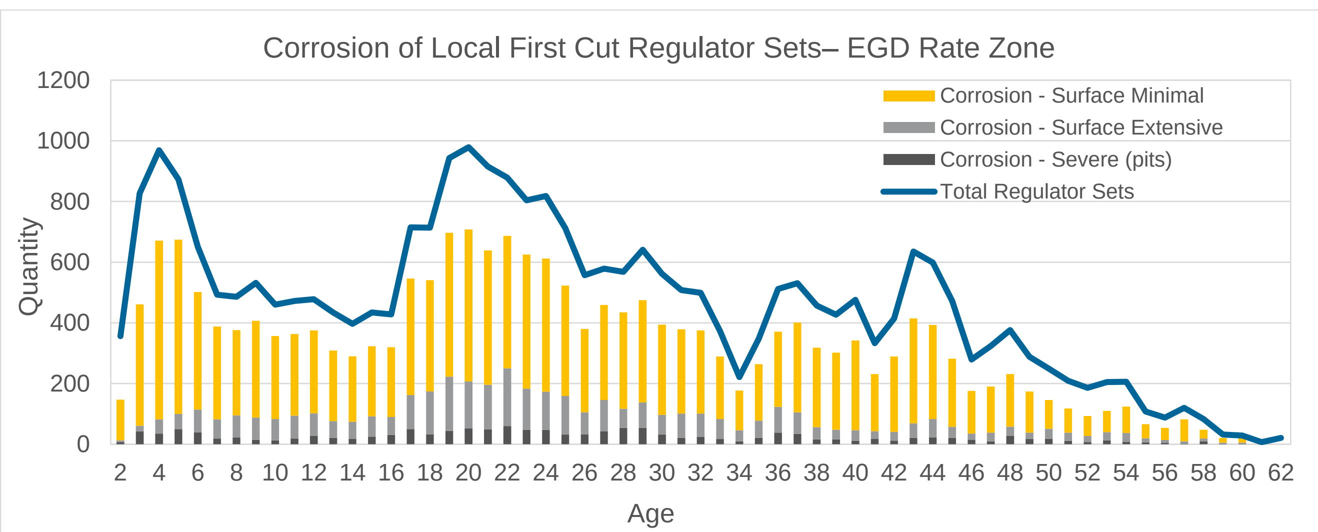


Figure 5.4-12: Corrosion of Local First Cut Regulator Sets– EGD Rate Zone

.

Adherence to Installation Specifications: Non-adherence to installation specifications were found on some of first cut regulator sets. Some of the issues identified include:

- Improper vent orientation
- Damage to the regulator cap
- Missing vent screens
- Presence of vent shields
- Missing external reliefs

All of the EGD rate zone sites with these issues were prioritized based on the likelihood of an incident occurring and were all remediated. Generally, older regulator sets were more likely to exhibit these issues as there is more likelihood of changes to site conditions and changes to installation policies. Sites found to have old/obsolete regulators were also remediated. The asset survey also found sites with minor specification issues–a program to remediate the rest of these minor variances is ongoing.

A process to identify and survey first cut regulator sets in the Union rate zones will start in 2020.

5.4.6.3.3 Risk and Opportunity

All distribution system pressure regulation systems have an inherent level of risk. Risks associated with local first cut regulator sets are safety and financial risks, due to the likely outcome of a failure only requiring remediation. The safety risk is low due to EGI policies for these assets (i.e. regulator exchanges through the MXGI program and removal of regulators older than 20 years).

The safety risk associated with local first cut regulator sets is associated with the loss of gas containment. Regulators (and associated relief valves) control gas pressure to protect the customer's piping and premise from over-pressure. An over-pressure event can result in damage to downstream equipment, loss of containment within the building, gas accumulation and a potential incident. A local first cut regulator set presents a higher consequence than traditional single cut regulator sets due to the higher pressures managed by two pressure cuts. The failure rate of local first cut regulator sets is very low due to the presence of multiple pressure regulators and multiple over-pressure protection devices installed in series.

The financial risk associated with first cut regulator sets is a consequence of responding to the events associated with the safety risk. Over-pressure and loss of containment generates costs associated with emergency response calls, repairs, commodity loss, relighting customers' gas appliances, property damage and/or other claims. Customer service disruptions and media coverage resulting from these events may result in reduced customer confidence in EGI.

5.4.6.3.4 Strategy Outcomes

The strategy for local first cut regulator sets is to proactively maintain and exchange units in conjunction with the MXGI program. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.

In order to ensure safety and reliability, EGI employed a variety of strategies to replace regulators prior to failure while extending their useful life. Assets identified with 200 and 400 series meters have regulators proactively replaced in conjunction with the MXGI program:

- First cut regulator and external relief valves are replaced when the second cut regulator is replaced.
- Regulators on commercial local first cut regulator sets are replaced if found to be 20 years or older, maintaining asset integrity, extending asset life and ensuring code compliance.
- Local first cut regulator sets are included in a data survey every four years and a comprehensive survey every eight years.

The continuous improvement strategy for this program is made possible through data collection. Data will continue to be collected on regulator sets that become part of the MXGI program. Data such as condition, adherence to installation specifications, regulator attributes and failure classifications will be collected to iterate data models. Refinements include validating criteria that assist in prioritizing high-risk locations and analyze asset life cycle and risk assessments.

As part of integration initiatives for the Utilization asset class, programs to assess local first cut regulator sets are being developed to better understand the condition of the broader population in both rate zones and to determine if further proactive processes or programs are required.

For the EGD rate zone, all immediate safety concerns from the 2015-2016 survey were remediated. As well, a strategy is in place to remediate remaining sites found to have minor compliance issues. Remediation measures are site-dependent. Remediation may entail a full replacement of the regulator set or may only require adjustments to bring the regulator set to current installation specifications.

.

Financial risk is managed through a planned and controlled spend of capital dollars. By proactively managing the health of local first cut regulator sets, the financial impact of responding to emergency calls is minimized. Customer satisfaction is managed by ensuring failures and corresponding customer outages are minimized. This strategy supports operational reliability, efficiency and safety.

For the Union rate zones, integration initiatives will allow for better documentation and asset health assessment of local first cut regulator assets.

5.4.6.4. Remote First Cut Regulator Sets (Farm Taps)

These double cut regulator sets (referred to as farm tap regulator configurations) make up less than 0.5% of all regulator sets. The majority of these assets are found in rural areas. A farm tap is a first cut regulator that reduces pressure from a higher to intermediate pressure to meet the design criteria for the downstream regulator. A malfunctioning farm tap regulator has the potential to create downstream hazards. A failure of the regulator set could potentially cause a higher than acceptable pressure entering customer premises. This over-pressure can result in downstream customer appliances failing, loss of containment inside the premises, gas accumulation and a potential incident.

As most farm tap regulators are installed away from the premises and near the property line, these assets are exposed to more elements originating from the roadway. Their placement can also make them susceptible to third-party damage from maintenance equipment and vehicles.

The majority of farm taps are 20 years old or younger (see **Figure 5.4-13**). In 2017, an inspection and remediation program in the EGD rate zone targeted the farm tap population 20 years and older. This program is currently ongoing.

For the Union rate zones, a sample survey of farm tap regulators is currently proposed for 2020 to provide initial knowledge on the condition of the asset subclass.

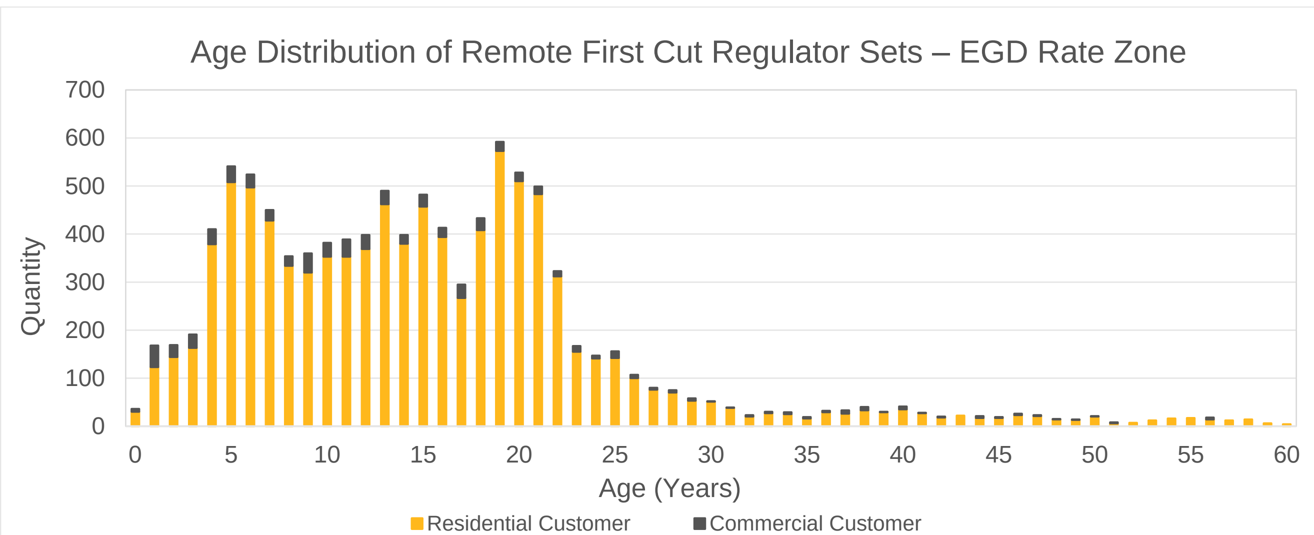


Figure 5.4-13: Age Distribution of Remote First Cut Regulator Sets – EGD Rate Zone

5.4.6.4.1 Condition Methodology

The condition methodology for remote first cut regulator sets is the same as for the 200 and 400 series regulator sets. Refer to **Section 5.4.6.1.1**.

For the EGD rate zone, a component-based Failure Mode and Effect Analysis (FMEA) was performed through SMA reviews to identify the critical components of all remote first cut regulator sets, their failure modes, causes and effects, required safeguards and potential consequences if safeguards fail.

.

5.4.6.4.2 Condition Findings

Sites for remote first cut regulator sets older than 15 years were determined to have more significant condition issues. Three main condition categories were evaluated for these assets: regulator performance, corrosion and adherence to installation specifications.

Regulator performance: Service regulators are required to be replaced if found to be 20 years or older. The current exchange policy also includes exchanging the regulator if the second cut regulator is being exchanged as part of the MXGI program. For the EGD rate zone, a program is currently in place to inspect and remediate remote first cut regulator sets older than 20 years to reduce the likelihood of age-related failures.

Failure data specific to remote first cut regulator sets has not historically been categorized. However, a visual integrity survey was conducted in 2015 on a sample population in the EGD rate zone. The issues identified in this survey formed the basis for future remediation work. Reliability modelling analysis was performed on remote first cut regulator sets through the Asset Health Review program using station regulator data as a proxy to help determine the condition of the assets. Over time, more remote first cut regulator set data will be collected and used for reliability modelling.

Corrosion of piping and regulators: Data from the 2015 sample survey in the EGD rate zone provides insight into the asset condition of farm taps. The extent of corrosion versus age is displayed in **Figure 5.4-14**.

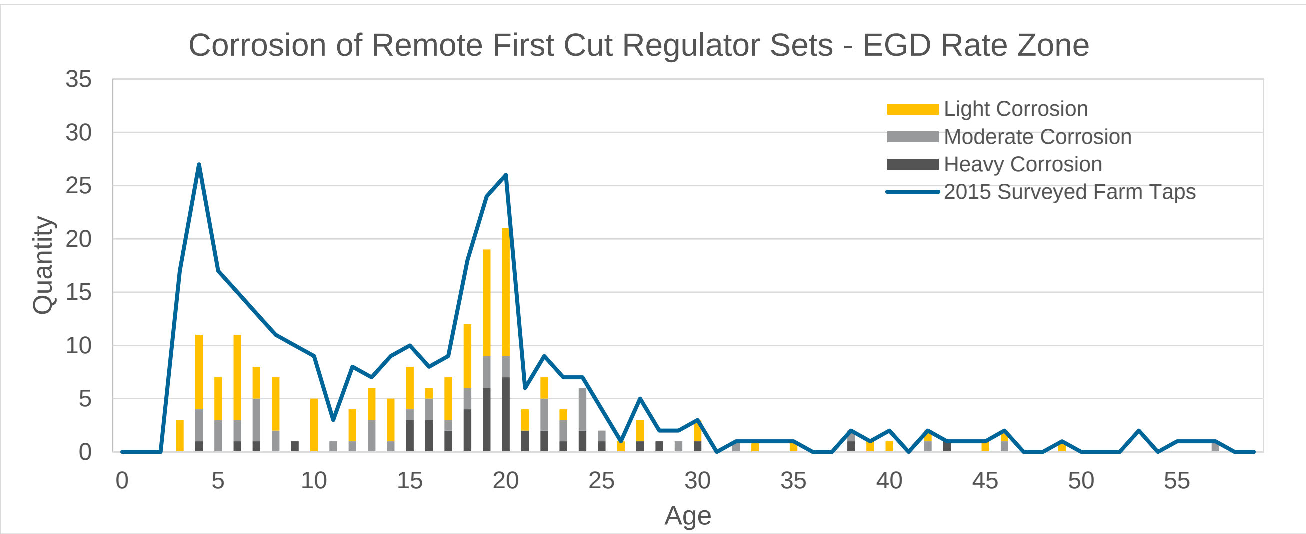


Figure 5.4-14: Corrosion of Remote First Cut Regulator Sets - EGD Rate Zone

Figure 5.4-14 indicates that a higher count of corrosion impact is observed on remote first cut regulator sets 15 years and older. This is attributed to their typical location (in rural areas above-ground and near roadways).

Adherence to installation specifications: The sample survey indicated that some remote first cut regulator set installations had issues related to adherence to installation specifications. The most frequent issues are as follows:

- Vent clearance issues
- Improper vent orientation
- Broken caps
- Missing vent screens
- Obsolete regulators

Most vintages had some level of non-adherence to installation specifications with an increasing trend as these assets approached 20 years of age. This is due to site conditions and installation specifications changing over time.

Based on the survey, remote first cut regulator sets older than 20 years were determined to have more significant condition issues and were prioritized for remediation. A proactive strategy to inspect and remediate these assets will prevent a potential peak in future failures. This approach also distributes future workload while reducing risk.

Based on the FMEA, the main critical components for farm taps are regulators, inlet and outlet shut-off valves, inlet and outlet risers, external relief valves and piping and fittings. A review of the potential consequences of these component failures reveals potential health and safety risks. The FMEA identifies the lack of maintenance as one of the main causes of failures on these critical components.

.

For the Union rate zones, a sample survey of farm tap regulators is currently proposed for 2020 to provide initial knowledge on the condition of the asset subclass.

5.4.6.4.3 Risk and Opportunity

Remote first cut regulator sets present higher risks due to the higher pressures managed by the regulator. Downstream of the remote first cut regulator is a second regulator cutting pressure to the service premises. The probability of failure of the service cut regulator is evaluated to be the same for all service regulators of any flow capacity delivering low pressure.

EGI may be exposed to a safety risk due a loss of containment if the regulator cannot control the gas pressure to the premises, leading to a gas over-pressure event that may damage downstream equipment and property and migrate into the customer's premises, resulting in gas accumulation and a potential incident.

Failure of these assets exposes EGI to financial risk. A loss of containment triggers emergency calls which may result in repair costs, commodity loss, relighting customers' gas appliances and property damage due to a gas leak. Regulator failure and customer service disruptions resulting from these failures may result in poor customer satisfaction .

The most likely risk for these assets is financial, followed by safety risk, due to the likely outcome of a failure requiring remediation. The probability of a safety risk is low due to internal engineering policies governing these assets. Regulator exchanges through the MXGI program and the protocol to remove regulators older than 20 years (as found through service calls) help manage this risk.

5.4.6.4.4 Strategy Outcomes

For the EGD rate zone, remote first cut regulator sets have largely been excluded as part of inspection and maintenance work due to their offset location and changes in procedures over time. A risk assessment will be completed in 2020 to determine mitigation strategies. Remediation may entail a full replacement of the regulator, meter and riser, as well as adjustments to bring the regulator set to current installation specifications.

The FMEA results on remote first cut regulator sets showed that a routine inspection and maintenance program over the lifetime of the asset would reduce in-service failures through the proactive identification of assets that have failed or are nearing end-of-life. After the full risk assessment for both rate zones is complete, a program will be developed to manage this asset subclass. Additionally, remote first cut regulator sets associated to 200 and 400 series meters are exchanged through the MXGI program. Current EGI policy requires the first cut regulator and external relief valves to also be replaced when the second cut regulator is replaced. As part of the Leak Survey program, remote first cut regulator sets are included in the four-year data survey cycle and the eight-year comprehensive survey cycle.

The strategy for these assets is to manage the safety risk by identifying and remediating potential compliance and integrity issues before they turn into failures, minimizing the risk to the safety of customers, employees and the public. This strategy will also minimize the financial impact of responding to emergency calls.

This proactive strategy ensures that the risk of failure is mitigated, minimizing customer outages and maintaining high customer confidence in EGI as a gas provider.

For the Union rate zones, a sample survey of remote first cut regulator sets is planned for 2020 and will provide initial knowledge on the asset subclass condition. As part of integration activities, a remote first cut regulator set assessment program will be developed to better understand the condition of the broader population at both rate zones and to determine if further proactive processes or programs will be required to ensure safe and efficient operations.

5.4.7 Below-ground and Internal Piping Systems

Below-ground and inside piping systems refer to piping running below grade and/or piping running inside a building, typically located upstream of inside meters. The Below-ground and Internal Piping Systems subclass is categorized into:

Service Extensions: Refers to service piping installed between the regulator (outside of the building) and the meter (inside the building) where the pipe enters the building below ground.

Multi-Family Building Services: Refers to gas distribution networks within multi-unit buildings. Each may consist of a garage header, vertical headers, off-garage service pipes and/or vertical headers supplying meters for individual units. There are two main metering configurations:

- **Ensuite Metering**: internal piping leading to meters inside individual units
- **Banked Metering**: internal piping leading to meters grouped together in the garage or basement on each individual level of the building

Bulk Meter Headers: Refers to gas distribution networks consisting of underground piping downstream of a meter feeding multiple individual customer buildings. Regulation occurs downstream of the meter. These networks are installed by EGI.

5.4.7.1. Service Extensions

Service extensions refer to EGI-owned steel piping from the regulator (outside the building) to the meter (inside the building). Its entry through the building wall is below grade. Service extensions are commonly found at urban wall-to-wall premises. Due to lack of frontage space at these locations, the riser, regulator and service extension are outside the building and the meter is located inside the basement. EGI currently has 13,666 service extensions that are found on 0.7% of services in the EGD rate zone. A study will be conducted in 2022 to determine the number of service extensions for the Union rate zones.

Figure 5.4-15 shows the age distribution for service extensions. The majority of the population is younger than 25 years. Some factors contributing to installations within this timeframe include the renewal of cast iron systems in downtown Toronto and a program moving regulators from inside to outside customer premises.

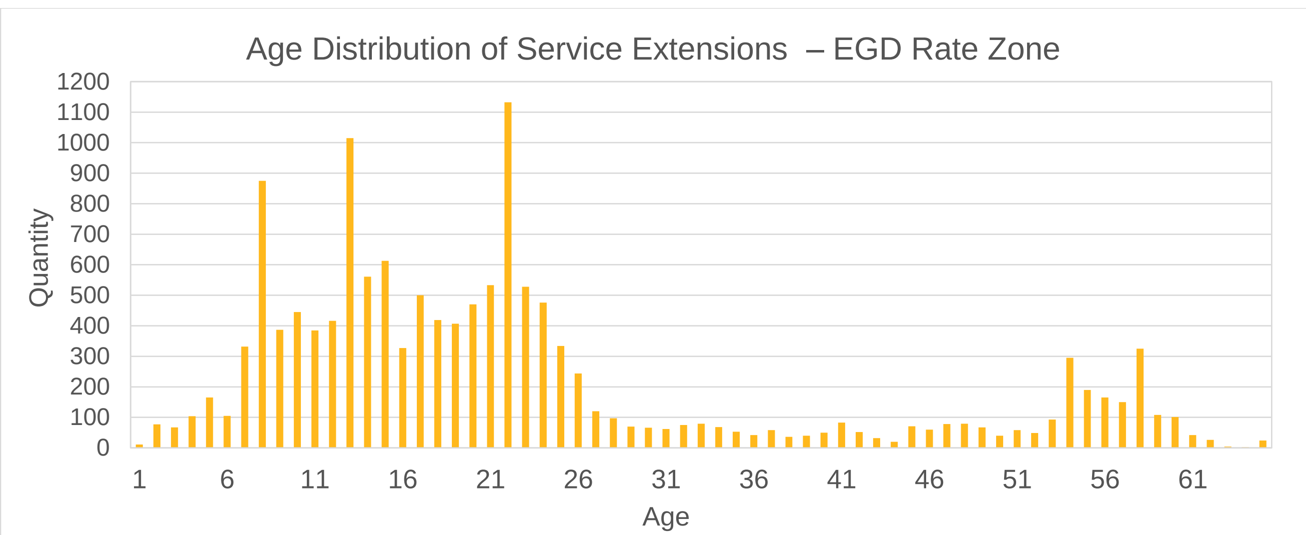


Figure 5.4-15: Age Distribution of Service Extensions – EGD Rate Zone

5.4.7.1.1 Condition Methodology

All service extensions are isolated from cathodically protected steel services. Service extensions with depleted anodes are unprotected and more susceptible to corrosion, ultimately resulting in a loss of containment. Cathodic protection and coating types are two parameters influencing corrosion rate. The application of cathodic protection on service extensions in the EGD rate zone was estimated by conducting pipe-to-soil inspections on a statistically representative sample. In addition, samples of unprotected service extensions were removed to determine wall loss. The sample sites were also inspected prior to

.

removal with non-destructive guided wave testing, designed to detect the magnitude and location of wall loss on buried pipe. Removed samples were inspected for condition and to validate the effectiveness of this technology. Installations were upgraded at all sample sites. Through integration efforts, the size and condition of the service extension population in each rate zone will be established.

5.4.7.1.2 Condition Findings

In the EGD rate zone, a cathodic protection survey determined some correlation between age and cathodic protection status (see **Figure 5.4-16**). Newer installations were more likely to be cathodically protected. Older service extensions were more likely to fail than newer service extensions. Twenty-four service extension sites identified as older than 50 years old were removed and replaced to assess pipe condition.

The results of the sample survey were used to refine a mechanical model that will determine the degradation rate of unprotected service extensions. The sampling validated the functionality of non-destructive guided wave technology for use in future inspections.

Further data collection is in progress to improve EGI's understanding of the service extension population and its condition. When complete, sites will be inspected for cathodic protection and if required, a program will be established to replace or improve the cathodic protection of these assets.

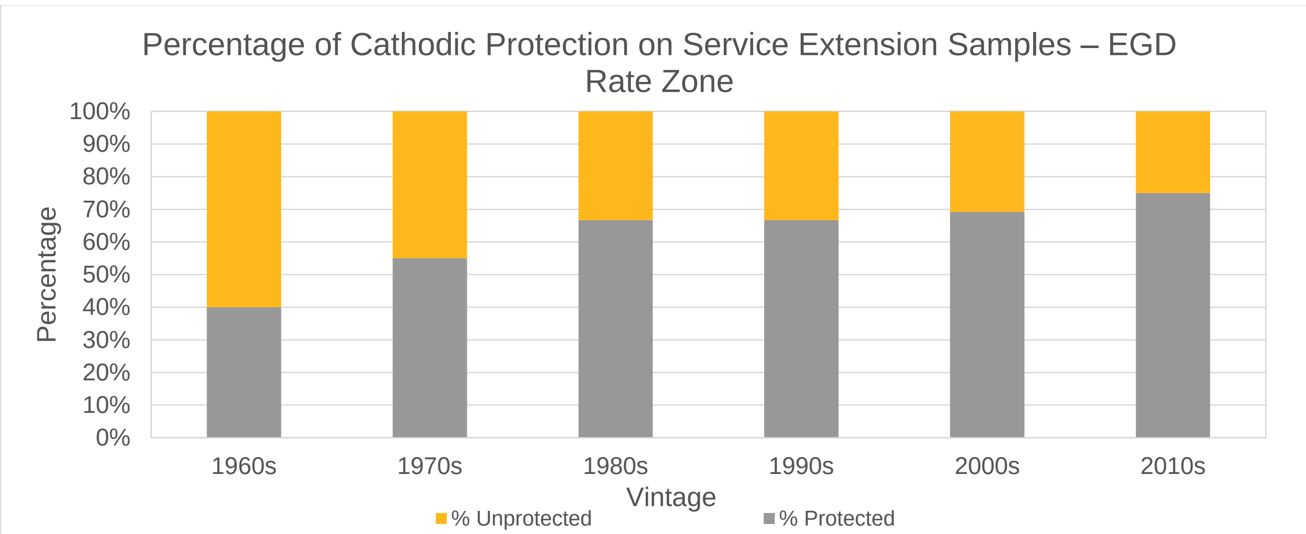


Figure 5.4-16: Percentage of Cathodic Protection on Service Extension Samples – EGD Rate Zone

5.4.7.1.3 Risk and Opportunity

If service extensions are not cathodically protected and properly coated, they can corrode at a higher rate than expected, eventually leading to a loss of containment if not remediated. Since this piping enters the building below grade, gas leaks may have a higher chance of migration into the building, resulting in gas accumulation and a potential incident. The EGD rate zone sample survey shows that the proportion of service extensions without cathodic protection increases with age. This may be due to old installation practices and depleted anodes over time.

Historical frequencies of failures for service extensions are low relative to the total population. Failure consequences can be high they include the potential for underground gas migrating into a building. As natural gas is odourized, leaks are likely to be detected and remediated before a hazardous indoor gas concentration is reached.

The safety risks identified for service extensions are gas leaks and gas migration. Identified financial risks include unplanned repair and relight costs, commodity loss and property damage caused by gas leaks. Service disruptions resulting from these failures may result in poor customer satisfaction.

.

5.4.7.1.4 Strategy Outcomes

The strategy for this asset subclass is to opportunistically replace service extension assets in conjunction with planned and unplanned service replacements and planned city sidewalk/road replacements. Comprehensive surveys were conducted in the EGD rate zone to verify the location of these assets. In addition, leak surveys include inspections for leaks up to the meter.

In parallel, these assets will be added to the Corrosion Monitoring program. Condition data will be collected over time, refining the failure model to more accurately predict end-of-life of these assets. In addition, current EGI policy requires adequate cathodic protection to be installed at the time of service extension installation.

Should the risk profile increase over time, a proactive approach of inspection and remediation will be considered. The collection of installation, condition, failure and maintenance data on the majority of the service extension population can be used to validate high-risk location criteria, reduce risk prioritized and supported by data and refine the remediation and inspection program pace.

This strategy will minimize safety risk by remediating integrity issues before they turn into failures and will also minimize the financial impact of responding to related emergency calls. This opportunistic approach minimizes costs associated with proactively renewing these assets.

5.4.7.2. Multi-Family Building Services

Multi-family building installations differ from typical installations significantly by having company-owned pipe within a building. The buildings are typically multiple-storied and contain many independent premises, each with their own meter installed either ensuite or in a rack of meters within the building. These buildings can also be multi-family occupied town housing or row housing.

This piping can contain pressure regulated by a customer station or a low pressure delivery regulation set. With ensuite configurations, the network of EGI-owned piping is extensive, as it includes all of the piping leading to each meter on different floors of the building. With banked metering configurations, company-owned piping typically terminates in a common area (such as a garage) where individual customer meters are grouped together.

5.4.7.2.1 Condition Methodology

Multi-family building installations have several challenges:

- Installation standards allow for these buildings to have higher pressure gas than a single-family residential unit.
- Piping location creates challenges for leak and cathodic protection surveys.
- Some units may have isolated steel pipe upstream of the meter.
- Unit density means potential incidents can have a greater impact.

In the EGD rate zone, leak surveys for multi-family building services are conducted once every three years. A system extract based on residential customers and two or more inside meters indicates there may be other locations that will need to be inspected. The extract aims to identify additional in-scope sites (such as row-housing with internal headers).

Figure 5.4-17 shows the distribution of vintages for this asset subclass, as well as the distribution of inside meters per building at these potential locations.

The scope expansion of the design standard for these assets also affects the scope and locations included in the Leak Survey program. A building with internal distribution piping that has not been included in the program has a high probability of not being inspected for leaks and condition issues since installation. If this internal piping is in poor condition, not physically supported properly, or damaged, there could be a loss of containment and gas accumulation within the building, making an incident possible.

An inventory investigation will determine how many of these configurations are in the Union rate zones. Once known, a survey of each site will be conducted and the assets will be included in Leak Survey and Cathodic Protection programs.

.

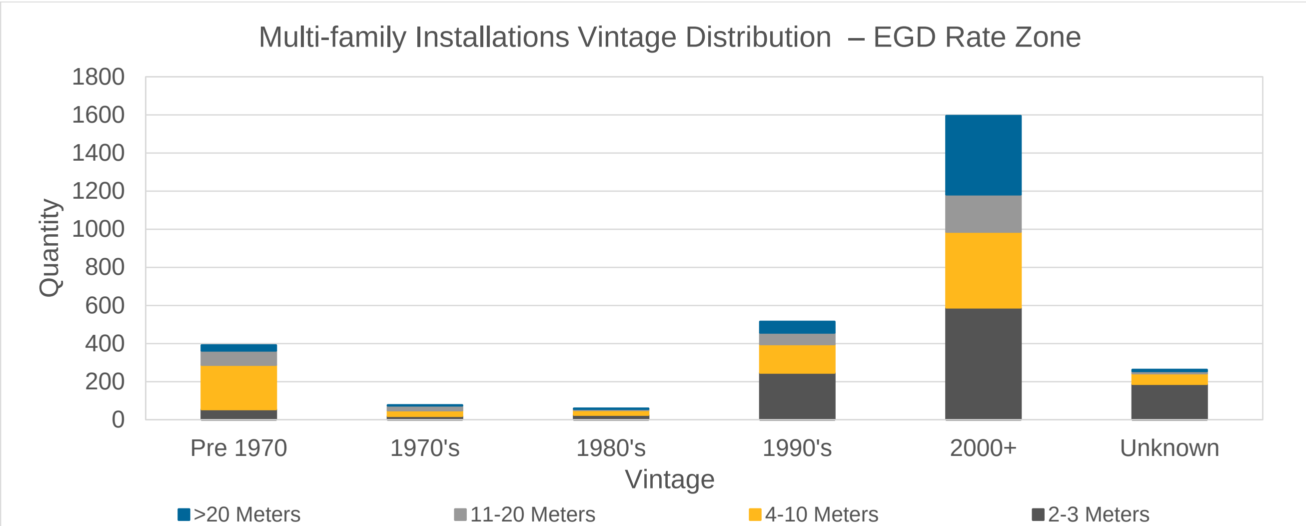


Figure 5.4-17: Multi-family Installations Vintage Distribution – EGD Rate Zone

In the EGD rate zone, two main condition categories were evaluated for multi-family building services:

Adherence to Installation Specifications

- Proper support for piping by approved bracketing and minimum spacing
- Proper support and spacing of meters
- Meter location: fit for purpose, vulnerability to damage, ventilation grille if enclosed
- Identification markings per code
- Pipe penetration through walls and floors and the provision of insulating fittings
- Valve location and accessibility
- Physical barriers: existence, location and condition

Corrosion

- Presence of corrosion on piping
- Presence of corrosion on joints
- Pipe penetration through walls, floors and into the building
- Presence of corrosion on valves
- Adequate corrosion protection

An inventory investigation is being completed under the Distribution Integrity Management Program (DIMP) to review all indoor meters excluded from the Leak Survey program and determine which belong to the multi-family building services population.

5.4.7.2.2 Condition Findings

EGI's leak survey program provides insight into the condition of multi-family building services assets. Generally, corrosion is found where the pipe intersects with the concrete wall–any severe corrosion that could affect safety is remediated. Any leaks found on these assets are remediated immediately. Given the nature of these systems, leaks that do occur are very minor. Any safety concerns are reviewed with the resident or landlord–instances such as encroaching on EGI assets have been found. The inventory investigation will give further insight to the population and will be monitored as part of an engineering integrity program.

5.4.7.2.3 Risk and Opportunity

If internal piping is in poor condition, not physically supported properly or damaged, there could be a loss of containment and gas accumulation within the building, making an incident possible. Buried piping from outdoor regulators to indoor meters is also at risk of leaking and migrating gas indoors. Since this piping system category is located inside high occupancy buildings, the potential consequence of failure is higher. Loss of containment will impact more people, resulting in a greater probability of personal injury. The historical frequency of incidents related to multi-family building services is low.

.

To ensure the safety risk remains low, programs are in place to identify these assets and to include them in programs that monitor condition, prevent failure and minimize failure impacts.

The safety risks for multi-family building services assets are gas leaks and migration through underground infrastructure into buildings, resulting in gas accumulation and potential incidents. The financial risks identified are losses due to repair costs, commodity loss, relighting customer gas appliances and any property damages caused by a gas leak. Operational risks identified are greenhouse gas emissions, environmental impacts and service interruptions. EGI continues to take steps to gather necessary information and better manage these assets and their risks.

5.4.7.2.4 Strategy Outcomes

The strategy for multi-family building services assets has two key components:

- Continue to conduct Leak Survey and Cathodic Protection Survey programs based on operating standards for existing multi-family building services assets.
- Continue to conduct population surveys to refine the total asset population and to understand asset condition.

Inventory surveys help ensure adequate corrosion protection and adherence to installation specifications. Data will be used to quantify risk and to determine if existing programs can mitigate these risks. If the risks cannot be managed within the scope and timing of existing programs, a targeted remediation program will be created to address issues identified.

This strategy manages safety risk by remediating all discovered compliance and integrity issues before they turn into failures, minimizing the risk to the safety of customers, employees and the public. This proactive strategy ensures that failures are prevented, minimizing customer outages and maintaining high customer confidence in EGI as a gas provider. As well, this strategy will help improve current levels of operational reliability.

5.4.7.3. Bulk Meter Headers

Some premises that have multiple buildings or suites are served natural gas through a common meter set, where the meter measures the consumption of all buildings or suites collectively (known as a bulk meter). Gas pressure may be reduced at either the same location as the bulk meter, or it may be regulated elsewhere downstream in the system, possibly even at each suite or building. Examples include:

- Multi-family buildings/townhouses
- Farms equipped with multiple fans for crop drying
- Academic, assembly, industrial and military campuses
- Shopping malls or plazas

An example of this type of configuration is shown in **Figure 5.4-18**. Note that the piping downstream of the bulk meter operates at intermediate pressure, the same pressure as the gas main serving the bulk meter.

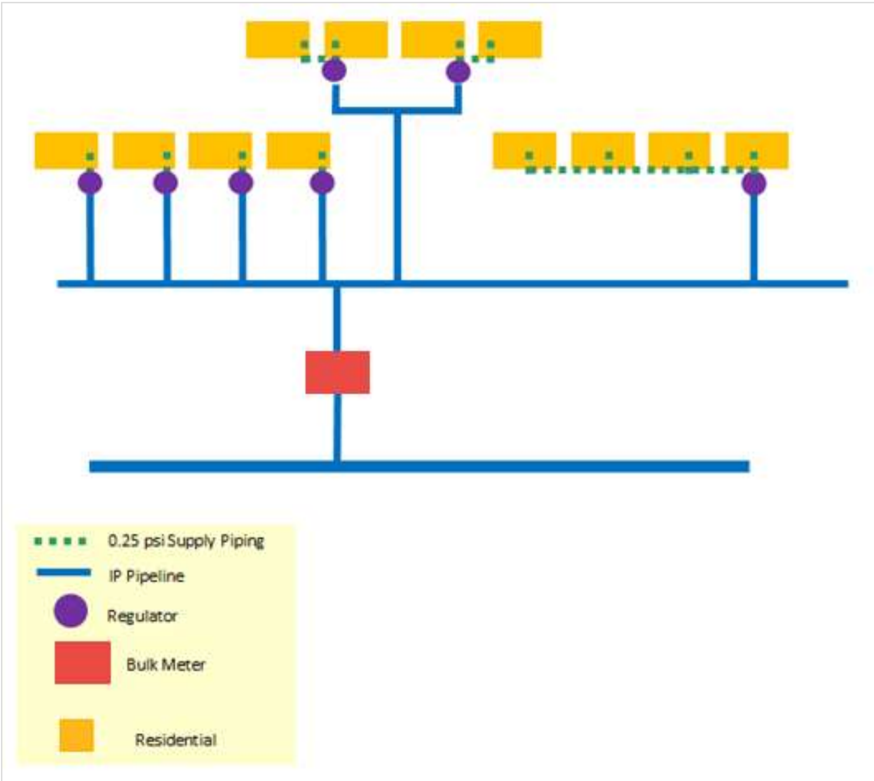


Figure 5.4-18: Bulk Meter Header Sample Configuration

5.4.7.3.1 Condition Methodology

In the EGD rate zone, 18 multi-residential locations with bulk meters were inspected to determine the existence of the following condition factors:

- Obsolete regulators 20 years and older
- Type of regulation
- Riser corrosion
- Lack of maintenance and plant oversight for more than 15 years as per records
- Evidence of unreported third-party damage
- Above ground copper loops
- Compression fittings
- AMP-fittings
- Header and service location unknown due to damaged tracer wire
- Materials and pressures not in compliance with *CSA B149.1* (downstream of the meter)
- Adherence to current installation specifications (vent clearances and configurations, all fittings above-ground, no obsolete components)

These findings, along with site factors such as the number of units and location, were used to remediate all sites in the initial survey.

In the Union rate zones, a process to identify bulk meter sites is being developed and a subsequent survey of the sites will be conducted.

5.4.7.3.2 Condition Findings

For EGI, the most common condition issues found on bulk meter headers are:

- No clear demarcation point between company and customer assets
- Obsolete regulators 20 years and older
- Non-adherence to current installation and maintenance specifications (records, leak and corrosion surveys)
- Vent clearances and configurations not met, not all fittings above-ground and obsolete components

5.4.7.3.3 Risk and Opportunity

Historically, the probability of failure is low for these assets. However, bulk meter headers have a high significance if failure was to occur since the buildings serviced are higher-occupancy units. Safety risks are related to gas leaks and migration through underground infrastructure into buildings, resulting in gas accumulation and potential incidents, as well as the additional risk of unclear demarcation between EGI and customer assets to identify who is responsible for maintenance and repairs. Financial risks identified are losses due to repair costs, commodity loss, relighting customer gas appliances, property damages and personal injury caused by a gas leak. Customer satisfaction may also be negatively impacted by service interruptions.

An initiative for bulk meter headers was created to ensure safe and reliable service to customers. Compliance with existing EGI policies on these assets will keep the safety risk low. The current process for assessing and remediating bulk meter sites provides continuous improvements and ensures the risk remains low.

5.4.7.3.4 Strategy Outcomes

In the EGD rate zone, bulk meter header configurations create uncertainty about the responsibility for asset maintenance. As a result, many of these sites may not have been maintained since installation. The strategy for this asset subclass is to clarify the delineation point between EGI- and customer-owned assets.

All bulk meter sites at multi-residential premises in the EGD rate zone were surveyed and changes in delineation and any necessary retrofits of the piping system were remediated. These improvements help to ensure EGI-owned assets are included in the relevant integrity management programs and allows EGI to communicate with the customer on the required maintenance of the systems they own.

The strategy for the Union rate zones will be determined following an inventory assessment of assets in this subclass.

.

5.4.8 Customer-owned Systems

Customer-owned systems are assets that are owned and maintained by the customer and located downstream of EGI-owned assets. Despite not owning these assets, EGI strives to obtain condition information to ensure public and employee safety, as well as to minimize the risk of consequential damage and impacts to connected EGI assets. These systems may consist of:

- **Customer-owned piping** refers to the gas piping or tubing downstream of the meter outlet tailpiece. This piping or tubing extends from the meter outlet tailpiece to customer appliances.
- **Service jumpers**: refer to a specific type of customer-owned pipe installed from an outside meter to inside the building. Its entry through the building is below-ground.
- **Customer appliances**: refer to gas appliances using gas delivered by EGI. Typical appliances include furnaces, water heaters, gas ranges and fireplaces.
- **Private downstream gas piping and sub-metering** refers to multi-use buildings with retail, condominium corporation-owned boiler rooms and emergency generators and residential ‘vertical’ occupancies where the gas piping is owned by the condo corporation. EGI supplies a customer station with a bulk meter to supply gas to all the facilitates of the multi-use building.

Customer-owned piping and appliances are designed to carry and operate on pressures ranging from pounds delivery to low pressure gas. Failure of these components can cause loss of containment and appliance malfunction, resulting in safety risk to customers and the public.

EGI must comply with *Ontario Regulation 212/01*, *clause 16 b) Supply of Gas*, which states:

> *“No distributor shall supply gas to premises unless the distributor is satisfied that the installation and use of the appliance or work comply with this Regulation and the distributor has inspected the appliance or work in accordance with a Quality Assurance inspection program.”*

EGI inspects customer-owned assets at the time of initial installation and after conducting relights. This includes inspection of appliances, supply piping, venting and combustion air systems from the customer’s transfer point. EGI ensures proper installation, correct appliance operation and no system leaks.

Warning tags and reject tags are issued to ensure that no gas-fired appliance, accessory, or equipment is left in an unsafe operating condition. There are two types of warning tags: A-tags and B-tags. A-tags are issued to identify unacceptable conditions that present immediate hazards on existing installations. A-tags are also issued when an existing B-tag has expired. B-tags are issued to identify unacceptable conditions that are not immediate hazards during both initial installation inspections and installation re-inspections. Reject tags are issued to identify unacceptable conditions that present immediate hazards on initial installation inspections.

5.4.8.1. Strategy Outcomes

The current strategy for customer-owned systems is to continue existing practices at initial installation. For any subsequent issues, the customer is responsible to take corrective action.

A sub-metering initiative with the Technical Standards and Safety Authority (TSSA) and the Sub-Metering Council of Ontario is also underway to formalize EGI’s policy and requirements on private gas piping installations with measurement systems.

.

5.4.9 Utilization Capital Expenditure Summary

EGI has spent an average of $35M and $49M annually in the EGD and Union rate zones respectively for the Utilization asset class. The total average capital spend is forecasted to be $57M (EGD RZ) and $60M (Union RZ) as summarized in **Table 5.4-8** and **Table 5.4-8**. The Utilization capital is further summarized as part of EGI's total five-year capital plan in **Section 6.**

Table 5.4-8: Utilization Capital Summary ($ Thousands) – EGD Rate Zone

Asset Subclass/Program Name	2021	2022	2023	2024	2025	Five-Year Forecast
Meters (Maintenance)	22,823	21,590	21,993	28,271	22,113	116,790
Meters (Growth)	9,521	9,444	10,094	9,407	9,938	48,404
Remediation	1,169	808	854	831	1,145	4,807
Regulator Refit	21,832	22,224	23,880	23,754	25,287	116,976
EGD Rate Zone Total	**55,345**	**54,065**	**56,820**	**62,263**	**58,484**	**286,978**

Table 5.4-9: Utilization Capital Summary ($ Thousands) – Union Rate Zones

Asset Subclass/Program Name	2021	2022	2023	2024	2025	Five-Year Forecast
Meters (Maintenance)	28,283	29,103	31,745	32,131	35,255	156,518
Meters (Growth)	8,823	9,080	9,906	10,027	11,003	48,839
Monitoring Systems	150	150	30	29	31	389
Regulator Refit	17,953	17,868	19,323	18,916	20,075	94,135
Union Rate Zones Total	**55,210**	**56,200**	**61,003**	**61,104**	**66,364**	**299,881**

.

5.5 Storage and Transmission Operations

EGI's Storage and Transmission Operations (STO) asset classes consist of a network of natural gas assets that serve to receive, store and transport natural gas. STO assets found at EGI include compressor stations, underground storage, transmission pipelines, dehydration and liquefied natural gas (LNG) storage.

EGI's storage and transmission assets are categorized in the following asset classes:

- Compressor Stations (includes Compression and Dehydration)
- Transmission Pipelines and Underground Storage
- Liquefied Natural Gas (LNG)

EGI owns and operates 35 underground storage pools located at Dawn and nearby Tecumseh, as well as approximately 3,500 kilometres of transmission pipelines. EGI has storage and transmission assets that serve to receive, store and transport natural gas for markets in Ontario, Québec and the U.S. Northeast. EGI's Dawn Hub in southwestern Ontario is connected to most of North America's major natural gas basins, including abundant and affordable gas supplies in the Western Canadian Sedimentary Basin and the Utica and Marcellus producing regions. It is similarly connected to the major demand markets.

EGI's storage and transmission system is highly integrated, making it very attractive to customers–they can purchase gas across North America when prices are lower, store it at Dawn and have it withdrawn and delivered when and where needed. Dawn is one of the top and most physically traded natural gas hubs in North America. Much like a stock exchange, more than 100 companies buy and sell natural gas at Dawn.

EGI uses compressors to move natural gas throughout the transmission system–gas is compressed into transmission pipelines designed for high flow. Compressors are also used to move gas in and out of underground storage reservoirs by providing a significant pressure increase at the expense of flow. The use of sub-surface facilities for natural gas storage enables increased operations efficiency, conservation of produced natural gas and more effective, reliable and economic delivery to markets. These facilities are usually natural geological reservoirs such as depleted oil or natural gas fields sealed on top by an impermeable cap rock. Natural gas demand for EGI's in-franchise and ex-franchise customers varies seasonally and is greatly affected by residential heating requirements. Underground storage provides seasonal balancing for the gas supply capability versus demand requirements of EGI's customers.

The storage capability of each reservoir is determined by the reservoir's maximum operating pressure, cushion pressure and the size of the pool. Through EGI's reservoirs, the total storage working inventory is approximately 312.7 petajoules (PJ) (199.4 PJ regulated and 113.3 PJ unregulated). Each reservoir is protected by a Designated Storage Area (DSA) which is determined by EGI and approved by the OEB to protect the reservoir from exploratory drilling. The land above each reservoir is leased from landowners with storage leases.

EGI's STO assets are mainly located in southwestern Ontario and employ over 800,000 horsepower of combined centrifugal and reciprocating compression. The majority of compression capacity is split between the Corunna and Dawn compressor stations, the largest underground storage facility in Canada and a key natural gas trading hub. Dawn has interconnections to 10 major transmission pipeline systems including Vector, TransCanada Energy, Tecumseh Gas Storage and Panhandle Eastern Pipeline through the EGI Panhandle Transmission system. The two stations consist of twenty compressors with a combined total of 290,000 ISO horsepower, a major natural gas dehydration plant, station piping, large diameter valves, electrical components and other equipment required to support operations.

Dehydration assets, used primarily to manage moisture content during withdrawal, are essential to storage and transmission systems. While dehydration units can be found at various sites, the Dawn compressor station houses a major dehydration plant and associated piping, large diameter valves, electrical components and other equipment required to support operations.

.

EGI operates one liquefied natural gas (LNG) facility, the Hagar station, located near Sudbury, Ontario. The Hagar station has been in operation since 1968. It is interconnected with the Sudbury lateral system, which is within the TransCanada Energy delivery area. As an integrated storage and transmission system operator, EGI requires capacity to support the integrity of the system and the provision of service to all customers–the Hagar facility provides reserve capacity that allows for operational balance and ensures reliable supply through EGI's storage, transmission and distribution systems during peak periods. The Hagar station is used to support the Sudbury area during peak periods and supply shortfalls and unplanned pressure drops or outages. The station served this purpose in 2011 during a TransCanada Energy pipeline rupture near Beardmore, Ontario.

5.5.1 Storage and Transmission Operations Objectives

The objectives for the STO asset classes are set at the system level (transmission, underground storage and LNG) to specify objectives independent for each system, as all three systems work interdependently. For example, identical compressors in the storage and transmission systems serve a different purpose, but are aligned with each system's objectives. Performance measures are identified for all system objectives. These objectives are in addition to the system integrity, reliability and compliance objectives for the Distribution Pipe, Distribution Stations and Utilization asset classes (see **Table 5.5-1**).

5.5.1.1. Transmission System Objectives

Dawn Parkway Transmission System

The Dawn Parkway Transmission System is composed of a series of parallel 26- to 48-inch diameter pipelines and compressor, metering and regulating stations running from the Dawn Operations Centre easterly toward the Greater Toronto Area (GTA), terminating at the Parkway compressor station and at the Lisgar and Albion custody transfer stations. This system has four major compressor stations (Dawn, Lobo, Bright and Parkway) to facilitate transport.

The primary purpose of this system is to transport natural gas easterly from Dawn to Parkway and to Albion. The system serves both transportation customers (gas moving between points on the system) and in-franchise regions along the route (GTA West, Southeast and portions of the Southwest regions).

Panhandle Transmission System

The Panhandle Transmission System is composed of 16-, 20- and 36-inch diameter pipelines and metering and regulating stations running westerly from the Dawn Operations Centre towards Windsor, terminating at the Ojibway River crossing where it interconnects with the Panhandle Eastern Pipeline system. Laterals which carry transmission system pressure into the Leamington/Kingsville area also form part of the system. One compressor station is used to facilitate gas movement easterly.

The primary purpose of this system is to transport natural gas from Dawn and the Panhandle Eastern Pipeline to the Windsor market gas distribution systems, serving a portion of the Southwest region. It also transports gas from Panhandle Eastern to Dawn.

Sarnia Industrial Line Transmission System

The Sarnia Industrial Line (SIL) Transmission System is composed of a series of parallel 10- to 20-inch diameter pipelines and metering and regulating stations running northerly from the Courtright stations to the City of Sarnia. An NPS 8 pipeline runs from the Dawn Operations Centre to the SIL and an NPS 20 pipeline runs from the Payne Storage pipeline to the SIL.

The primary purpose of this system is to transport natural gas from the Vector and Great Lakes pipelines at Courtright Station, DTE Energy (via St. Clair Pipelines L.P.) at St. Clair Line station, Bluewater pipeline (via St. Clair Pipelines L.P.) at Bluewater Interconnect, Dow A Pool and Dawn to the gas distribution system, serving a portion of the Southwest region.

Table 5.5-1 shows a summary of transmission system requirements and the objectives for each system.

Table 5.5-1: Transmission System Objectives Summary

Requirement	Dawn Parkway	Panhandle	Sarnia Industrial Line
Design Day Requirements	Serve the design day demand requirements of all firm in-franchise and transportation customers as modelled on design day and other days as required.	Serve the design day demand requirements of all firm in-franchise customers as modelled on design day and other days as required.	Serve the design day demand requirements of all firm and interruptible in-franchise customers as modelled on design day and other days as required.

.

Requirement	Dawn Parkway	Panhandle	Sarnia Industrial Line
Transportation Requirements	Serve the transportation market between Dawn, Kirkwall and Parkway in both easterly and westerly directions as required.	Serve the Ojibway to Dawn transportation requirements as required.	Serve the transportation market between St. Clair and Dawn and Bluewater and Dawn as required.
Loss of Critical Unit (LCU)	Maintain the required LCU capability at the Dawn, Lobo/Bright and Parkway systems.	N/A	N/A
Measurement	Accurately measure all flow in and out.	Accurately measure all flow in and major stations out.	Accurately measure all flow in and flow out at major customers and pipeline interconnects.
Monitoring, Control and Operation	Monitor, operate and control transmission systems from remote control rooms at all times and in emergencies.		
Shutdowns and Outage Management	Minimize customer outage impacts during integrity work, construction activities and emergency situations. System design must allow for ongoing inspection with minimal customer disruptions.		
System Growth	System design and maintenance must consider future system growth implications.		

5.5.1.2. Underground Storage Objectives

The underground storage system is largely situated in the area surrounding the Dawn Operations Centre in Lambton County in Southwestern Ontario. Storage is split into regulated and unregulated businesses, with a total working inventory of approximately 312.7 petajoules (PJ). The annual injection and withdrawal cycle relies on compression at the Dawn and Corunna stations, on remote compression at a variety of individual storage pools and the Dawn dehydration plant. Maintenance work and capital projects are scheduled on an annual basis to meet design day and contractually firm requirements throughout the season. The objectives for the underground storage system are as follows:

- Operate and maintain 312.7 PJ of natural gas storage (199.4 PJ regulated and 113.3 PJ unregulated).
- Develop the storage system to ensure storage space is effectively and efficiently cycled. Each storage pool is designed to be filled and emptied within a prescribed timeframe to achieve the following:
  - Maximize design day deliverability to serve regulated and unregulated businesses.
  - Integrate legacy storage system operations to more efficiently fill and empty the storage system, increasing design day deliverability and reducing operating and maintenance costs.
  - Position EGI for future growth opportunities through added storage capacity and deliverability.
- Provide natural gas supply to the transmission system that meets required quality standards.

5.5.1.3. Liquefied Natural Gas System Objectives

The Liquefied Natural Gas (LNG) system's primary purpose is to supply natural gas to support the Sudbury area during peak periods and for system integrity requirements during the winter season, providing ongoing availability to meet potential shortfalls. Natural gas feedstock is converted to liquid and pumped into a tank during the off-peak summer and fall seasons. The stored LNG is vapourized back into natural gas as required during the winter season. Under full load demand, the tank carries enough inventory to supply the Sudbury market for approximately five to seven days. The objectives of the LNG System are as follows:

- Targeted full nominal capacity of 610 million cubic feet (MMcf) by December 1 annually
- Targeted daily tank vapourization capability up to 90 MMcf deliverability (for injection into the Sudbury Lateral pipeline system)
- 100% availability of any LNG balances during the winter season (typically until the end of March) net of any system integrity withdrawals and gas boil-off

.

5.5.1.4. Performance Measures

The performance measures for the STO asset classes are as follows:

- Safety and environmental metric
- Number of incidents/asset ruptures
- Number of spills, orders and/or charges
- GHG emissions reduction (measured in fugitive emissions and fuel consumption reporting)
- Work management process conformance
- Direct leak assessment/leak survey results
- Capital portfolio management delivery to plan
- Reliability percentage for transmission compression
- Percentage of successful compressor starts
- Compressor availability
- Fuel consumption and maintenance costs trended against annual turnover volume
- Predicted Fuel Consumption Variance (Synergi) vs. actual variance
- Year-end Unaccounted For Gas (UFG) estimation

To achieve the STO asset class objectives, asset investment decisions are governed by the life cycle management strategies outlined in **Table 4.1-1**.

5.5.2 Storage and Transmission Operations Hierarchy

The subclass breakdown for STO is organized by system and illustrated in **Figure 5.5-1**.

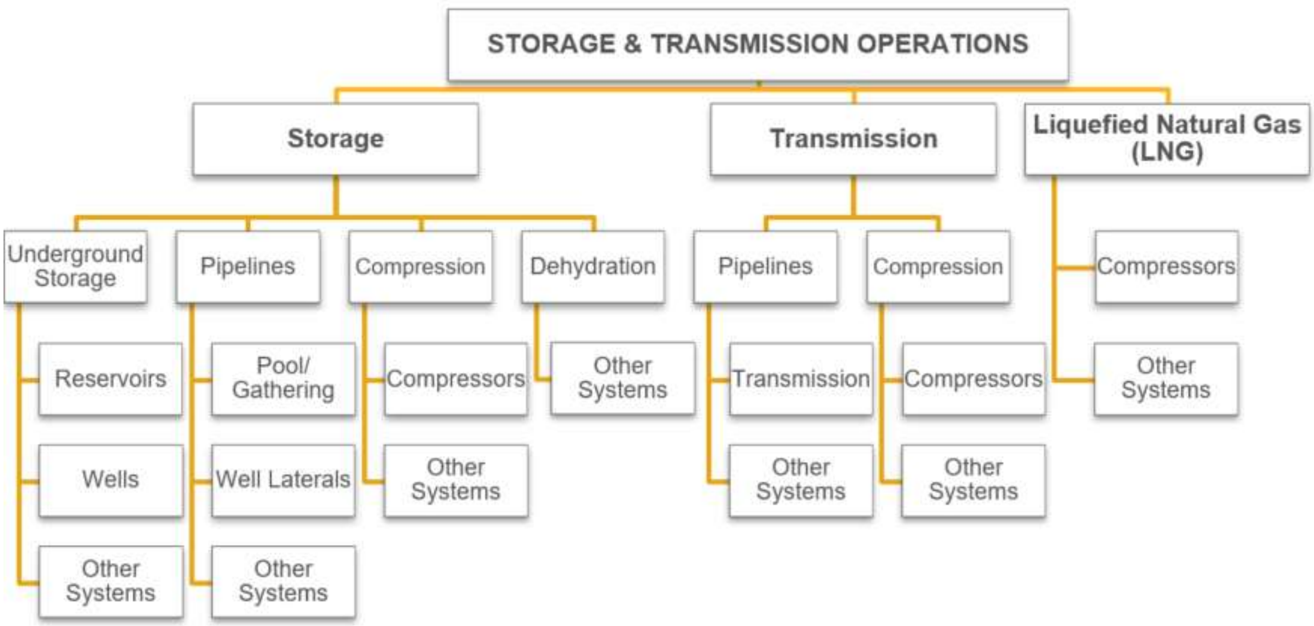


Figure 5.5-1: STO Hierarchy

Notes:

- **Compression Systems** include engine assemblies, centrifugal and reciprocating compressor assemblies, gas aftercoolers, heating and cooling systems and valve systems.
- **Other Systems** consist of the following:
  - Mechanical Systems includes components such as filters, separators, heat exchangers, fans, valves and pumps.
  - Electrical Systems includes components such as breakers, switchgear, motor control centres and lighting.
  - Safety and Controls Systems includes control valves, relief valves and fire suppression systems.
- **Pipelines** and **Underground Storage** assets include pipe, well casings and valves.

.

5.5.3 Storage and Transmission Operations Asset Inventory

The asset inventory is presented in **Table 5.5-2**.

Table 5.5-2: STO Asset Inventory

Asset Subclass	EGD Rate Zone	Union Rate Zones
Compression (#)		
Compressors	15	35
Dehydration (#)		
Dehydrators	3	4
Underground Storage (#)		
Reservoirs	11	25
Wells	129	229
Pipelines (km)		
Transmission	46	1150
Pool/Gathering	60	128
Well Laterals	8	29
LNG (#)		
Compressors	N/A	3

Note: Pipe inventory is also accounted for in the Pipe asset class (see **Section 5.2.3**).

5.5.4 Storage and Transmission Operations Condition and Strategy Overview

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

5.5.5 Compression Stations

Compressors are used in both transmission and storage systems, along with the liquefied natural gas process. Compression in the transmission system supports the function of transmission pipelines which require high flow, while in underground storage compression, it provides a significant pressure increase.

To support the transmission systems, four critical compressor stations are strategically located along the Dawn to Parkway Transmission System: Dawn, Lobo, Bright and Parkway (see **Figure 5.5-2**). Discrete blocks of compression are located at each station and used in various combinations to manage seasonal and weather-dependent system flow demands.

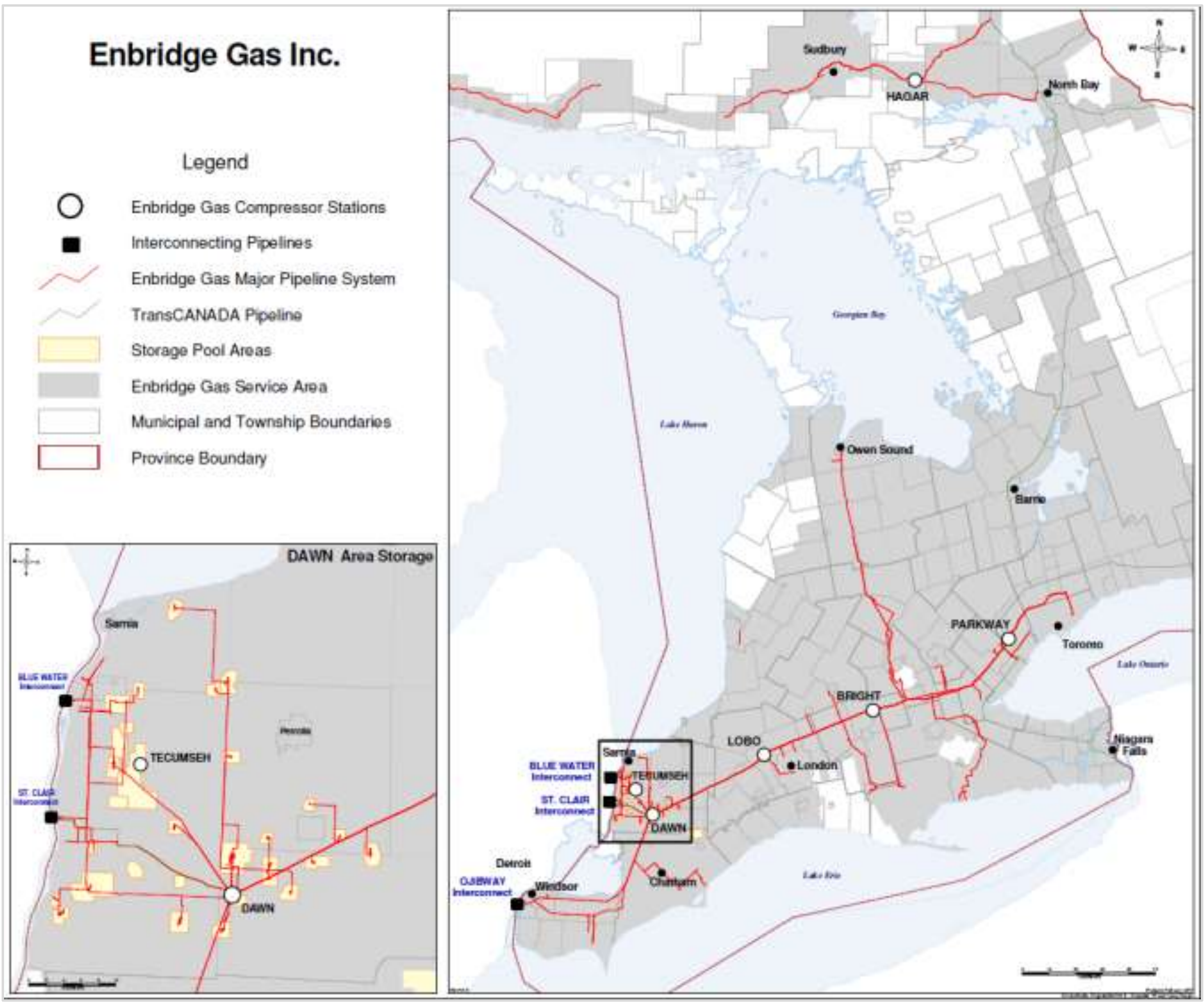


Figure 5.5-2: Compressor stations in the Dawn to Parkway Transmission System

The hub-and-spoke style storage system consists of two primary hub locations containing multiple compressor units, with the majority of compression capacity located between the Corunna and Dawn compressor stations.

All gas compressors are natural gas-fueled, comprised of both centrifugal and reciprocating (both integral and separable models) compressors, each one designed to support a specific function. Compressors vary in horsepower and consist of different vintages, makes and models. Gas compressors are designed for continuous operation, but are operated based on daily fluctuating system demands. Failures are influenced by service conditions (operating hours) and the design life expectancy of its components. Some key components are wear items, requiring regular inspection to establish wear tolerances and to replace as needed.

Compressor packages are comprised of several sub-systems, such as engine assemblies, compressor assemblies, valve and piping, heating and cooling, gas conditioning and ancillary equipment (such as lube oil, fuel supply and electronic control systems) which are required for the compressor to operate. Compressor packages are located throughout EGI's operating regions, including major underground storage facilities and in remote geographic areas. **Table 5.5-3** lists the inventory at each compressor station.

Table 5.5-3: Compressor Inventory and General information

Location	Number of Compressors	Notes
Dawn Compressor Station	8	Interconnects with pipelines from a number of other companies and EGI's storage system. Provides supply to the EGI transmission system and loss-of-critical-unit coverage for the Dawn Parkway System.
Lobo Compressor Station	5	Supports gas transmission from London towards Woodstock and provides loss-of-critical-unit coverage for the Dawn Parkway System.
Bright Compressor Station	4	Supports gas transmission from Woodstock towards Toronto (Parkway) on the Dawn Parkway System.
Parkway Compressor Station	2	Provides required delivery pressure and acts as a custody transfer station to TransCanada Pipelines (TCPL).
Parkway West Compressor Station	2	Provides required delivery pressure and acts as a custody transfer station to TCPL as well as loss-of-critical-unit coverage for the Dawn Parkway System.
Sandwich Compressor Station	1	Supports movement of gas from the Panhandle Eastern Pipeline system towards the Dawn compressor station.
Corunna Compressor Station	11	Supports storage injections and withdrawals. Daily winter flows are transported to market via the Dawn Parkway System. Gas is received from and delivered to Dawn and Vector pipeline systems.
Remote Storage Pool Compressor Stations	14	Supports storage injections and withdrawals. Daily winter flows are transported to market via the Dawn Parkway System.
Hagar Liquefied Natural Gas Station	2	Supports the Sudbury system during peak periods and provides additional compression as required to maintain pressure.
Iroquois Falls Compressor Station	1	Supports required delivery pressure for an industrial plant in Iroquois Falls.

5.5.5.1. Condition Methodology

Engine and compressor condition is primarily maintained through a preventive maintenance (PM) program comprised of rigorous inspections and renewals via overhauls based on manufacturer recommended intervals. As it relates to compressors, condition refers to the ability of an asset to reliably and cost-effectively perform its intended function, which can include achieving the performance expectation of the operator/owner, or providing adequate process safety measures. Gas compressors are repairable assets–asset condition can be improved through component repair or replacement, restoring asset reliability.

Between overhaul intervals, an understanding of asset condition is obtained through an inspection and maintenance program. Compressors are high-speed, rotating equipment that require constant monitoring based on rapid condition changes and failure occurrences. Control room operators provide the first line of defense by recognizing changing conditions and reacting in near real time. Online monitoring provides protection via control systems. Activities in response to the component condition or operational performance are captured in the work and asset management system. Component condition is determined using the experience and recommendations of Subject Matter Advisors (SMAs). As asset condition and performance degrade, risks are raised through the risk management process.

For components managed via an overhaul strategy, condition is viewed as a saw tooth function (see **Figure 5.5-3)**. Condition degrades over the recommended overhaul interval and increases suddenly after an overhaul. **Figure 5.5-3** is a simplified illustration of the degradation of asset condition over the course of each interval and the function of an overhaul to restore condition to 100%. In reality, some degradation in condition occurs over the entire life of the asset that cannot be restored through overhaul activities.

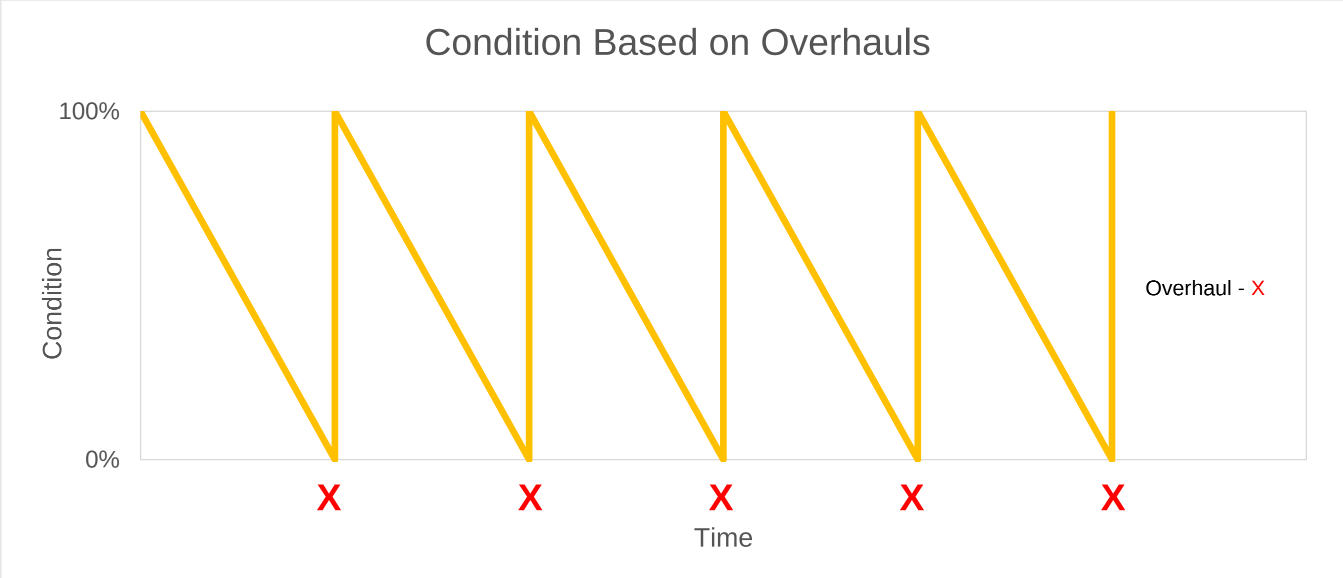


Figure 5.5-3: Condition Based on Overhauls

The overhaul schedule for compressors is based on operating hours, using the average annual usage to forecast the timing of the next maintenance activity. As weather is a factor for compression requirements during an operating season, the overhaul forecast is updated annually to reflect current operating hours and any changes to predicted annual usage. Operating hours provide the basis for planning overhaul activities, but the results of inspections may lead to the advancement or delay of an overhaul.

An Asset Health Review (AHR) was initiated for the compressors located at the Corunna compressor station. Assets were assessed based on reliability, combined with a multiplier-based, apparent condition modelling approach. Using historical maintenance data, a recurrent data analysis using statistical modelling was performed to determine the relationship between failure frequency and gas compressor operating hours. SMAs were then consulted to define and quantify the effect of failure-influencing factors. A condition status was assigned to seven key reciprocating gas compressor sub-assets, based on a conditional reliability metric (at least one sub-asset failure will occur within a 2000-hour mission time).

Condition findings are expected to be directionally informative at this time. New reliability relationship information is needed for separable compressors to apply the reliability model to reciprocating gas compressors at remote storage pool compressor stations in both rate zones. Expanding the AHR methodology to other assets such as centrifugal compressors will enhance asset health understanding for compression facilities.

Aside from scheduled preventive maintenance programs, age is also considered as a condition indicator for reliability and obsolescence. As the asset ages, vendor support declines until the risk becomes intolerable. Obsolescence poses a risk as repairs become progressively more challenging to complete. As service providers reduce support for products reaching end-of-life, the duration of an equipment outage may become extended. Asset failure under these circumstances may be unrepairable, which could pose a significant operational challenge.

Compressor stations also include yard auxiliary systems to support the primary function of the facility. Yard auxiliary systems include all piping elements (pipe, fittings, valves, regulators, boilers, pumps, air compressors, etc.) as they relate to systems like fuel gas, low point drains, atmospheric vents, compressed air, glycol supply/return, power gas, lube oil supply, potable water and fire water. The condition of yard auxiliary systems is determined using the experience and recommendations of SMAs and is assessed through routine PM inspections as prescribed by the manufacturer, through internally developed standards, or through opportunistic inspections presented during construction activities. As asset condition and performance degrade, risks are raised through the risk management process.

.

Instrumentation, controls and electrical assets support many other sub-asset types and systems within compression facilities and are primarily affected by obsolescence. As condition assessment for many of these assets is not practical, the methodology for establishing condition is to consider the expected life cycle of equipment and systems and to proactively anticipate obsolescence.

5.5.5.2. Condition Findings

Overhauls are based on current run hours, forecasted annual usage and manufacturer recommended overhauls. As a result, the forecasted number of overhauls is 18 over the next five years. Asset age is considered as a condition indicator in terms of obsolescence. The age range for compressor units based on their date of installation from 2021 is shown in **Figure 5.5-4**.

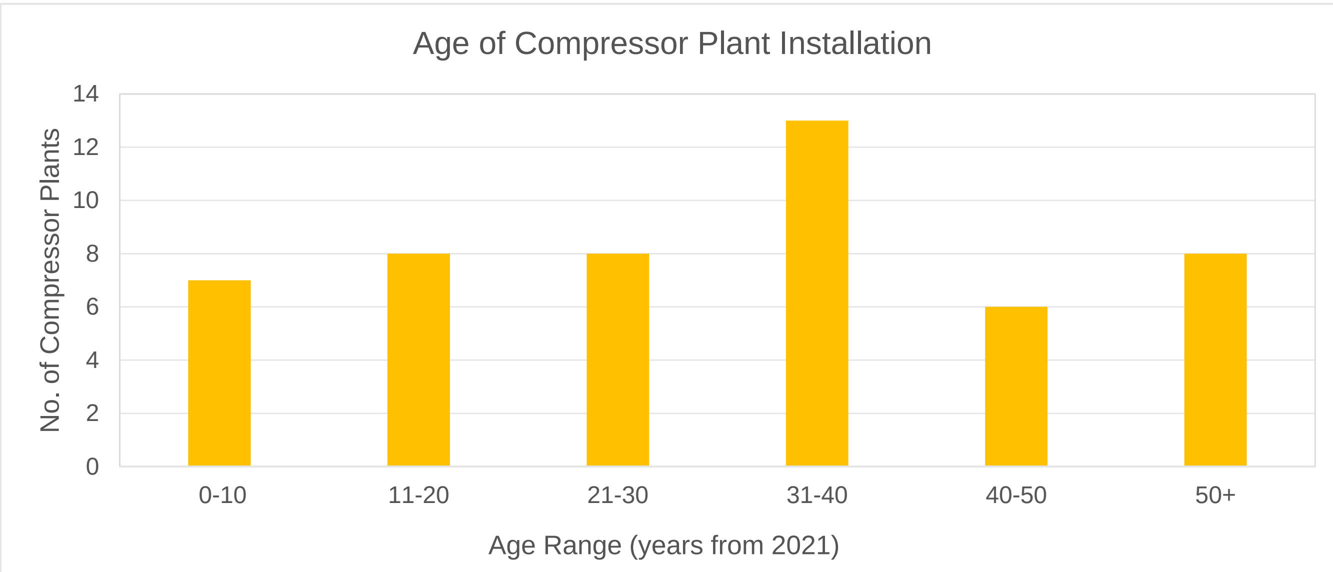


Figure 5.5-4: Age Range of Compressor Plant Installation

Previously, a gas turbine-driven centrifugal compressor was deemed as obsolete by the manufacturer and no longer supported at around 40 years old. The Dawn C compressor from the same manufacturer will be 40 years old in 2023. Using 40 years as a guideline for indicating a critical point in an asset's life, the Dawn D and Lobo A1 plants are nearing the age of 40 years. Although there has been no recent experience with non-RB211 units identifying obsolescence at 40 years, the units at Payne, Sandwich and Bickford will exceed 40 years of age within the next 10 years. The compressors at Hagar will exceed 50 years of age within the next 10 years.

Currently, five reciprocating compressors are considered at end-of-life due to obsolescence, displaying reduced reliability and increasing need for component replacement, with reduced vendor support. The five units include K701, K702 and K703 at the Corunna compressor station along with the Crowland and Waubuno compressors.

Several other compressors will be considered at end-of-life due to obsolescence over the next 10 years. Compressors K704 to K708 will all be exceeding 50 years old within the next 10 years and may experience similar reliability and parts availability issues that the K701, K702, K703, Crowland and Waubuno compressors are experiencing today.

The AHR assessment for compressors at the Corunna compressor station had the following findings and recommendations:

- Crank assemblies seem to experience an increasing misalignment rate over time. The K706 compressor has the lowest asset health compared with all other units, due to foundation issues, which resulted in a foundation replacement in 2018. Foundation issues have been identified as a degradation factor for crankshaft misalignment. Based on historical failures, the K705 crankshaft was found cracked after its foundation replacement in 2017. As the K706 compressor has been subjected to the same foundation replacement, it is recommended to monitor the K706 crankshaft regularly until the K705 cracked crankshaft root causes are identified.
- Engines on units K701, K702 and K703 have the lowest reliability and asset health and should be prioritized over other engine units if a replacement strategy is developed.

.

- In general, compressors have the lowest reliability and asset health compared to other asset subclasses. As a result, compressor overhauls are required to maintain a required level of reliability.
- According to failure intensity results, glycol leaks are the major failure modes in heating and cooling systems, which seem to be a random type of event in these systems. As heating and cooling systems showed low asset health conditions in compressor stations within the EGD rate zone, an inspection and maintenance program is recommended to improve the reliability of these systems.

EGI continues to enhance its understanding of the asset health and life cycle cost for compression facilities, through the development of its Facilities Integrity Management Program (FIMP) and through the analysis of asset data captured in the work and asset management system, which inform future capital investment requirements. FIMP is currently focused on the assessment of assets within compressor facilities, not inclusive of the compressors themselves.

5.5.5.3. Risk and Opportunity

Compressors can pose a significant consequence of failure as they are integral assets required to achieve storage and transmission system deliverability requirements throughout the year. The consequence of compressor failure is dominated by gas cost impacts to customers. System risk associated with failure of a single compressor is heavily influenced by the time of year, weather severity and time to mitigate the failure.

The path to failure for critical internal wear components is generally concurrent with operating hours. If operating hours are extended too far, additional operational stress on internal components may increase the rate of replacement during overhauls. This may add significant cost to the base overhaul and increases the risk of an unexpected failure, leading to system unreliability and further cost increases.

Operational Risk: The reliability of gas compressors is integral to managing operational risk and customer impact. Unplanned failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs.

Gas compressor reliability risk changes continuously during annual inventory turnover. At early injection or withdrawal, compression is not required at all times to meet delivery requirements. Power requirements increase steadily and reach a maximum during late injection or late withdrawal. There is a reduced probability, in the shoulder seasons, that a single, repairable compressor failure will yield a significant consequence. Individually, each compressor asset creates a moderate operational reliability risk. Compressor outages are managed by securing gas from alternative sources at higher prices. The longer the outage, the greater the direct cost to customers. Long term outages of multiple compressors during a harsh winter can incur higher costs to customers because of the inability to meet nominations and the resulting need to purchase gas at less favorable market conditions. Short duration outages can happen regularly, however long-term outages are much less frequent.

Public Safety Risk and Employee and Contractor Safety Risk: Safety risk related to loss of containment from the compressor units is considered, however, the chance of a significant leak is low and safety systems (e.g., gas detection, flame detection, emergency shutdown) reduce the chance of an escalation (i.e., fire, explosion) even further. Associated risks are mitigated by process design, procedures and formal operator qualification and training.

Financial Risk: Financial risk is significantly mitigated by regular inspections, which then inform the necessary preventive maintenance work. A preventive maintenance program mitigates financial risk by reducing the chance of unexpected failures. Compressor failures (unplanned outages) result in unexpected repair costs (both materials and labour) and frequently involve collateral damage. The likelihood for a compressor failure to cause an event affecting non-company property and experience commodity loss is low due to mitigations within a compressor building (i.e., gas/flame detection and emergency shutdown systems).

Failure to comply with new or changing regulatory requirements could potentially limit the use of compression equipment until compliance is achieved. Restricted use of compression equipment could reduce deliverability and trigger the need to secure gas from alternate sources, at additional gas supply cost. Examples of changing regulatory requirements include:

- New federal GHG emission regulations focused on methane reductions impose new restrictions on specified fugitive and vented emission sources within EGI’s storage and transmission operations, including but not limited to compressor stations. This will include repair timelines for leaks, limits on facility venting, compressor seals/rod packing and pneumatic devices.
- There is increasing pressure to further mitigate noise levels to meet permitting requirements (such as environmental compliance approval) due to encroachment of new residential developments.

.

5.5.5.4. Strategy Outcomes

Detailed inspections at set frequencies, subsequent remedial activities and constant condition monitoring help identify suspect equipment conditions, reducing the likelihood of compressor failure and large-scale outages.

The renewal strategy for compression assets targets the overhaul of compressor components based on run time, inspection, condition, Original Equipment Manufacturer (OEM) recommendations and SMA review. Full replacement is generally based on design life, historical obsolescence and OEM equipment support.

Overhauls

These projects consist of the OEM-prescribed scheduled maintenance and overhauls for engines, power turbines and compressors. These overhauls satisfy the OEM recommendations to maintain equipment reliability and ensure continued asset and system reliability, aligned with 2020 Customer Engagement survey results that indicated customers are supportive of investing to maintain current levels of safety and reliability. All projects include full internal inspections and replacement of wear items to maintain reliability and reduce the risk of failure. If OEM-recommended maintenance intervals are exceeded, the risk of reduced reliability and performance increases. Regular scheduled inspections, preventive maintenance activities and machine monitoring may identify the need to perform an overhaul in advance of the OEM recommendation. Overhaul plans are based solely on operational hours and are reviewed and updated on an annual basis.

Corunna K701, K702, K703 Replacement

The obsolete K701, K702 and K703 compressors at the Corunna compressor station need to be replaced as their operating reliability is decreasing. Much of the reliability challenge stems from lean burn conversions. During the mid-1990's, the EGD rate zone embarked on an emissions abatement program, which would see all units retrofitted with low nitrogen oxide combustion systems. Lean burn (low emissions) systems were readily available for units K704 thru K710 (model KVR). The globally installed base for the KVR compressor model is large. K701 thru K703 are an earlier compressor model (KVT) with a much smaller number of units in the world. Indications from SMAs suggest that there are only four lean burned KVT units in the world and EGI owns three of them. As a result, the KVT lean burn conversion kits, which were not designed for mass production, have resulted in several reliability concerns. Reliability concerns related to these compressors translate directly into peak day deliverability risk, as all three units are needed to achieve peak day flow rates.

Corunna Meter Area Replacement

The replacement of the meter area in the Corunna compressor station is based on the risk of loss of containment, process safety and thermal expansion piping stresses. The meter area has been repurposed to perform functions it was not originally designed for, hindering further plant updates and expansion.

The existing meter area is no longer used for inventory management– it is simply the flow path used to convey gas back and forth from reservoirs. Limited cross-flow functionality is provided in the current meter area piping. This project addresses these concerns by redesigning the current meter area, installing properly-sized cross-flow functionality, pressure control and over-pressure protection and designing for the integration of additional assets.

Dawn Plant-C Compression Life Cycle

The Dawn C Plant must be replaced due to the obsolescence of a second generation RB211-24A compressor (installed in the early 1980s). Previous experience with a unit from the same manufacturer and of similar age resulted in the unit being deemed obsolete and no longer supported at about 40 years old. A similar unit was deemed obsolete and retired in 2017 due to unavailability of parts–compressor parts and components required may no longer be available.

Waubuno Compression Life Cycle

The aging storage compressor at the Waubuno station is used to inject natural gas into the Waubuno storage pool. The compressor is over 30 years old and becoming difficult to maintain. Sourcing replacement parts is difficult and continued manufacturer support is limited. To ensure a reliable storage and withdrawal service, this unit needs to be replaced to avoid a significant outage.

Crowland Station Renewal

The facility condition of the aging Crowland compressor station is considered poor. The compressor station suffers from process safety concerns, obsolescence issues, code concerns and property clearance concerns related to neighbouring buildings and the nearby rail line. The strategy includes reviewing alternatives considering future operation of storage both with and without compression.

Foundation Block Replacements

The foundation blocks for the K704 and K707 compressors at the Corunna compressor station require replacement due to age, operating hours, oil contamination and condition (the engine block foundations are deteriorating). Without remediation,

.

failing foundations will allow unit settlement, creating bearing misalignments. As the frequency of bearing failures increases, the operational reliability of the unit decreases. There is also the potential for collateral crankshaft damage.

Header and Isolation Valve Replacements

The multi-year Header Valve Replacement program will address all valves on the compressor suction and discharge headers within the Corunna compressor station. The approach is to address one header per year as there can be up to 24 valves per header. Compressor station yard isolation valves that do not have sufficient seal quality to provide isolation during normal maintenance activities or emergency situations were also identified for replacement.

Leaking valve seals are not necessarily valves that leak to the atmosphere or pose a loss of containment threat. These particular valves allow gas to flow when in the closed position, posing a process safety threat, a loss of system performance by creating recycle loops and a decreased ability to provide a safe work environment for maintenance activities that require double block and bleed. These valves are sometimes used to separate piping with different MOPs. If these valves are allowed to leak, there is an increased threat of an over-pressure event at lower-pressure pipe as gas bleeds through the valve from higher-pressure pipe.

Run-to-Failure Based Programs

Several programmatic spend items are required to support operations and are planned for based on historical expenditures. Assets are identified during the year based on failures or indications that failure is imminent. Replacements are required to ensure site equipment reliability for the following:

- UPS batteries
- Lighting
- Safety and security upgrades
- Mechanical equipment

Time-based Replacement Programs

Time-based replacement is used when condition-based assessment is not comprehensive enough to identify the next failure interval. Time-based replacement is also used to proactively replace assets identified as obsolete. Targeted upgrades or replacements of control and communication assets is required to mitigate obsolescence, ensure adequate redundancy of critical systems and mitigation of emerging process safety risks. Due to the number of devices within the storage and transmission system, replacements are planned based on device types and volume.

Time-based replacement strategies are volume-driven and applied to the following groups based on obsolescence:

- Control systems (including Programmable Logic Controllers (PLCs), SCADA, Human Machine Interfaces (HMIs))
- Fire and gas detection instrumentation
- Uninterruptible Power Supply (UPS) and Motor Control Centres (MCCs)

Siemens Valve Controller Replacement

As of July 2020, Siemens will no longer support valve controllers required in the start sequence of their compressors. Three controllers service three valves on each engine skid. Each valve/controller combination is unique in operation with no redundancy. If one controller fails, it must be replaced, rendering the entire unit unavailable until replacement and set up is complete. The replacement program will replace valve controllers for two compressor plants per year through 2024.

High Performance Coating

High Performance Coating (HPC) is required on above-grade piping to reduce the chance of external corrosion. HPC has an expected life of approximately 15 years while standard coatings typically last five to eight years. HPC was recently mandated as the coating system to be used. Majority of sites only have standard coating, which is at end-of-life. Approximately 45 remote sites, four compressor facilities and one LNG facility (Hagar) with above-grade piping will be managed through this annual program.

Condition-based Replacements

Condition-based replacements are identified by detailed inspections and condition monitoring. Asset issues are raised through the work management system and risk processes, through which the appropriate treatment is determined and may result in a maintenance expenditure. Many of the discrete investments within the portfolio are identified and planned using this approach.

As EGI develops its risk management and process safety management practices, the company intends to perform periodic condition assessments at critical facilities. Although the plan for the Facilities Integrity Management Program (FIMP) is under development, there are several aging facilities that provide critical infrastructure support to Storage and Transmission Operations. A more comprehensive understanding of the condition of these facilities will support risk management and the decision process. As the risk assessments are completed and the long term needs for Storage and Transmission are assessed, EGI will develop maintenance and replacement strategies to balance performance, risk and cost. Some specific sites where risk assessment is anticipated in the coming years are Corunna, Crowland and Hagar.

5.5.5.5. Capital Expenditure Summary

The summary of Compression projects and programs under the Compressor Stations asset class is described in **Section 5.5.6.5**.

5.5.6 Dehydration

Integral to Storage and Transmission, dehydration facilities remove moisture from natural gas as it is taken from underground storage. This ensures that gas entering the transmission and distribution system meets the contractual standard of moisture content and avoids operational problems related to high moisture content. Natural gas in combination with water, when cooled, can form methane hydrates that can plug valves, fittings or even pipelines. The dehydration process involves contact between the natural gas and liquid glycol streams to remove excessive moisture from the natural gas stream. The resultant output natural gas helps to ensure pipelines are dry and customer quality specifications for moisture content are met. EGI is obligated to meet a gas quality specification (moisture content) of 4 lbs H20/MMscf, as set out in *C1 & M12 Tariffs & Interconnect Operating Agreements*.

5.5.6.1. Condition Methodology

Dehydration systems are comprised of mechanical, rotating, electrical and control system equipment similar to compression auxiliary equipment. The maintenance strategies for dehydration facilities are based on the same inspection methodologies as compression (see **Section 5.5.5.1**).

5.5.6.2. Condition Findings

Dawn Hub Send-out Gas Quality
The Dawn Hub operation blends multiple sources of supply on a daily basis. As such, the Dawn send-out moisture content is dependent on the daily supply balance of upstream supplies (i.e. Vector/Great Lakes) and storage supplies and their respective moisture content to meet gas quality requirements. Through assessment of contractual moisture content obligations of interconnecting pipelines and modelled moisture content, it is expected that incremental dehydration facilities will be required to ensure EGI is able to reliably serve firm customer demands. In meeting current supply obligations, the following is considered:

- EGI's ability to operationally blend multiple sources of supply from upstream pipelines and the storage system to ensure the safe and reliable delivery of natural gas and meet contractual obligations
- Assessment of contractual moisture content obligations of upstream supply sources to the Dawn Hub (e.g. DTE Energy, Bluewater, Panhandle Eastern Pipeline, Vector and Great Lakes pipeline systems)
- Design day storage inventory levels by pool and the expected moisture content of the pools on design day

Tanks
Installed in 2005, the Dawn dehydration process tank is a 92,000-litre buried fibreglass single wall tank with a blanket gas system. External pressure on the tank wall could lead to cracking and undetectable small tank leaks.

Process Controls
SMAs have not identified condition concerns related to existing automated dehydrators and incinerators at this time. The Chatham D and Crowland stations lack remote automation of the dehydration and incinerator systems, creating a process safety concern that could experience an undetected failure.

5.5.6.3. Risk and Opportunity

Although a detailed risk analysis has not yet been completed to address Dawn gas quality concerns, it is believed this is a significant risk to the ability to supply gas at quality levels that ensure safe and reliable service to customers. A risk assessment will be completed to validate understanding of the issue and timing requirements.

Operational Risk: Inability to maintain EGI obligation of 4 lbs H20/MMscf under the *C1 & M12 Tariffs and Interconnect Operating Agreements* can impact firm service to all distribution customers, the storage and transmission system and third-party storage providers. A number of dehydration systems at remote storage locations are also being considered for upgrades or abandonment due to obsolescence or legacy designs.

Environmental Risk: Dehydration systems could experience a failure that would result in a spill of triethylene glycol to the environment. The likelihood is greater at manually-operated locations and in systems containing single-walled tanks.

.

Financial Risk: Inability to maintain EGI's obligation of 4 lbs H20/MMscf under the *C1 & M12 Tariffs and Interconnect Operating Agreements* may result in financial consequences if market supply needs to be replaced in a limited market or in the event of potential revenue loss, as well as damage claims from customers.

5.5.6.4. Strategy Outcomes

Detailed inspections at set frequencies, subsequent remedial activities and control room condition monitoring help to identify suspect equipment condition, reducing the likelihood of failure and large scale outages.

The replacement strategy for dehydration assets is proactive replacement that targets equipment based on condition and obsolescence. This strategy is generally dependent on OEM support. The goal of this strategy is to proactively replace or rebuild station components prior to end-of-life to reduce risk and maintain a safe and reliable dehydration system, aligned with 2020 Customer Engagement survey results which indicated customers are supportive of investing to maintain current levels of safety and reliability.

The maintenance and replacement strategy for dehydration includes:

Replacements

The condensate process tank at the Dawn dehydration plant must be replaced with a double-walled tank with the capability to identify a breach of either the inner or outer wall. The Dawn dehydration motor control centre (MCC) requires replacement due to obsolescence.

Improvements

Upgrading dehydration controls at the Chatham D plant and connecting to existing remote I/O devices at the incinerator provides remote visibility and automation capabilities. Similar upgrades are planned for the Crowland station.

Dehydration Expansion

This project will conduct a risk assessment of the Dawn Hub send-out gas quality and provide recommendations. Based on SMA input, it is forecasted that incremental dehydration capacity may be required for Winter 2023-2024 at either the Dawn or Corunna compressor stations.

5.5.6.5. Compressor Stations Asset Class Capital Expenditure Summary

EGI has spent an average of $12M and $137M annually in the EGD and Union rate zones respectively for the Compression Stations asset class. The total average capital spend is forecasted to be $86M (EGD RZ) and $45M (Union RZ) as summarized in **Table 5.5-4** and **Table 5.5-5**. Storage and Transmission capital is further summarized as part of EGI's total five-year capital plan in **Section 6.**

Table 5.5-4: Compression Stations Asset Class Capital Summary ($ Thousands) – EGD Rate Zone

Program/Project Name	2021	2022	2023	2024	2025	Five-year Forecast
Growth	**5,005**	**27,707**	**16,421**	**1,637**	**-**	**50,769**
Dehydration Expansion	5,005	27,707	16,421	1,637	-	50,769
Replacements	**12,901**	**11,808**	**19,031**	**218,759**	**8,179**	**270,678**
SCOR: K701/2/3 Reliability - Replacement	-	973	11,924	214,088	4,089	231,083
Overhauls	**586**	**900**	**487**	**-**	**430**	**2,403**
Integrity	**61**	**61**	**64**	**62**	**66**	**314**
Improvements	**27,528**	**34,196**	**23,312**	**11,328**	**8,554**	**104,918**
SCOR: Meter Area-Upgrade	18,717	22,971	-	-	-	41,688
SCRW: Station Renewal In-Place	-	6,848	15,605	6,840	6,090	35,383
EGD Rate Zone Total	**46,081**	**74,672**	**59,315**	**231,786**	**17,229**	**429,082**

Table 5.5-5: Compression Stations Asset Class Capital Summary ($ Thousands) – Union Rate Zone

Program/Project Name	2021	2022	2023	2024	2025	Five-year Forecast
Replacements	**4,253**	**23,688**	**92,672**	**69,711**	**7,133**	**197,456**
Dawn Plant-C Compression Life Cycle	-	19.730	89,413	51,421	5,603	166,167
Waubuno Compression Life Cycle	-	-	1,113	14,507	643	16,263
Siemens Valve Controllers Replacement	-	974	1,027	1,006	-	3,006
Overhauls	**298**	**4,485**	**3,601**	**152**	**2,976**	**11,512**
Integrity	**1,531**	**684**	**722**	**706**	**750**	**4,393**
High Performance Coating	565	562	593	581	616	2,917
Land Structures and Improvements	**1,530**	**734**	**454**	**463**	**224**	**3,405**
Improvements	**1,682**	**2,872**	**733**	**397**	**627**	**6,311**
Union Rate Zones Total	**9,293**	**32,463**	**98,181**	**71,429**	**11,710**	**223,076**

.

5.5.7 Underground Storage

The use of subsurface facilities for natural gas storage allows for increased efficiency in operations, conservation of produced natural gas and more effective and economic delivery to markets. Natural gas is stored in depleted oil or natural gas fields sealed on the top by an impermeable cap rock.

Wells are used to inject into and withdraw natural gas from underground storage reservoirs and to monitor reservoir pressure. EGI well assets consist of 129 and 229 wells in the EGD and Union rate zones respectively. This includes natural gas storage wells and observation wells.

EGI's storage wells are located primarily in agricultural areas. **Figure 5.5-5** displays the ages of EGI well assets by drilling date (the original well construction date). **Figure 5.5-6** shows well age based on production casing (the innermost casing) age. A well's production casing age indicates a new casing was added to the well to improve its integrity, an effective method for extending its life.

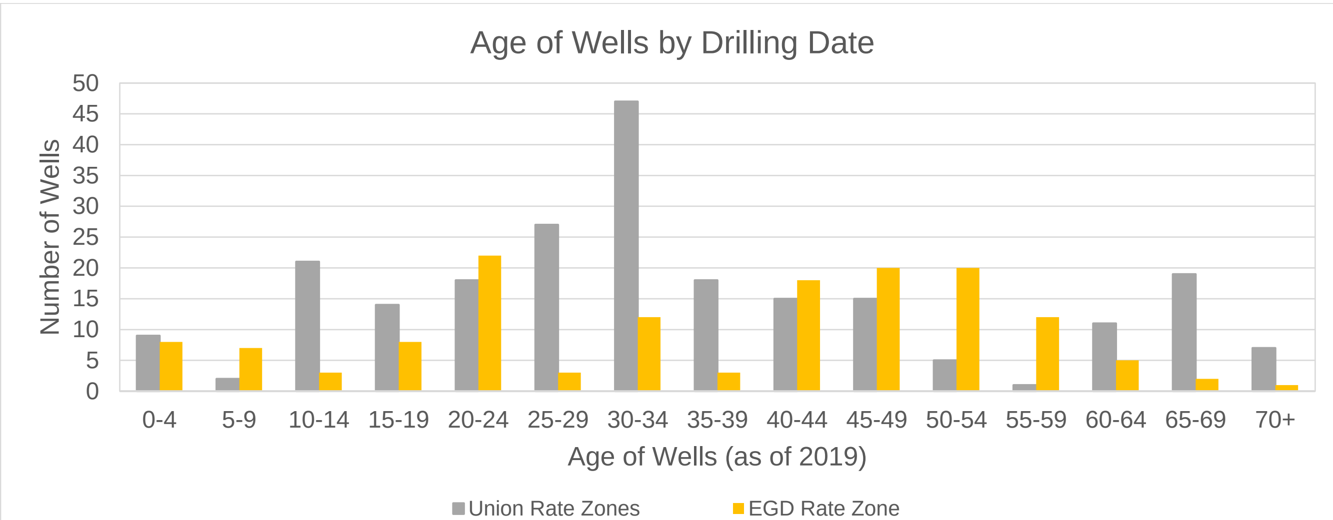


Figure 5.5-5: Age of Wells by Drilling Date

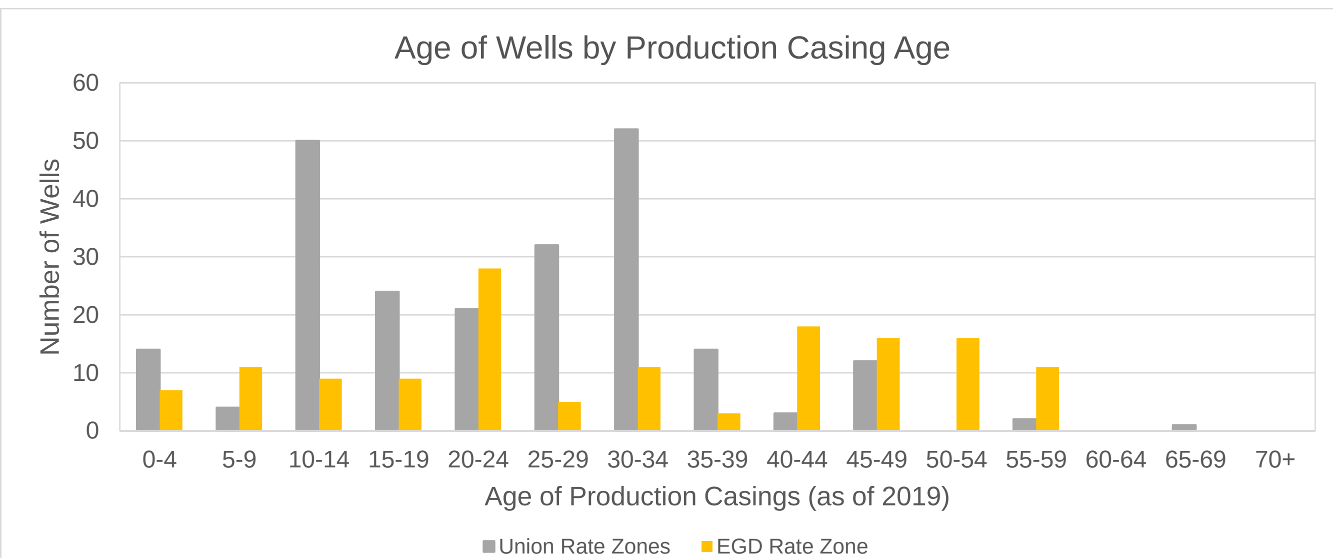


Figure 5.5-6: Age of Wells by Production Casing Age

.

Degradation of well assets is generally experienced as casing wall loss. Wall loss can be internal or external and can be caused by factors such as mechanically induced damage during drilling operations or corrosion influenced by various geological layers and subsurface fluids. As wall loss progresses, previously insignificant defects become more pronounced. For newer wells, the number of well casing defects requiring action is expected to be low.

The top two joints of well casing (approximately the top 20 meters from the surface) can be repaired. These repairs, known as casing back-offs, result in the removal of a short section of old casing and replacement with new casing, extending the well's life expectancy.

Replacement of casing below the first 20 meters becomes difficult - primary options are relining or abandonment. Relining is performed by inserting a new smaller diameter production casing inside the affected casing and filling the annular space with cement. Abandonment is performed by filling the wellbore with cement and removing it from service. Relining and abandonment may be followed by the drilling of new wells to restore lost deliverability.

5.5.7.1. Condition Methodology

Well condition is assessed by the Storage Downhole Integrity Management Program (SDIMP) using casing inspection logs (similar to in-line inspection tools used for pipelines). Well casing inspection logs are completed per *CSA Z341*. The logging tool is based on magnetic flux leakage (MFL) technology that infers changes in pipe wall thickness. As per code, a baseline casing inspection log is run on the production casing of all new wells drilled (and when a well is relined with a new production casing). *CSA Z341* stipulates that wells receive their second casing inspection log five years after the baseline log. Subsequent inspection frequencies depend on wall loss and the growth rate of metal loss features.

Following each casing inspection log, the minimum yield pressure of the production casing and the corrosion growth rate (the percentage of metal loss per year) are calculated based on the maximum wall loss detected by the casing inspection log. Based on calculation results, the next inspection date is required in five or 10 years. However, if the minimum yield pressure of the production casing is less than maximum operating pressure of the storage zone (or if a pressure test fails), the well will either be relined to continue its operation or removed from service. New wells would be required to restore the lost deliverability from the well abandonment.

5.5.7.2. Condition Findings

A condition model has been developed to predict the end-of-life for each storage well as shown in **Figure 5.5-7**. Condition assessment is based on data collected from casing inspection logs. The model estimates the corrosion growth rate by extrapolating the historical measured growth rate and predicting when the corrosion will exceed an acceptable limit. The acceptable limit is defined by *CSA Z341* and will trigger remediation or abandonment to ensure well integrity.

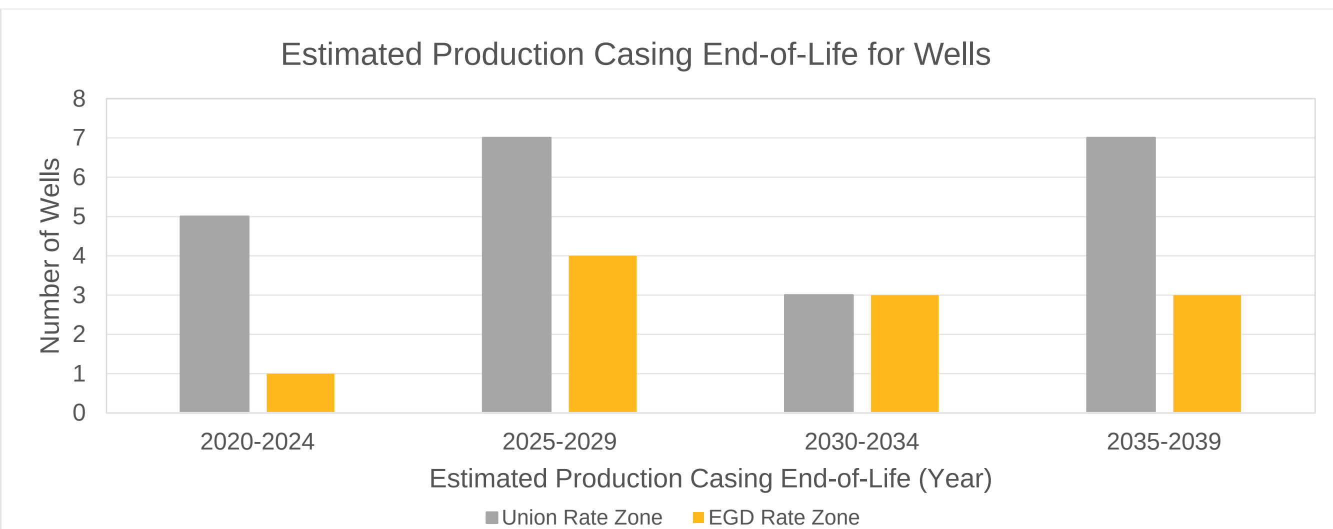


Figure 5.5-7: Estimated Production Casing End-of-Life for Wells

.

The condition model considers factors such as:

- Previous condition from the most recent casing inspection
- Rate of corrosion growth over multiple casing inspections
- Accuracy of casing inspection technology used during previous inspections. Note that inspection technology has become more accurate over time and may affect projections.

It should be noted that as more inspection data is obtained, these estimates are expected to change. EGI transitioned to high-resolution casing inspection log technology in 2009. The first high resolution well logs showed that previously reported metal loss features were reduced in many instances. Furthermore, as technology evolves and more field data is obtained, data quality interpretations continue to improve and metal loss features may differ over repeated logs. As new data is loaded into the model, end-of-life projections are expected to change. When a well's production casing reaches end-of-life, evaluations are conducted to determine whether the well should be relined or abandoned. Activities to restore lost system deliverability are also performed, which may include the drilling of a new natural gas storage well.

In addition to the above estimated casing mitigation actions, the following findings require investments that will support the safety and reliability expectations for underground storage assets:

Wellhead Upgrades

EGI inspects and evaluates the condition of its wellheads on an ongoing basis, including wells grandfathered under previous versions of *CSA Z341*. Through this work, several wellheads were identified to be updated based on CSA code changes. Since 2002, *CSA Z341* specifies that all connections above the casing bowl shall have flanged connections, as threaded connections are more prone to leaks and have a higher failure rate. In addition, *CSA Z341* no longer allows the pressure rating of the wellhead to be de-rated based on the pressure rating of the master valve. Five wellheads were identified as having threaded side-ports on the intermediate spool section. EGI has established that it will no longer allow threaded connections or pressure de-rating on any storage well.

Well Testing

The deliverability of natural gas storage wells declines over time, associated with the normal operation of the storage pools. Deliverability and transient pressure testing are conducted annually at selected storage wells to assess well deliverability, identify any decline in deliverability and to assess the likelihood of whether well stimulation can recover any deliverability losses.

Well deliverability and pressure transient testing is conducted on selected wells following the fall and spring stabilization period. Wells are individually tested over 72 hours with fixed flow-rate and shut-in periods. Well pressures and flow rates are recorded and the data is used to determine reservoir properties, wellbore damage and well performance. Well performance is compared with previous tests to quantify any deliverability loss. Wells are also selected for acid stimulations. Retesting occurs approximately every 10 years depending on pool operational demands and maintenance requirements.

Well Security and Accessibility

Approximately 20% of wells are in areas where personnel access is limited. These wells are often in the middle of an agricultural field and, at the request of the landowner, laneways were not installed. During normal maintenance activities, personnel are required to access these wells, exposing them to difficult physical conditions. Working with landowners, investments are required to install laneways and facilitate personal access to these wells for essential maintenance activities.

The largest risk to storage wellheads is farm traffic. Each wellhead is surrounded by a chain link or metal post fenced area. Based on the results of a risk assessment, EGI has installed four pre-cast concrete blocks around each fenced area in the EGD rate zone to reduce or eliminate any impact to the wellhead by farm equipment. This program will install pre-cast concrete blocks around all wellheads in agricultural areas where practical.

Cathodic Protection

Wells in the Union rate zones have cathodic protection installed at each storage field for protection; wells in the EGD rate zone are not similarly protected. EGI is in the process of studying the benefits of cathodic protection to develop a strategy for underground storage assets.

Crowland Storage Pool

The Crowland storage pool in the Niagara region is used to balance natural gas demands in the local market. The pool has 16 natural gas storage wells and eight observation wells for pressure monitoring. Since amalgamation, the flow capability of the pool has been assessed through deliverability testing. Evaluations are being completed on local market options that may simplify the operation of the pool if sufficient market demand is available in the local distribution market. An integrity assessment for each well is required to determine if existing wells can be upgraded or will need to be abandoned. Replacement wells may be required depending on the outcome of the assessment.

.

A1 Observation Wells

Observation wells are used to monitor the pressure in natural gas storage pools and do not cycle gas in and out of the reservoir. Each pool has an official Guelph observation well that monitors the pressure of the Guelph reef formation where gas is stored. However, many pools have a tighter secondary formation where gas can migrate, known as the A1 Carbonate formation. A1 observation wells are used to monitor the movement of gas in and out of the A1 Carbonate formation. The gas in the formation is contained within the reservoir but may not be accessible working gas that can be cycled on an annual basis. As gas is less accessible in this formation and requires the pool pressure to be lowered before migrating back to the Guelph reef, observation wells are required to be incorporated into the storage facility in accordance with *CSA Z341*.

The A1 observation wells are used as a tool in storage pool material balance studies. Biannually, storage pools are stabilized and the Guelph pressure is used to calculate an inventory based on pressure. This is then compared with the pool's metered inventory and variances above a certain threshold are investigated. In some instances, gas movement into the A1 Carbonate formation contributes to these variances. An A1 observation well can confirm this issue and assist with explanations and potential adjustments to pool size and inventory. For effective inventory management, one or more A1 observation wells are required to monitor the gas in the A1 Carbonate formation. Pools that do not have A1 Carbonate wells will be targeted for the addition of an observation well.

5.5.7.3. Risk and Opportunity

Currently, measured condition data is obtained through the Storage Downhole Integrity Management Program (SDIMP), which currently indicates that well abandonments will be required over the duration of the program.

Safety Risk: If unmitigated, risks related to safety are generally expected to increase slowly due to continued corrosion. Wells exceeding corrosion tolerances will be abandoned as prescribed by code, proactively reducing significant safety risks. Risk modelling considers the possibility of injury to the public and personnel, as these assets have a major influence on public and employee safety risk. Wells have the potential to cause injury during a loss of containment event.

Financial Risk: If unmitigated, loss of containment risks are generally expected to increase slowly due to continued corrosion. Risk modelling considers loss of containment and damage to infrastructure. However, the probability of failure is generally very low. Wells represent significant financial risk to EGI and regulated customers. Unexpected well failures carry a large cost of replacement and lost product.

Well abandonment is a safety and financial risk mitigation of the existing wells. However, once an existing well is abandoned, the flow capacity of the associated reservoir is reduced. Reduced reservoir may reduce storage deliverability, which could require that gas supply be obtained from other potentially more expensive sources. Risk reduction is achieved by drilling new wells to replace those that have been abandoned. Well failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply, requiring gas to be obtained from other potentially more expensive sources. A single well failure can shut down an entire reservoir for a long duration.

The operational reliability consequences of an unexpected well failure can be significant for regulated customers. Such a failure could cause a decrease in gas supply, requiring gas to be obtained from other potentially more expensive sources to regulated customers, as a portion of required gas would need to be sourced from other suppliers for the entire duration of the event. Consequences may be moderate because other reservoirs continue to operate if a single reservoir experiences an outage.

Well-related activities are targeted to reduce or explain unaccounted for gas (UFG). UFG is a contributor to gas supply costs to regulated customers. Activities intended to reduce UFG provide a positive benefit to EGI's customers.

5.5.7.4. Strategy Outcomes

The capital maintenance and renewal programs for underground storage wells are as follows:

Well Casing Inspection and Maintenance

As part of the life cycle management strategy, well condition is continually assessed to determine condition and develop mitigation plans, as per *CSA Z341* and the *Oil, Gas and Salt Resources (OGSR) Act.* Projections of well life expectancy are updated as new inspections are completed and additional operational data is obtained. Remediation is performed on wells on a case-by-case basis through either relining or abandonment to ensure the safe and reliable operation of EGI's underground storage systems. This is aligned with 2020 Customer Engagement survey results where customers are supportive of investing to maintain current levels of safety and reliability.

.

Wellhead Upgrades

A multi-year plan has been developed to replace wellheads with threaded connections and wellheads that have been de-rated based on their master valve rating. EGI is also planning to install emergency shutdown valves on all storage wells, a long-term goal supported through capital investment.

Well Testing and Acid Stimulations

Based on the results of annual well testing program, wells are stimulated with acid to mitigate lost deliverability. Well testing can confirm the magnitude of lost deliverability and whether acid stimulation can recover deliverability.

An activity testing and stimulation program for wells has been in place for the Union rate zones over the past fifteen years. Most wells in the EGD rate zone have not been stimulated and additional well testing data is required. The program focus will shift to conducting initial acid stimulations for wells in the EGD rate zone, which will also need to be tested to determine current performance coefficients, lost deliverability and reservoir properties. The program will return to a system-wide focus once these activities have been completed.

Well Accessibility

Where EGI is able to come to an agreement with landowners, laneways will be constructed to improve access to wells that currently do not have laneways. Capital will be required to install proper laneways on these wells.

Cathodic Protection

Actions taken on cathodic protection will be dependent on the outcome of the cathodic protection study on storage wells. Increased capital may be required to add or modify cathodic protection on storage wells in the EGD rate zone.

Crowland Storage Pool

The current scope of the Crowland Wells Upgrade project includes the installation of two new horizontal wells, an observation well and new wellheads and master valves to 16 existing storage wells and eight observation wells. Additional integrity assessments are underway to confirm existing well condition and anticipated deliverability of any new wells.

A1 Observation Wells

The Corunna and Ladysmith storage pools do not currently have A1 observation wells. The Coveny storage pool also requires a new A1 observation well. Regional geology and past studies suggest there is a potential for gas to be migrating into the A1 Carbonate formation at these storage pools. A new A1 observation well will be drilled to confirm the movement of gas into the A1 and used to support inventory material balance studies in the future. This may result in adjustments to pool inventory or size.

EGI continues to enhance its understanding of asset health and life cycle cost for wells, which will inform future capital investment requirements.

5.5.7.5. Capital Expenditure Summary

The summary of Underground Storage projects and programs under the Transmission Pipe and Underground Storage asset class is described in **Section 5.5.8.5**.

.

5.5.8 Transmission Pipelines

Pipeline assets are a critical component of the storage and transmission operations and transport gas between custody transfer points, distribution networks, as well as storage gathering systems. Pipelines are categorized in three asset subclasses:

- **Transmission pipelines** connect compressor stations to custody transfer points or other transmission pipelines and distribution networks and generally operate at or above 30% Specified Minimum Yield Strength (SMYS).
- **Pool/Gathering pipelines** connect compressor stations to reservoirs. Multiple reservoirs can be connected to a single compressor station by individual pool pipelines. The central collection lines that interconnect wells within a reservoir, gathering lines, are generally larger diameter pipe – matching the size of the associated pool pipeline to collect and distribute gas to smaller well laterals.
- **Laterals** connect individual wells to a gathering pipeline. Laterals are generally NPS 10 pipe. In some cases, more than one well is connected to a single branch connection extending from the gathering pipeline.

The largest operational threat to the storage pipeline system is internal corrosion/erosion due to entrained reservoir liquids and solids. Third-party damage is also a significant threat due to annual installation of agricultural drain tile by landowners. Note that third-party damage potential has diminished with Ontario One Call legislation.

Pipelines are inspected regularly for leaks, depth of cover and effectiveness of the cathodic protection system. Aerial inspections are also performed. The system is monitored for changes in area class location due to encroachment.

5.5.8.1. Condition Methodology

See **Section 5.2.5.1** for the condition methodology of Pipe assets.

5.5.8.2. Condition Findings

See **Section 5.2.5.2** for the condition findings of Pipe assets. Specific findings for the following assets are also noted:

Panhandle Line Replacement

- The river crossing pipelines cannot be inspected using in-line inspection (ILI), but their age infers that the pipe condition could be degrading.
- Other challenges related to the pipe construction method make it unlikely that current technologies can provide usable data to improve decision-making.

Dawn-Cuthbert

The section of NPS 26, NPS 34 and NPS 42 pipelines leaving Dawn toward the Cuthbert station (one kilometre away) cannot be inspected using in-line inspection(ILI). The current technique for inspecting these sections is external corrosion direct assessment (ECDA) which provides important information when no other option is available. However, to thoroughly inspect these pipelines, ILI is internally accepted as the required level of diligence for direct assessment of >30% SMYS pipe.

.

5.5.8.3. Risk and Opportunity

See **Section 5.2.5.3** for risks and opportunities of Pipe assets. Specific risks and opportunities for the following assets are also noted:

Panhandle Line Replacement

The principal risk is the lack of ILI data needed to inform effective decision-making to mitigate a potential loss of pipeline containment (leak). Replacement of the river crossing pipelines with a new single pipeline, designed, manufactured and constructed to current standards that is ILI-capable can address this risk.

Dawn-Cuthbert

Any gas release of a >30% SMYS pipeline can result in significant risk to public safety and may require a substantial emergency response and temporary shutdown. The Dawn-Cuthbert pipeline segments are highly critical assets which carry a significant portion of the capacity on the Dawn Parkway System. The absence of inline inspection data creates challenges in appropriately managing the risk of these highly critical pipeline segments.

5.5.8.4. Strategy Outcomes

Refer to **Section 5.2.5.4** for more details on the TIMP strategy for pipe assets. Projects for the following assets are also noted:

Panhandle Line Replacement

EGI is investigating the replacement of two NPS 12 river crossing pipelines installed in 1947. A potential replacement would be a single pipeline and would be designed, manufactured and constructed to current standards and would be in-line inspection capable.

Dawn to Cuthbert

Three sections of pipe (NPS 26, NPS 34 and NPS 42) each 800 metres in length, located between the Dawn facility and the Cuthbert metering station, cannot be inspected using ILI tools. This project will involve installing ILI launchers and receivers within the Dawn facility and performing existing line retrofits to remove restrictive fitting or pipe configurations, which will allow for the pipeline segments to be in-line inspected with a targeted in-service date of late summer 2022.

5.5.8.5. Transmission Pipe and Underground Storage Asset Class Capital Expenditure Summary

EGI has spent an average of $8M and $85M annually in the EGD and Union rate zones respectively for the Transmission Pipe and Underground Storage asset class. The total average capital spend is forecasted to be $12M (EGD RZ) and $113M (Union RZ) as summarized in **Table 5.5-6** and **Table 5.5-7**. Transmission Pipe and Underground Storage capital is further summarized as part of EGI's total five-year capital plan in **Section 6.**

Table 5.5-6: Transmission Pipe and Underground Storage Capital Summary ($ Thousands) – EGD Rate Zone

Asset Subclass/ Program Name	2021	2022	2023	2024	2025	Five-Year Forecast
Replacements	**3,898**	**6,557**	**4,850**	**9,918**	**2,311**	**27,535**
PCRW: Wells-Upgrade	-	-	-	552	1,706	2,258
Land/Structures Improvements	**300**	**226**	**1,456**	**82**	**87**	**2,152**
Integrity	**5,719**	**5,687**	**3,077**	**8,059**	**1,619**	**24,161**
Improvements	**2,620**	**2,068**	**762**	**635**	**785**	**6,870**
EGD Rate Zone Total	**12,537**	**14,538**	**10,145**	**18,695**	**4,803**	**60,719**

Table 5.5-7: Transmission Pipe and Underground Storage Capital Summary ($ Thousands) – Union Rate Zones

Asset Subclass/ Program Name	2021	2022	2023	2024	2025	Five-Year Forecast
Replacements	**14,288**	**14,561**	**39,629**	**13,562**	**10,664**	**92,705**
Panhandle Line Replacement	-	1,971	31,789	4,266	-	38,026
Growth	**30,405**	**210,494**	**11,406**	**127,364**	**5,218**	**384,888**
Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)	-	208,225	6,386	-	-	214,611
Sarnia Expansion (Novacor Station)	7,853	42	-	-	-	7,894
Sarnia Expansion - Bluewater Energy Park (Asset #1)	344	343	3,053	73,668	3,923	81,331
Sarnia Expansion - Bluewater Energy Park (Customer Station)	-	12	41	14,100	628	14,782
Sarnia Expansion - Bluewater Energy Park (Asset #2)	-	609	1,926	39,596	667	42,797
Sarnia Expansion (NPS 20 Dow to Bluewater)	22,208	1,264	-	-	-	23,472
Land/Structures Improvements	**140**	**140**	**147**	**144**	**-**	**572**

.

Asset Subclass/ Program Name	2021	2022	2023	2024	2025	Five-Year Forecast
Integrity	**7,948**	**40,064**	**9,341**	**13,607**	**12,840**	**83,800**
Dawn - Cuthbert - ECDA to ILI Retrofit NPS 42, 34, 26	1,223	28,721	-	-	-	29,944
Improvements	**306**	**714**	**565**	**525**	**567**	**2,677**
Well Optimization Program	306	304	321	314	334	1,579
Wellhead Upgrades	-	393	342	297	-	1,032
Union Rate Zones Total	**53,087**	**265,975**	**61,089**	**155,202**	**29,289**	**564,642**

.

5.5.9 Liquefied Natural Gas (LNG)

Hagar Station is EGI's liquefied natural gas (LNG) storage facility, located near Sudbury, Ontario (see **Figure 5.5-8**). The station serves to provide reserve capacity and balance operational loads during peak periods throughout the storage, transmission and distribution systems, ensuring system integrity and gas supply reliability.

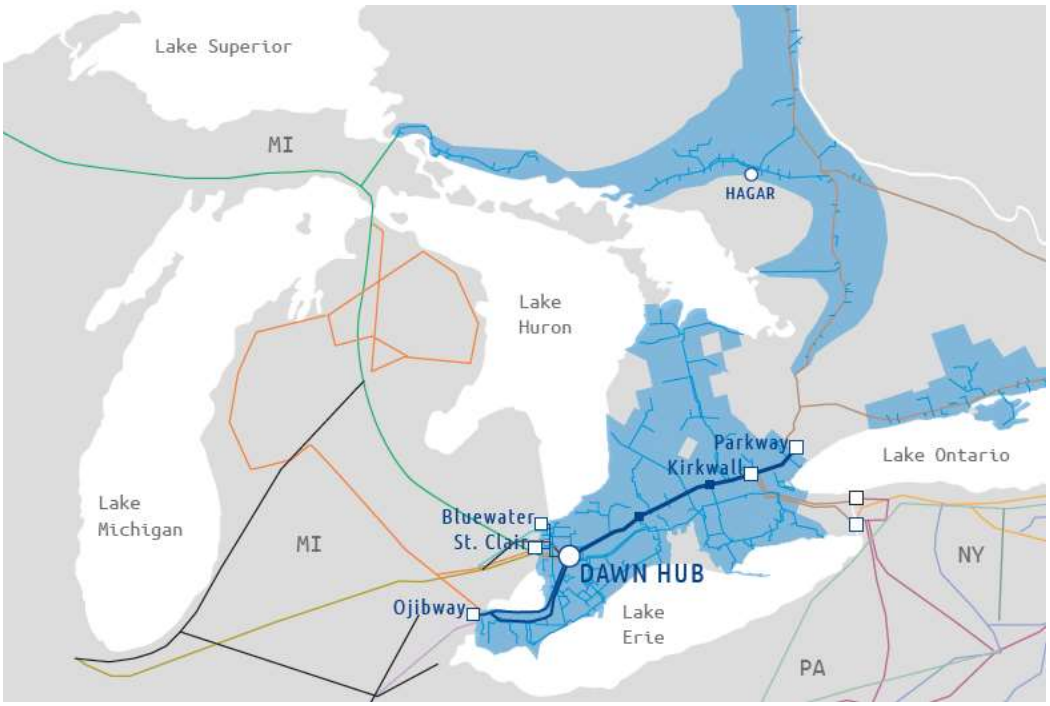


Figure 5.5-8: Hagar LNG Station Location

5.5.9.1. Condition Methodology

Liquefied natural gas system condition is determined primarily based on a preventive maintenance (PM) program comprised of rigorous inspections and renewals through component repair or replacement to improve system reliability.

The system is constantly monitored–control room operators provide the first line of defense by recognizing changing conditions and reacting in near real time. Online monitoring provides protection via control systems. Activities, such as corrective maintenance in response to component condition or operational performance, are captured in the work and asset management system. Component condition is determined using the experience and recommendations of both internal and external subject matter advisors (SMAs). As asset condition and performance degrade, risks are raised and assessed through the risk management process.

Aside from scheduled PM programs, age is also considered as a condition indicator for reliability and obsolescence, although it is generally insufficient on its own to use for replacement project decisions. As the asset ages, vendor support declines until the risk becomes intolerable. Obsolescence poses a risk as repairs become progressively more challenging to complete. As service providers reduce support for products reaching end-of-life, the duration of an equipment outage may become extended. Asset failure under these circumstances may be unrepairable, which could pose a significant operational challenge to fulfil facility requirements.

The LNG facility includes mechanical systems to support its primary function–compressors, vapourizers, a cold box (a series of heat exchangers), pumps, a cryogenic tank, generators, pipe, fittings, valves, regulators, boilers and air compressors (see **Figure 5.5-9**). The refrigeration system uses a mixed refrigerant consisting of methane, ethane, propane, butane and pentane. The condition of mechanical systems are assessed through routine PM inspections as prescribed by the manufacturer, through internally developed standards or through opportunistic inspections presented during construction activities.

Instrumentation, controls and electrical systems support many other asset types and systems within the LNG facility and are primarily affected by obsolescence. As condition assessment for many of these assets is not practical, the methodology for establishing condition is to consider the expected equipment life cycle and proactively anticipate obsolescence.

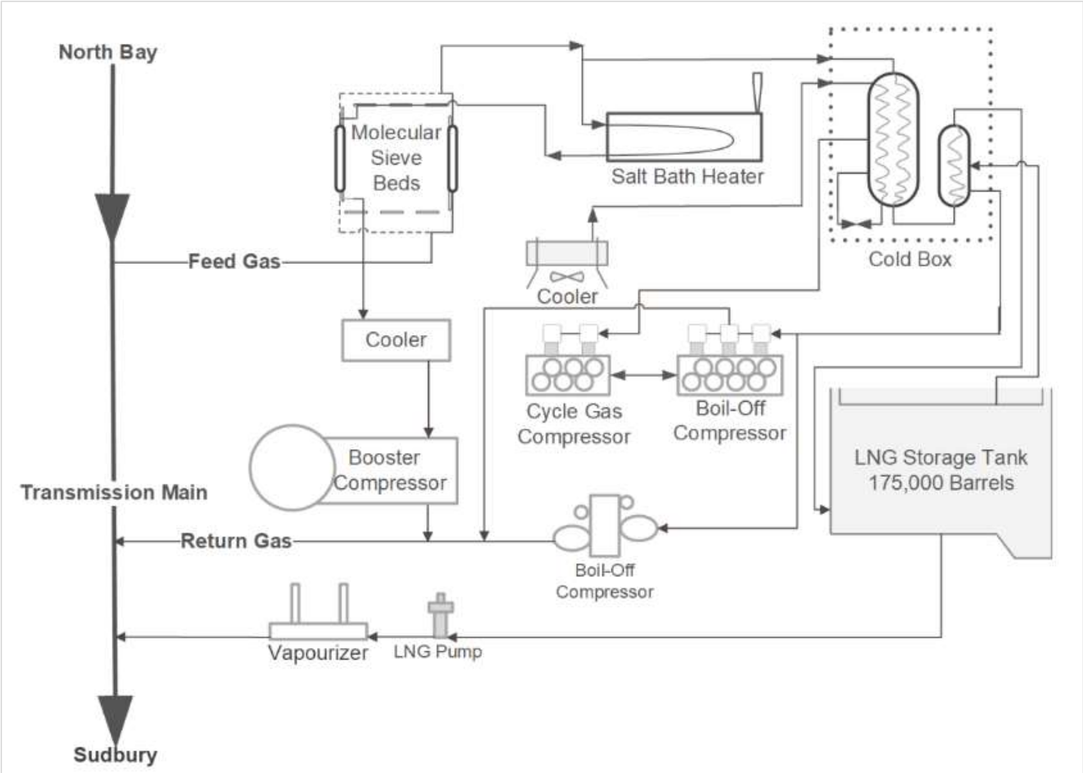


Figure 5.5-9: LNG Station

5.5.9.2. Condition Findings

EGI hired a third-party consultant to provide a condition assessment report for the Hagar LNG plant in 2017. The assessment focused on process performance limitations and equipment condition that could affect reliability and potentially lead to unplanned shutdowns. The assessment was supported through the annual risk review process with input from SMAs.

Assessment results indicated that the Hagar boil-off gas (BOG) compressor has far exceeded its design life as the unit has approximately 40 years of operational hours–it is original equipment in place since plant installation in 1968. A key LNG station component, the typical lifespan of a BOG compressor is 20 years, based on industry data and external SMA input.

Results also showed the cycle gas compressor has over 16 years of total operating hours (~140,000 hours) and is nearing end-of-life. The liquefaction system (composed of a cold box, cycle gas compressor, mixed refrigerant and auxiliary equipment) is also approaching end-of-life.

Operating life is only one measure of plant condition–other factors to consider include plant cycling frequency (On/Off) and plant age (regardless of operation). On/Off operation, particularly in unplanned shutdowns or quick start-ups, can result in thermal stress leading to material fatigue, cracking and pump cavitation. Time-dependent failure modes include corrosion, embrittlement and stress corrosion cracking.

The cold box was observed to have wall ice formations and minor foundation cracks–both are being monitored for progression. The condition assessment report also suggests insulation is degrading; frequent stops and starts will accelerate crack growth and should be minimized. The cold box has also undergone a considerable number of thermal cycles over its 50-year operating life–thermal cycling induces stress on piping and heat exchangers. A cold box failure will have a significant impact on plant availability and its replacement is considered a high priority as a considerable amount of time is required for design, procurement, construction and commissioning activities.

SMAs have confirmed the BOG and cycle gas compressors are no longer supported by the manufacturer and custom machining is required for parts other than typical wear items, rendering the equipment obsolete. A major concern is damage to the engine or compressor block due to a crankshaft, connecting rod or piston rod failure. The turnaround time for machined parts for the BOG compressor is likely to be less than a year but far longer for the cycle gas compressor, based on sheer size. Availability of replacement cast components for the cycle gas compressor is very limited. The control panel for the back-up generator has also been identified as obsolete and replacement parts are no longer available. Obsolescence occurs when equipment is no longer supported by the manufacturer and replacement parts cannot be fabricated and installed in time to meet the plant's operating requirements.

The areas around the LNG tank, near the LNG pipe supports and the LNG building suffer from water pooling, which can cause foundation settling. Differential settling between the tank and piping can cause stress in the piping and connections. Relative movement between the pipe, LNG pump and tank support foundations would result in internal tank nozzle loading and potential cracking.

5.5.9.3. Risk and Opportunity

The Hagar LNG plant provides security of supply to the Sudbury industrial and distribution markets. In addition to security of supply, the plant has also been placed in service on occasion over the years to manage system demand. The consequence of LNG system failure is dominated by gas cost impacts to customers. System risk associated with failure is heavily influenced by the time of year, weather severity and time to mitigate the failure.

Operational Risk: The reliability of the LNG system is integral to managing operational risk and customer impact. Unplanned failures, especially during peak periods, supply shortfalls and unplanned pressure drops or outages, can have a significant impact on the security of supply for the Sudbury area. The operational risks existing within the LNG facility are primarily related to obsolescence and the long lead time associated with a failure on critical assets within the liquefaction process (BOG compressor, cycle gas compressor and cold box).

Financial Risk: Financial risk is significantly mitigated by regular inspections, which then inform the necessary preventive maintenance work. A preventive maintenance program mitigates financial risk by reducing the chance of unexpected failures. Unplanned outages result in unexpected repair costs.

5.5.9.4. Strategy Outcomes

Detailed inspections at set frequencies, subsequent remedial activities and control room condition monitoring help identify suspect equipment condition, reducing the likelihood of failure and large-scale outages.

The replacement strategy for the LNG asset subclass is proactive replacement that targets equipment based on condition and obsolescence and is generally dependent on OEM support. This strategy aims to proactively replace or rebuild station components before end-of-life to reduce risk and maintain a safe and reliable LNG system.

This section outlines resolution of a number of discrete risks through replacement of individual components. EGI continues to broaden its understanding of the compatibility of new equipment with the existing balance of the plant. When replacing obsolete assets, EGI will continue to re-evaluate new technology to support a holistic plan for the modernization of the Hagar plant. The outcome of this analysis may result in an approach that favors broad plant renewal.

JVG Boil-off Gas (BOG) Compressor Replacement

This project involves replacement of the BOG compressor to mitigate the risk of a system failure due to a non-repairable, critical compressor part. The BOG compressor is one of the two compressors used to power the refrigerant process which cools the natural gas feedstock to -160 Celsius (at which point the natural gas turns into a liquid). Over its more than 50 years of operation, the 240-horsepower Ingersoll Rand BOG compressor has amassed 325,000 operational hours and deemed to be at the end of its design life. Although normal wear components are still available, core compressor replacement parts such as cylinders, crankshafts, pistons, etc., required to support a critical failure are no longer manufactured. In a critical failure, securing used parts (which are rare) or after-market custom machining services are the only options for repair. If custom machining services cannot repair the part, a custom-designed after-market casting option or complete replacement of the compressor will be required, rendering the LNG plant out of service for at least one operational season and unable to perform its regulated requirements.

KVGR Cycle Gas Compressor Replacement

This project involves replacement of the KVGR cycle gas compressor to mitigate the risk of a system failure due to a non-repairable, critical compressor part. The KVGR compressor is one of the two compressors used to power the refrigerant process (the other is the BOG compressor). Over its 50 years of operation, the 1500-horsepower Ingersoll Rand KVGR cycle gas compressor has amassed 140,000 operational hours and deemed to be at the end of its design life. This replacement is required for the same reasons as the BOG compressor.

.

Cold Box Replacement

This project involves replacement of the cold box to address anticipated leaks that will impair the plant's ability to produce LNG. The cold box is a series of several heat exchangers used to cool natural gas, turning it into a liquid. Over its 50 years of operation, the cold box has amassed 140,000 operational hours. Significant failure modes include gas or refrigerant leaks out of the piping into the interior of the cold box shell and heat exchanger cross leaks that reduce refrigeration effectiveness. Both failure modes impair LNG production, leading to the plant missing its annual production requirements. Troubleshooting and repair of these failure modes is extremely difficult and time consuming, as cold box internal components are encased in very densely packed insulation and clad in an outer steel jacket. Considering the repair or replacement complexity, reactively responding to internal leakage will halt the liquefaction process, which lead to the non-fulfilment of EGI's regulated requirements for at least an operating season.

Site Drainage Improvements

This project includes the development of a drainage plan, engineering design, permitting and site remediation work to address water pooling near the LNG storage tank drainpipe, the LNG pump and the LNG building to prevent the foundation from sinking.

.

5.5.9.5. LNG Asset Class Capital Expenditure Summary

EGI has spent an average of $0.8M annually in the Union North rate zone for the Liquefied Natural Gas (LNG) asset class. The total average capital spend is forecasted to be $5M as summarized in **Table 5.5-8**. Storage and Transmission capital is further summarized as part of EGI's total 5-year capital plan in **Section 6.**

Table 5.5-8: Liquefied Natural Gas Capital Summary ($ Thousands) – Union Rate Zones

Asset Subclass/ Program Name	2021	2022	2023	2024	2025	Five-Year Forecast
Replacements	**-**	**-**	**16,030**	**-**	**-**	**16,030**
JVG Boil-off Gas (BOG) Compressor Replacement	-	-	8,015	-	-	8,015
KVGR Cycle Gas Compressor Replacement	-	-	8,015	-	-	8,015
Land/Structures Improvements	**-**	**243**	**-**	**189**	**354**	**786**
Site Drainage Improvements	-	-	-	189	354	542
Integrity	-	-	-	-	**8,327**	**8,327**
Cold Box Replacement	-	-	-	-	8,327	8,327
Improvements	**339**	**-**	**-**	**-**	**-**	**339**
Union Rate Zones Total	**339**	**243**	**16,030**	**189**	**8,681**	**25,483**

5.6 Real Estate and Workplace Services

The Real Estate and Workplace Services (REWS) asset class includes properties (buildings and land) and furnishings. Properties are categorized into regional operations and administrative centres, operations depots, land, operations micro depots and head offices. The requirements for these properties are primarily based on function, headcount and organizational structure.

5.6.1 Real Estate and Workplace Services Objectives

The objectives of the Real Estate and Workplace Services asset class are listed in **Table 5.6-1**.

Table 5.6-1: Asset Class Objectives

Asset Class Objective	
Create and support safe, efficient and collaborative environments across EGI.	Sustain the integrity and adequacy of all facilities for safe and reliable use.
	Continuously evolve the understanding of condition and risk associated with real estate assets and use risk, cost and performance information to drive asset-related decisions.

The performance measures for the Real Estate and Workplace Services asset class are:

- Physical Assessment: Facility Condition Index (FCI)
- Functional Assessment: Adequacy Index (AI)
- Cost per square foot (lease and building operating expenditures)
- Utilization rate

To achieve the Real Estate and Workplace Services asset class objectives listed in **Table 5.6-1**, asset investment decisions are governed by the life cycle management strategies outlined in **Table 4.1-1**.

.

5.6.2 Real Estate and Workplace Services Hierarchy

The asset class hierarchy is summarized in **Figure 5.6-1**.

Figure 5.6-1: Real Estate and Workplace Services Hierarchy

5.6.3 Real Estate and Workplace Services Inventory

The inventory for Real Estate and Workplace Services assets can be found in **Table 5.6-2**.

Table 5.6-2: Real Estate and Workplace Services Asset Class Inventory

Asset Subclass	EGD Rate Zone	Union Rate Zones
Properties (Buildings/Land)	18	74
Head Offices	1	0
Regional Operations and Administrative Centres	3	8
Operations Depots	12	42
Operations Micro Depots	0	18
Land	2	6
Workspace Furniture	~2,400	~3,200

The total building square footage is 774,665 and 1,245,291 for the EGD and the Union rate zones respectively.

.

5.6.4 Real Estate and Workplace Services Condition and Strategy Overview

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

.
.

5.6.5 Properties

5.6.5.1. Condition Methodology

For the Properties (buildings/land) asset subclasses, a Facility Assessment is used to:

- Assess the physical condition of each facility
- Assess the operational functionality of each facility
- Identify potential gaps in service area coverage
- Create a long-term real estate portfolio strategy
- Create quality indoor environments with access to natural light and views which result in increased productivity, decreased absenteeism and improved morale

The Facility Assessment is based on a defined set of standards representing industry best practices relating to exterior site works, architectural elements, interiors, furniture and amenities.

The Functional Obsolescence or Adequacy Index (AI) is a condition index tool used to illustrate the functional condition of the asset expressed in a percentage ratio of required functional upgrade costs divided by the replacement value of the asset to meet functional needs. Based on EGI's standards, scores between 0% and 49% are considered good and scores of 50% and above are considered poor/critical. The AI is calculated as follows:

Adequacy Index Calculation

$$\mathbf{AI} = \frac{\textbf{Functional Upgrade Costs}}{\textbf{Cost to Replace the Building with its Functional Equivalent}}$$

An asset's physical condition is assessed based on the Facility Condition Index (FCI). The FCI is a generally-accepted industry benchmarking tool. It is a scoring mechanism comparing the relative physical condition of the existing components of a group of facilities. All EGI properties have been inspected for the purpose of calculating an FCI and creating a long-term capital plan. Based on EGI's standards, scores between 0% and 5% are considered good, 5% to 10% fair, 10% to 30% poor and greater than 30% critical. The FCI is calculated as follows:

Facility Condition Index Calculation

$$\mathbf{FCI} = \frac{\textbf{Cost to Remediate Immediate or Short– term Maintenance Deficiencies}}{\textbf{Current Replacement Value of Facility}}$$

Site functionality and utilization are based on critical functional criteria (yard size, access, sufficient office area, tracked utilization, etc.) and are scored as Good, Challenged, or Obsolete. The typical yard size is 2.5 acres (the appropriateness is dependent on EGI site-specific requirements).

Properties are assessed based on multiple parameters such as; site and building functional obsolescence, physical obsolescence, Ontario Building Code (OBC) compliance and renewal/replacement strategy costs. Each property is assigned a priority rank from highest to lowest. To attain this rank, building functional obsolescence (AI), physical obsolescence index (FCI), site functional obsolescence index and the recommended strategy for correcting the deficiencies were considered. Higher priority is given to the facilities posing larger and more immediate financial and/or safety risk to the organization.

Compliance to current OBC requirements is factored, depending on the Part, Group and Division each property falls under. These include (but are not limited to) barrier-free path of travel and barrier-free and universal washroom facilities. Furthermore, compliance with fire code regulations on load-bearing structures, fire resistance ratings, sprinkler systems and combustible/non-combustible construction are also considered. It is important to note that major renovations to a structure may require that area to be brought up to current OBC compliance standards, potentially requiring a substantial investment.

.

5.6.5.2. Condition Findings

Table 5.6-3 shows the facility assessment results for all EGI properties and the summary strategy for each property. Based on EGI's standards, FCI scores between 0% and 5% are considered good, 5% to 10% fair, 10% to 30% poor and greater than 30% critical. AI scores between 0% and 49% are considered good and scores of 50% and above are considered poor/critical. Site functionality and utilization are based on critical functional criteria (yard size, access, sufficient office area, tracked utilization, etc.) and are scored as Good, Challenged, or Obsolete.

Table 5.6-3: EGI Facility Assessment Results

Property Name	Age (Years)	Physical Obsolescence (FCI)	Functional Obsolescence: Building (AI)	Functional Obsolescence: Site	Summary Strategy
50 Keil Drive	56	12.91%	44.64%	Obsolete	Renovation
555 Riverview Operations Centre	48	10.03%	24%	Good	Renovation
Ancaster Operations Centre	28	8.88%	63%	Obsolete	Expansion and Renovation
Bloomfield Administration Centre	28	0.47%	0.18%	Good	Maintenance
Brantford Regional Operations Centre	25	2.77%	17%	Obsolete	Renovation
Burlington Operations Centre	12	1.77%	11%	Obsolete	Renovation
Cambridge Operations Centre	58	11.76%	16%	Obsolete	Disposition
Dawn Hub Operations Centre	50	16.95%	28%	Obsolete	New build on existing site
Dryden Operations Centre	41	11.33%	87%	Obsolete	New build on new site
Guelph Operations Centre	63	14.97%	46%	Obsolete	Disposition
Kingston Operations Centre	11	0.32%	15%	Good	Maintenance
Hamilton Operations Centre (Park Street)	60	26.86%	100%	Obsolete	Disposition
Hamilton Operations Centre (Pritchard Road)	13	7.91%	21%	Obsolete	Renovation
Leamington Operations Centre	59	9.85%	65%	Good	Renovation
London Operations Centre	52	6.48%	14%	Good	Disposition

.

Property Name	Age (Years)	Physical Obsolescence (FCI)	Functional Obsolescence: Building (AI)	Functional Obsolescence: Site	Summary Strategy
Milton Operations Centre	26	14.09%	63%	Obsolete	Disposition
North Bay Operations Centre	56	16.87%	8%	Good	New build on new site
Orillia Operations Centre	46	18.07%	15%	Obsolete	Renovation
Owen Sound Operations Centre	14	4.52%	32%	Obsolete	Expansion and Renovation
Sault Ste. Marie Operations Centre	42	13.90%	24%	Good	Renovation
Simcoe Operations Centre	64	8.42%	100%	Good	Demolish and New Build
St. Thomas Operations Centre	41	12.59%	22%	Obsolete	Disposition
Stratford Operations Centre	53	11.96%	22%	Good	Expand on current land
Sudbury Operations Centre	36	8.49%	13%	Obsolete	Renovation
Thunder Bay Regional Operations Centre	24	2.57%	41%	Obsolete	Renovation
Timmins Operations Centre	61	2.88%	25%	Good	Renovation
Woodstock Operations Centre	38	13.87%	26%	Obsolete	Renovation
Atikokan Micro-Operations Centre	53	11.37%	61%	Good	Revitalization Program
Black River Micro-Operations Centre	52	36.09%	46%	Good	Revitalization Program
Bracebridge Micro-Operations Centre	53	19.41%	32%	Good	Revitalization Program
Cochrane Micro-Operations Centre	54	15.28%	50%	Good	Revitalization Program
Ear Falls Micro-Operations Centre	6	6.82%	56%	Good	Maintenance
Elliot Lake Micro-Operations Centre	41	29.09%	9%	Good	Revitalization Program
Engelhart Micro-Operations Centre	Unknown	25.42%	83%	Good	Revitalization Program
Geraldton Micro-Operations Centre	56	12.09%	68%	Good	Revitalization Program

.

Property Name	Age (Years)	Physical Obsolescence (FCI)	Functional Obsolescence: Building (AI)	Functional Obsolescence: Site	Summary Strategy
Haileybury Micro-Operations Centre	55	22.60%	18%	Good	Revitalization Program
Hearst Micro-Operations Centre	47	6.76%	79%	Good	Revitalization Program
Huntsville Micro-Operations Centre	51	24.34%	52%	Good	Revitalization Program
Huron Park Micro-Operations Centre	80	42.40%	22%	Good	Disposition
Iroquois Falls Micro-Operations Centre	54	28.84%	16%	Good	Revitalization Program
Kapuskasing Micro-Operations Centre	30	7.11%	0%	Good	Maintenance
Kirkland Lake Micro-Operations Centre	56	11.38%	69%	Good	Revitalization Program
Nipigon Micro-Operations Centre	57	10.27%	57%	Good	Revitalization Program
Palmerston Micro-Operations Centre	Unknown	9.56%	88.7%	Good	Revitalization Program
Parry Sound Micro-Operations Centre	7	3.75%	19%	Good	Maintenance
Arnprior Operations Centre	50	3.82%	58%	Obsolete	Renovation
Barrie Operations Centre	15	1.61%	58%	Obsolete	Disposition
Brampton Operations Centre	22	11.02%	49%	Obsolete	Renovation
Brockville Operations Centre	50	7.53%	84%	Obsolete	New build and land
Kelfield Operations Centre	60	10.47%	71%	Obsolete	New build and land
Kennedy Road Operations Centre	60	6.51%	95%	Obsolete	New build and land
Oshawa Operations Centre	31	14.92%	30%	Obsolete	Renovation
Ottawa Regional Operations and Admin. Centre	60	4.65%	43%	Obsolete	Consolidation
Peterborough Operations Centre	39	10.38%	32%	Obsolete	Disposition
SMOC Operations Centre	25	2.04%	24%	Obsolete	Disposition

.

Property Name	Age (Years)	Physical Obsolescence (FCI)	Functional Obsolescence: Building (AI)	Functional Obsolescence: Site	Summary Strategy
Station B Operations Centre	52	12.28%	49%	Obsolete	New build
Tecumseh (Gas Storage)	4	0.81%	0%	Good	Maintenance
Tecumseh (Engineering)	11	0.28%	0%	Good	Maintenance
Thorold Regional Operations and Admin. Centre	28	3.09%	59%	Obsolete	Renovation
TOC Regional Operations and Admin. Centre	9	0.08%	5%	Good	MEC and Telemetry Expansion
VPC Head Office	52	5.59%	11%	Good	Renovation, new build

5.6.5.3. Risk and Opportunity

Examples of deficiencies observed at EGI sites were as follows:

- Inadequate building or yard size leads to unfulfilled operational requirements.
- Non-conformance to current OBC life safety, barrier-free and universal design standards
- Site area constraints hinder vehicular circulation and increases the probability of motor vehicle incidents.
- Configuration of site functions and circulation is inefficient.

These deficiencies pose the following risks:

Employee and Contractor Safety Risk: Facilities with operational deficiencies pose a safety risk to employees and hinder execution of tasks. Some facilities have inadequate operations yard and administrative parking. The mix of industrial and employee vehicles is a potential contributor to motor vehicle incidents. Best practices dictate keeping industrial vehicles away from administration parking areas.

Financial Risk: EGI faces financial risk if properties are not maintained, hindering operations and administrative functions. Some facilities use more energy than a comparable renovated facility (utilizing current OBC and energy standards). Inadequate site configuration and lack of office and support areas hinder operations and administrative functions. Older buildings have high greenhouse gas emissions and use more energy than a comparable new construction.

5.6.5.4. Strategy Outcomes

The strategies for the Properties asset subclass were developed to align with business requirements and the OBC as well as correct deficiencies on site:

- Renovating existing facilities
- Building new facilities
- Disposing of current site and relocating to a new site
- Continuing maintenance of the current site

Choosing the appropriate strategy is based on a combination of business requirements and physical/functional assessments described in **Section 5.6.5.1** and support of the business strategy. See **Table 5.6-3** for the summary strategy for each EGI property. This approach to long term planning of EGI properties aligns with the feedback received from customers in the 2020 Customer Engagement Survey. A vast majority of customers prefer that investments in renovating older buildings and building new ones be spread evenly over a longer period of 10 years as opposed to delaying these investments until they can no longer be avoided and funded more quickly, which could cost more in the long run.

Major investments for this asset class were identified through a facility assessment of the properties' physical condition and operational function and gaps in service area coverage, to allow for a standardized look and feel to all Enbridge facilities. Major projects include four new buildings and the relocation and consolidation of the Ottawa facilities for better operational coverage. Improvements at the 50 Keil Drive administrative facility are intended to extend the useful life of the property and accommodate over 800 employees. The investment will correct physical and functional deficiencies by renovating and renewing the existing building, using less energy and emitting less greenhouse gases.

Building Systems Program

A third-party engineering consultant analyzed factors such as age of equipment, maintenance records, repair cost, building standards and compliance issues to determine overall risks and timing of replacement for HVAC equipment, plumbing, electrical equipment and exterior site improvement.

The property assessment report identifies equipment at end-of-life and recommends a replacement plan over a 25-year span. The report focused on the design, installation, operation and monitoring of building systems required for a safe, comfortable and environmentally friendly environment for employees.

Unplanned failures occur occasionally which require immediate action. A review of each cost determines the decision to repair or replace the defective equipment. The service life of new assets is 15 to 20 years.

If building systems are not properly maintained, there is a financial risk to EGI as failure of these systems increase substantially year over year, which can potentially lead to loss of productivity.

The strategy for building systems assets is to maximize the equipment's useful life and replace systems before failure can cause business interruptions.

.

The replacement of equipment is targeted but not solely specific to the building envelope, HVAC and electrical systems. Compliance to environmental standards, interior comfort and overall security are major considerations to ensure safe and reliable operations.

The annual program for these initiatives is determined based on historical spend as well as building assessments and condition analysis.

GHG and Energy Reductions Program

Enbridge has begun work on energy efficiency and emissions from office buildings. These improvements ensure current building systems are operated in an efficient manner that reduces carbon fuel use. The strategy on energy efficiency and emissions from office buildings identifies natural gas air-sourced heat pumps and other opportunities as a potential abatement opportunity at EGI’s office facilities.

Some existing EGI facilities use more energy than a comparable new or renovated facility (utilizing current OBC and energy standards), increasing operating costs. This program will offer EGI the opportunity to reduce these costs by implementing energy efficiency measures in its office buildings, reducing GHG emissions.

Where work is not already a part of the five-year plan, improvements will still be reviewed to see if they can be accommodated, leading to further reduction in GHG and energy usage. The process will identify a mix of measures with a range of implementation costs and energy/greenhouse gas savings. On completion, measures, findings and an action plan to measure energy conservation implementation will be developed, as well as verification and ongoing commissioning, which will include operational and capital improvements. Lessons learned from each activity will be implemented on future initiatives. This is a recurring yearly program for five years, determined based on building assessments and condition analysis.

Micro-Operations Depot Revitalization Program

This program covers the renovation or replacement of 14 micro-operations depots located in the Northern region that are on average over 50 years old, consisting of 17 owned and one leased property. The sites are in aging physical condition and do not meet required functionality.

Risks include the financial impact of low utilization or functionally and physically deficient assets. Current physical conditions pose a hazard to employee and contractor safety. Legacy buildings with obsolete systems have high GHG emissions and use more energy than a comparable new construction.

The strategy is to renovate or replace the sixteen micro-operations depots. Renovations or replacement will include the building envelope, HVAC and electrical systems. Compliance to environmental standards, building codes, accessibility and overall security are major considerations to ensure safe and reliable operations.

5.6.6 Workplace Furnishings

5.6.6.1. Condition Methodology

Workspaces at each site consist of workstations and office furniture. These furnishings are either considered current (meeting EGI standards) or legacy (not meeting current standard). Current EGI furniture standards provide:

- Ergonomic support
- Day lighting and views for building occupants through use of mid-height workspace systems and perimeter placement
- Task seating required to address a range of body types
- Consistent workstation configuration, contributing to lower operating costs by creating fixed environments and allowing a broad range of administrative requirements without change
- Designs using materials and features reducing the "cubicle feel"
- Designs supporting power and network wiring

Legacy furniture (20+ years old) does not meet EGI's current condition standards. Legacy furniture is comprised of furniture systems purchased in the mid-1980s when the concept of systems furniture was first implemented. Office environment and related standards have evolved over the past 30 years. The systems still in use are high-paneled, impeding daylight into the office environments. Legacy furniture has surpassed its 10-year warranty period (the anticipated use length) and is approaching 30 years in age.

In addition, ergonomic requirements have changed to support EGI's goal of zero injuries in the office. The height of the existing fixed workstation at 29" is a contributing factor of repetitive strain injury. Current standard workstations allow for adjustable height work surfaces, allowing employees to adjust their work surface to the appropriate height or to stand if desired.

Ancillary furnishings refer to all support furnishings, including (but not limited to) guest seating, informal and collaborative areas, conference room and common space furniture, filing cabinets and bookcases. The condition of ancillary furnishings is based on an assessment of age, physical condition and utilization and is also evaluated as either meeting or not meeting EGI standards.

5.6.6.2. Condition Findings

The facility assessment results for all EGI properties included an assessment of workplace furnishings. Results indicate that except for the Victoria Park Centre (VPC) and Technology and Operations Centre (TOC) properties, all of EGI's workplace furnishings are rated as legacy based on EGI standards. 30% of furnishings are current; 70% are legacy.

5.6.6.3. Risk and Opportunity

Without adequate furniture and ergonomics in place, there is financial risk as productivity can potentially suffer due to inefficient space allocation and unnecessary workstation re-configuration costs. Improper ergonomics support can pose a safety risk as lack of task seating that addresses a range of body types can potentially cause repetitive strain injuries.

Financial Risk: Furnishings approaching 30 years old reduce productivity and increase maintenance costs.

Employee and Contractor Safety Risk: Legacy furnishings do not meet current ergonomics standards; therefore, employees are more likely to suffer from repetitive strain injuries and other ailments stemming from the inability to adjust workstation configurations.

5.6.6.4. Strategy Outcomes

The strategy for furniture and ergonomics assets is to replace office and meeting room furnishings as required due to failure. Ergonomic modifications and tools are issued as recommended to prevent repetitive strain injuries and accommodate return-to-work employees. The annual program is based on historical spend.

Remaining legacy office, meeting room and ancillary furnishings are replaced with current standard systems as building life cycle renewal is executed.

.

5.6.7 Real Estate and Workplace Services Capital Expenditure Summary

EGI has spent an average of $19M and $12M annually in the EGD and Union rate zones respectively for the Real Estate and Workplace Services (REWS) asset class. The total average capital spend is forecasted to be $33M (EGD RZ) and $35M (Union RZ) as summarized in **Table 5.6-4** and **Table 5.6-5**. REWS capital is further summarized as part of EGI's total five-year capital plan in **Section 6.**

Table 5.6-4: REWS Capital Summary ($ Thousands) – EGD Rate Zone

Asset Subclass/Program	2021	2022	2023	2024	2025	Five-year Forecast
Furniture/Structures and Improvements	**58,556**	**45,882**	**21,553**	**16,339**	**24,810**	**167,140**
Kennedy Road Expansion	1,221	14,597	2,564	-	-	18,832
Station B New Building	18,921	-	-	-	-	18,921
SMOC/Coventry Facility Consolidation	9,766	14,597	13,897	-	-	38,241
Kelfield Operations Centre	6,104	5,717	1,410	-	-	13,231
VPC Core and Shell	-	-	-	12,447	13,219	25,666
Building Systems Program	2,313	2,345	2,513	2,483	2,683	12,338
Targeted GHG and Energy Reductions	427	426	449	436	463	2,200
EGD Rate Zone Total	**59,556**	**44,882**	**21,553**	**16,339**	**24,810**	**167,140**

Table 5.6-5: REWS Capital Summary ($ Thousands) – Union Rate Zones

Asset Subclass/Program	2021	2022	2023	2024	2025	Five-year Forecast
Furniture/Structures and Improvements	**44,928**	**35,736**	**26,280**	**21,498**	**48,570**	**177,011**
Thunder Bay Regional Operations Centre	-	-	-	754	12,806	13,561
New Site No. 4	12,228	12,170	11,299	-	-	35,697
Targeted GHG and Energy Reductions	428	426	449	440	467	2,210
Micro-Operations Depot Revitalization	2,446	2,434	2,568	2,514	2,668	12,630
Union Rate Zones Total	**44,928**	**35,736**	**26,280**	**21,498**	**48,570**	**177,011**

.

5.7 Fleet and Equipment

The Fleet and Equipment asset class provides EGI with the necessary vehicles, equipment and tools to safely and efficiently run regulated business operations. EGI sustains the integrity of the fleet through a strong maintenance program and uses risk, cost and performance information to drive asset-related decisions.

The Fleet and Equipment asset class consists of three asset subclasses: Fleet, Heavy Equipment and Tools. Fleet includes light duty vehicles (LDVs), medium duty vehicles (MDVs) and heavy duty vehicles (HDVs). LDVs include cars, vans and pickup trucks. MDVs include vehicles which range from mechanic repair trucks to utility service trucks. Heavy duty vehicles are comprised of large vehicles with a Gross Vehicular Weight (GVW) between 26,001 - 150,000 pounds. Heavy equipment assets consists of backhoes, trailers, compressors, forklifts, welders and boring equipment. The Tools asset subclass consists of all tools that support EGI's business operations, ranging from gas surveyors and concrete saws, to fusion machines, pipe squeeze-off tools and stop/tap tooling equipment.

5.7.1 Fleet and Equipment Objectives

Table 5.7-1 describes the asset class objectives for Fleet and Equipment.

Table 5.7-1: Fleet and Equipment Asset Class Objectives

Asset Class Objectives	
Supportability	Provide the business with the necessary vehicles, equipment and tools to safely and efficiently run regulated business operations.
Integrity and Reliability	Sustain the safety and reliability of all vehicles, equipment and tools.
	Use risk, cost and performance information to drive asset-related decisions.

The performance measures for the Fleet and Equipment asset class are:

- 100% completion of end-user requirements
- Preventive maintenance activities completed on schedule
- Fleet management system reporting and qualitative reviews completed

To achieve Fleet and Equipment asset class objectives listed in **Table 5.7-1**, asset investment decisions are governed by the life cycle management strategies outlined in **Table 4.1-1**. For this asset class, specific life cycle activities include:

- Convert LDVs where applicable to operate on natural gas, reducing overall GHG emissions.
- Install Auxiliary Power Units (APU) on MDVs (An APU is an anti-idling device that reduces overall GHG emissions and prevents premature engine wear and tear).
- Optimize natural gas as a fuel source for LDVs to reduce overall GHG emissions.
- Install telematics/GPS technology to optimize asset utilization.
- Use telematics/GPS technology to create a proactive approach to vehicle maintenance and reduce downtime.

5.7.2 Fleet and Equipment Hierarchy

The asset subclass breakdown for the Fleet and Equipment asset class is illustrated in **Figure 5.7-1.**

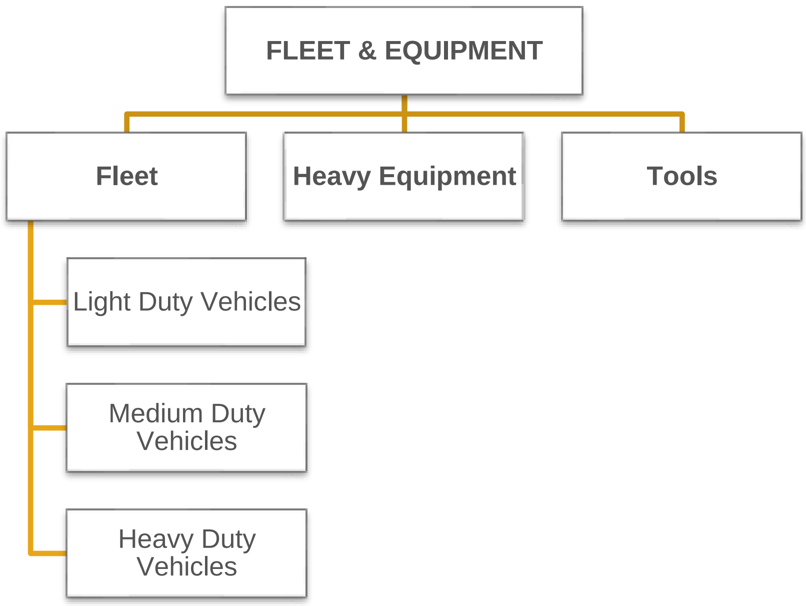


Figure 5.7-1: Fleet and Equipment Asset Class Hierarchy

5.7.3 Fleet and Equipment Inventory

The Fleet and Equipment asset class inventory is shown in **Table 5.7-2**.

Table 5.7-2: Fleet and Equipment Inventory

Asset Subclass	EGD Rate Zone	Union Rate Zones
Fleet	1069	826
Light Duty Vehicles	880	550
Medium Duty Vehicles	6	233
Heavy Duty Vehicles	183	43
Heavy Equipment	689	510
Tools	~5000	~6000

5.7.4 Fleet and Equipment Condition and Strategy Overview

<table>
<tr><th colspan="2">Asset Subclass</th><th>Avg. Age (Year)</th><th>Condition</th><th>Risk / Opportunity</th><th>Maintenance Strategy</th><th>Replacement / Renewal Strategy</th></tr>
<tr><td rowspan="3">FLEET</td><td>Light-Duty Vehicles</td><td>5.3 (EGD RZ)
4.5 (Union RZ)</td><td>Analysis indicates that average maintenance costs exceed the market value of a light-duty vehicle at an approximate age of five to seven years or 160,000 kilometres, depending on the vehicle’s weight class.</td><td rowspan="4">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.</td><td>Vehicle maintenance every 8,000 kilometres (approximately every three months)</td><td>Light Duty Vehicle (LDV) Replacement Strategy: this proactive program replaces vehicles based weight class, mileage and assessed condition. The replacement schedule is as follows:
• Class 1 Vehicles – 60 months
• Class 2 Vehicles – 72 months
• Class 3 Vehicles – 84 months
The average replacement age for LDVs is 6 years and the optimal average age for the asset pool (the midpoint of the average replacement) is calculated at 3 years.</td></tr>
<tr><td>Medium-Duty Vehicles</td><td>9.3 (EGD RZ)
5.2 (Union RZ)</td><td>Analysis indicates that average maintenance costs exceed the market value of a medium-duty vehicle at approximately seven to 12 years old or 175,000 kilometres, depending on the vehicle’s weight class.</td><td>Vehicle maintenance every 10,000 kilometres or 500 engine hours (approximately every four months)</td><td>Medium Duty Vehicle (MDV) Replacement Strategy: this proactive program replaces vehicles based on weight class, mileage and assessed condition. The replacement schedule is as follows:
• Class 4 Vehicles – 84 months
• Class 5 Vehicles – 120 months
• Class 6 Vehicles – 144 months
The average replacement age for MDVs is 9.7 years and the optimal average age for the asset pool is calculated at 4.85 years.</td></tr>
<tr><td>Heavy-Duty Vehicles</td><td>7.6 (EGD RZ)
8.1 (Union RZ)</td><td>Analysis indicates that average maintenance costs exceed the market value of a heavy-duty vehicle at 12 years old or 350,000 kilometres, depending on the vehicle’s weight class.</td><td>Vehicle maintenance every 10,000 kilometres or 500 engine hours (approximately every four months)</td><td>Heavy Duty Vehicle (HDV) Replacement Strategy: This proactive program replaces vehicles based on weight class, mileage and assessed condition. The replacement schedule is as follows:
• Class 7 Vehicles – 144 months
• Class 8 Vehicles – 144 months
The average replacement age for HDVs is 12 years and the optimal average age for the asset pool is calculated at 6 years.</td></tr>
<tr><td colspan="2">Heavy Equipment</td><td>10.7 (EGD RZ)
7.9 (Union RZ)</td><td>Analysis indicates that average maintenance costs exceed the market value of heavy equipment at approximately 12 years old.</td><td>Equipment maintenance is conducted on a scheduled basis, ranging from three to 12 months, depending on the type of equipment.</td><td>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.</td></tr>
<tr><td colspan="2">Tools</td><td>N/A</td><td>The general condition and functionality of tools are assessed by the operator prior to use and during scheduled inspections and calibrations.</td><td>Aging, broken, or inadequate tools pose the following risks:
Financial Risk: Increased maintenance costs and lower productivity
Employee and Contractor Safety Risk and Public Health and Safety Risk: Increased employee, contractor and customer safety and health risks if tools are not in good condition.
Operational Risk: Service and/or emergency response reliability</td><td>N/A</td><td>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</td></tr>
</table>

5.7.5 Fleet

5.7.5.1. Condition Methodology

As part of integration activities, fleet data will be migrated to an enterprise-wide fleet management service provider in 2020, to use fleet management software (Element) that stores asset records and analyzes vehicle condition over their life cycle. This includes all maintenance costs, fuel consumption, mileage, age and hours of use.

Fleet management software provides data to analyze a vehicle's cumulative maintenance cost against the asset class's average cost and the asset condition. An asset is assessed and considered for replacement once the average maintenance cost surpasses market value, unless there are conditions observed that justify shortening or prolonging asset life. If a vehicle exhibits higher maintenance costs than average, the vehicle is considered for earlier replacement. On the other hand, if a vehicle exhibits lower maintenance costs and assessed to be in good condition, it is considered for later replacement. This approach is guided by risk analysis, operating expense and asset performance to sustain asset integrity. A steady pace of replacements spread out evenly over a longer period is consistent with customer engagement feedback.

Retaining vehicles and heavy equipment too long increases operating and maintenance costs. Furthermore, retiring these assets too early results in the partial loss of their useful life, impacting capital replacement requirements. For vehicles, the population's average point at which maintenance costs exceed the market value of the vehicle is used as a guide, as it helps identify vehicles approaching end-of-life. These vehicles require a detailed condition assessment to determine their fitness for service, which consists of appraising vehicle attributes such as engine, transmission, body and interior condition. For heavy equipment, the standard used to determine the optimal replacement point is when maintenance costs begin to exceed the market value of the asset.

In addition to reports, detailed condition assessments are conducted on vehicles and heavy equipment assets every three to six months. This assessment includes a physical and visual evaluation of the asset's physical and functional condition, a comparison of hours of service and an assessment of the maintenance history of the asset relative to its class. If the asset is assessed to be in good working condition, it is kept in service and refurbished to extend its useful life. If the asset is assessed to be in poor condition and not fit for continued service, it is replaced.

To understand how company vehicles are being used, fleet vehicles are equipped with Global Positioning System (GPS)/Telematics tracking devices, managed by fleet management software (Geotab). The Geotab system also provides real-time vehicle diagnostics, giving EGI the ability to be proactive with fleet vehicle assessments and repairs.

5.7.5.2. Condition Findings

Figure 5.7-2 shows the average age for fleet assets across EGI.

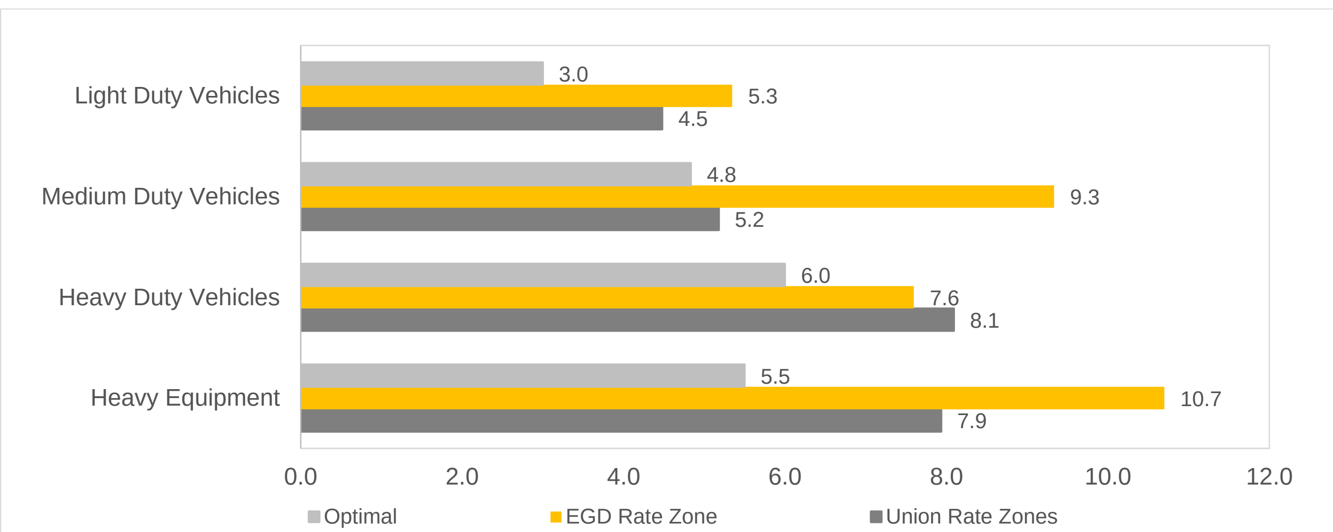


Figure 5.7-2: EGI Average Vehicle Age

.

Depending on a vehicle's weight class, analysis indicates that average maintenance costs exceed the market value of a light-duty vehicle at an approximate age of five to seven years or 160,000 kilometres. For medium-duty vehicles, this point of replacement occurs at approximately seven to 12 years old or 175,000 kilometres. For heavy duty vehicles, this occurs at 12 years old or 350,000 kilometres.

As **Figure 5.7-2** shows, the average age of fleet assets for both rate zones is higher than the optimal age, highlighting the need for increased investments to ensure that fleet replacements continue to occur as per the replacement strategy. As part of integration activities to align fleet inventories and classifications, a single classification standard in line with broader industry standards was chosen and is now being applied across the enterprise.

5.7.5.3. Risk and Opportunity

Fleet vehicles and heavy equipment assets (see **Section 5.7.6**) have similar risks and opportunities. There are a number of consequences to EGI when vehicles and equipment exceed their useful life:

- Aging asset condition, resulting in decreased safety and reliability
- Increased maintenance costs
- Increased downtime (vehicles are more frequently in the shop for maintenance), decreasing employee productivity
- Operational safety concerns potentially affecting employees, contractors and the public when vehicles fail
- Increased downtime due to repairs can reduce overall productivity and can affect EGI's ability to serve its customers.
- Equipment that operates beyond its warranty sees an additional increase in maintenance costs (i.e., the cost of repairing certain equipment components that are out of warranty)

Based on the risk assessment analysis, fleet vehicles primarily pose a financial risk to EGI if they are not maintained or replaced as needed. Maintenance costs increase beyond the vehicle warranty and productivity is reduced due to increased downtime as a result of more frequent maintenance activities. On-road failure would also impact public safety and decrease productivity. Decreased productivity can affect the ability to serve our customers, potentially creating a risk to customer satisfaction.

5.7.5.4. Strategy Outcomes

Starting in 2020, the EGI Fleet and Equipment department will leverage the Fleet Category Management (FCM; also known as Supply Chain) organization to arrange the purchasing of all vehicle and heavy equipment assets, in alignment with Enbridge's enterprise supply chain strategy. The FCM team is accountable to source and purchase all vehicle and equipment assets to support EGI business operations (this strategy does not include tools purchases).

As part of integration activities, a comparison of EGD and Union rate zone assets was conducted. Analysis shows the asset hierarchy is very similar for both. Variances are explained by differences in work procedures.

As utility integration efforts continue to align workforce and work processes/procedures, the Fleet and Equipment department will adapt their inventories to support this change. The impacts of such changes may result in a new approach to vehicle standards, as well as equipment and tool use. Regardless of change initiatives in flight, transformation of the Fleet and Equipment asset base will likely require many years to complete.

The optimal replacement strategy for all fleet vehicles is determined by the lowest cost of a vehicle or equipment's lifetime. The lowest cost is determined by analyzing cost curves for maintenance. Asset replacement decisions are evaluated against the optimal replacement analysis plus age, mileage, hours of use, condition, risk of failure and functional requirements. Each asset is ranked and evaluated annually. In general, the optimal replacement point is determined when the maintenance costs begin to exceed the market value of the asset.

Table 5.7-3 shows the replacement cycle for light duty vehicles.

Table 5.7-3: Replacement Cycle for Light-Duty Vehicles

Class	Gross Vehicle Weight Rating	Replacement Cycle (Months)	Replacement Cycle (Kilometres)
1	0 – 6,000 lbs.	60	160,000
2	6,001 - 10,000 lbs.	72	160,000
3	10,001 - 14,000 lbs.	84	175,000

.

Table 5.7-4 shows the replacement cycle for medium duty vehicles.

Table 5.7-4: Replacement Cycle for Medium-Duty Vehicles

Class	Gross Vehicle Weight Rating	Replacement Cycle (Months)	Replacement Cycle (Kilometres)
4	14,001 - 16,000 lbs.	84	175,000
5	16,001 - 19,500 lbs.	120	175,000
6	19,501 - 26,000 lbs.	144	350,000

Table 5.7-5 shows the replacement cycle for heavy duty vehicles.

Table 5.7-5: Replacement Cycle for Heavy-Duty Vehicles

Class	Gross Vehicle Weight Rating	Replacement Cycle (Months)	Replacement Cycle (Kilometres)
7	26,001 - 33,000 lbs.	144	350,000
8	33,001 - 150,000 lbs.	144	350,000

5.7.6 Heavy Equipment

Heavy equipment is described as off-road building equipment; at EGI this asset subclass primarily consists of backhoes, trailers, compressors, forklifts, welding machines and directional drilling equipment. These assets are grouped together due to similarities in condition methodology and approach.

5.7.6.1. Condition Methodology

The analysis of heavy equipment assets used the same condition methodology for fleet vehicles. See **Section 5.7.5.1.**

5.7.6.2. Condition Findings

The average age for heavy equipment is 10.7 years for the EGD rate zone and 7.9 years for the Union rate zones. Analysis indicates that average maintenance costs exceed the market value of heavy equipment at approximately 12 years old (see **Figure 5.7-2**).

Based on Fleet Management system reporting, industry standards and asset assessment trends, the typical average useful life threshold for heavy equipment is at approximately 12 years of age (or approximately 7,000 service hours). This threshold is used as a guide for further detailed inspections. The condition of these units is thoroughly assessed when they reach their useful life threshold to make an informed decision to replace or refurbish the asset for continued service.

As **Figure 5.7-2** shows, the average age of heavy equipment assets for both rate zones is higher than the optimal age, highlighting the need for increased investments to ensure that heavy equipment replacements continue to occur as per the replacement strategy.

5.7.6.3. Risk and Opportunity

See **Section 5.7.5.3.**

.

5.7.6.4. Strategy Outcomes

EGI has an annual heavy equipment program based on average historical spending and is driven by proactively replacing assets based on detailed physical condition assessments and reactively acquiring new equipment based on business needs. Depending on evaluation results, there could be a decision to refurbish the asset instead of replacement. The current replacement cycle for heavy equipment is 144 months (12 years).

5.7.7 Tools

EGI uses a wide variety of tools, including electric air movers, drills, concrete saws, clay spades, gas surveyors, personal gas monitors, pipe locators, pipe squeeze-off tools, shoring boxes, torpedoes, grease guns, etc. In total, there are approximately 11,000 tools currently in use.

Due to the variety of tools and equipment, several inspection and calibration frequencies are in place. The general condition and functionality of tools are assessed by the operator prior to use and during scheduled inspections and calibrations. Deficiencies identified are reported where an assessment of the repair and replacement costs is completed to determine the appropriate course of action.

5.7.7.1. Risk and Opportunity

Not maintaining EGI's tool population presents both a safety risk to employees and customers during operation. In addition, productivity will decline due to increased downtime as a result of using inadequate tools, posing both a financial risk to EGI as well as impacting customer satisfaction.

5.7.7.2. Strategy Outcomes

The strategy for tools is to establish an annual replacement program based on average historical spend. The program is reactive in nature and driven by replacing/acquiring tools that are:

- Showing signs of wear and tear, or are broken and not repairable
- Stolen or lost
- Deemed obsolete by the manufacturer
- No longer approved for use due to evolving engineering standards and practices
- Required by EGI Operations departments for business function

Tools and equipment deemed obsolete and/or are no longer approved for use are removed from service, decommissioned and approved replacement assets are acquired.

5.7.8 Fleet and Equipment Capital Expenditure Summary

EGI has spent an average of $8M and $9M annually in the EGD and Union rate zones respectively for the Fleet and Equipment asset class. The total average capital spend is forecasted to be $12M (EGD RZ) and $13M (Union RZ) as summarized in **Table 5.7-6** and **Table 5.7-7**. Fleet and Equipment capital is further summarized as part of EGI's total five-year capital plan in **Section 6.**

Table 5.7-6: Fleet and Equipment Capital Summary ($ Thousands) – EGD Rate Zone

Program/Project Name	2021	2022	2023	2024	2025	Five-year Forecast
Vehicles	5,938	6,065	6,471	6,434	6,993	31,902
Heavy Work Equipment	3,827	3,909	4,170	4,146	4,507	20,560
Tools	1,099	1,119	1,205	1,195	1,295	5,913
EGD Rate Zone Total	**10,864**	**11,094**	**11,847**	**11,775**	**12,796**	**58,375**

Table 5.7-7: Fleet and Equipment Capital Summary ($ Thousands) – Union Rate Zones

Program/Project Name	2021	2022	2023	2024	2025	Five-year Forecast
Vehicles	6,048	6,170	6,589	6,606	7,176	32,590
Heavy Work Equipment	3,734	3,809	4,068	4,078	4,430	20,119
Tools	1,944	1,972	2,119	2,112	2,281	10,427
Union Rate Zones Total	**11,727**	**11,951**	**12,776**	**12,796**	**13,887**	**63,137**

Assumptions:

- *Vehicle and heavy equipment forecasts are based on the current fleet profile of 60.18% vehicles and 39.82% heavy equipment.*
- *The Tools forecast is based on historical spend values and an annual increase of 2.0% to account for inflation.*

.

5.8 Technology and Information Services (TIS)

The Technology and Information Services (TIS) asset class includes the Hardware, Software and Communications subclasses (**Figure 5.8-1**).

The Hardware asset subclass has three types of assets: laptops/desktops, desktop sustainment equipment and core & security infrastructure hardware. Desktop sustainment equipment includes the additional components that equip the end user, such as keyboards, telephone headsets, computer monitors, audio/visual equipment, telephony, printers, scanners and ergonomic equipment.

Core and security infrastructure hardware assets include network components, servers, security appliances and telephony equipment. Network hardware consists of routers, switches, hubs, firewalls, devices required to maintain voice communication and video conferencing networks. Servers consist of devices that operate EGI's applications and store data. Security hardware refers to equipment used to protect control systems, business applications, computer infrastructure and data networks. Telephony equipment includes routers, switches and desk telephones.

The lifespans of hardware assets typically range between four and seven years depending on the device. As the devices within each group vary in age, a portion of all the hardware assets are upgraded each year to ensure ongoing operational reliability.

Software assets consist of packaged applications (purchased from and generally supported by a vendor), developed applications (custom built in-house) and application infrastructure software (foundational infrastructure software and tools for applications).

Communications assets include mobile phones and field devices (such as GPS devices, push-to-talk radios, leak survey field technology and truck modems).

TIS applications and related technology work activities are driven by a combination of enhancement projects and life cycle upgrades and/or replacements. The over-arching objective is to ensure that TIS applications and related technologies provide desired functionality, perform efficiently and are usable, reliable, maintainable and compatible with other applications and technologies, while ensuring the required standard of security.

Effort is made to ensure the needs of each business area are met, including considerations related to legislative compliance, regulatory orders, and financial accounting and reporting requirements.

Investments are developed for each TIS investment and are prioritized using compliance, life cycle, financial and strategic drivers.

During the TIS application life cycle, technology and design reviews are held to ensure new systems are implemented in the most cost-effective manner, using standard tools and proper security coding practices.

5.8.1 Technology and Information Services Objectives

The overall goal of the TIS asset class is to meet EGI's information technology needs, established in response to asset, process and system objectives and concerns. The response to these needs and the decision to undertake a solution is guided by the TIS asset class objectives listed in **Table 5.8-1**.

Table 5.8-1: TIS Asset Class Objectives

Asset Class Objectives	Description
Functionality	Ensure solutions provided are fit for purpose based on business requirements and value.
Reliability	Maintain the ability of the asset to perform its required function over its useful life.
Security	Ensure controls and checks are in place for applications/software/data that protects the asset against threats and vulnerabilities.
Availability	Ensure that hardware, devices and/or applications/software are readily available for use when required and will work as intended.
Supportability	Maintain the ability of support and service staff to install, configure and monitor assets, identify exceptions and faults, isolate defects/issues preventing the asset from functioning as expected and provide maintenance services.
Maintainability	Continually ensure that assets are maintainable to isolate and correct defects, prevent unexpected breakdowns, maximize their useful life, meet new business requirements and simplify future maintenance procedures.
Continuous Improvement	Continuously evolve the understanding of condition and risk for TIS assets and use risk, cost and performance information to drive asset-related decisions.

The performance measures for the TIS asset class are as follows:

- Number of application/system outages
- Number of defects
- Number of vulnerabilities and security-related incidents
- Adherence to security policies and scorecard objectives
- Security patching levels
- Overall system and application availability metrics
- Number of hardware incidents
- Number of change and enhancement requests
- Incident response time and resolution time met

To achieve the Technology and Information Services asset class objectives listed in **Table 5.8-1**, asset investment decisions are governed by the life cycle management strategies outlined in **Table 4.1-1**.

.

5.8.2 Technology and Information Services Hierarchy

The asset subclass hierarchy for the Technology and Information Services asset class is illustrated in **Figure 5.8-1**.

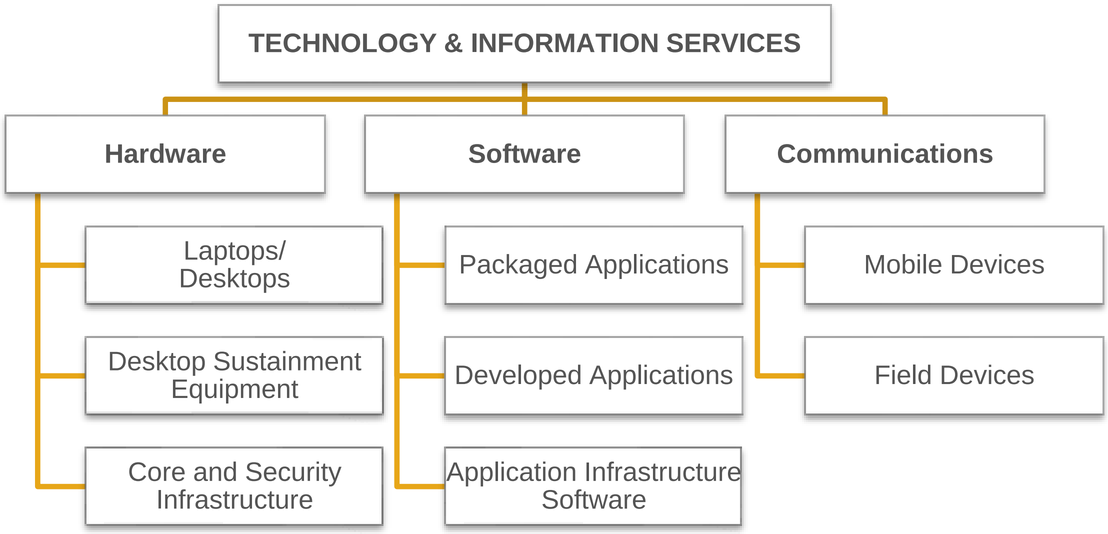


Figure 5.8-1: Technology and Information Services Hierarchy

5.8.3 Technology and Information Services Inventory

The TIS asset class inventory is presented in **Table 5.8-2.**

Table 5.8-2: TIS Asset Class Inventory

Asset	EGD Rate Zone	Union Rate Zones
Hardware		
Laptops and Desktops	2,050	2,003
Desktop Sustainment Equipment	N/A*	N/A*
Core and Security Infrastructure	2437	2862
Software		
Packaged Applications	199	35
Developed Applications	76	28
Application Infrastructure Software	11	19
Communications		
Mobile Phones	2,463	1,845
Field Devices	1,070	832

******The inventory count for Desktop Sustainment Equipment assets is not recorded.*

.

5.8.4 Technology and Information Services Condition and Strategy Overview

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

.

5.8.5 Laptops and Desktops

This TIS asset subclass includes over 4,000 laptops and desktops. The majority of employees and contractors rely heavily on the day-to-day performance of their laptops and desktops to perform daily tasks and to access company communications, applications and resources on EGI's networks and systems.

Laptops and desktops are covered by the manufacturer's warranty for three years.

5.8.5.1. Condition Methodology

The condition of laptops and desktops is not proactively monitored. If these assets experience failures or signs of operating issues, a request for support and resolution is logged through ServiceNow, the TIS Service Management system. All laptops and desktops are labelled with a unique asset tag number to identify the asset for tracking purposes. The ServiceNow request is mapped to the user's unique asset tag number, which ensures the necessary remediation work is completed on the appropriate asset.

5.8.5.2. Condition Findings

Laptops and desktops tend to experience performance issues and failures in their fourth year of operation, a year after their warranty expires. Laptop failures can occur for a variety of reasons, including complete hard drive failures, processor board failures, memory failures and significantly degraded performance.

In 2019, 80% of laptops and desktops were replaced in a significant initiative to move to the Windows 10 operating system due to Windows 7 being at end-of-life. This resulted in an almost 40% reduction in total logged incidents by users, demonstrating that replacing these assets before problems start to occur reduces the number of incidents reported.

5.8.5.3. Risk and Opportunity

The major risk identified for laptops and desktops is financial risk–aging assets result in a reduction in productivity and increase in maintenance costs. There are a number of consequences if these assets are not replaced soon after warranty expiry:

- Replacement parts for existing hardware become obsolete, resulting in an asset that is more expensive to repair.
- Existing hardware is not compatible with newer operating systems and applications, resulting in an asset with reduced functionality.
- Maintenance costs can become excessive after warranty expiry.
- There is an overall reduction in productivity due to aging assets.

5.8.5.4. Strategy Outcomes

EGI's renewal strategy is to replace laptops and desktops every four years. Industry best practice suggests replacing laptops and desktops every three years, in line with its warranty (also three years). EGI's strategy allows for one additional year past warranty expiration prior to replacement, reducing the overall capital cost of the laptop refresh cycle.

Defective or poorly performing laptops that are out of warranty are repaired if the problem is quickly determined and if the repair can be done cost-effectively. Otherwise, the device is replaced. The impact of repairing an out-of-warranty device includes productivity loss to the end user, technician repair time and the cost of unbudgeted parts for repair. As more and more out-of-warranty devices fail over time, EGI's replacement strategy is most effective at balancing risk, cost and performance for this group of assets.

The four-year replacement policy for laptops and desktops has been in place for the last 20 years and has proven to be sufficient and manageable from a resourcing perspective.

EGI follows both a proactive and reactive maintenance strategy for these assets, managed through ServiceNow.

.

5.8.6 Desktop Sustainment Equipment

Desktop sustainment assets include all TIS hardware equipment required for business operations. Audio/visual equipment, printers, monitors, keyboards, mice, privacy screens and headsets are some examples of desktop sustainment equipment.

5.8.6.1. Condition Methodology

The condition of desktop sustainment equipment is evaluated on the following:

- New hire onboarding information
- Hardware incident requests
- Feedback and requests from ergonomic specialists and business users

The condition and health of desktop sustainment equipment is not proactively monitored.

5.8.6.2. Condition Findings

Annually, there are approximately:

- 350-400 ergonomic-related requests requiring ergonomic equipment
- 400-450 onboarding requests requiring desktop sustainment equipment to support new employees/contractors
- 650-700 hardware incidents

5.8.6.3. Risk and Opportunity

The major risks identified for desktop sustainment equipment are:

- **Employee and Contractor Safety Risk**: Inadequate desktop sustainment equipment may compromise the health and safety of employees who require specific equipment for ergonomic purposes.
- **Operational Risk**: Inadequate or lack of desktop sustainment equipment required for new and existing employees results in a reduction in productivity.

5.8.6.4. Strategy Outcomes

Desktop sustainment equipment is provided on an as-needed, reactive basis. Desktop sustainment equipment is issued based on the following:

- Equipment is damaged, broken or malfunctioning.
- Equipment is required based on an ergonomic assessment.
- Equipment is required for new employee and contractor hires.

EGI uses historical spend to project the capital requirements for the replacement of desktop sustainment equipment.

.

5.8.7 Core and Security Infrastructure

5.8.7.1. Condition Methodology

Servers and appliances tend to experience performance issues and failures in their fifth year of operation (constituting approximately 30% of these assets). The physical condition of core and security hardware is not proactively monitored. If these assets experience failures or signs of operating issues, the hardware vendor is contacted for support and an incident ticket is logged through ServiceNow.

5.8.7.2. Condition Findings

Core and security hardware asset failures can occur for a variety of reasons, including hard drive failures, processor failures, memory failures and significantly degraded performance.

5.8.7.3. Risk and Opportunity

The major risk identified for core and security hardware failures is financial risk–aging assets result in a reduction in productivity due to incidents and outages and increase in maintenance costs. There are a number of consequences if these assets are not replaced soon after warranty expiry:

- Existing hardware is not compatible with newer operating systems and applications, resulting in an asset with reduced functionality.
- Maintenance costs can become excessive after warranty expiry.

5.8.7.4. Strategy Outcomes

EGI's strategy is to replace servers and appliances for core infrastructure and security hardware every five years. For most of their life (four years), these assets are under warranty. This strategy allows for a short extended use of the asset past warranty expiration (one additional year) prior to replacement.

Defective or poorly performing servers and appliances that are out of warranty are repaired by the vendor through hardware maintenance contracts following warranty expiry. The impact of repairing an out-of-warranty device includes potential productivity loss to the end user due to applications being unavailable and the costs required for the hardware maintenance contracts. As more and more devices fail over time, EGI's replacement strategy is most effective at balancing performance, cost and risk for this group of assets.

EGI follows both a proactive and reactive maintenance strategy for these assets, managed through ServiceNow and the hardware vendor(s).

5.8.8 Packaged and Developed Applications

TIS assets include a number of key applications that provide critical functionality to EGI employees and customers, contributing to the support and growth of its natural gas storage, transmission and distribution businesses. Key TIS applications also rely on ancillary systems that have been added over time to provide additional functionality as business needs change and grow.

Packaged applications, also known as Commercial-off-the-Shelf (COTS) software, are solutions purchased from and primarily supported by a vendor; support includes software version upgrades. Software upgrades are required for the application to stay current and supported. For some solutions, EGI provides functionality and enhancement requests and the vendor provides additional software releases to address these requests. The age range of packaged applications extends out as far as 15 years; however, the majority are within a 10-year range.

Developed applications are custom-built solutions by EGI to meet business requirements. This generally occurs when no packaged solutions are available to support business requirements. The age range for developed applications can extend out as far as 20 years before a life cycle replacement or significant upgrade occurs. Technology upgrades and enhancements may occur regularly for internally developed solutions.

5.8.8.1. Condition Methodology

The condition of packaged and developed applications is evaluated on the following:

- Ability to meet business requirements
- Hardware to meet vendor support requirements
- Software to meet vendor support life cycle (for packaged applications)
- Ability to enhance and support existing applications

5.8.8.2. Condition Findings

Table 5.8-3 summarizes the key packaged applications used at EGI and outlines their current state and condition. Each rate zone continues to operate some systems. Over time, most systems will be integrated. After the systems are integrated, their maintenance costs will be allocated to the rate zones.

Table 5.8-3: Application State – Key Packaged Applications[11]

Application	Application Overview	Age (Years)	Application State
AutoSol Communication Manager (UG)	Polling engine application for reading measurement information	15	Hardware is currently under warranty. Software is current and supported.
Corrosion Survey Management System (CSMS)	Application for leak survey inspection-related work	4	The solution is built on eGIS, which is being upgraded in 2020. The application software will be upgraded in 2020-2021.
Corrosion Survey (DNV GL SynerGi Pipeline)	Pipeline integrity software used in the Union rate zones for scheduling, tracking and field collection of pipeline risk management data	7	Software update completed in 2018.
Customer Information System (CIS)	Customer care and billing applications (SAP CIS and Banner)	9	CIS applications used in both rate zones will be migrated to a SAP cloud-based solution in 2021 as part of EGI integration.

[11] *Copperleaf C55 is not listed as it is managed by Corporate Services.*

.

Application	Application Overview	Age (Years)	Application State
EGI Extranet	EGI external website for the EGD rate zone with self-service capabilities	3	Hardware was replaced in 2017/2018. Rewrite and foundational software upgrade occurred in 2017/2018. This application is being integrated with the uniongas.com extranet in 2021.
Geographic Information System (eGIS)	Application for developing geographic views of EGD rate zone asset data	7	Hardware was replaced in 2020. Software was upgraded in 2020.
GIS Suite - G/Technology (Hexagon)	Contains spatial and attribute information related to UG rate zone underground assets	6	Application is being upgraded in 2020 to maintain supportability.
GMAS	Collection and validation system for measurement information in the Union rate zones	20	Hardware is currently under warranty. Software is current and supported.
ITRONFCS	Used to facilitate the meter reading process in the Union rate zones	1	Software was upgraded in 2019.
Leak Survey Management System (LSMS)	Application for leak survey inspection-related work	5	The solution is built on eGIS, which is being upgraded in 2020. The application software will be upgraded in 2020-2021.
Meter Reading System (MVRS)	Application for storing manually-gathered meter readings and meter maintenance information	1	The hardware and application software were upgraded in 2019. This application will be integrated with the ITRONFCS solution as part of EGI integration in 2021.
PIMSlider	Application for analyzing asset condition data and the optimal lifespan of assets	4	Hardware is currently under warranty. Software is current and supported.
Powerspring (formerly Metretek)	Application providing automated meter readings for large volume customers	3	Hardware and software were upgraded to current and supported versions in 2017.
ProjectWise	Managed environment for EGI employees in the Union rate zones to deposit, store, retrieve and allow for the disposition of engineering records	4	Application is being upgraded in 2020 to maintain support.
PureConnect	Call centre application for call management in the Union rate zones	1	Software was last upgraded in 2019 to the current version. An annual upgrade is performed to stay current. Hardware was replaced in 2018.
SCADA	Supervisory control and data acquisition systems that monitor and control underground transmission pipelines	1	Hardware was upgraded in 2019 as part of the GDS control centre migration and SCADA consolidation. Software is being upgraded in 2020.
Service Suite (Advantex)	Electronic planning and dispatch application for the Union rate zones	1	This application is to be replaced by the integrated Work and Asset Management solution.
Teldig	Locate-tracking application used through Ontario One Call	7	Hardware was upgraded in 2019. Application software was upgraded in 2019.

.

Application	Application Overview	Age (Years)	Application State
uniongas.com	EGI external website for the Union rate zones with self-service capabilities		This application is being integrated with the EGD rate zone extranet in 2021.
Work and Asset Management (WAMS)	Application to manage work and assets	3	Hardware will upgraded in 2020. This application is to be replaced by the Enbridge Unify solution.

Table 5.8-4 summarizes the key developed applications used at EGI and outlines their current state and condition.

Table 5.8-4: Application State – Key Developed Applications

Application	Application Overview	Age (Years)	Application State
Capital and O&M Management (COMMS)	Application suite for managing EGI capital investments	10	Hardware is currently under warranty. Software was upgraded in 2018.
Classify Allocation Report and Exchange (CARE)	Nominations and scheduling system for gas storage and transportation	25	Hardware is currently under warranty. Software is current and supported.
Construction Administration Records System (CARS)	Application managing construction work orders for new customer service lateral attachments	20	This application is to be replaced by the Enbridge Unify solution in 2023.
Contrax	Application used to create, renew, manage and bill non-cycle large volume customers (Union RZ)	1	Hardware is currently under warranty. Software is current and supported.
Cross Bore Risk Mitigation	Analytics tool used to assess the probability of cross bores	1	Hardware is currently under warranty. Software is current and supported.
Customer Connections Worksuite	Application for managing Customer Connections information	5	Hardware is currently under warranty. Software is current and supported.
eApp	Tool used to submit natural gas services requests online	10	This application is being integrated with the getConnected application used in the Union rate zones in 2021 as part of EGI integration.
Energy Cost Reporting (EnCore)	Application used to develop cost models for energy supply	6	Hardware is currently under warranty. Software is current and supported.
EnTrac	Management software for large volume and direct purchase contracts	14	Hardware will be out of warranty in 2021. Software is current and supported.
Field Record Access (FRA)	Application used to locate asset information	1	The solution is built on eGIS, which is being upgraded in 2020. Newly implemented in 2020; replaced the aging Datapak application.
Finance Business Analysis (FBA)	Data warehouse for reconciliation of customer consumption	5	Hardware is currently under warranty. Software is current and supported.
GetConnected	Tool used to submit natural gas services requests online	10	This application is being integrated with the eApp application used in the EGD rate zone in 2021 as part of EGI integration.
iViewer	Image repository for as-laid drawings, scans of service tickets and field notes	10	Hardware is currently under warranty. Application software is being upgraded in 2020 to maintain support.

.

Application	Application Overview	Age (Years)	Application State
Land Management (rowAMPS)	Application to manage land/property and municipal taxation work	3	Cloud solution as a service offering; implemented in 2017.
Revenue Analysis and Volume Estimation (RAVE)	Application for volumetric analysis, estimation and budgeting	16	Hardware is currently under warranty. Software is current and supported.
Unbundled Rate Compliance (URICA)	Application to request and track unbundled services as per Natural Gas Electricity Interface Review (NGEIR) direction	13	Hardware is currently under warranty. Software is current and supported.
Unionline	Secure web-based tool providing online services to contract customers	20	Hardware is currently under warranty. Software is current and supported.

5.8.8.3. Risk and Opportunity

The major risks identified for packaged and developed applications are:

- **Financial Risk**: Unplanned software outages may compromise EGI's ability to meet business needs and requirements, reducing overall productivity, and may compromise EGI's ability to meet financial and reporting compliance requirements. Maintenance costs may increase due to reactively addressing required software and hardware repairs.
- **Operational Risk**: Inadequate (or the lack of) applications required for employees to complete assigned tasks may contribute to productivity loss.
- **Reputational Risk**: cybersecurity exposure due to the inability to apply required security patches may potentially lead to negative reputational impacts for EGI if any breaches occur.

5.8.8.4. Strategy Outcomes

The replacement strategy for packaged applications is driven by vendor release schedules specific to each application and changes in business requirements. A replacement and/or upgrade can also occur due to the vendor discontinuing software support or application enhancements.

The replacement strategy for developed applications is driven by forecasted requirements for the business. Maintenance releases and software defect fixes are rolled out regularly to reactively maintain the performance of the application. Major enhancements and renewals are implemented for projected new or changing business requirements.

Applications are replaced when business requirements change or when a vendor ceases support for the application. EGI integration will drive a number of application replacements and migrations during the 2021-2023 timeline.

.

5.8.9 Application Infrastructure Software

The Application Infrastructure Software asset subclass encompasses software products and tools that support and serve as the platform environment for TIS solutions. Some of the key components of this asset subclass include database software used to store data for various applications, application deployment and execution software, integration software used for interfacing between applications and services and reporting tools.

5.8.9.1. Condition Methodology

The condition of application infrastructure software is evaluated on the following:

- Ability to meet the vendor's support life cycle strategy
- Ability to support key foundational software required for business applications

5.8.9.2. Condition Findings

Table 5.8-5 outlines the current age and state of key application infrastructure software used at EGI:

Table 5.8-5: State of Application Infrastructure Software

Application	Application Overview	Age (Years)	Year(s) since last refresh	Application State
DataStage	Extract, transform and load (ETL) integration tool	18	1	Software is current and supported.
Harvest	Source code management software	20	8	Software is supported.
Quality Assurance and Testing Suite	Testing and quality assurance tool suite	17	5	Software is supported.
Microsoft SQL Server	Database management software	21	1	Software is current and supported.
Oracle Database	Database management software	21	3	Upgrade to current version scheduled in 2020-2021.
Oracle Fusion	Integration suite providing interfacing capabilities between applications	8	1	Software is current and supported.
Oracle Golden Gate	Data replication software	5	5	Software is current and supported.
Oracle WebLogix Application Server	Management software for deployment and execution of applications	17	3	Software is current and supported.
SAP Business Objects Reporting Suite	Suite of reporting tools for business reporting and analytics	12	4	Upgrade to current version scheduled for 2020- 2021.
BizTalk	Message queuing and orchestration software for real-time application to application integrations	20	5	Upgrade to current version scheduled for 2021.
Team Foundation Server	Foundational software used for .Net application development	15	8	Upgrade to current version taking place in 2020.

.

5.8.9.3. Risk and Opportunity

The risks identified for application infrastructure software is the same as for packaged and developed applications (**Section 5.8.8.3**).

5.8.9.4. Strategy Outcomes

A proactive replacement strategy is in place for application infrastructure software, driven by forecasted changes of existing software applications and business requirements. Maintenance is reactive–performance issues or software defects are addressed as they are identified. The application infrastructure software systems identified for upgrade/renewal in the next three years are:

- Microsoft SQL Server instances and databases
- Oracle Database instances and databases
- Oracle WebLogic application servers and Oracle Fusion integration software
- SAP Business Objects reporting software
- BizTalk integration software
- Team Foundation development platform software

.

5.8.10 Mobile Devices

Mobile devices consist of smartphones, cell phones and Push-to-Talk radios. The industry best practice to replace mobile devices is two to three years, which aligns with smartphone manufacturers' release cycles, as well as the typical data plan contract.

5.8.10.1. Condition Methodology

The condition of mobile devices is not proactively monitored. If these assets experience failures or signs of operating issues, the user contacts the TIS Service Desk. In addition, the TIS asset class relies on new hire and business needs requests for equipping new mobile device users.

5.8.10.2. Condition Findings

Annually, there are approximately 1,230 mobile device requests, including both normal life cycle replacement and mobile device replacement due to hardware issues.

5.8.10.3. Risk and Opportunity

The major risks identified for mobile device assets are:

- **Employee and Contractor Safety Risk; Public Health and Safety Risk**: Inadequate (or the lack of) mobile devices hinder the ability of employees to respond to emergency field situations, which may contribute to the severity of an incident and potentially endanger lives of the public.
- **Operational Risk**: Inadequate (or the lack of) mobile devices hinder the ability of employees to resolve off-hours, on-call situations, which may affect the reliable and safe operations of EGI's systems and networks.

5.8.10.4. Strategy Outcomes

The TIS asset class strategy for mobile devices is to stay one release cycle behind manufacturer releases as mobile devices are available at much lower cost. As such, mobile devices have a proactive replacement strategy of every three years driven by industry best practice and release cycles.

Mobile devices are reactively maintained to address performance issues and damaged/broken devices on an as-needed basis within the three-year replacement window. Approximately 500 devices are replaced annually as per the refresh strategy.

EGI uses historical spend to project the capital requirements for the replacement of mobile devices.

5.8.11 Field Devices

Field devices include ruggedized laptops, Toughpads and Toughbooks, printers, plotters and multi-function devices, GPS devices and truck modems for signal strengthening.

5.8.11.1. Condition Methodology

The following inputs are used to assess the condition and suitability of field devices:

- Incident requests logged in ServiceNow
- Feedback from end users on field device performance
- Business needs driving field devices requirements

5.8.11.2. Condition Findings

Typically, field devices experience an elevated level of breakage and performance issues by the fourth year of use. Due to exposure to tough working conditions, field devices experience significant wear and tear, requiring maintenance on a frequent and reactive basis.

5.8.11.3. Risk and Opportunity

The major risks identified for field devices are:

- **Employee and Contractor Health and Safety Risk; Public Health and Safety Risk**: Inadequate (or the lack of) field devices hinders the ability of employees to respond to emergency field situations due to device unavailability
- **Operational Risk**: Inadequate (or the lack of) field devices may result in productivity loss due to increased time travelling between office and job sites.

5.8.11.4. Strategy Outcomes

The majority of field devices, such as ruggedized laptops, Toughbooks and Toughpads, have a four-year replacement strategy, based on industry best practices and EGI's condition experiences. Some assets (such as truck modems) do not have an industry-directed replacement cycle and are reactively replaced as they fail. TIS uses historical spend to project the capital requirements for the replacement of field devices.

.

5.8.12 Technology and Information Services Capital Expenditure Summary

EGI has spent an average of $32M and $24M annually in the EGD and Union rate zones respectively for the Technology and Information Services asset class. The total average capital spend is forecasted to be $30M (EGD RZ) and $23M (Union RZ), as summarized in **Table 5.8-6** and **Table 5.8-7**. The TIS capital is further summarized as part of EGI's total five-year capital plan in **Section 6.**

Table 5.8-6: TIS Capital Summary ($ Thousands) – EGD Rate Zone

Program/Project Name	2021	2022	2023	2024	2025	Five-Year Forecast
TIS Infrastructure	4,882	8,225	5,816	10,513	6,132	35,568
Business Solutions	23,456	31,215	25,027	16,828	18,632	115,158
EGD Rate Zone Total	**28,216**	**39,365**	**30,796**	**27,284**	**25,109**	**150,770**

Table 5.8-7: TIS Capital Summary ($ Thousands) – Union Rate Zones

Program/Project Name	2021	2022	2023	2024	2025	Five-Year Forecast
TIS Infrastructure	5,062	9,077	6,432	12,684	7,945	41, 201
Business Solutions	6,261	9,109	7,730	24,669	24,972	72,741
Union Rate Zones Total	**11,323**	**18,186**	**14,162**	**37,352**	**32,918**	**113,942**

.

6. Summary of Capital Expenditure

6.1 Portfolio Optimization

Using the methodology for optimization outlined in **Section 4**, this section describes the summary of the capital expenditures required to meet EGI's asset management goals and to balance risk, cost and performance. Through careful consideration of the key inputs to the asset investment planning process (risk, customer engagement feedback, resource constraints), this plan provides critical direction for the next five years.

6.1.1 Investment Criteria

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

- Investment scope met EGI's capitalization policy.
- Investments presented a well-articulated purpose, need and timing aligned with asset class objectives and life cycle management strategies.
- Investment scope definition and alternatives adequately addressed project risks and/or opportunities.
- Investments supported the asset management principles of balancing risk, cost and performance.
- Execution risks were reasonable (resource capacity).
- Initiatives identified as mandatory were justified, based on:
  - Compliance requirements
  - Exceeding a risk limit within EGI's intolerable risk region or Very High risks on the Enbridge Risk Matrix (**Figure 4.1-7**)
  - Third-party relocation driven
  - Program work with sufficient history and risk to warrant continuation
  - Projects that meet the economic feasibility tests in *EBO 188* and *EBO 134*
  - Investments that were already executing with costs continuing into 2021-2025

In total, 1,251 Union rate zone investments and 863 EGD rate zone investments were included in the optimization of the five-year plan. Separate optimizations were run for each rate zone. The initial pre-optimized request for capital is illustrated in **Figure 6.1-1** and **Figure 6.1-2**, generated from the asset investment planning tool (C55).

6.1.2 Capital Considerations

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

To complete EGI's latest portfolio optimization, the outcome of the MAADs Decision (*EB-2017-0306/EB-2017-0307*) and smoothing the impact to ratepayers were considered when establishing the capital constraint. The MAADs Decision established the Regulatory framework and provided EGI with the approved five-year (2019-2023) annual Incremental Capital Module (ICM) Materiality Threshold, giving EGI access to rate recovery for qualifying capital investments over and above this Materiality Threshold through the OEB's Incremental Capital Module. The 2021 ICM Materiality Threshold formula was used to determine EGI's capital constraint for 2021. For the years 2022 to 2025, the capital constraint was escalated based on the projected growth factor, allowing EGI to balance rate impacts with the utility's obligation to serve and maintain its plant. The capital constraint is inclusive of overheads[12].

EGI's capital spend requirements up to the OEB-approved ICM Materiality Threshold is described as Base Capital. To understand which projects would be considered incremental and potentially ICM-eligible, EGI applied descriptions of Base Capital and Incremental Capital Eligible to all investments for optimization (**Table 6.1-1**):

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

.

Table 6.1-1: Base Capital and ICM-eligible Capital Descriptions

Term	Description
Base Capital	• Represents the ongoing capital requirements of the utility to maintain safe and reliable operations and to economically attach new customers and pursue opportunities for innovation • Driven by asset class strategies and programmatic work that has sufficient history and risk to warrant continuation • Supported by existing rates (through depreciation expense, annual price cap index rate increases, or incremental revenues from customer growth)
ICM-eligible Capital	• Represents discrete projects requiring an in-service capital investment of over $10M • Refers to spend driven by asset class strategies and not supported by existing rates • Total incremental spend will include all capital costs associated with the identified project incurred up to the project's in-service year when ICM is requested. • ICM eligibility does not confirm that EGI will seek ICM recovery for these projects.

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

6.1.3 Optimization Results

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

For the EGD rate zone, the initial pre-optimized request for capital exceeded the capital constraint in 2021, 2022 and 2024 (**Figure 6.1-1**). For the Union rate zones, the initial pre-optimized request for capital exceeded the capital constraint in all years (**Figure 6.1-2**). It is important to note that while overheads are included with each investment's forecast when the plan is approved, at the time of optimization, overheads are managed as their own annual forecast due to the potential time shifting of investments. Overhead amounts are approximated based on the most recent approved plan at the time of optimization and then refined at the investment level once project timing is confirmed and the plan approved.

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

.

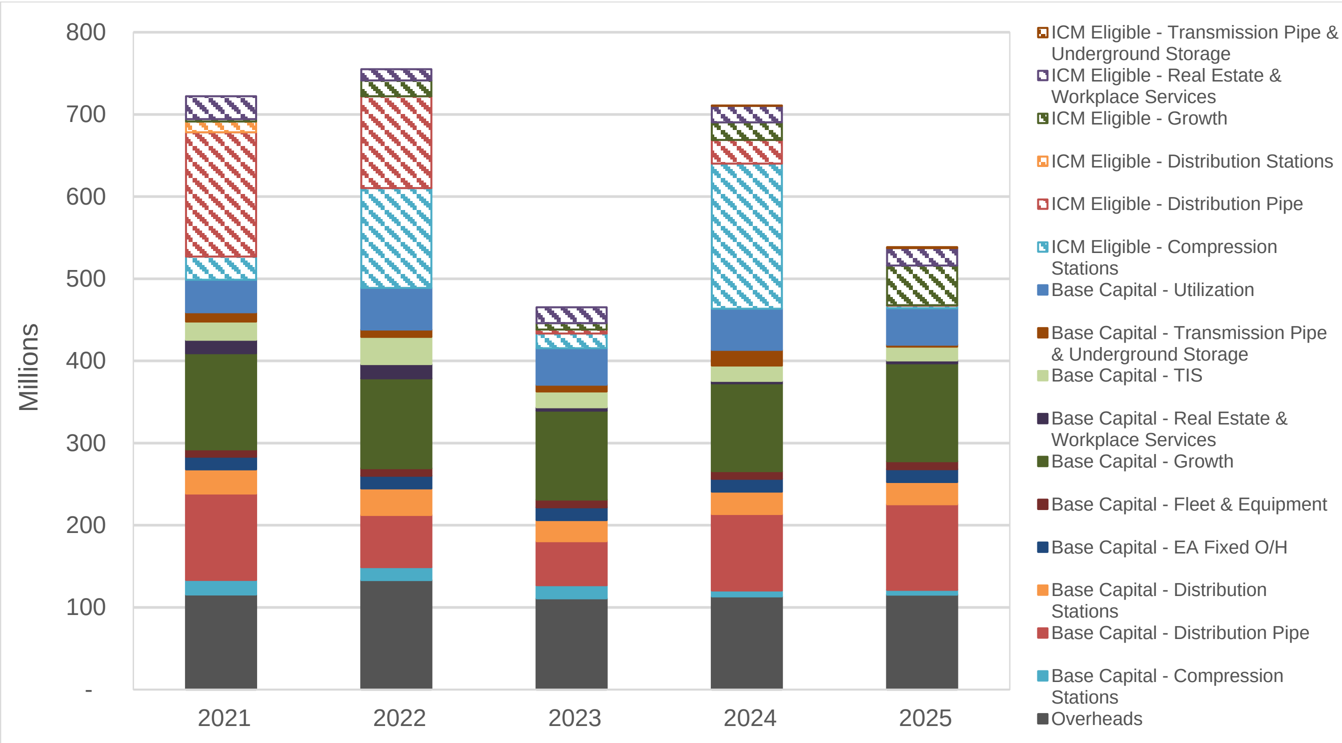


Figure 6.1-1: EGD Rate Zone Pre-Optimized Spend Profile (Capital Expenditure)

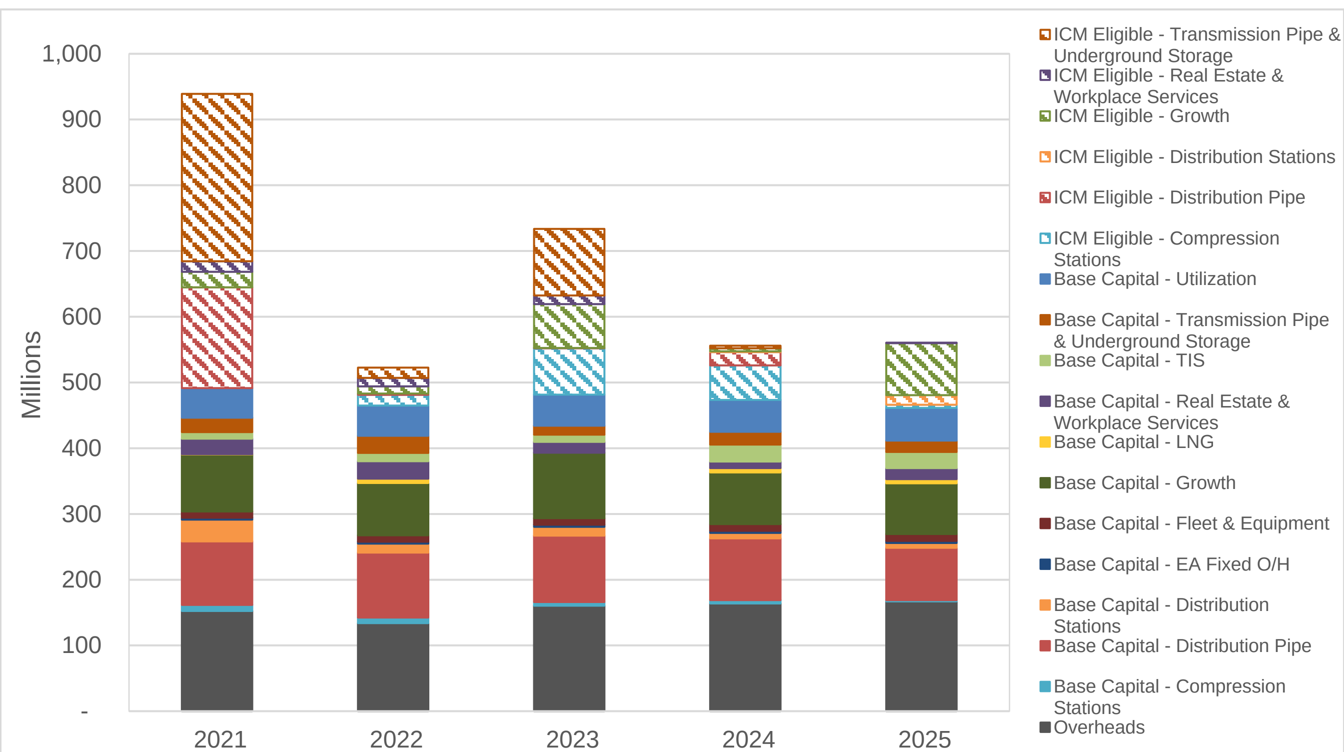


Figure 6.1-2: Union Rate Zones Pre-Optimized Spend Profile (Capital Expenditure)

.

Prior to optimization, investments were categorized into planning groups (**Table 6.1-2**) in the asset investment planning tool, C55, based on asset management principles; this supported optimization activities where different treatment (fixed or variable timing) could be applied to the investment groups at the time of optimization. A majority of investments (85%) have fixed timing while approximately 15% have variable timing.

Table 6.1-2: Planning Groups

Planning Group	Description	Optimization Treatment
Base Capital - Compliance	Investment compliance requirements validated	Fixed timing
Base Capital – Mandatory	Investment mandatory requirements validated	Fixed timing
Base Capital - Executing	Executing investment to continue with previously approved timing	Fixed timing
Base Capital – Executing Flagged for Re-Optimization	Executing investment that could potentially have the remainder of the work shifted in timing	Timing optimized based on value
Base Capital – Risk Based	Value framework completed on the investment and not compliance, mandatory nor executing	Timing optimized based on value
Overheads	Overheads	Fixed timing
Incremental Capital Eligible – Risk Based	Investment meets ICM criteria. Value framework completed on the investment and not compliance, mandatory nor executing	Timing optimized based on value
Incremental Capital Eligible – Non-Risk Based	Investment meets ICM criteria. Compliance/ mandatory requirements validated or executing.	Fixed timing

Running C55 optimization at the defined capital constraint for each rate zone, an optimized solution could not be obtained. This was due to the level of fixed and mandatory projects.

To resolve this, a review of all investments that met the incremental capital requirements was completed. ICM-eligible investments that were likely to be causing the optimization runs to fail were removed from optimization, providing EGI with the best understanding of an optimized typical base spend profile. These investments were brought back into the plan after optimization was rerun. The objective was to consider as many investments within base capital before pursuing incremental capital treatment.

The optimized result and ICM-eligible projects were reviewed with all asset managers and business stakeholders. Proposed adjustments were driven by resource capacity, re-alignment with life cycle management strategies and where possible, maintaining a total spend within the capital constraint. Resource implications were also considered for routine maintenance activities to ensure that project pace and timing met life cycle strategies, adequately reduced risk and identified as feasible. Given the challenges faced in 2020, once COVID-related impacts to 2020 were starting to be identified, adjustments were made to reflect the impact on timing and cost of specific investments. Updates for any ICM-eligible projects were also reviewed and adjusted. Adjustments were incorporated as necessary through consultation with asset managers and using the value framework for project comparison.

Figure 6.1-3 and **Figure 6.1-4** present the five-year capital requirements by asset class, with five years of historical spend. For the EGD rate zone, the capital requirements to meet asset class objectives and life cycle management strategies, while managing risk, exceed the capital available for optimization in most years. For the Union rate zones, the capital requirements exceed the capital available for optimization in all years. The capital that exceeds the capital available for optimization can be considered as ICM-eligible capital per the definition in **Table 6.1-1**. The final five-year portfolio of spend was reviewed and approved by the Vice President of Engineering and the Asset Management Steering Committee.

Note: The total forecasted capital expenditures categorized by asset class depicted in **Figure 6.1-3** and **Figure 6.1-4** are comprised of each investment's direct costs and the associated overheads. Asset class historical spend profiles do not include associated overheads; for this reason, overheads are identified as a separate category historically.

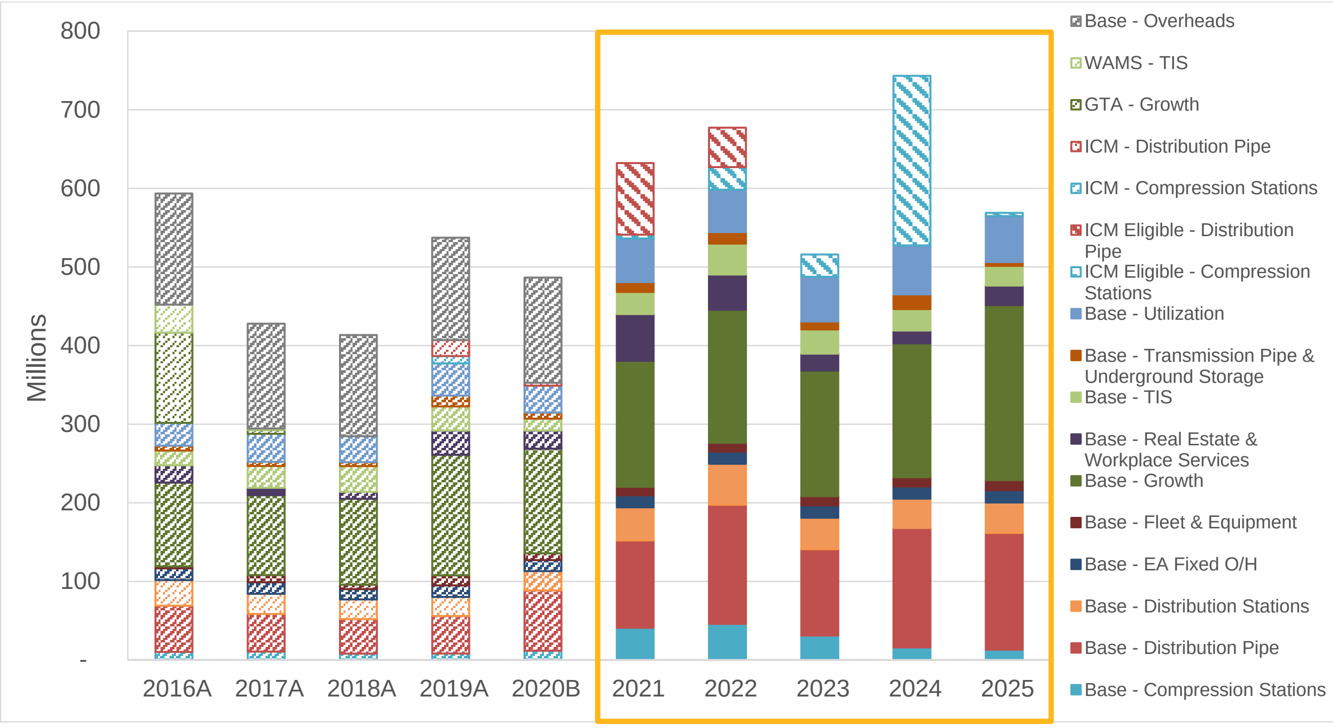


Figure 6.1-3: Final Five Year Plan by Asset Class (with ICM) – EGD Rate Zone (Capital Expenditure)

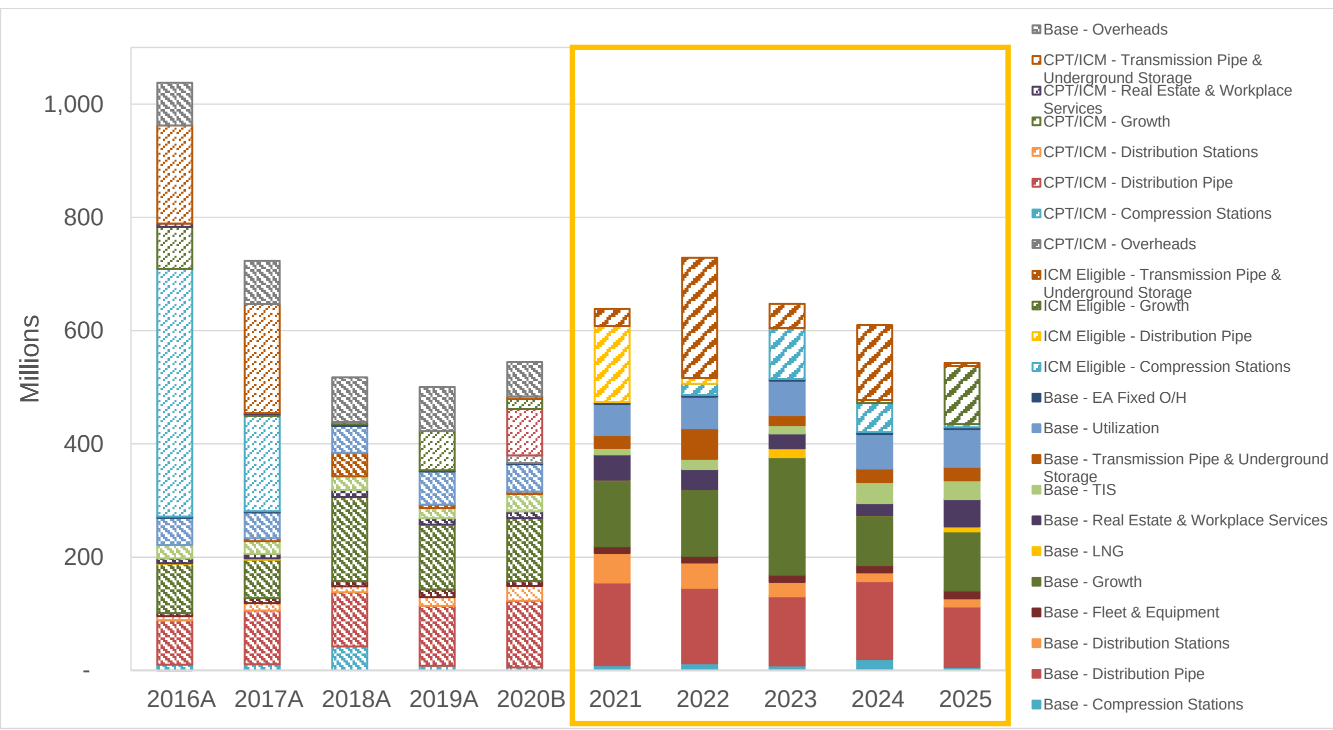


Figure 6.1-4: Final Five Year Plan by Asset Class (with ICM) – Union Rate Zone (Capital Expenditure)

Note: Historical actuals include both Capital Pass Through (CPT) Mechanism / Incremental Capital Module (ICM) projects. Forecast legend references ICM-eligible projects.

.

Table 6.1-3 and **Table 6.1-4** list the ICM-eligible capital projects for the EGD and Union rate zones respectively. Investment costs do not include overheads.

Table 6.1-3: ICM-Eligible Capital Projects – EGD Rate Zone

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

[13] *The St. Laurent portfolio of work consists of four phases of work and each phase is comprised of separate projects. Phases 1 & 2 have been previously completed, with Phases 3 & 4 remaining in this forecast period. Phase 3 includes the following investments: Three PE main investments in 2021 including Lower Section, Coventry/Cummings/St Laurent and Montreal to Rockcliffe. Phase 4 includes the following investments: NPS 12 St. Laurent Aviation Pkwy and NPS 12 St. Laurent Queen Mary/Prince Albert in 2022. The investments comprising Phases 3 & 4 will be combined in a single Leave to Construct application that will be submitted in Fall 2020.*

.

Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total Net Capital ($M)	Driver
	SCOR: Meter Area-Upgrade	Ph 1 - 2021	34.2	45.5	Condition
		Ph 2 - 2022			
	Storage Crowland (SCRW): Station-Renewal In-Place	2025	27.9	27.9	Obsolescence
Transmission Pipe and Storage	Crowland Pool (PCRW): Wells-Upgrade	2026	1.7	11.7	Compliance, Condition
REWS	Kennedy Road Expansion	2023	15.0	26.3	Condition
	Station B New Building	2021	15.5	17.6	Condition, Function, In Progress
	SMOC/Coventry Facility Consolidation	2023	30.8	30.8	Function and Service Coverage Duplication
	Kelfield Operations Centre	2023	10.8	10.8	Condition, Function
	VPC Core and Shell	2025	20.0	20.0	Condition

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

Table 6.1-4: ICM-Eligible Capital Projects – Union Rate Zones

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

.

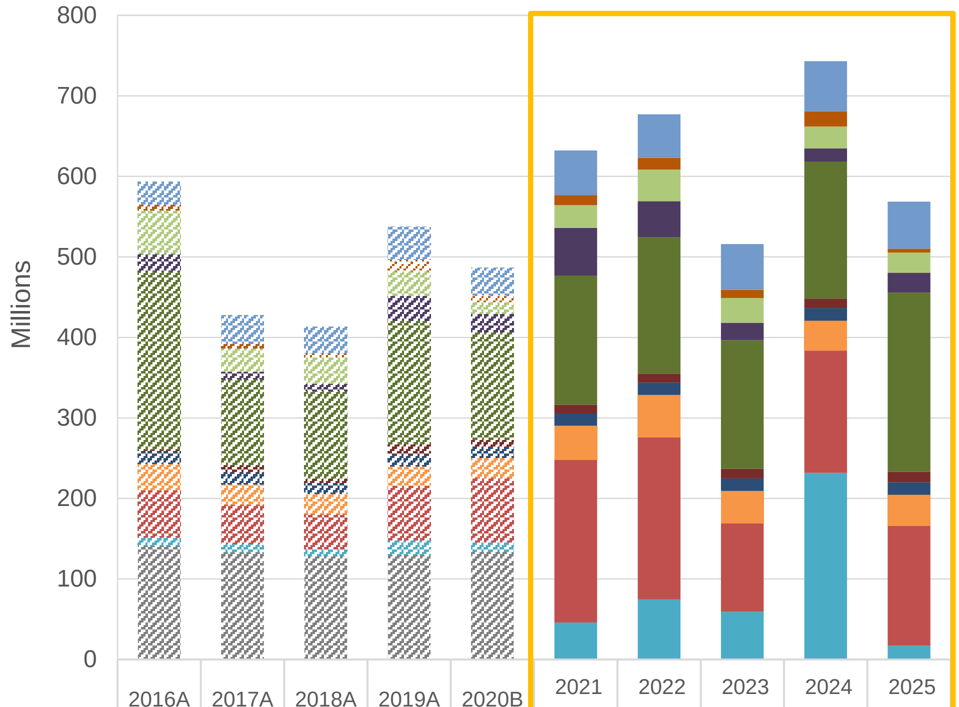
Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total Net Capital ($M)	Driver
	SUDB: Marten River Compression Reinforcement	2023	51.6	51.6	Mandatory: Reinforcement Specified per Network Analysis
Distribution Pipe	NPS 8 Port Stanley Replacement	2024	20.6	20.6	Condition
	INTE: North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

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

.

6.2 Summary of Capital Expenditure

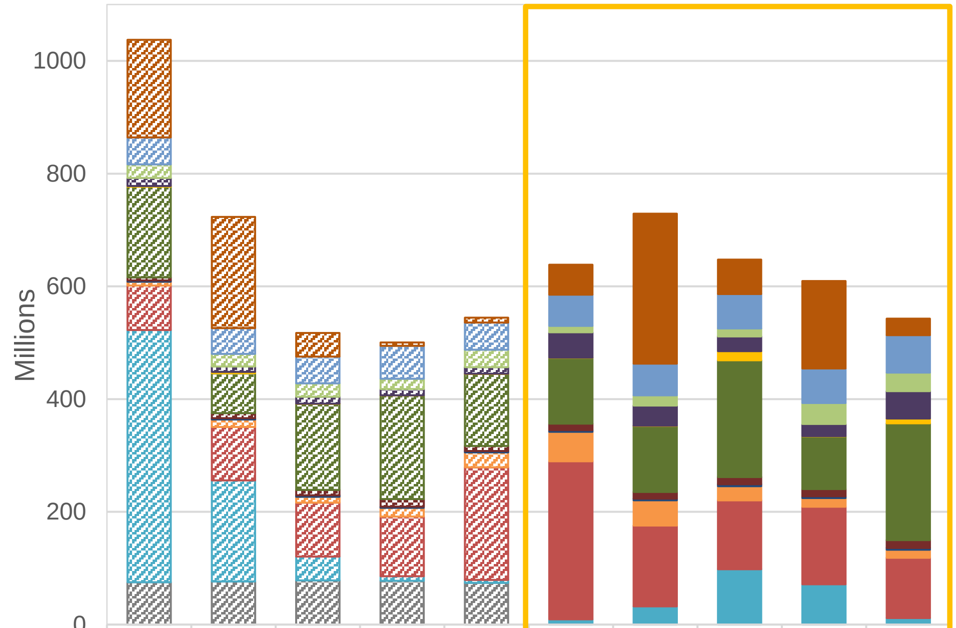
Figure 6.2-1 and **Figure 6.2-2** present the direct five-year capital profile for EGI from 2021-2025, totaling over $3.1B and $3.2B in proposed asset expenditures for the EGD and Union rate zones respectively.



	2016A	2017A	2018A	2019A	2020B	2021	2022	2023	2024	2025
Utilization	28.9	35.7	32.9	40.9	34.3	55.3	54.1	56.8	62.3	58.5
Transmission Pipe & Underground Storage	6.4	5.3	5.1	13.9	7.8	12.5	14.5	10.1	18.7	4.8
TIS	54.3	29.6	32.8	30.6	15.1	28.2	39.4	30.8	27.3	25.1
Real Estate & Workplace Services	22.1	9.4	8.8	30.9	23.1	59.6	44.9	21.6	16.3	24.8
Growth	221.5	106.5	109.2	153.4	133.1	160.1	169.3	159.8	170.3	222.6
Fleet & Equipment	2.3	9.1	5.7	12.9	8.6	10.9	11.1	11.8	11.8	12.8
EA Fixed O/H	15.1	14.7	13.2	14.6	14.0	15.4	15.4	15.5	15.6	15.7
Distribution Stations	32.5	25.7	24.9	24.2	24.6	42.1	52.2	40.2	37.2	38.7
Distribution Pipe	58.8	47.9	43.9	68.0	80.3	202.0	201.7	109.9	151.9	148.6
Compression Stations	10.3	10.7	8.1	17.6	11.8	46.1	74.7	59.3	231.8	17.2
Overheads	141.4	133.3	128.6	130.2	133.8					

Figure 6.2-1: EGI Five-year Capital Profile by Asset Class (2021-2025) – EGD Rate Zone

Figure 6.2-2: Five-year Capital Profile by Asset Class (2021-2025) – Union Rate Zones



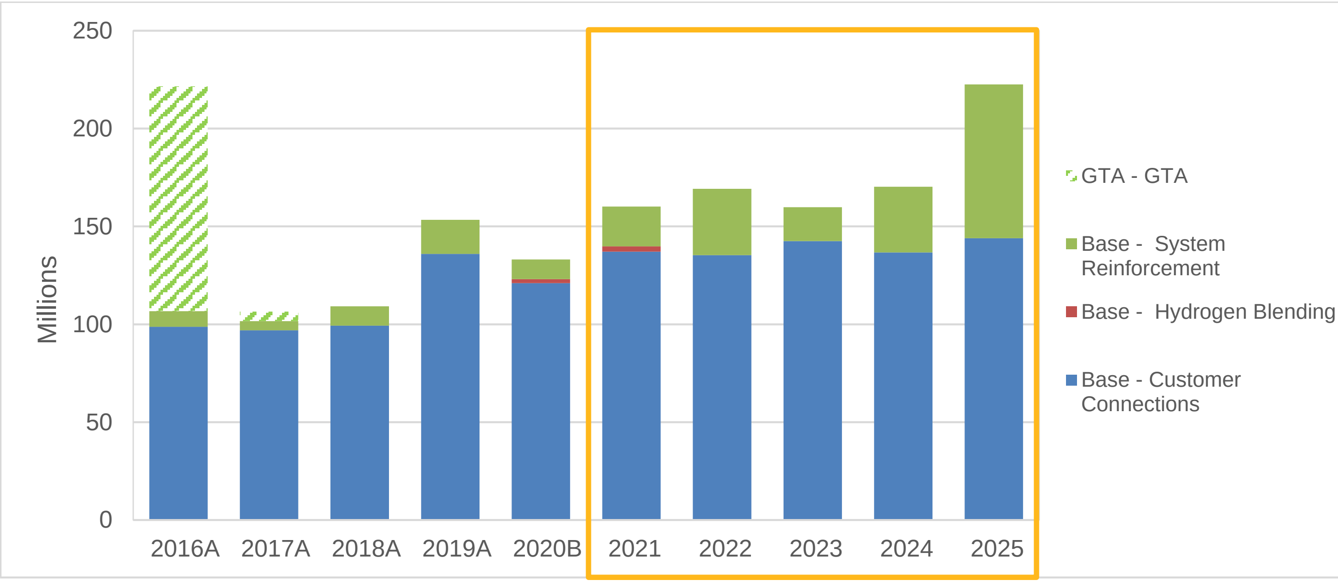
	2016A	2017A	2018A	2019A	2020B	2021	2022	2023	2024	2025
Transmission Pipe & Underground Storage	173.1	197.2	41.9	5.9	8.6	53.1	266.0	61.1	155.2	29.3
Utilization	47.8	45.7	47.4	58.4	48.2	55.2	56.2	61.0	61.1	66.4
TIS	24.0	22.4	23.8	18.2	31.0	11.3	18.2	14.2	37.4	32.9
Real Estate & Workplace Services	14.4	9.5	12.4	11.2	11.7	44.9	35.7	26.3	21.5	48.6
LNG	1.1	2.4	0.1	0.0	0.3	0.3	0.2	16.0	0.2	8.7
Growth	161.0	70.9	152.8	184.0	127.9	116.9	117.2	207.4	93.6	207.0
Fleet & Equipment	5.4	8.9	9.6	13.4	8.9	11.7	12.0	12.8	12.8	13.9
EA Fixed O/H	2.2	2.3	2.6	2.1	2.4	2.8	3.0	3.1	3.2	3.3
Distribution Stations	6.9	13.3	10.4	15.5	26.6	52.3	44.7	25.2	15.5	14.3
Distribution Pipe	78.9	94.7	95.7	105.9	199.6	280.4	143.2	122.2	137.6	106.8
Compression Stations	447.4	179.4	42.3	8.1	5.3	9.3	32.5	98.2	71.4	11.7
Overheads	75.1	76.4	78.3	77.7	74.0					

Note: The total forecasted capital expenditures categorized by asset class depicted in **Figure 6.2-1** and **Figure 6.2-2** are comprised of each investment's direct costs and the associated overheads. Asset class historical spend profiles do not include associated overheads; for this reason, overheads are identified as a separate category historically.

.

6.2.1 Growth

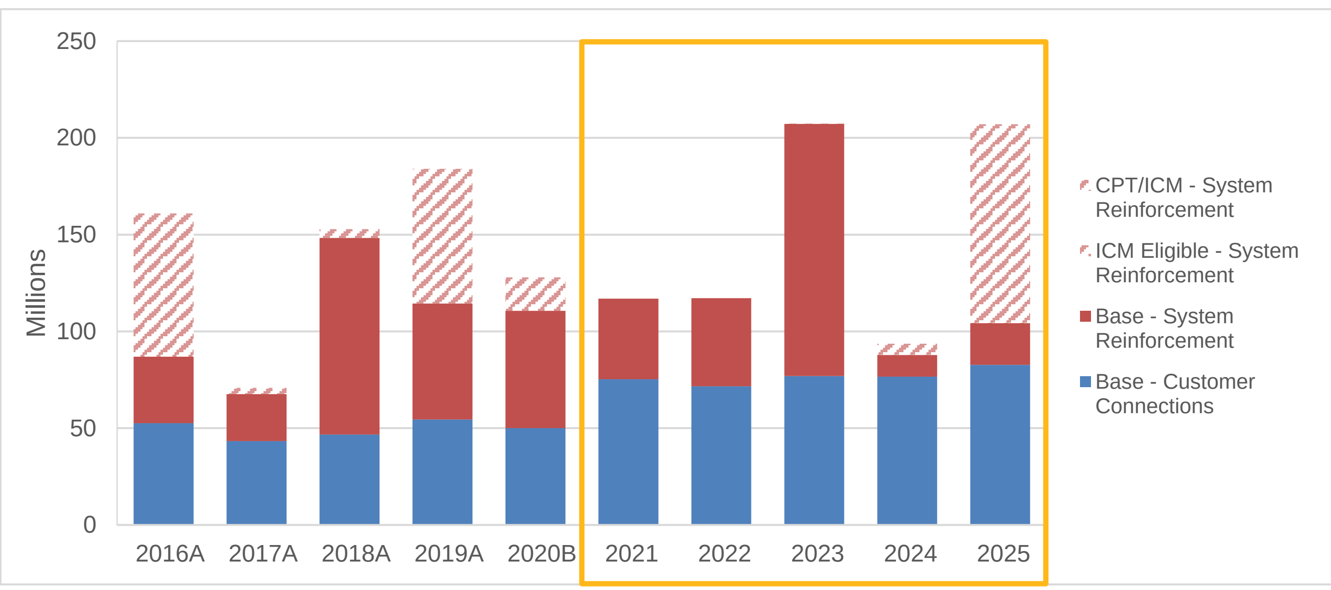
EGI has spent an average of $145M and $140M annually in the EGD and Union rate zones respectively for the Growth asset class. The total average capital spend is forecasted to be $163M (EGD RZ) and $148M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-3** and **Figure 6.2-4**.



Note: Overheads excluded in historical spend.

Figure 6.2-3: Capital Expenditure over Time for Growth - EGD Rate Zone

The increase in capital requirements for the Growth asset class in 2025 in the EGD rate zone is primarily driven by reinforcement projects including Rideau Reinforcement and York Region Reinforcement project (2026 target in service).



Note: Overheads excluded in historical spend.

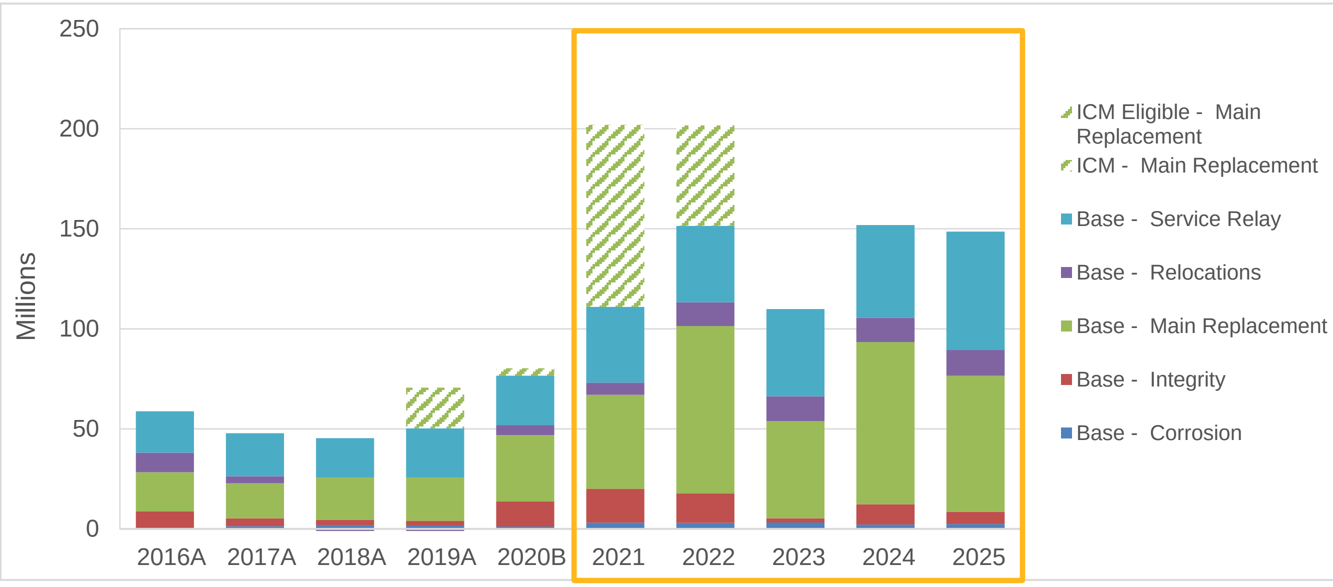
Figure 6.2-4: Capital Expenditure over Time for Growth - Union Rate Zones

The increase in capital requirements for the Growth asset class in the Union rate zones is primarily driven by the Sudbury Reinforcement project in 2023 and the Owen Sound Reinforcement project in 2025. The forecast also reflects increased costs per customer for customer connections based on actuals. Refer to **Section 5.1** for further details on the Growth asset class.

.

6.2.2 Distribution Pipe

EGI has spent an average of $60M and $115M annually in the EGD and Union rate zones respectively for the Distribution Pipe asset class. The total average capital spend is forecasted to be $161M (EGD RZ) and $157M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure** 6.2-5 and **Figure 6.2-6.**



Note: Overheads excluded in historical spend.

Figure 6.2-5: Capital Expenditure over Time for Distribution Pipe – EGD Rate Zone

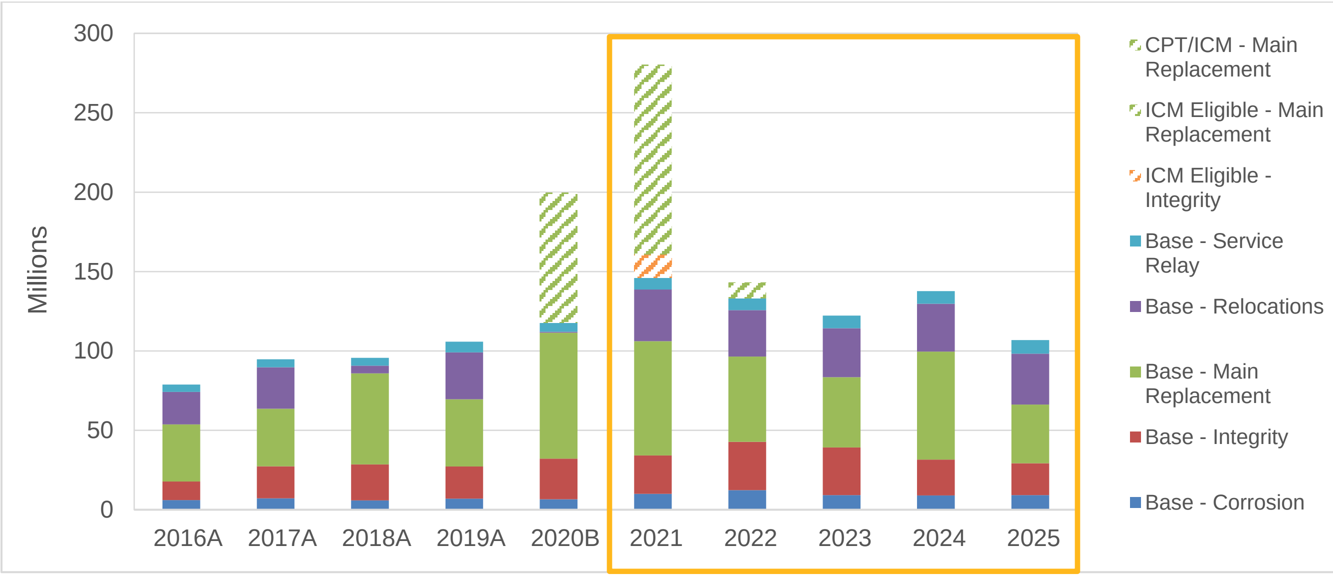
The increase in capital requirements for the Distribution Pipe asset class in the EGD rate zone is primarily driven by an increased spend in the **Base – Main Replacement** portfolio in part due to increased proactive spend to renew vintage steel pipe. See **Section 5.2.4** and **Section 5.2.6.1.4** for the respective maintenance and replacement strategies for the Pipe asset class.

As a part of the Vintage Steel Mains Replacement program (see **Section 5.2.6.1.4**), EGI has identified large vintage steel main sub-systems that require renewal due to condition and risk.

Specific ICM-eligible projects include:

- NPS 20 Lake Shore Replacement (Cherry to Bathurst) (2022 In-service Date (ISD))
- St. Laurent Phase 3 (2021 ISD)
  - St. Laurent Plastic - Montreal to Rockcliffe
  - St. Laurent Plastic - Coventry/Cummings/St Laurent
  - St. Laurent Plastic - Lower Section
- NPS 12 St. Laurent Aviation Pkwy (2022 ISD)
- NPS 12 St. Laurent Queen Mary/Prince Albert (2022 ISD)
- NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Road (2024 ISD)
- NPS 10 Glenridge Avenue, St. Catharines (2025 ISD)

.



Note: Overheads excluded in historical spend.

Figure 6.2-6: Capital Expenditure over Time for Distribution Pipe – Union Rate Zones

The increase in capital requirements for the Distribution Pipe asset class in the Union rate zones is primarily driven by investments to complete the **Bare and Unprotected Steel Pipe Replacement** program (**Section 5.2.6.1.4**) by 2024 and replacement of large Vintage Steel Mains sub-systems that require renewal.

In all rate zones, Integrity capital has increased, reflecting EGI's Integrity Management program improvements which will require all pipelines operating at >30% SMYS to be retrofitted for in-line inspection. There is also expected to be an increase in the number of Integrity digs.

Specific ICM-eligible projects include:

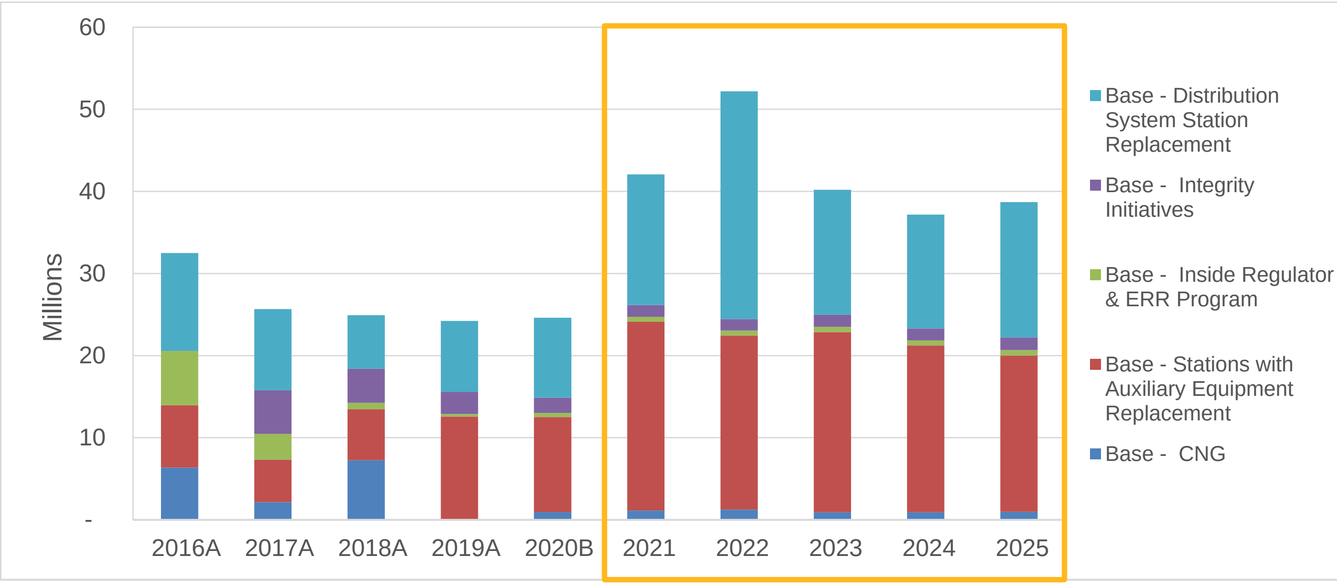
- London Lines Replacement (2021 ISD)
- NPS 8 Port Stanley Replacement (2024 ISD)
- INTE: North Shore - Section A: Retrofit ECDA to ILI (2021 ISD)
- Kirkland Lake Lateral Replacement (2022 ISD)

Refer to **Section 5.2** for further details on the Pipe asset class.

.

6.2.3 Distribution Stations

EGI has spent an average of $26M and $15M annually in the EGD and Union rate zones respectively for the Distribution Stations asset class. The total average capital spend is forecasted to be $41M (EGD RZ) and $31M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-7** and **Figure 6.2-8**.



Note: Overheads excluded in historical spend.

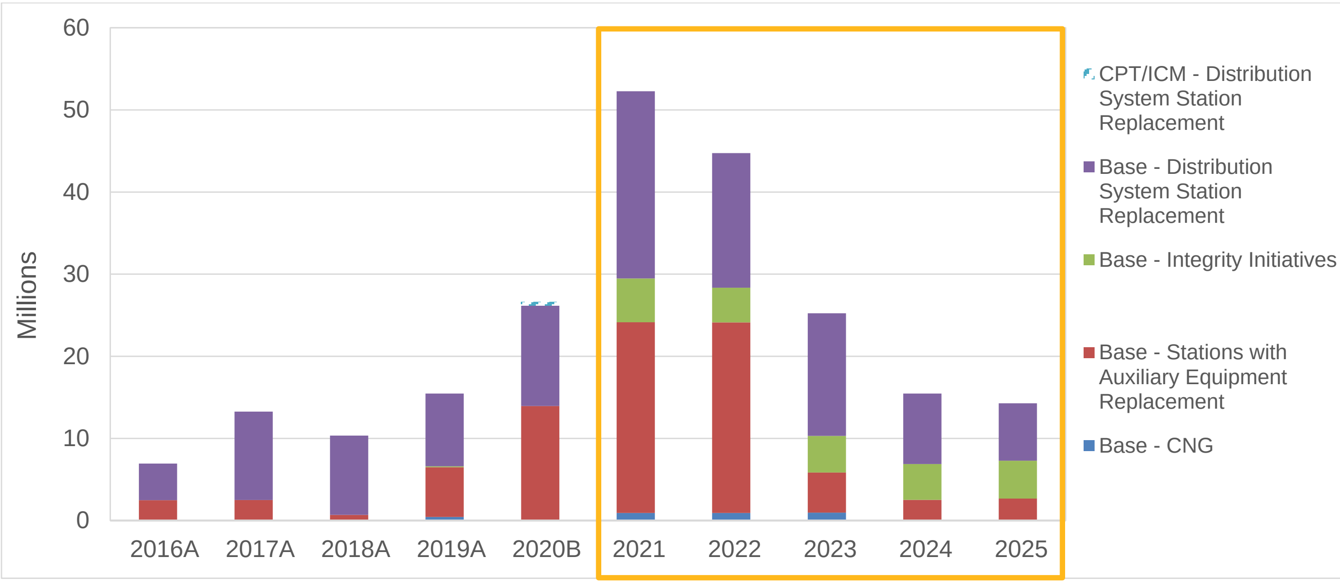
Figure 6.2-7: Capital Expenditure over Time for Distribution Stations - EGD Rate Zone

The increase in capital requirements for the Distribution Stations asset class in the EGD rate zone is primarily driven by the strategies identified in **Section 5.3** (Distribution System Station Replacement and Stations with Auxiliary Equipment Replacement). The strategies aim to reduce risk, maintain a safe and reliable distribution system by the proactive replacement or the rebuild of station components prior to end-of-life.

The **Distribution System Station Replacement** portfolio has slight increases due to the strategies identified for the District, Header and Sales Stations programs. A large project in 2022 (Harmer District Station rebuild) skews the 2022 budget.

The **Stations with Auxiliary Equipment Replacement** portfolio has a similar quantity of projects as previous years, targeting larger stations and components for replacement in the next five years. Execution costs are higher in some areas due to complexities compared to preceding years, such as the inclusion of filtration that was previously not consistent across rate zones and pre-fabricated heating systems that standardize design.

.



Note: Overheads excluded in historical spend.

Figure 6.2-8: Capital Expenditure over Time for Distribution Stations - Union Rate Zones

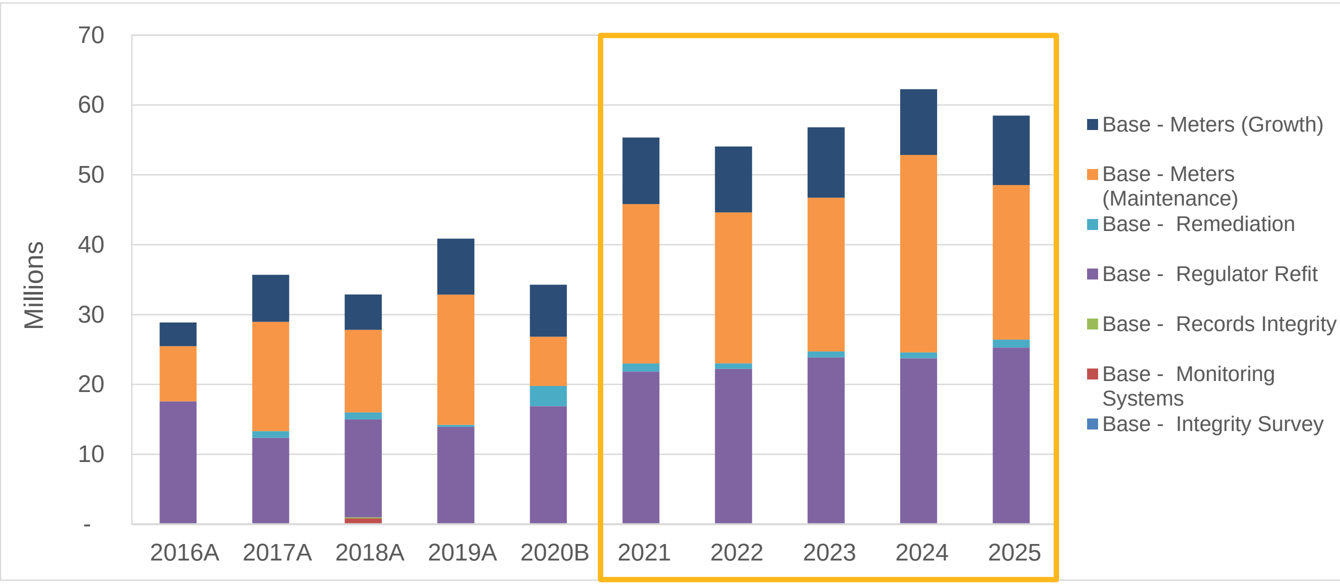
The increase in capital requirements for the Distribution Stations asset class in the Union rate zones is primarily driven by the inclusion of Odourant programs (previously in the Measurement asset class) and the inclusion of projects from the Growth asset class.

At the time of portfolio development, a number of the inputs to develop the proactive programs for this rate zone were in varying stages of maturity (such as FIMP and DIMP). Proactive programs are being developed and future year spend is expected to increase and will be supported with the requisite analysis that is underway.

Refer to **Section 5.3** for further details on the Distribution Stations asset class.

6.2.4 Utilization

EGI has spent an average of $35M and $50M annually in the EGD and Union rate zones respectively for the Utilization asset class. The total average capital spend is forecasted to be $57M (EGD RZ) and $60M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-9** and **Figure 6.2-10**.

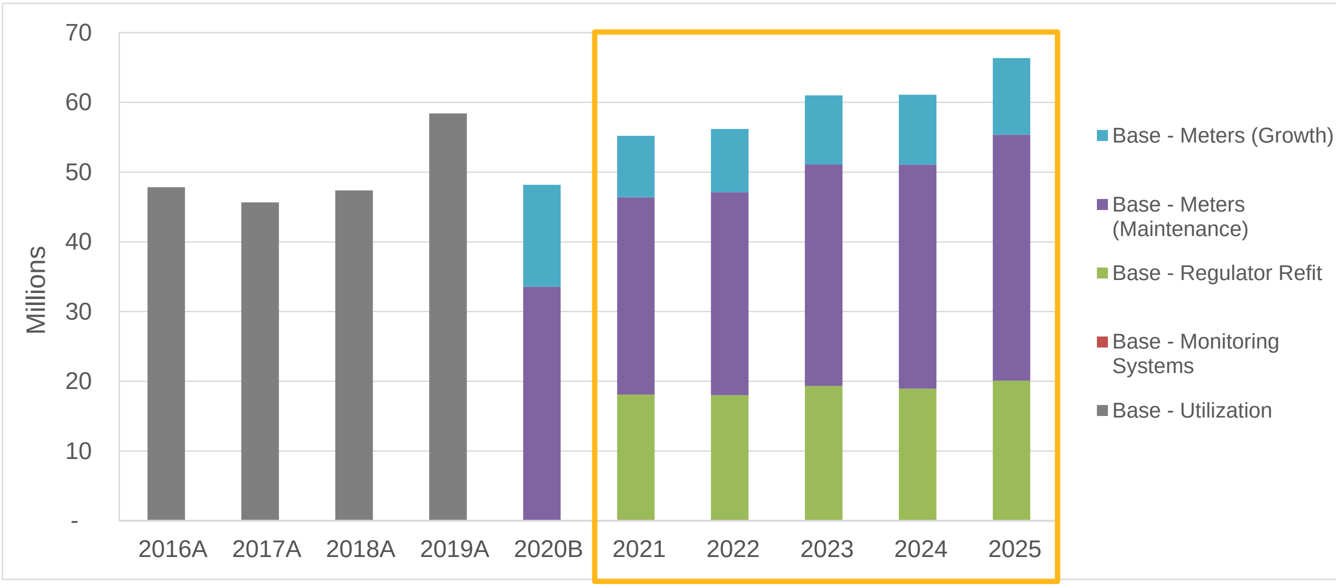


Note: Overheads excluded in historical spend.

Figure 6.2-9: Capital Expenditure over Time for Utilization - EGD Rate Zone

The increase in capital requirements for the Utilization asset class in the EGD rate zone is primarily driven by a forecast increase in the number of meter replacements.

.



Note: Overheads excluded in historical spend.

Figure 6.2-10: Capital Expenditure over Time for Utilization - Union Rate Zones

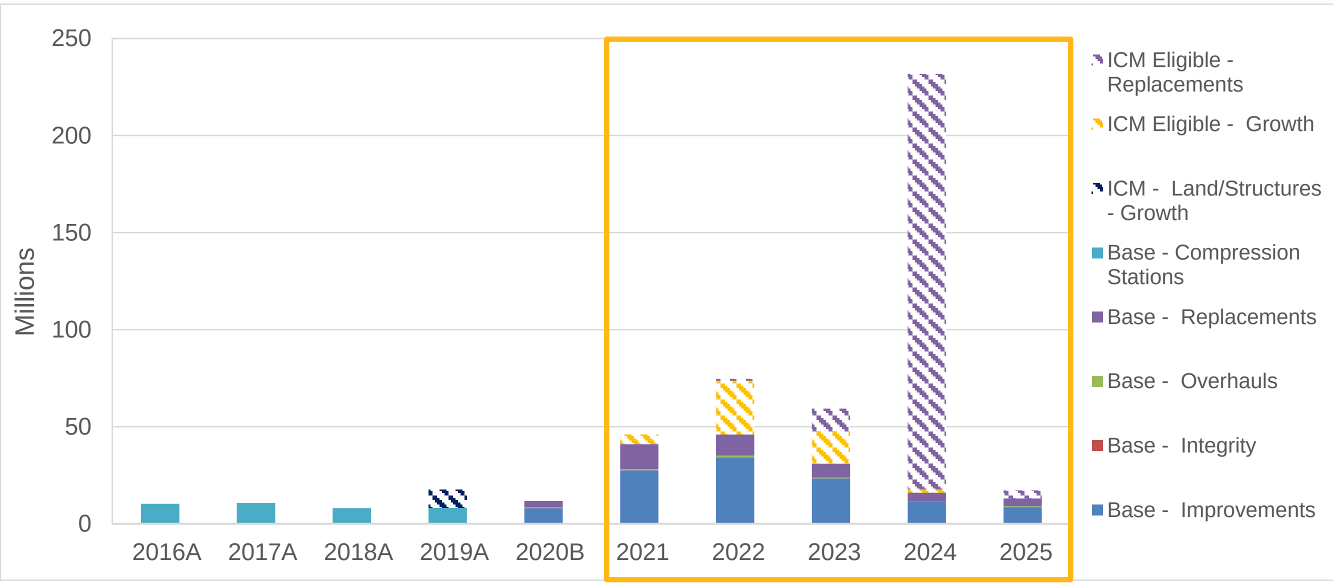
The forecast for the Utilization asset class in the Union rate zones is a steady trend of capital spend.

Refer to **Section 5.4** for further details on the Utilization asset class.

6.2.5 Compression Stations

EGI has spent an average of $12M and $137M annually in the EGD and Union rate zones respectively for the Compression Stations asset class. The total average capital spend is forecasted to be $86M (EGD RZ) and $45M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-11** and **Figure 6.2-12.**

Note: The Compression Stations asset class includes Dehydration investments.



Note: Overheads excluded in historical spend.

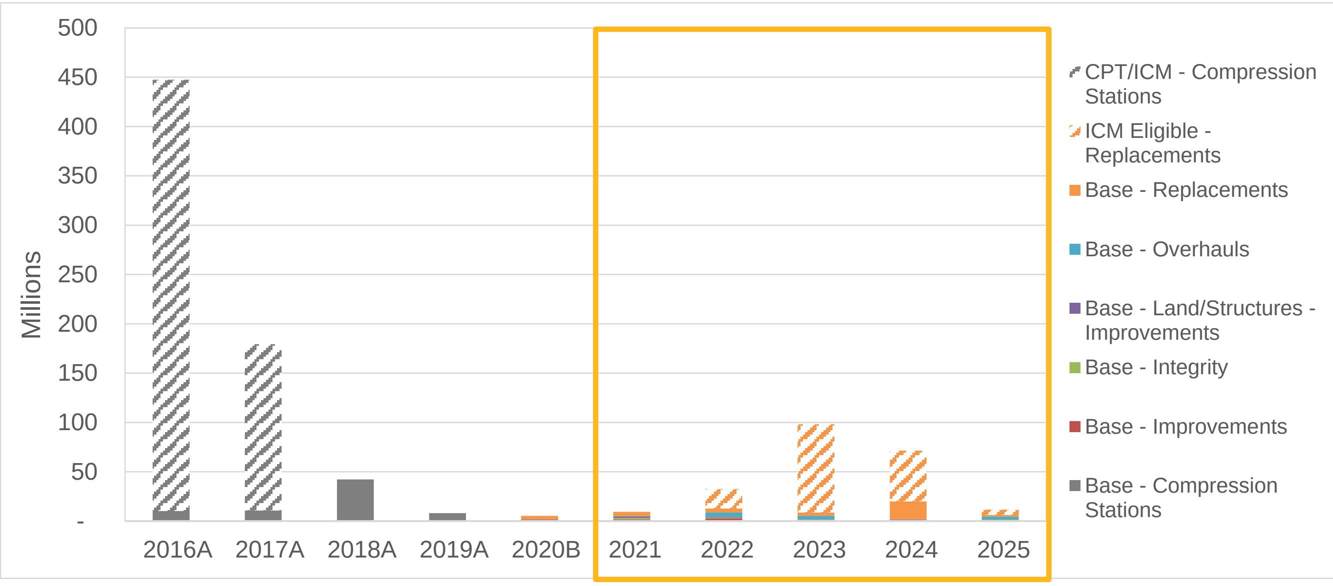
Figure 6.2-11: Capital Expenditure over Time for Compression Stations - EGD Rate Zone

In addition to the large ICM-eligible projects listed below, the increase in capital requirements for the Compression Stations asset class in the EGD rate zone is primarily driven by valve replacements in the Corunna compressor station, compressor foundation block replacement (2022) and improvements to the power cylinder balancing system for the Corunna compressors.

Specific ICM-eligible projects include:

- SCOR: K701/2/3 Reliability – Replacement (2024 ISD)
- Dehydration Expansion (2023 ISD)
- SCOR: Meter Area Upgrade - Phase 1 (2021 ISD) and Phase 2 (2022 ISD)
- SCRW: Station Renewal In-Place (2025 ISD)

.



Note: Overheads excluded in historical spend.

Figure 6.2-12: Capital Expenditure over Time for Compression Stations - Union Rate Zones

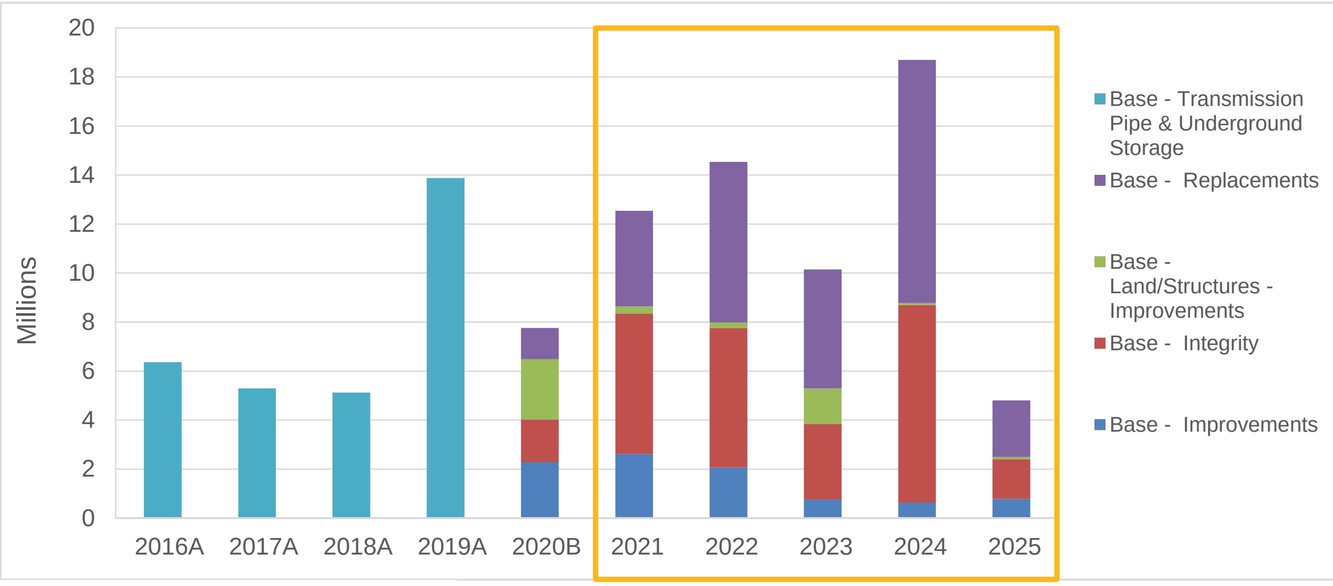
The increase in capital requirements for the Compression Stations asset class in the Union rate zones is driven by compressor engine overhauls, replacement of the obsolete Waubuno compressor (ISD 2024) and replacement of the compressor control panels at the Hagar LNG station. The Dawn Plant-C Compression Life Cycle (a multi-year project spanning 2022-2025) accounts for majority of 2023 spend.

Refer to **Section 5.5.5** for further details on the Compression Stations asset class.

6.2.6 Transmission Pipe and Underground Storage

EGI has spent an average of $8M and $85M annually in the EGD and Union rate zones respectively for the Transmission Pipe and Underground Storage asset class. The total average capital spend is forecasted to be $12M (EGD RZ) and $112M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-13** and **Figure 6.2-14.**

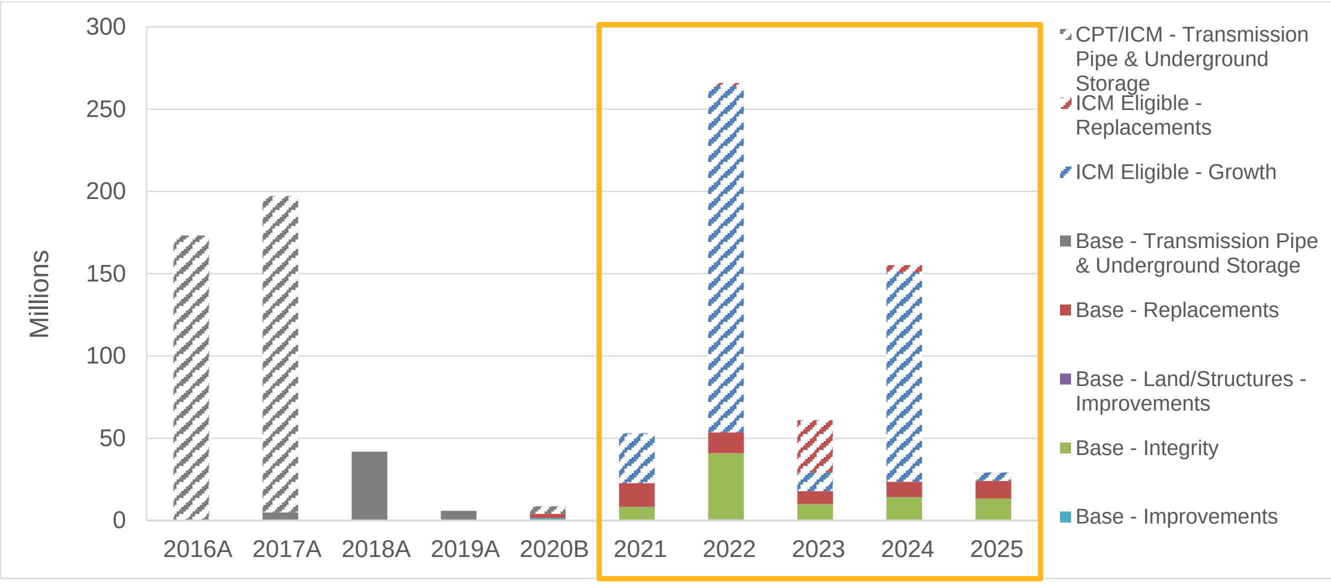
Note: The Transmission Pipe and Underground Storage class includes transmission reinforcement investments.



Note: Overheads excluded in historical spend.

Figure 6.2-13: Capital Expenditure over Time for Transmission Pipe and Underground Storage - EGD Rate Zone

The increase in capital requirements over the next five years is driven by the spend to install new storage wells, replacing lost storage deliverability due to well abandonments completed in the past five years.



Note: Overheads excluded in historical spend.

Figure 6.2-14: Capital Expenditure over Time for Transmission Pipe and Underground Storage - Union Rate Zones

The Transmission Pipe and Underground Storage capital profile in the Union rate zones is largely made up of the Integrity Digs program and the Depth of Cover Mitigation program over the next five years.

Specific ICM-eligible projects include:

- Dawn Parkway Expansion (Kirkwall-Hamilton NPS 48) (2022 ISD)
- Sarnia Expansion - Bluewater Energy Park (2024 ISD)
- Panhandle Line Replacement (2023/2024 ISD)
- Sarnia Expansion - (2021 ISD)
- Dawn-Cuthbert (2022 ISD)

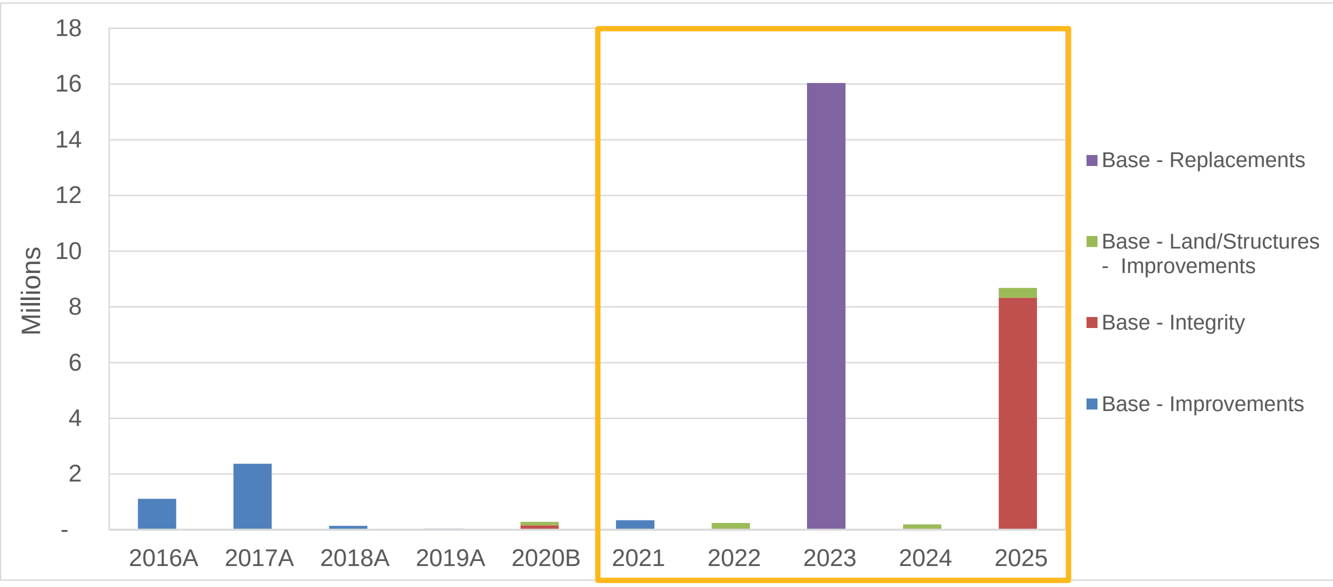
In both rate zones, Integrity capital has increased reflecting EGI's Integrity Management Program (IMP) improvements which will require all pipelines operating at >30% SMYS to be retrofitted for in-line inspection. There is also expected to be an increase in the number of Integrity digs.

Refer to **Section 5.5.7**and **Section 5.5.8** for further details on the Transmission Pipe and Underground Storage asset class.

.

6.2.7 Liquefied Natural Gas

EGI has spent an average of $0.8M annually in the Union rate zones for the Liquefied Natural Gas (LNG) asset class. The total average capital spend is forecasted to be $5M over the five years identified. The historical and projected five-year spend profile is presented in **Figure 6.2-15**.



Note: Overheads excluded in historical spend.

Figure 6.2-15: Capital Expenditure over Time for Liquefied Natural Gas - Union Rate Zones

The increase in capital requirements is driven by the replacement of critical assets in the LNG process due to obsolescence and condition. The significant investments identified are replacement of the boil-off gas compressor (2023), cycle gas compressor (2023) and the cold box (2025).

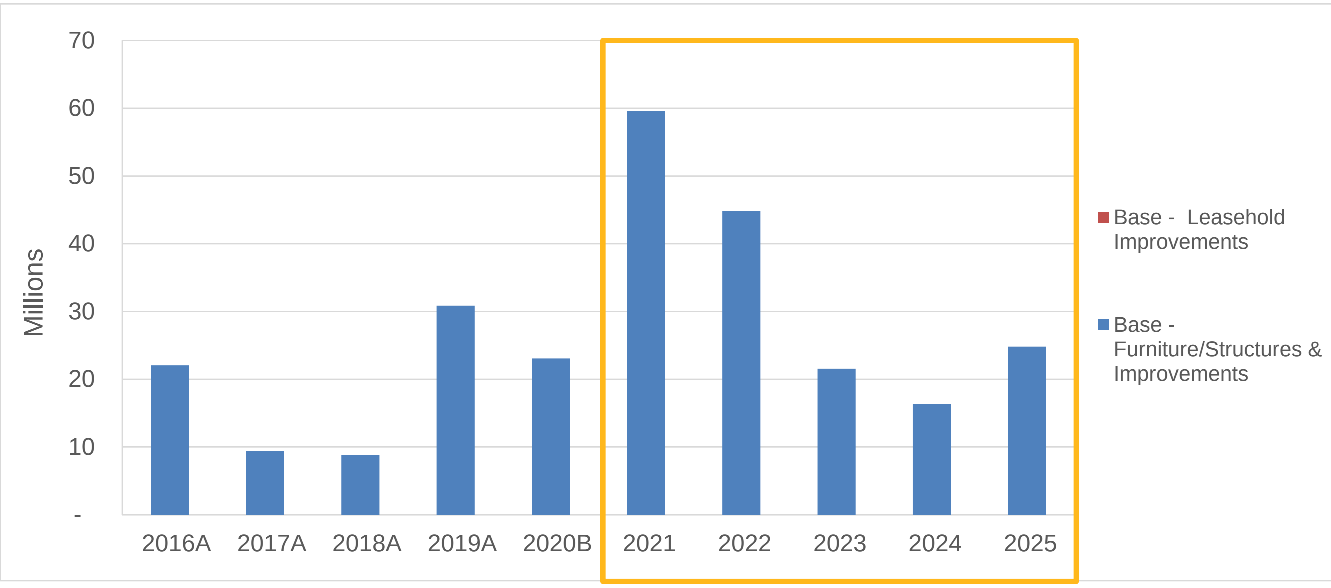
Note: LNG assets are in the Union North rate zone only.

Refer to **Section 5.5.9** for further details on the LNG asset class.

.

6.2.8 Real Estate and Workplace Services

EGI has spent an average of $19M and $12M annually in the EGD and Union rate zones respectively for the Real Estate and Workplace Services (REWS) asset class. The total average capital spend is forecasted to be $36M (EGD RZ) and $34M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-16** and **Figure 6.2-17**.



Note: Overheads excluded in historical spend.

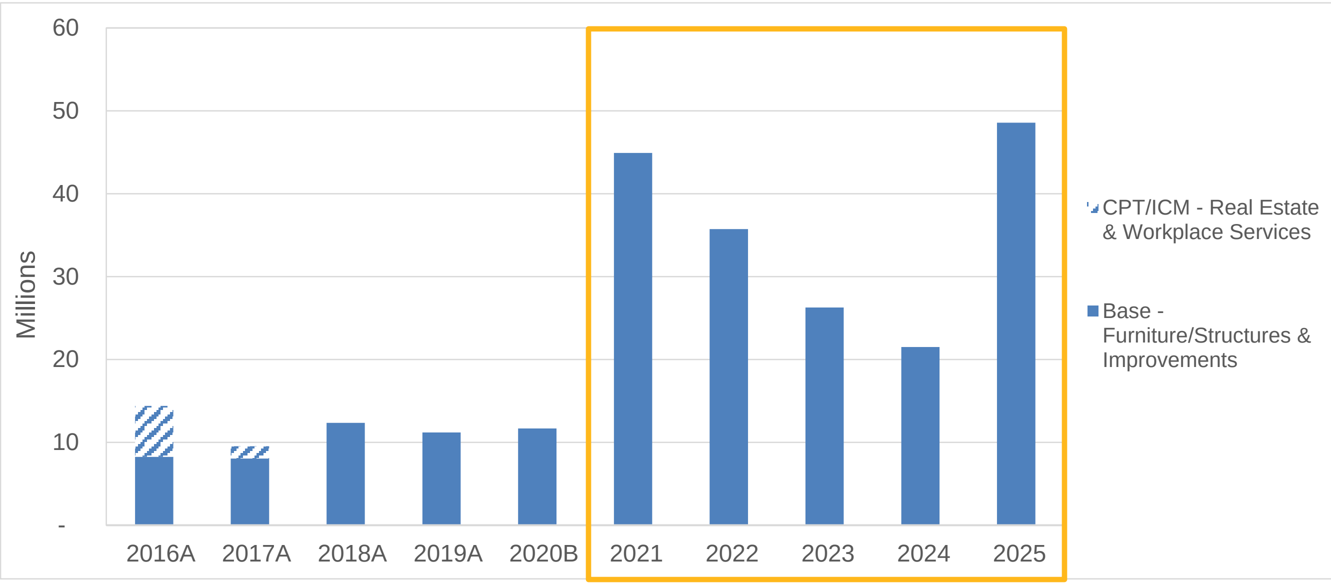
Figure 6.2-16: Capital Expenditure over Time for REWS - EGD Rate Zone

EGI continues to respond to the needs of its operations and growing customer needs, leveraging the facility assessment process to best determine whether existing facilities should be upgraded or replaced.

Specific ICM-eligible projects include for the EGD rate zone include:

- Kennedy Road Expansion (2024 ISD)
- Station B New Building (2021 ISD)
- SMOC/Coventry Facility Consolidation (2027 ISD)
- Kelfield Operations Centre Obsolescence (2023 ISD)
- VPC Core and Shell Obsolescence (2025 ISD)

.



Note: Overheads excluded in historical spend.

Figure 6.2-17: Capital Expenditure over Time for REWS - Union Rate Zones

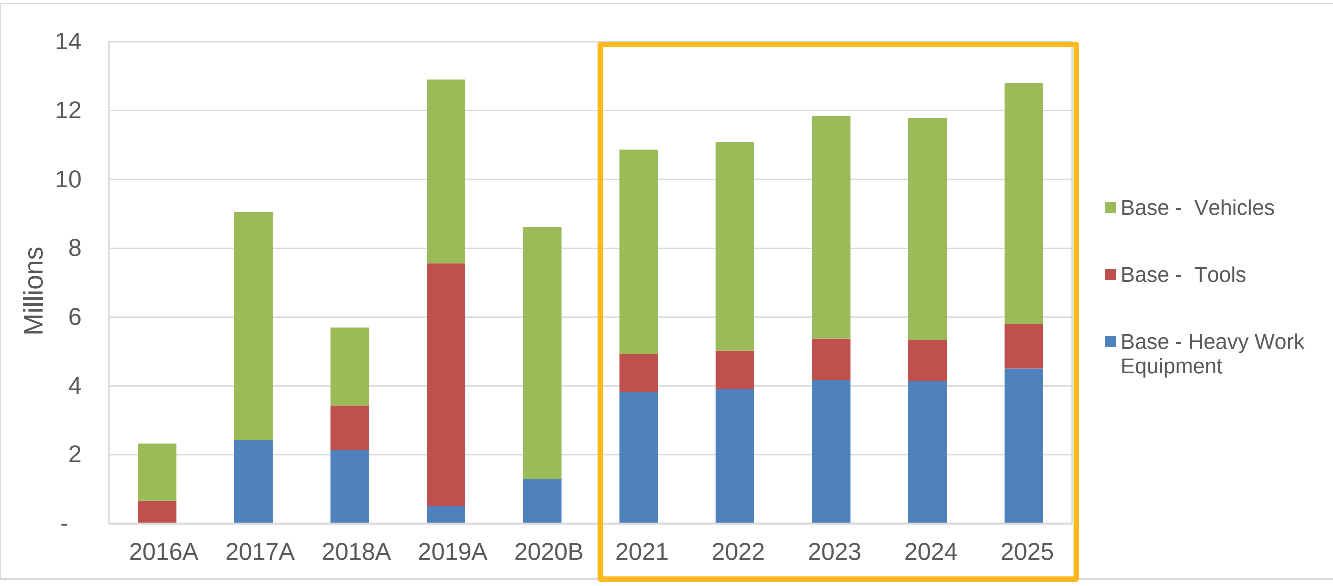
Projects for the Union rate zones include improvements to 50 Keil Drive and the Micro-Operations Sites program as well as specific ICM-eligible projects including:

- Thunder Bay Regional Operations Centre (2026 ISD)
- New Site No. 4 (2023 ISD)

Refer to **Section 5.6** for further details on the REWS asset class.

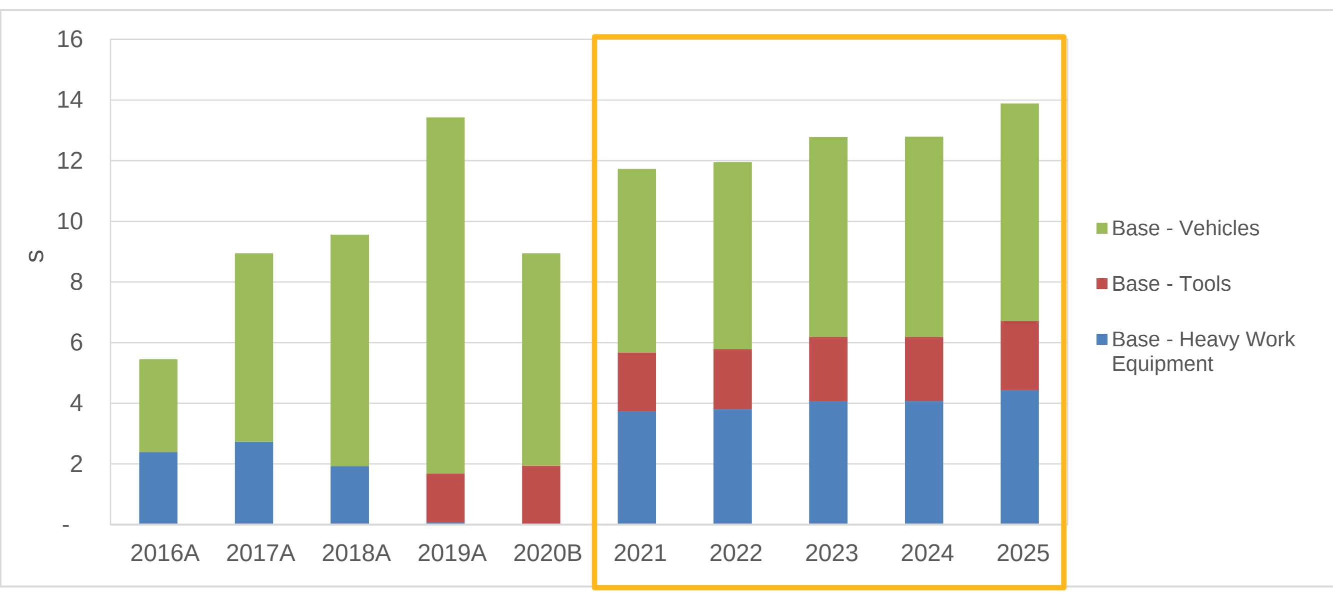
6.2.9 Fleet and Equipment

EGI has spent an average of $7M and $9M annually in the EGD and Union rate zones respectively for the Fleet and Equipment asset class. The total average capital spend is forecasted to be $11M (EGD RZ) and $12M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-18** and **Figure 6.2-19**.



Note: Overheads excluded in historical spend.

Figure 6.2-18: Capital Expenditure over Time for Fleet and Equipment - EGD Rate Zone



Note: Overheads excluded in historical spend.

Figure 6.2-19: Capital Expenditure over Time for Fleet and Equipment - Union Rate Zones

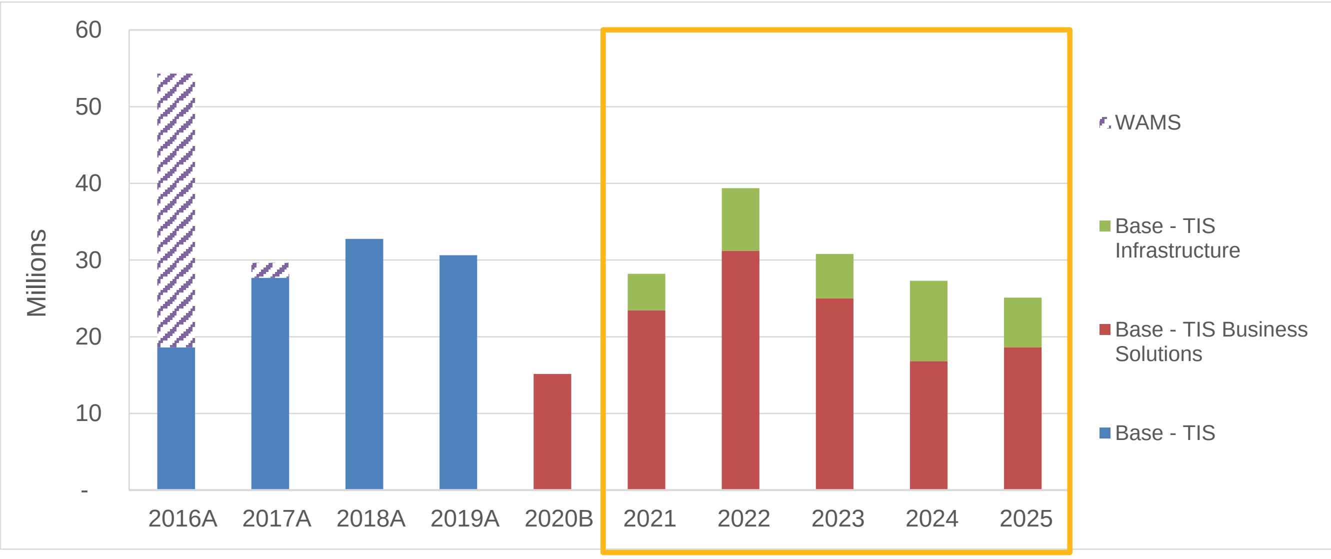
For fleet investments in both rate zones, the forecast is a steady trend of capital to replace vehicles and equipment (based on fleet management strategy) to maintain the quality of the fleet.

Refer to **Section 5.7** for further details on the Fleet and Equipment asset class.

.

6.2.10 Technology and Information Services (TIS)

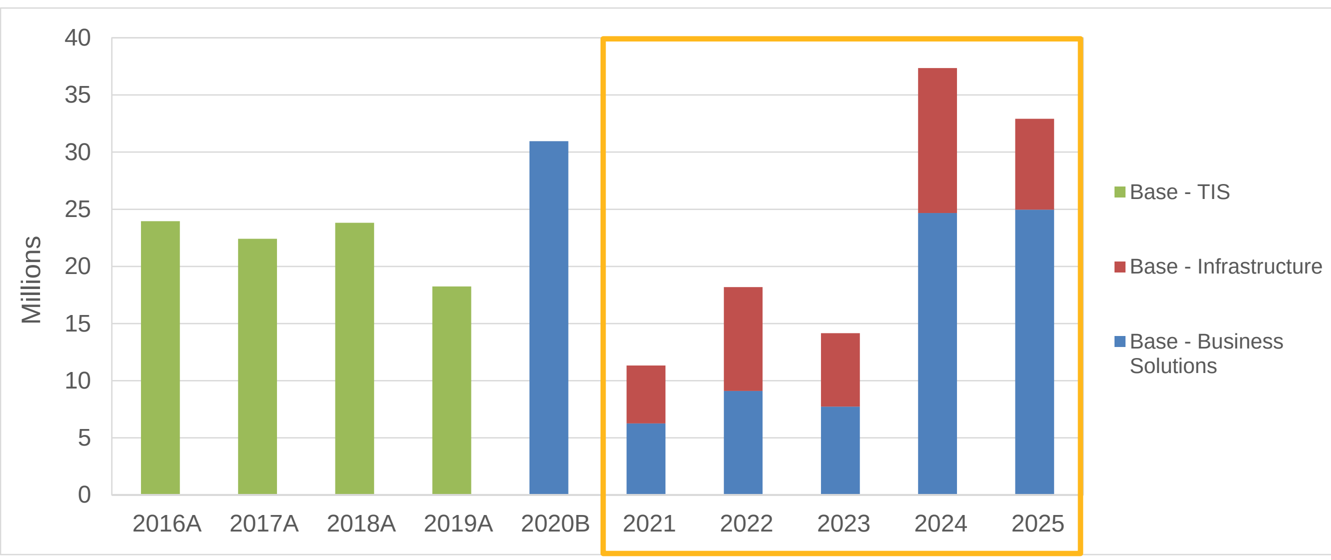
EGI has spent an average of $32M and $24M annually in the EGD and Union rate zones respectively for the Technology and Information Services (TIS) asset class. The total average capital spend is forecasted to be $30M (EGD RZ) and $22M (Union RZ) over the five years identified. The historical and projected five-year spend profiles are presented in **Figure 6.2-20** and **Figure 6.2-21**.



Note: Overheads excluded in historical spend.

Figure 6.2-20: Capital Expenditure over Time for TIS - EGD Rate Zone

Spend in 2020 has been lower as TIS has been concentrating on integration activities, which are not reflected in the core capital numbers. The increased forecast spend is driven by enhancements to already integrated applications and new business solutions for the utility are identified. Specifically, in 2022, the increase is reflective of a couple of large initiatives in the Customer Care space, building on the newly integrated CIS application.



Note: Overheads excluded in historical spend.

Figure 6.2-21: Capital Expenditure over Time for TIS – Union Rate Zones

TIS spending for the Union rate zones has decreased as TIS will be concentrating on integration activities, which are not reflected in core capital numbers. The increase in 2024 and 2025 reflects specific investment on a proposed major system replacement of the applications used in the Nominations solution. Refer to **Section 5.8** for further details on the TIS asset class.

.

6.3 Assumptions

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

Table 6.3-1: Assumptions for All Categories

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

Table 6.3-2: Renewal Assumptions

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

Table 6.3-3: Customer Growth Assumptions

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

Table 6.3-4: Solution Planning Assumptions

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

.

7. Appendix

Page intentionally left blank.

EGI Asset Management Plan 2021-2025 Appendix

Growth

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
19968	2021	5

Investment Name

[Low Carbon Energy Project]: TOC Hydrogen Blending Facility

Investment Description

Enbridge Gas Inc. (EGI) has identified an opportunity which will allow the gas distribution system to contribute towards reducing the environmental impacts of greenhouse gas emissions (GHG) in Ontario by injecting a controlled quantity of hydrogen into the natural gas stream.

This opportunity, which is consistent with the environmental goals of public policy provincially and federally, with EGI's corporate strategy, and with direction provided by the Ontario Energy Board (Board), is called the Low Carbon Energy Project (LCEP or the Project).

The LCEP is a pilot project that will allow the company to green a portion of the natural gas grid in Ontario. The experience gained through the implementation of the LCEP will position EGI to then expand hydrogen injection into other parts of its gas distribution system, further enhancing reductions to GHG emissions across the province by greening the gas distribution system.

- LTC submission, Planning, and design in 2020
- Construction in 2021
- In Service Date: 2021

Assets: New hydrogen blending facility

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
- Install 750 metres of NPS 6 pipeline along Woodbine Avenue and within EGI property.
- Install NPS 2 PE IP and 1st and 2nd cut Station for NGV.
- Install hydrogen blending facility that includes a station, H2 Panel, RTU, HP-IP Stn in the parcel of land next to exisiting TOC compound.
- Disconnect 1 ¼ PE IP gas main and NPS 6 PE IP gas main on Hazelton Avenue and Major Mackenzie Drive to isolate Loop S1 from the rest of Network 3724.
- Back off two stations by reducing pressure at Station 35064A Elgin Mills & Boyd and Station 3136644 Markland and Russell Dawson from 55 psig to 35 psig.
- Leave to Construct application to the Ontario Energy Board will be required.

Resources: Company crews, contractor labour and third-party vendor suppliers

Solution Impact: The LCEP is a pilot project that will allow EGI to green a portion of the natural gas grid in Ontario. The experience gained through the implementation of the LCEP will position EGI to then expand hydrogen injection into other parts of its gas distribution system, further enhancing reductions to GHG emissions across the province by greening the gas distribution system.

Project Timing and Execution Risks:
- LTC submission, Planning, and design in 2020
- Construction in 2021
- In Service Date: 2021
- Execution Risks - approval of materials, pipeline route, budget

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - Hydrogen Blending
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	30 - Richmond Hill
	Asset Program (EGI)	GTH - Hydrogen Blending
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (2,622,902)	0.00	$ 3,039,103	1/1/2018

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,184,735	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
19968	2021	5

Investment Name

[Low Carbon Energy Project]: TOC Hydrogen Blending Facility

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,623)	100%
Total	**(2,623)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
7732	2021	5

Investment Name

AJAX Reinforcement

Investment Description

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure to maintain the capacity to meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Project Purpose/ Need:
- Customer growth data coupled with zoning bylaw and site plan applications suggest that Network 4543 is expected to experience significant load growth.
- System lacks supplementary supply from the northern end of the network; network flexibility is compromised and reliability is a concern during emergency or maintenance situations.
- Due to current system configuration, a NPS 4”steel main (located on Station Street, between Old Station Street and Thomson Street) acts as a bottleneck in the HP system, dropping pressure by approximately 8psi and hindering maximum pressures available downstream at station inlets.

Risk if not completed: System risks without reinforcement:
- Three stations that feed gas into the network will have inlet pressures below the minimum, starting in 2022.
- The low inlet pressures at the stations will inhibit the ability to deliver gas to the network, downstream of the station.
- In 2022 there are approximately 21,120 customers that would be connected to the network that may be impacted.

Assets (preferred option):
- Preferred reinforcement option is comprised of approximately 2.1 kilometres of 6”steel HP pipe along Church Street North, originating from the existing NPS 16”steel Vital Main (at Taunton Road & Church Street North) and terminating at Church Street North and Rossland Road West.
- Two (2) stations need to be installed – 1 station at Church and Taunton and 1 station at Church and Rossland.
- Additionally, 450 metres of 8”PE IP pipe would need to be installed along Rossland Road West, from Church Street North to 120 metres east of Harkins Drive.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
- Install 2.1 kilometres of 6"ST-HP on Church Street North from Taunton Road (Node 45810115) to Rossland Road W.
- Install two stations - (1) XHP-HP Station at Church & Taunton and (1) HP-IP Station at Church and Rossland.
- Install 450 metres of 8"PE-IP on Rossland Road W, from Church Street to 120 metres east of Harkins Drive.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Timing: This project is scheduled to be in Service in 2021.

Project Timing and Execution Risks: Risks - weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - System Reinforcement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	40 - Whitby
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (2,982,124)	0.00	$ 3,212,025	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,103,655	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
7732	2021	5

Investment Name

AJAX Reinforcement

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,982)	100%
Total	**(2,982)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
23189	2021	5

Investment Name

Almonte Reinforcement - Phase 2

Investment Description

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Project Purpose/Need: This reinforcement addresses issues with the IP network, fed by Almonte District (6A143A) and Scott St. District (6A206A). The interior subdivision piping are undersized, based on the growth predictions of customers' demands. Evidence of densification has become apparent through load sheets. Without the reinforcement, growth cannot be supported in the downstream system.

Pressure issue/concern: The minimum system pressure is forecasted to be infeasible by 2021.
Customer growth issue/ concern: The Phase 1 reinforcement will enable the current system to continue adding new customers after the 10 customers from 2017-2019 as of the proposed in-service date, as per current known 11 customer growth projects equaling 870 m3/hr of load. However, Phase 1 only provides an additional 300m^3/hr capacity for any additional growth outside of this and a Phase 2 reinforcement will be required for further system growth.

Assets: Thee options include 1.2 to 1.3 kilometres of 4" XHP ST, or pressure increase of the system from 30 psi to 55 psi (involves 2.21 kilometres PE IP, 10-15 km ST IP, 350 service replacements, 970 relights, 30 valve replacements).

Related Programs: 21353 (Almonte Reinforcement Phase 1)

Recommended Alternative Description

Scope of Work: 1.2 kilometres of 4" XHP, one district station and will require to install by HDD across the Mississippi River and tie into Carss Street.

Resources: Company crews, contractor labour and third-party vendor suppliers

Solution Impact: The town of Almonte is growing with a majority of the growth on the north end of town, fed by one main which is nearing the limit of its capacity. This side of town is opposite of the high-pressure line separated by the Mississippi River. The pressure for this network is limited to 35 psi.

Project Timing and Execution Risks: According to Network Analysis forecast, this would be required for Winter 2021. Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - System Reinforcement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 3	Recommended	$ (3,881,481)	0.00	$ 4,160,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,760,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

	Value Function Measure	Value	Value in Percentage
■	Total Investment Cost (CA)	(3,881)	100%
	Total	**(3,881)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
16744	2021	5

Investment Name

Amaranth System Reinforcement

Investment Description

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure to maintain the capacity to meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Project Purpose/ Need: The existing station equipment is inadequate to handle volume flow increase brought by the yearly load LRP growth as projected. Hence, at a certain time it will not be operating efficiently and thus impact the IP downstream. The rebuild of the two stations will mitigate the identified issue. Consequent to the yearly LRP load growth as projected; the HP source at the tail end of the NPS4 ST HP main will be degraded at a certain time. The NPS 8 ST HP main reinforcement will mitigate the identified issue.

Risk if not completed: If the two stations are not rebuilt, downstream pressures will be below the minimum system pressure due to the droop. If the NPS 4 HP ST main is not looped with a larger diameter pipe (NPS 8), the HP minimum inlet pressure will be below the minimum system pressure which again will make the station droop and thus affecting the IP system pressures which will be below the minimum system pressure.

Assets (preferred option):
Phase 1 2021 - Rebuild the district station feeding NW 2176 (RS20031A, Mill Street).
Phase 2 2022 - Rebuild the district station feeding NW 2166 (RS20024A, Melody Lane).
Phase 3 2024 - Install approximately 5000 metres NPS 8 ST HP Main Reinforcement on Sideroad 5 from Crago Station Outlet main road to 5th Line.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Phase 3
- Install app 5000 metres NPS 8 ST HP Main Reinforcement on Sideroad 5 from Crago Station Outlet main road to 5th Line.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Project Timing and Execution Risks: Scheduled to be in service in 2024
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	20 - Mississauga
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (6,871,221)	0.10	$ 10,294,684	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 200,000	$ 200,000	$ -	$ 9,894,684	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ 107,046	$ -

ENBRIDGE

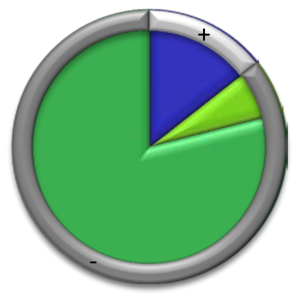
Investment Summary Report

Investment Code	Report Start Year	Number of Years
16744	2021	5

Investment Name

Amaranth System Reinforcement

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Revenue Impact (CA)	1,395	14%
Financial Risk	0	0%
Public Safety Risk	0	0%
Budget Savings OPEX (CA)	(637)	7%
Total Investment Cost (CA)	(7,630)	79%
Total	**(6,871)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
1024	2021	5

Investment Name

Rideau Reinforcement

Investment Description

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

This network in Ottawa is predominantly made up of residential and commercial customers. In the current configuration, a high pressure network is exclusively fed by both the Ottawa and Richmond Gate Stations. Network Analysis has identified an upstream flow constraint at the Ottawa Gate Station, along with a bottleneck constraint for gas fed from Richmond Gate Station. The South outlet of Ottawa Gate can be set to as low as 400 psig (normally 470 psig) while Richmond Gate is kept at 470 psig, thus flowing more gas from the west to the east.

The preferred option is to not rely on system biasing (temporary reduction in station pressure to adjust flows) and keep Ottawa South station set at 470 psig. Additionally, in the current configuration, an existing NPS 12 high pressure pipeline along Fallowfield Road is a bottleneck for gas flowing from the west, to Richmond Gate Station, and to eastern areas. The previously constructed Ottawa Reinforcement Plan (ORP) Phase 1 as well as the Strandherd River crossing has helped move gas from Richmond Gate eastward to areas of concentrated and growing gas demand.

This reinforcement will assist in moving additional gas from Richmond Gate toward the areas that would be serviced by Ottawa Gate, and remove the bottleneck constraint. There are approximately 193,553 customers on the associated networks in 2016.

Assets: A combination of Pipe and Station assets to meet project objectives.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
The proposed scope includes the installation of 7 kilometres of NPS 20 high pressure main from Greenbank Road and W Hunt Club Road to Princess of Wales Drive and W Hunt Club Road along W Hunt Club Road.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Project Timing and Execution Risks:
The Project is proposed to start in 2021 and be completed by 2025.
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (24,506,425)	0.33	$ 53,489,000	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 268,000	$ 5,348,000	$ 47,070,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

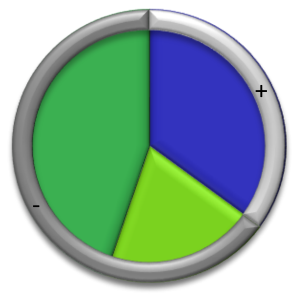
Investment Summary Report

Investment Code	Report Start Year	Number of Years
1024	2021	5

Investment Name

Rideau Reinforcement

Alternative Value - Recommended



	Value Function Measure	Value	Value in Percentage
	Revenue Impact (CA)	28,709	35%
	Financial Risk	0	0%
	Public Safety Risk	0	0%
	Budget Savings OPEX (CA)	(16,544)	20%
	Total Investment Cost (CA)	(36,672)	45%
	Total	**(24,506)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
16751	**2021**	**5**

Investment Name

Thornton Reinforcement

Investment Description

Issue/Concern:
Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Project Purpose/ Need: Customer growth in the surrounding area will drive this reinforcement. Increase in load will cause tail end pressures to go below the minimum pressure of 100 psi without reinforcement.

Risk if not completed: This reinforcement will limit the risk of customer loss up to forecast temperatures under normal operating conditions. Customer additions might be limited if this reinforcement is not completed.

Assets (preferred option):
Phase 1 in 2022: Proposed 2.5 kilometres of 12” SC on Innisfil Beach Road, from Thornton Gate Station #3613819 outlet to County Road 53
Phase 2 in 2024: Proposed 6 kilometres of 8” SC on Lockhart Road, from tail end of existing 8” SC at Lockhart Road/Yonge Street to 25 Sideroad

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
-Phase 1 in 2022, Proposed 2.5 kilometres of 12” SC XHP on Innisfil Beach Road, from Thornton Gate Station #3613819 outlet to County Road 53
-Phase 2 in 2024 Proposed 6 kilometres of 8” SC XHP on Lockhart Road, from tail end of existing 8” SC XHP at Lockhart Road/Yonge Street to 25 Sideroad

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Resources: Company crews, contractor labour, and third-party vendor suppliers.

Project Timing and Execution Risks: This project is scheduled to be in service in 2023.
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

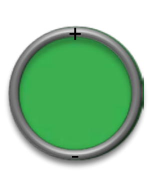
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	50 - Barrie
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (8,914,106)	0.00	$ 10,935,636	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 3,669,622	$ 7,266,014	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 89,414	$ 96,132	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(8,914)	100%
Total	**(8,914)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	1213	2021	5
	Investment Name: York Region Reinforcement		

Investment Description

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Number of customers impacted by year:
The growth projection for this project (suite of pipes and stations over time) is in the value framework and reproduced below. Only totals are provided by year.

2018	2881
2019	1679
2020	1532
2021	1253
2022	1111
2023	1132
2024	1107
2025	1036
2026	1026
2027	1069
2028	1101

Length and diameter of pipe to be installed:
2022: 5.4 kilometres of NPS 12
2024: 4 kilometres of NPS 6
2026: 7.6 kilometres NPS 12

Assets: A combination of Pipe and Station assets to meet project objectives.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
2018: Rebuild Glenwoods and Woodbine Station (3546065) so that it has a differential of 35 psi or less.
2018: Rebuild Doane & Woodbine Station (2937273) so it has a differential of 50 psi or less and can handle the existing capacity.
2019: Install 2.1 kilometres of 4" high pressure pipe on Civic Centre Road from Baseline Road to 200 meters south of Metro Road N.
2022: Install 5.4 kilometres of 12" high pressure pipe starting at Bondhead Gate station and replacing the existing 6" high pressure pipe all the way to the intersection of Hwy 88 and 10th Line. This may result in the requirement for a rebuild of Bondhead Gate Station for capacity reasons, pending confirmation of the max station throughput.
2024: Install 4.0 kilometres of 6" high pressure pipe on Baseline Road from McCowan Road to Dalton Road, north along Dalton Road to Black River Road, east along Black River Road to Station 3872873.
2026: Install 7.6 kilometres of 12" high pressure pipe on Bathurst Street from Gamble Road to McClellan Way. Install 7.1 kilometres of 8" SC high pressure pipe on Bathurst Street from McClellan Way to Mulock Drive. Install one XHP to HP Station at Bathurst Street and Bloomington Road.
2026: IP HP pressure elevation must be completed.
1. Elevate IP to HP new district stations
- 1 station at Bathurst Street and Mulock Road
- 1 HP to IP station at Bathurst Street and William Dunn Crescent
- 1 HP to IP station at Mulock Drive and Yonge Sever IP locations
- Bathurst Street and Keith Avenue
- Mulock Drive and Columbus - Way Elevate IP to HP
- NPS12, NPS8, NPS4 and NPS2 main – approximately 7 kilometres
- Main located on Bathurst Street, Mulock Drive, 19th Sideroad and Old Bathurst Street
If the engineering assessment indicates that IP cannot be elevated to HP, the following must be completed instead: Install 1.7 kilometres of 8" SC high pressure pipe on Mulock Drive from Bathurst Street to Yonge Street.
Install XHP-HP station at Bathurst and Mulock. Install HP-IP station at Yonge and Mulock.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Resources: Company crews, contractor labour, and third-party vendor suppliers

Project Timing and Execution Risks: This multi-year project will be phased in each year from 2021 to 2026
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Growth - System Reinforcement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	30 - Richmond Hill
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
1213	2021	5

Investment Name

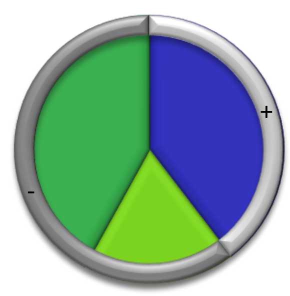
York Region Reinforcement

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (22,997,686)	0.51	$ 65,846,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,656,000	$ 15,400,000	$ 280,000	$ 6,260,000	$ 1,280,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Revenue Impact (CA)	43,957	40%
Financial Risk	0	0%
Public Safety Risk	0	0%
Budget Savings OPEX (CA)	(20,384)	18%
Total Investment Cost (CA)	(46,571)	42%
Total	**(22,998)**	**100%**

Distribution Pipe

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100504	**2021**	**5**

Investment Name

A10: Kipling Ave & Lake Shore Blvd W, Etobicoke, Replacement

Investment Description

Issue/Concern:

General Concerns:
Vintage Steel Replacement Program: Proactive replacement program to renew aging vintage steel pipe assets before reaching end-of-life. Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third-party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion related failures, while the C55 value framework and the 40-year risk projection are showing an aggressive increase in the safety risk associated with steel main failures. Vintage steel systems also have potential to include: compression couplings, shallow installation depth and shallow assemblies making pipe susceptible to third party damage, and manufactured defects associated with seam welds and fittings.

Site-specific Concerns:
A 1955 vintage NPS 8 HP steel main is susceptible to the issues outlined above. Operations field personnel reported past stray current issues from the streetcar tracks and their roundabout. Combining with coating holidays on the steel main, the stray current could negatively affect the cathodic protection effectiveness and causing accelerated corrosion on the steel main. The NPS 8 gas main traverses in a highly-populated, residential area in downtown Toronto, which could drive up the consequence in the event of a failure.
An urgent section is identified near Humber College, where stray current from streetcar tracks is causing corrosion issues on the steel pipe. The number of repairs that have been done has caused Operations to flag the section. By replacing the steel HP pipe with plastic IP pipe, this corrosion issue can be avoided.

Assets: Steel main on Lake Shore Boulevard and Kipling Avenue

Related Programs: N/A

Recommended Alternative Description

Scope: Replace 883 metres of 2" SC HP GM, 557 metres of 4" SC HP GM and 173 metres of 8" SC HP GM with approximately 1628 metres of 4" PE IP GM. Approximately 29 customers affected (28 Services + 1 Header. 10 Meter Relites).

Resources: NPL

Solution Impact: Eliminate risk by replacing steel HP pipe with polyethylene IP pipe to avoid corrosion issues.

Project Timing: Planning in 2020, execution in 2021.

Execution Risks: No TRCA permit required. Moratorium expires in 2022. Urgent section needs to be replaced therefore a moratorium exception may be required to get this work done in 2021 as per AR&I's request.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 2	Recommended	$ (1,294,978)	0.43	$ 2,443,077	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,443,077	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 755,591	$ -	$ -	$ -	$ -

ENBRIDGE

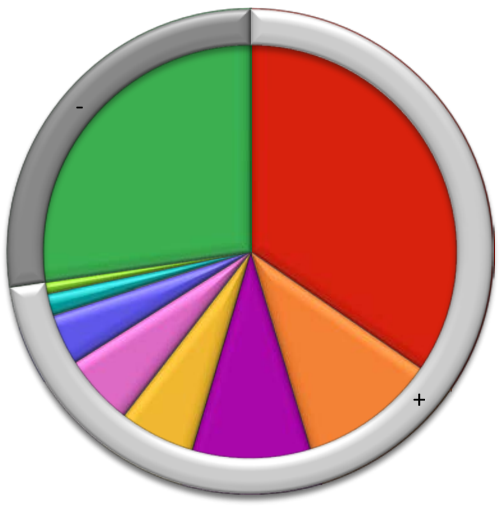
Investment Summary Report

Investment Code	Report Start Year	Number of Years
100504	**2021**	**5**

Investment Name

A10: Kipling Ave & Lake Shore Blvd W, Etobicoke, Replacement

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Public Safety Risk	2,865	35%
Cost Avoidance OPEX (CA)	890	11%
Financial Risk	764	9%
Operational Risk	489	6%
Reputational Risk	462	6%
Avoided GHG Emissions (CA)	327	4%
Employee And Contractor Safety Risk	143	2%
Budget Savings OPEX (CA)	77	1%
Cost Avoidance CAPEX (CA)	0	0%
Environmental Risk And Remediation	0	0%
Total Investment Cost (CA)	(2,262)	27%
Total	**3,755**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
101343	2021	5

Investment Name

A60: Sparks St, Ottawa, Replacement

Investment Description

Issue/Concern:
Sparks Street's NPS 12 steel main is approaching end-of-life and a replacement is necessary. This main was installed in the 1960s and 1970s and has compression couplings, Dresser-style fittings, drips and blow off valves. Sparks Street is a pedestrian path through the downtown core of Ottawa with no vehicular access, therefore performing maintenance activities or accessing the site during emergencies is a challenge.

Assets: Approximately 1100 metres of NPS 12 intermediate pressure (IP) steel pipe on Albert Street, 900 metres of NPS 4 IP Polyethylene (PE) pipe on Sparks Street and 175 metres of NPS 4 PE pipe from Lyons to Wellington.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:This pipeline project involves installing approximately 1100 metres of NPS 12 intermediate pressure (IP) steel pipe on Albert Street, 900 metres of NPS 4 IP Polyethylene (PE) pipe on Sparks Street and 175 metres of NPS 4 PE pipe from Lyons to Wellington. Due to the Parliament Hill location, construction will be slow and permitting / accessibility issues will not allow for a single year construction project.

Resources: Regional planners and construction crews.

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public.

Project Timing and Execution Risk: Planning of the project has commenced in Q1 of 2020, proposed construction date is Q2 of 2021 (earliest) and proposed in-service date is Q4 2020.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
NPS 12 Replacement	Recommended	$ (5,563,120)	0.28	$ 9,326,660	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,305,000	$ 2,305,000	$ 2,305,000	$ 2,203,580	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

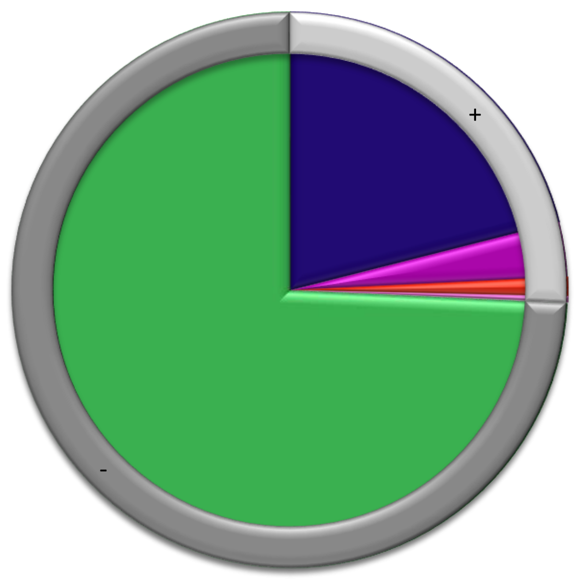
Investment Summary Report

Investment Code	Report Start Year	Number of Years
101343	2021	5

Investment Name

A60: Sparks St, Ottawa, Replacement

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance CAPEX (CA)	2,204	21%
Financial Risk	333	3%
Public Safety Risk	114	1%
Reputational Risk	37	0%
Avoided GHG Emissions (CA)	3	0%
Budget Savings OPEX (CA)	1	0%
Operational Risk	0	0%
Employee And Contractor Safety Risk	0	0%
Cost Avoidance OPEX (CA)	0	0%
Environmental Risk And Remediation	0	0%
Budget Savings CAPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(7,768)	74%
Total	**(5,076)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
23230	2021	5

Investment Name

Black Creek Rd and River Trail, Fort Erie - VPM Aldyl-A MP lined in steel

Investment Description

Issue/Concern:
General: Vintage Plastic Replacement Program: Proactive replacement program to renew aging vintage plastic pipe assets before reaching end-of-life. Vintage plastic Aldyl A mains are the earliest plastic mains used within the distribution system; the installation period of Aldyl A plastics started in the late 1960s on a field trial basis and was concluded by the end of 1976 for the EGD rate zone and 1984 for the Union rate zones. It is well known and studied in the North American gas industry that Aldyl A plastic mains have brittle-like cracking properties. The oxidation of the inner wall surface during manufacturing (also known as Low Ductile Inner Wall (LDIW)) and the large spherulites found in its microstructure causes pipe to be susceptible to cracking and premature failure in the presence of stress intensifiers such as a large number of connections, squeeze-off locations, and the presence of rock impingement points caused by rocky soil types.

Site specific: MP vintage plastic main lined within old steel mains. If pipe is damaged or leaks, the migration path could cause gas to travel long distances. Difficult to pinpoint leaks and increased risk of migration into other conduits/utilities.

Assets: Black Creek Road and River Trail, Fort Erie - VPM Aldyl-A MP lined in steel

Project proposed: 2235 metres NPS 4” PE IP, 8200m NPS 2” PE IP, 277 Service Relays (MP to IP), 18 Service Relays (IP to IP); Abandonment: 8200 metres MP Main (Various Sizes), 632 metres IP Main (4” & 3”), 277 MP Services, 18 IP Services.

Related Program: N/A

Recommended Alternative Description

Scope of Work: Project proposed: 2235 metres NPS 4” PE IP, 8200 metres NPS 2” PE IP, 277 Service Relays (MP to IP), 18 Service Relays (IP to IP); Abandonment: 8200 metres MP Main (Various Sizes), 632 metres IP Main (4” & 3”), 277 MP Services, 18 IP Services.

Resources: District operations is planning and is constructing this project utilizing extended alliance partner NPL.

Solution Impact: The existing vintage plastic pipe will be removed from EGI system.

Project Timing and Execution Risks: Work is planned to be completed over two years and starting with survey and design 2020 and execution 2021/22. Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Plastic Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	80 - Niagara
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (3,939,405)	0.00	$ 4,414,980	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,174,990	$ 2,174,990	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 720,508	$ 720,508	$ -	$ -	$ -

ENBRIDGE

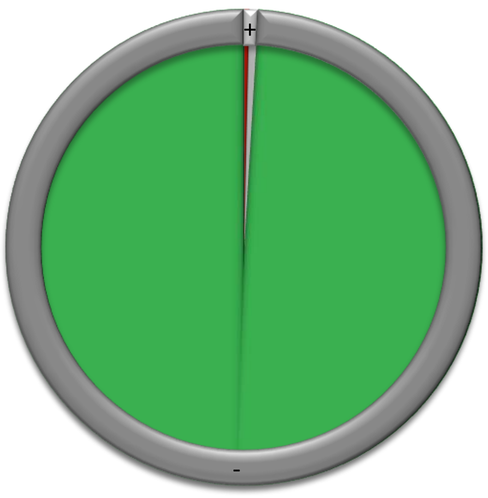
Investment Summary Report

Investment Code	Report Start Year	Number of Years
23230	2021	5

Investment Name

Black Creek Rd and River Trail, Fort Erie - VPM Aldyl-A MP lined in steel

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Public Safety Risk	13	0%
Avoided GHG Emissions (CA)	7	0%
Operational Risk	5	0%
Financial Risk	4	0%
Reputational Risk	4	0%
Cost Avoidance OPEX (CA)	2	0%
Budget Savings OPEX (CA)	2	0%
Employee And Contractor Safety Risk	1	0%
Cost Avoidance CAPEX (CA)	0	0%
Environmental Risk And Remediation	0	0%
Total Investment Cost (CA)	(3,944)	99%
Total	**(3,905)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
21947	**2021**	**5**

Investment Name

Burleigh Rd Fort Erie - Replacement

Investment Description

Issue/Concern:
This area (Hyman Avenue, Fort Erie) is very low and wet; with through-wall corrosion on the LP steel mains, water was able to get into the main and services on Hyman Avenue and is disrupting gas service to customers. This low pressure (LP) network consists of 1960s black-coated and 1970s vintage mains. Some LP to intermediate pressure (IP) replacement has already completed over past 20 years due to corrosion leaks.
Phase 2 of the Hyman Ave Fort Erie replacement will see the replacement of 8125 meters of existing LP pipe (combination of ST and PE, NPS 2, 3 and 4). In addition to replacing this pipe, the area will be tied into IP Network 8120, relaying 415 services, and tying over another 75 services. Any previous steel installation in this area will also be replaced for corrosion purposes as part of Phase 2. Phase 2 will also see the abandonment of two stations (IP to LP).

Assets: 8125 metres of existing LP pipe (combination of ST and PE, NPS 2, 3 and 4) on Hyman Avenue, Fort Erie.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Phase 2 of the Hyman Avenue Replacement will see the replacement of 8125 metres of existing LP pipe (combination of NPS 2,3, and 4 both polyethylene (PE) and steel). In addition to replacing this LP pipe, it will also be tied over to IP Network 8120, relaying 415 services, and tying over 75 services.

Proposed approx. 1,400 metres of NPS 4 PE IP and 14,800 metres of NPS 2 PE IP.

Resources: Project will be executed with extended alliance contractor resources.

Solution Impact: Replacing this vintage steel pipe will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and the general public.

Project Timing and Execution Risks: Survey and planning in 2019 approved, execution in 2020/2021. Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

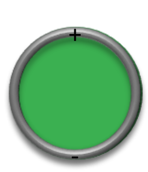
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	80 - Niagara
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,826,853)	0.00	$ 5,140,632	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,641,872	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 423,465	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(4,827)	100%
Total	**(4,827)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	1938	2021	5
	Investment Name: NPS 10 Glenridge Avenue, St. Catharines		

Investment Description

Issue/Concern:
GENERAL CONCERNS: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion related failures, while the C55 value framework and the 40-year risk projection are showing an aggressive increase in the safety risk associated with steel main failures.

SITE SPECIFIC CONCERNS:
This project looks to replace approximately 8.7 kilometres of mostly 1954 to 1960s vintage NPS 10 intermediate pressure (IP) pipe with sections of NPS 12 and NPS 8 spliced in over the years as repairs. Fittings and equipment are not readily available with some NPS 10 components taking several months to a year to receive if needed for repair / replacement. It is difficult to identify all possible fittings that may be required for repair work and expensive to sustain an extensive warehouse of components. For example, a recent repair that typically would have used a Shortstop 3-way tee could not be used once the pipe was excavated due to shallow depth of cover. Instead, a TDW spherical 3-way tee needed to be used.

Depth of cover (DOC) is a significant issue throughout the NPS 10 system. A 2019 DOC survey found that 366 (33%) survey locations had less than 90 cm of cover, and 90 survey locations (8%) had DOC<60cm, with one location found having exposed pipe due to creek erosion. Poor depth of cover leads to increased third-party damages (as has been seen with blow-off valves). Other risk factors include black coal tar pipe coatings used on 1959/1960 vintage NPS 10 pipe which show evidence of degradation, yielding to corrosion.

There are many unusual fittings (Stop-and-Go) and unusual construction practices (such as using unrestrained compression couplings to tie in service connections) that can lead to difficult emergency responses. For example, a recent leak repair took 24 days to complete at a cost of almost $500K due to complications from DOC, components, and construction practices. Unrestrained compression couplings have been the source of leaks due to ground settlement and increase the risk of pull-out. The river crossing at Twelve Mile Creek is very difficult to access due to steep creek banks and heavy vegetation, making it difficult to perform cathodic protection and leak surveys. It will pose as a significant concern for any required emergency response. The numerous transitions from NPS 8 to NPS 10 to NPS 12 also creates concern and difficulties for operational work to be completed.

There are two main line valves that are suspected to be tied in with unrestrained compression couplings (CC) as per an Integrity Assessment for suspect CC locations. Cathodic protection for some of the NPS 10 segments has been historically poor, showing as much as 25% of historical readings over the last 20 years below minimum required levels.

Assets:
8.7 kilometres of mostly 1954 to 1960s vintage NPS 10 IP pipe with sections of NPS 12 and NPS 8 spliced in over the years as repairs that run along Glenridge Avenue from Russel Avenue south to Lockhart Drive, then along Lockhart Drive west to First Street Louth.

Related Programs: N/A

Recommended Alternative Description

SCOPE OF WORK: AR&I Main Replacement - Replace approximately 7500 m of vintage main NPS 10" ST IP and approx 110 service connections with NPS 8 PE.

RESOURCES: External Alliance contractors

SOLUTION IMPACT:
Main replacement project identified by Operations - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results.

PROJECT TIMING & EXECUTION RISKS:
This confirmed the timing for execution of this replacement project for 2024/25.
Execution Risks: Moratoriums, 3rd party developments, COVID-19 impacts, permitting and required easements.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	80 - Niagara
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
NPS 8 PE option	Recommended	$ (8,367,776)	0.00	$ 11,804,455	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 435,000	$ 5,912,929	$ 5,456,526
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ 3,565,604

ENBRIDGE

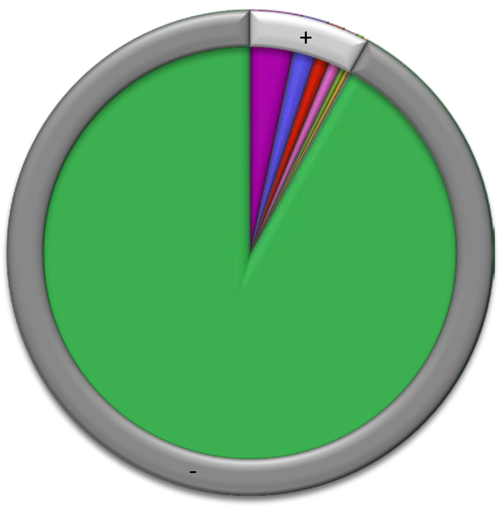
Investment Summary Report

Investment Code	Report Start Year	Number of Years
1938	2021	5

Investment Name

NPS 10 Glenridge Avenue, St. Catharines

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Financial Risk	308	3%
Avoided GHG Emissions (CA)	157	2%
Public Safety Risk	105	1%
Reputational Risk	85	1%
Budget Savings OPEX (CA)	37	0%
Operational Risk	36	0%
Employee And Contractor Safety Risk	11	0%
Cost Avoidance CAPEX (CA)	0	0%
Cost Avoidance OPEX (CA)	0	0%
Environmental Risk And Remediation	0	0%
Total Investment Cost (CA)	(8,405)	92%
Total	**(7,666)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
22444	2021	5

Investment Name

NPS 12 & NPS 8 Blackhorse Gate to Chippewa Creek NW8983 Retrofit

Investment Description

Issue/Concern:

Project Specific: NPS 12 and NPS 8 Blackhorse Gate to Chippewa Creek NW8983 pipeline has been identified for inclusion in the Integrity Management Program (IMP), according to TSSA CAD, FS-220-16, Clause 10.3.11, as identified by the MOP team. If the pipelines are operating above 29.5% SMYS, they fall within the definition of an IMP pipeline that is in scope of EGI's Integrity Management Program.

General: The Integrity Retrofit portion of the Integrity Management Program is to specifically capture retrofit work to make pipelines inline inspectable. The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of pipeline systems at EGI to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30% SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and remediation of pipeline segments with integrity issues that are identified through the inspections.

Assets: NPS 12 and NPS 8 Blackhorse Gate to Chippewa NW8983

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
The following retrofits are required: Install One NPS 12 above-ground launcher isolation valve kicker and permanent trap. Remove IPSCO fitting at outlet of gate station. (one site, two digs); Install one below-ground NPS 12 receiver isolation valve and two below-ground NPS 8 launcher isolation valves. (Trap and kicker line will be temporary) (one site); Install Two NPS 8 below-ground receiver isolation valves and kicker line valves (trap and kicker line will be temporary). Remove spherical at inlet to the station at one of these sites FN 8-585-95 (two sites); Remove NPS 8 Rockwell plug valve. FN 8-227-118 (One site); Remove Mueller line stopper, Rockwell plug valve, reconfigure tie-in. FN 8-228-2 (possibly part of below-ground receiver isolating valve installation); Remove two Mueller line stopper fittings, reconfigure tee at Tie-in of NPS 12 reinforcement 8N1013-2 (one site).

Solution Impact: The NPS 12 and NPS 8 Blackhorse Gate to Chippewa Creek NW8983 lines can be in-line inspected after the retrofit work, ensuring compliance of the EGI TIMP and the safe and reliable operation of the pipeline.

Resources: Engineering Construction will manage the planning and execution of this project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Integrity - Integrity Retrofit
Investment Stage	Long Term Planning		

Investment Overview

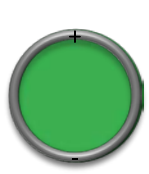
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	80 - Niagara
	Asset Program (EGI)	DP - Integrity
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Retrofit	Recommended	$ (3,496,902)	0.00	$ 3,883,883	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,436,291	$ 1,447,592	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(3,497)	100%
Total	**(3,497)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
22445	2021	5

Investment Name

NPS 12 & NPS 8 Blackhorse to Forks Rd NW8980 Retrofit

Investment Description

Issue/Concern:

General: The Integrity Retrofit portion of the Integrity Management Program is to specifically capture retrofit work to make pipelines inline inspectable. The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of pipeline systems at EGI to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30% SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and remediation of pipeline segments with integrity issues that are identified through the inspections.

Project-specific Concerns: NPS 12 and NPS 8 Blackhorse Gate to Forks Road NW8980 pipeline has been identified for inclusion in the Integrity Management Program (IMP), according to TSSA CAD, FS-220-16, Clause 10.3.11, as identified by the MOP team. If the pipelines are operating above 29.5% SMYS, they fall within the definition of an IMP pipeline that is in scope of EGI's Integrity Management Program.

Assets: Network #NW8980 NPS 12 and 8 Blackhorse to Forks Road

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
NPS 8: Install two below-ground launcher isolation valve and kicker line valve. (Trap and kicker line will be temporary) (tw sites); Install two above-ground receiver isolation valve and kicker line valve, and permanent trap. (2 sites); Remove two Mueller line stoppers, FN 8-263-1-4 (one site, two digs); Remove NPS 8 Mueller line stopper at station tie-in FN 8-342-125 (1 site); Check configuration of piping to remove NPS 6 bottleneck, FN 8-771-182; Remove NPS 8 spherical FN 8-491-8-10 (one site)
NPS 12: Install one above-ground launcher isolation valve, kicker line and permanent trap. (one site); Install one above-ground receiver isolation valve, kicker line and permanent trap. (one site); Remove two Mueller line stoppers FN 8-275-101,102 (one site, two digs); NPS 12 valve Kerotest, planning needs to confirm. Plug valve needs to be removed, FN 8-62-73A; Remove two Mueller line stoppers, FN 8-266-77-79 (one site, two digs); Remove two Mueller line stoppers and insulating flange set, replace with weld-in insulator FN 8-353-41-44 (one site, two digs); Install solid piggable insert into Mueller line stopper fitting. FN-461-23-26 (one site)

Solution Impact: The NPS 12 and NPS 8 Blackhorse to Forks Road lines can be in-line inspected after the retrofit work, ensuring compliance of the EGI TIMP and the safe and reliable operation of the pipeline.

Resources: Engineering Construction will manage the planning and execution of this project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Integrity - Integrity Retrofit
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	80 - Niagara
	Asset Program (EGI)	DP - Integrity
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Compliance to TIMP program as this line is identified as operating > 30% SMYS.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Retrofit	Recommended	$ (5,992,100)	0.00	$ 6,714,513	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,433,404	$ 3,281,109	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(5,992)	100%
Total	**(5,992)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	10086	2021	5
	Investment Name: NPS 12 Martin Grove Rd - Clements Rd to Lavington		

Investment Description

General Concerns:
Vintage steel mains have shown signs of declining health due to the cumulative effects of poorly manufactured coatings, construction practices, latent third-party damages to pipe coatings and the effect of stray currents from transit infrastructure (such as the subway and streetcars). The current failure projection model forecasts an exponential increase in the number of corrosion-related failures. The C55 value framework and the 40-year risk projection show an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and or higher risk of third-party damage in the following ways:
-Compression couplings
-Shallow blow-off valve assemblies that could be damaged during excavation activities
-Reduction in the original depth of cover
-Continuous exposure to road salt and seasonal ground movement on bridge crossing assets
-Lack of cathodic protection on pipe casings that could result in corrosion and could lead to the loss of containment
-Manufacturing defects associated with seam welds and fittings that could result in a loss of containment due to prolonged stress and corrosion
-Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, resulting in accelerated corrosion and potentially loss of containment

Site-specific Concerns:
The Martin Grove project is a size for-size replacement of NPS 12 HP steel main on Martin Grove Road. There are a number of service connections tied into the high pressure main where vintage field applied coatings become a corrosion inducing location due to degradation. For example, an opportunistic dig along this main for a service connection found a corrosion pit under the field applied coating at a tee. Further, this main has coal tar coating which is know to disbond and create corrosion concerns. Depth of cover is a significant concern, where a 2018 depth of cover survey found 91 measurements of 192 (47%) had a depth less than the EGI standard of 0.90 metres and 25 measurements (13%) recorded a depth of less than 0.60 metres (CSA Z662 minimum standard). Poor DOC can lead to increased third-party damages. Additional risk factors include the presence of unrestrained compression couplings, as these create a risk of leak due to frost heave and ground movement and may even pull-out completely as they provide no pull-out retention. CP protection levels over the past 20 years have shown that as much as 37% of the time readings have been below acceptable levels. Poor cathodic protection levels can lead to corrosion.

Assets: NPS 12 ST HP gas main

Related Programs: 6421, 11443

Recommended Alternative Description

Scope of Work: Phase 1 of Martin Grove NPS 12 - HP replacement of approximately 1.2 kilometres of main from Clements Road to Lavington, and replacement of three district stations.

Phase 1: Includes the installation of approximately 1.2 kilometres of NPS 12 HP steel main on Martin Grove Road from Lavington Drive to Clement Road in Etobicoke and the abandonment of approximately 1.2 kilometres of NPS 12 HP steel main along Martin Grove Road. Phase 1 also includes the replacement of three pressure reduction stations and approximately 10 services. The new route will follow Municipal Right of Way and is planned for construction in 2020. The planning and engineering will take place in 2019.

Resources: 2020 - OTC for Phase 1 and resources TBD.

Solution Impact: Main replacement project identified by Asset Management - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results.

Project Timing and Execution Risks:
Phase 1 - 2020
Phase 2 - 2024
Risks: moratoriums and easements.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (6,349,544)	0.00	$ 6,890,651	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 6,818,951	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 563,028	$ -	$ -	$ -	$ -

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
10086	**2021**	**5**

Investment Name

NPS 12 Martin Grove Rd - Clements Rd to Lavington

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(6,350)	100%
Total	**(6,350)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
11443	2021	5

Investment Name

NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Rd.

Investment Description

Issue/Concern:

General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effects of poorly manufactured coatings, construction practices, latent third-party damages to pipe coatings, and the effect of stray currents from transit infrastructure (such as the subway and streetcars). The current failure projection model forecasts an exponential increase in the number of corrosion-related failures. The C55 value framework and the 40-year risk projection show an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:
- Compression couplings
- Shallow blow-off valve assemblies that could be damaged during excavation activities
- Reduction in the original depth of cover
- Continuous exposure to road salt and seasonal ground movement on bridge crossing assets
- Lack of cathodic protection on pipe casings that could result in corrosion and could lead to the loss of containment
- Manufacturing defects associated with seam welds and fittings that could result in a loss of containment due to prolonged stress and corrosion
- Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, resulting in accelerated corrosion and potentially loss of containment

Site-specific Concerns:
Martin Grove to St. Albans Road: Address NPS 12 pipe from Lavington Drive South to Burnhamthorpe Road, then west to Ashbourne Drive, then following Auckland Road south to St. Albans Road.

There are over 360 service connections that will be removed from the HP steel main and an intermediate pressure (IP) polyethylene (PE) subsystem installed to reconnect these customers. Depth of cover (DOC) has been identified as a significant concern for these main segments as identified by 2018 and 2019 DOC surveys that found over 52% of the survey locations had DOC less than 90 centimetres, with 77 survey locations measuring less than 60 centimetres of cover. Poor DOC can lead to increased third-party damages. Additional risk factors include two unrestrained compression couplings (CCs), nine restrained CCs, and three suspect valves where due to their installation dates, may have been tied in using unrestrained CCs (as discovered by an Integrity Assessment showing significant correlation between valves of this vintage with unrestrained CC tie-ins).

Cathodic protection history for the past 20 years shows that over 15% of the readings taken each year were below the minimum requirements. Poor cathodic protection levels can lead to corrosion.

Assets: NPS 12 pipe from Lavington Drive south to Burnhamthorpe Road, then west to Ashbourne Drive, then following Auckland Road South to St. Albans Road.

Related Programs: 6421, 10086.

Recommended Alternative Description

Scope of Work: Replacement of approximately 6.4 kilometres of NPS 12 steel main from Martin Grove Road and Lavington Drive South to Burnhmthorpe Road, then west to Ashbourne Drive, then south to Auckland Road and St. Albans Road. Approximately 360 services to be reconnected to a new IP PE sub-system.

Resources: 2024 OTC Phase 2 and resources TBD

Solution Impact: Main replacement project identified by Asset Management - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results.

Project Timing and Execution Risks: moratoriums and easements.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (13,436,574)	0.00	$ 18,292,755	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 400,000	$ 17,292,755	$ 600,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

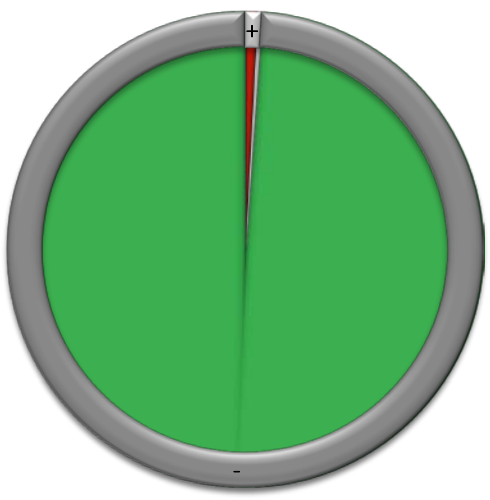
Investment Summary Report

Investment Code	Report Start Year	Number of Years
11443	**2021**	**5**

Investment Name

NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Rd.

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Public Safety Risk	105	1%
Financial Risk	31	0%
Employee And Contractor Safety Risk	11	0%
Reputational Risk	4	0%
Environmental Risk And Remediation	1	0%
Operational Risk	0	0%
Avoided GHG Emissions (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Cost Avoidance CAPEX (CA)	0	0%
Cost Avoidance OPEX (CA)	0	0%
Total Investment Cost (CA)	(13,437)	99%
Total	**(13,285)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code 10293	Report Start Year 2021	Number of Years 5
	Investment Name NPS 12 St. Laurent Aviation Pkwy		

Investment Description

Issue/Concern:
General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third-party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion-related failures, while the C55 value framework and the 40-year risk projection are showing an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third party damage in the following ways:
-Compression couplings
-Shallow blow-off valve assemblies that could be damaged during excavation activities
-Reduction in the original depth of cover
-Continuous exposure of road salt and seasonal ground movement on bridge crossing assets
-Lack of cathodic protection with pipe casings that could result in corrosion causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment
-Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion
-Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.

Site-specific Concerns:
Unable to determine leaks due to the close proximity of the NPS 12 470 psi system. Cathodic protection wasn't installed until the early 1970s. Approximately 429 services are off this network.

This project is to install 8543 metres of 16/12 NPS on Aviation Pkwy tying into the Network 6580 (Ottawa Gate) and running to Rockcliffe Station. And abandon 12 kilometres of NPS 12. Scheduled to be replaced 2022.

Full replacement of main comprising Network 6584 - The NPS 12 St. Laurent Ottawa North line is 13.3 kilometres and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St Laurent Control Station to Industrial Ave as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral main along Tremblay Road (but does not include the crossing at the Rideau River to Station #61171A).

Assets: Approximately 2.4 kilometres of NPS 16 ST and 6.9 kilometres of NPS 12 Station to be installed and rebuild three stations (Rockcliffe, Birch and St Laurent Control).

Related Programs: 6422, 10089, 10288, 10290, 10291, 10292, 10289, 10294

Recommended Alternative Description

Scope of Work: Install 8268 kilometres of NPS 12, abandon NPS 12, install two new stations and rebuild two stations and rebuild of St Laurent and Rockcliffe Control.

In 2018, pressure increase to Avenue O was completed. In 2019, approx. 3.1 kilometres of plastic pipe was installed on Tremblay and the Avenues and the services transferred over to IP. Also, due to a road moratorium, 2 kilometres of 6" PE IP main on St. Laurent between Donald Street and Montreal needs to be brought forward from 2021 to 2019, as well as approximately 80 services.

In 2021, approximately 8.9 kilometres of plastic pipe will be installed and all the services will be transferred over to IP. Four IP stations will be abandoned and one new station will be installed. Approximately 6.5 kilometres of NPS 1 to 8 will be abandoned. Also, approximately. 0.6 kilometres of 4" SC will be installed to feed four stations that cannot be increased due to the age of the pipe.

In 2022, approximately 12 kilometres of steel pipe will be installed. Rockcliffe, Birch, and St. Laurent Control will be rebuilt, and approximately 9.3 kilometres of NPS 12/16 will be abandoned.

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public.

Resources: TBD

Timing and Execution Risks: Phase 4 is to executed in 2022, but the NPS 16/12 cannot be abandoned until this main is installed and all the services have been transferred onto the new IP system.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
10293	2021	5

Investment Name

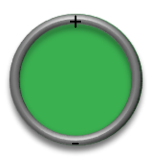
NPS 12 St. Laurent Aviation Pkwy

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 2	Recommended	$ (25,442,683)	0.00	$ 29,787,880	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 250,000	$ 27,737,880	$ 1,550,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 4,894,920	$ 450,000	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(25,443)	100%
Total	**(25,443)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	10294	2021	5
	Investment Name: NPS 12 St. Laurent Queen Mary/Prince Albert		

Investment Description

Issue/Concern:

General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion related failures, while the C55 value framework and the 40-year risk projection are showing an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third party damage in the following ways:
-Compression couplings
-Shallow blow-off valve assemblies that could be damaged during excavation activities
-Reduction in the original depth of cover
-Continuous exposure of road salt and seasonal ground movement on bridge crossing assets
-Lack of cathodic protection with pipe casings that could result in corrosion causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment
-Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion
-Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.

Site-specific Concerns: Unable to determine leaks due to the close proximity of the NPS 12 470 psi system. Cathodic protection wasn't installed until the early 1970s. Approximately 429 services are off this network.

Full replacement of main comprising Network 6584 - The NPS 12 St. Laurent Ottawa North line is 13.3 kilometres and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St. Laurent Control Station to Industrial Ave as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral main along Tremblay Road (but does not include the crossing at the Rideau River to Station #61171A).

In 2018, pressure increase to Avenue O was completed. In 2019, approx. 3.1 kilometres of plastic pipe was installed on Tremblay and the Avenues and the services transferred over to IP. Also, due to a road moratorium, 2 kilometres of 6" PE IP main on St Laurent between Donald Street and Montreal needs to be brought forward from 2021 to 2019 and approximately 80 services.

Assets: (Phase 4) This project is to install 3685 metres of NPS 12 in 2022 and relay 1 service.

Related Programs: 6422, 10089, 10288, 10290, 10291, 10292, 10293, 10289

Recommended Alternative Description

Scope of Work: Install 3780 metres NPS 12, and relay one service.
In 2021, approximately 8.9 kilometres of plastic pipe will be installed and all the services will be transferred over to IP, four IP stations will be abandoned and one new station will be installed. Approximately 6.5 kilometres of NPS 1 to 8 will be abandoned. Also, approx. 0.6 kilometres of 4" SC will be installed to feed four stations that cannot be increased due to the age of the pipe.
In 2022, approx. 12 kilometres of Steel will be installed, Rockcliffe, Birch and St Laurent Control will be rebuilt, and approximately 9.3 kilometres of NPS 12/16 will be abandoned.

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public.

Resources: TBD - Bid process

Timing and Execution Risks: Phase 4 is to executed in 2022, but the NPS 16/12 cannot be abandoned until this main is installed and all the services have been transferred onto the new IP system.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 2	Recommended	$ (9,448,268)	0.00	$ 11,050,071	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 100,000	$ 10,340,071	$ 530,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 1,824,718	$ 180,000	$ -	$ -

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	10294	2021	5
	Investment Name: NPS 12 St. Laurent Queen Mary/Prince Albert		

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(9,448)	100%
Total	**(9,448)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	10088	2021	5
	Investment Name: NPS 20 Lake Shore Replacement (Cherry to Bathurst)		

Investment Description

Issue/Concern:

General Concerns:
Vintage steel mains have shown signs of declining health due to the cumulative effects of poorly manufactured coatings, construction practices, latent third-party damages to pipe coatings and the effect of stray currents from transit infrastructure (such as the subway and streetcars). The current failure projection model forecasts an exponential increase in the number of corrosion-related failures.
In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:
- Compression couplings
- Shallow blow-off valve assemblies that could be damaged during excavation activities
- Reduction in the original depth of cover
- Continuous exposure to road salt and seasonal ground movement on bridge crossing assets
- Lack of cathodic protection on pipe casings that could result in corrosion and lead to the loss of containment
- Manufacturing defects on seam welds and fittings that could result in leaks due to prolonged stress and corrosion
- Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, resulting in accelerated corrosion and potentially loss of containment

Site-specific Concerns:
The NPS 20 Lake Shore Replacement project from Cherry Street to Bathurst Street addresses vintage steel mains installed in 1954. This project was assessed using Asset Health Review methodology, the C55 value framework, tacit knowledge from internal stakeholders and in-line inspection (ILI)/Integrity dig results. In addition to the declining health demonstrated by vintage steel mains, this pipeline is part of the KOL system in the Toronto area, known to have a number of features that make it more susceptible to accelerated degradation and/or higher risk of third-party damage. These features include but are not limited to:
- Compression couplings on mains and services
- Reduced depth of cover
- Shallow blow-off valves
- Lack of cathodic protection
- Live stubs
- Stray current from hydro infrastructure
- Possibly contaminated soils

In 2016 and 2018, inline inspections (ILI) using a robotic crawler were performed on approximately 1.9 kilometres of the 4.5 kilometres of pipe selected for Phase 1. The 2016 ILI survey found 2 areas that required immediate rehabilitation activities via 2 Integrity digs. There are an additional six Integrity digs recommended over the next 10 years. The 2018 inspection identified 24 further dig locations that would require Integrity remediation over the next 10 years as per the guidance from CSA Z662. These digs are required to mitigate the corrosion and dent features that could exhibit more than 80% wall loss or have a high probability of failure, representing significant degradation of the pipe. Costs for such Integrity digs, based on the integrity digs in 2017 and 2018, range from $350,000 to $450,000 per integrity dig. This implies that over the next 10 years EGI could be expected to spend $10,500,000 to $13,500,000 to rehabilitate these 30 locations, leaving the remaining pipe as bad as old. These Integrity digs would also require multiple construction zone impacts to the local traffic and businesses in a highly congested area of downtown Toronto. The multiple interruptions would have a negative impact to the reputation of safe and reliable service for EGI. Furthermore, the ILI survey also indicated another 10 features that may require mitigation activity within 15 years ($3.5M~$4.5M additional spend), which is an indication that the pipe is reaching the end of its safe and reliable service life and that a repair approach is not a sustainable approach.

Recommended Alternative Description

Scope of Work: This project is a size-for-size replacement of the existing NPS 20 HP steel main on Lake Shore Blvd from Cherry Street to Bathurst Street. This work includes approximately 4850 metres of NPS 20 and 500 metres of NPS 20 on Mill Street, it runs on Lake Shore Boulevard from Parliament Street to Bathurst Street.

Resources: 2021 - OTC and would be bid on by external contractors

Solution Impact: Main replacement project identified by Asset Management - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results. Further investigation was completed in 2018 to collect additional pipe condition data to assist in the planning, engineering and risk components. This confirmed the timing for execution of this replacement project for 2021.

Project Timing and Execution Risks: Moratoriums, third-party developments, Gardiner realignment and required easements.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
10088	2021	5

Investment Name

NPS 20 Lake Shore Replacement (Cherry to Bathurst)

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (94,067,357)	0.00	$ 104,689,659	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 64,118,854	$ 39,315,232	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 2,000,000	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(94,067)	100%
Total	**(94,067)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
17365	**2021**	**5**

Investment Name

NPS 8 Eagleson Rd (Kanata) Retrofit for ILI

Investment Description

Issue/Concern:
An Area 60 pipeline was identified to be operating at a Maximum Operating Pressure (MOP) above the threshold for integrity mains (operating above 29.5% SMYS) by the MOP team. The pipeline is identified as NPS 8 Eagleson Road (Kanata) that is operating at 470 PSI which corresponds to 30.8% SMYS. The current operating set pressure for the pipeline as acquired from Source Records 2016/2017 is 400 PSI, corresponding to 30.4% of pipe material SMYS, which means that the pipeline needs to be included in the Integrity Management Program, according to TSSA CAD, FS-220-16, Clause 10.3.11.

General: The Integrity Retrofit portion of the Integrity Management Program is to specifically capture retrofit work to make pipelines inline inspectable. The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of pipeline systems at EGI to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30% SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and remediation of pipeline segments with integrity issues that are identified through the inspections.

Assets: Network #6581

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
The specific scope of work involves: Installation of temporary launcher and receiver; replace a mixture of NPS 6 and 8 main with NPS 8 main; NPS 6 kerotest valve cutouts and installation of piggable valves; LSF cutout and installation of piggable fittings.

Solution Impact: Execution will allow for the safe inspection of the IMP main as per EGI's Integrity Management Program.

Resources: Engineering Construction, TFS and EGI Contractor.

Timing and Execution Risks: This project is scheduled for Fall 2020 and Spring/Summer 2021.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Integrity - Integrity Retrofit
Investment Stage	Executing		

Investment Overview

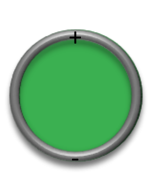
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Integrity
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	The Integrity retrofits portion of the Integrity Management Program is to specifically capture work to retrofit pipelines for inline inspection (ILI). It includes installation costs for permanent ILI tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations, and the retrofit of some pipelines that were initially assessed through ECDA to accommodate ILI tools and improve the completeness of the integrity assessments. The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Retrofit	Recommended	$ (4,145,778)	0.00	$ 4,357,440	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,857,440	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(4,146)	100%
Total	**(4,146)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
12268	**2021**	**5**

Investment Name

NPS 8 East Valley - Lancaster to Alexandria Pipeline - Retrofit/Replacement

Investment Description

Issue/Concern/Opportunity: This retrofit project will allow in-line inspection of the pipeline which is required as per the Integrity Management Program.

General: The Integrity Retrofit portion of the Integrity Management Program is to specifically capture retrofit work to make pipelines inline inspectable. The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of pipeline systems at EGI to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30% SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and remediation of pipeline segments with integrity issues that are identified through the inspections.

Assets: Network 6587 NPS 8 East Valley line.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Installation of permanent launcher and receiver. Retrofit nine locations containing unpiggable fittings (LSFs, undersized valves, and reduced port flange) with full port piggable fittings.

Solution Impact: Execution will allow for the safe inspection of the IMP main as per EGI's Integrity Management Program.

Resources: Engineering Construction, TFS and EGI contractor

Timing and Execution Risks: This project is scheduled for Fall 2020 and Spring/Summer 2021.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Integrity - Integrity Retrofit
Investment Stage	Executing		

Investment Overview

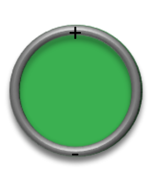
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Integrity
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	This project is part of the Gas Storage and Transmission System (GSTS) Integrity management plan that satisfies the requirements of the Pipeline Integrity Management Program mandated by CSA Z662-15 clause 3.2 and 10.3.10 as audited by the TSSA. The pipeline project is compliance driven and must be completed as part of the IMP.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Retrofit Line for ILI	Recommended	$ (3,148,967)	0.00	$ 3,242,364	1/1/2018

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 1,260,864	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(3,149)	100%
Total	**(3,149)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
10290	2021	5

Investment Name

St. Laurent Plastic - Coventry/Cummings/St Laurent

Issue/Concern:

General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion related failures, while the C55 value framework and the 40-year risk projection are showing an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third party damage in the following ways:
-Compression couplings
-Shallow blow-off valve assemblies that could be damaged during excavation activities
-Reduction in the original depth of cover
-Continuous exposure of road salt and seasonal ground movement on bridge crossing assets
-Lack of cathodic protection with pipe casings that could result in corrosion, causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment
-Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion
-Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.

Site-specific Concerns: Unable to determine leaks due to the close proximity of the NPS 12 470 psi system. Cathodic protection wasn't installed until the early 1970s. Approximately 429 services are off this network.
Full replacement of main comprising Network 6584 - The NPS 12 St. Laurent Ottawa North line is 13.3 kilometres and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St. Laurent Control Station to Industrial Avenue as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral main along Tremblay Road (but does not include the crossing at the Rideau River to Station #61171A).

In 2018, pressure increase to Avenue O was completed. In 2019/2020, approximately 3.1 kilometres of plastic pipe has been installed on Tremblay and the Avenues and the services transferred over to IP. Due to a road moratorium, 2 kilometres of 6" PE IP main on St. Laurent between Donald Street and Montreal was brought forward from 2021 to 2019/2020 and approximately 80 services.

Assets: This project is to install 800 metres NPS 6, 525 metres NPS 2 IP, transfer 27 services to IP from XHP, abandon one station on Coventry and Cummings.

Related Programs: 6422, 10089, 10288, 10289, 10291, 10292, 10293, 10294

Recommended Alternative Description

Scope of Work: Install 800 metres of NPS 6 and 525 metres of NPS 2 pipe, transfer 27 customers to IP. Abandon one station.

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public.

Resources: OTC 2021/22 - Resources TBD

Timing and Execution Risks: Scheduled for execution in 2021, but will need to balance this work with regional resourcing to achieve in 2021.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Plastic Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (3,322,128)	0.00	$ 3,677,958	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,581,554	$ 1,081,020	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 519,750	$ 360,672	$ -	$ -	$ -

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
10290	2021	5

Investment Name

St. Laurent Plastic - Coventry/Cummings/St Laurent

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(3,322)	100%
Total	**(3,322)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	10288	2021	5
	Investment Name: St. Laurent Plastic - Lower Section		

Investment Description

Issue/Concern:

General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third-party damages to pipe coating and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion related failures, while the C55 value framework and the 40-year risk projection are showing an aggressive increase in the safety risk associated with steel main failures.

In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third party damage in the following ways:
-Compression couplings
-Shallow blow-off valve assemblies that could be damaged during excavation activities
-Reduction in the original depth of cover
-Continuous exposure of road salt and seasonal ground movement on bridge crossing assets
-Lack of cathodic protection with pipe casings that could result in corrosion causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment
-Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion
-Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.

Site-specific Concerns:
Unable to determine leaks due to the close proximity of the NPS 12 470 psi system. Cathodic protection wasn't installed until the early 1970s. Approximately 429 services are off this network. Full replacement of main comprising Network 6584 - The NPS 12 St. Laurent Ottawa North line is 13.3 kilometres and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St. Laurent Control Station to Industrial Avenue as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral main along Tremblay Road (but does not include the crossing at the Rideau River to Station #61171A).

In 2018, pressure increase to Avenue O was completed. In 2019/2020, approximately 3.1 kilometres of plastic pipe has been installed on Tremblay and the Avenues and the services transferred over to IP. Due to a road moratorium, 2 kilometres of 6" PE IP main on St. Laurent between Donald Street and Montreal was brought forward from 2021 to 2019/2020 and approximately 80 services.

Assets: Lower Section is comprised of 2 projects:
Lower Section Part 1: Lancaster and Gladwin Cres Install 1.9 kilometres of 4" PE relaying 17 services, eight headers and pressure increasing two headers and relighting 170 customers
Lower Section Part 2: Industrial Avenue Install 1.3 kilometres of 4" PE and relay 13 services and pressure increase 2 headers and relight approximately 44 customers

Related Programs: 6422, 10089, 10289, 10290, 10291, 10292, 10293, 10294

Recommended Alternative Description

Scope of Work: Install 2924 metres of NPS 4, abandon 2970.6 metres of SC, transfer 126 connections to IP.

In 2021, Install approximately 1.1 kilometres of NPS 4 IP PE on St. Laurent Blvd and Industrial Avenue Street transferring 44 customers to IP. Abandon approximately 565 metres of 4 SC and 371 metres of 12 higher-pressure pipe. Tie-in to 6544 at Bourassa Street and St. Laurent Boulevard a 55# IP system and Russell Road and Industrial Avenue making this a two-way feed.

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public.

Resources: Regional Construction and Engineering Construction (if there is no capacity from Regional Construction).

Timing and Execution Risks: To be executed in 2021, will need to work with region to ensure resourcing so this is achievable.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Plastic Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,152,951)	0.00	$ 4,512,874	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 4,289,202	$ 200,000	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 68,843	$ -	$ -	$ -	$ -

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
10288	**2021**	**5**

Investment Name

St. Laurent Plastic - Lower Section

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(4,153)	100%
Total	**(4,153)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	10292	2021	5
	Investment Name: St. Laurent Plastic (Montreal to Rockcliffe)		

Investment Description

Issue/Concern:
General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third-party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion related failures, while the C55 value framework and the 40-year risk projection show an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third party damage in the following ways:
-Compression couplings
-Shallow blow-off valve assemblies that could be damaged during excavation activities
-Reduction in the original depth of cover
-Continuous exposure of road salt and seasonal ground movement on bridge crossing assets
-Lack of cathodic protection with pipe casings that could result in corrosion causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment
-Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion
-Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.

Site-specific Concerns:
Unable to determine leaks due to the close proximity of the NPS 12 470 psi system. Cathodic protection was not installed until the early 1970s. Approximately 429 services are off this network.

Full replacement of main comprising Network 6584 - The NPS 12 St. Laurent Ottawa North line is 13.3 kilometres and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St Laurent Control Station to Industrial Avenue as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) but does include the NPS 12 lateral main along Tremblay Road (but does not include the crossing at the Rideau River to Station #61171A).

In 2018, pressure increase to Avenue O was completed. In 2019/2020, approximately 3.1 kilometres of plastic pipe has been installed on Tremblay and the Avenues and the services transferred over to IP. Due to a road moratorium, 2 kilometres of 6" PE IP main on St. Laurent between Donald Street and Montreal was brought forward from 2021 to 2019/2020 and approximately 80 services.

Assets: Install approx. 2.9 kilometres of 6" PE and 122 metres of 2" PE, transfering 135 customers to the IP, pressure decrease Hillsdale Rd and abandon St 6B882 Lansdowne/Hillsdale.

Related Programs: 6422, 10089, 10288, 10290, 10291, 10289, 10293, 10294

Recommended Alternative Description

Scope of Work: Install 3385 NPS 6, 445 NPS 4 and 348 NPS 2, transfer 123 connections to IP. Abandon eight stations and install one new station.

In 2021, approximately 8.9 kilometres of plastic pipe will be installed and all the services will be transferred over to IP, four IP stations will be abandoned and one new station will be installed. Approximately 6.5 kilometres of NPS 1 to 8 will be abandoned. Approximately 0.6 kilometres of 4" SC will be installed to feed four stations that cannot be increased due to the age of the pipe.

In 2022, approximately 12 kilometres of steel pipe will be installed. Rockcliffe, Birch and St. Laurent Control will be rebuilt, and approximately 9.3 kilometres of NPS 12/16 will be abandoned. This project tasks are:
- Install three kilometres NPS 6, 445 metres of NPS 4 and 300 metres of NPS 2 IP.
- Transfer 123 services to IP.
- Abandon one station on St. Laurent and Sandridge from Montreal to Rockcliffe Station.

Solution Impact: Replacing the main will ensure the continued operation of EGI's gas distribution system, and will mitigate safety risks to employees, contractors, and general public.

Resources: Regional Construction and Engineering Construction if there is no capacity from Regional Construction.

Timing and Execution Risks: Phase 3 is to executed in 2021, but due to the volume of work for the region this may not be achieved in 2021.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DP - Main Replacement - Vintage Plastic Replacement Program
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
10292	**2021**	**5**

Investment Name

St. Laurent Plastic (Montreal to Rockcliffe)

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (3,882,224)	0.00	$ 4,248,935	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,582,985	$ 652,770	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 195,750	$ 313,347	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(3,882)	100%
Total	**(3,882)**	**100%**

Distribution Stations

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	7061	2021	5
	Investment Name: Brampton Gate Station Rebuild		

Investment Description

Issue/Concern:
The Brampton gate station has the following issues by subsystem:

Pipe, Valves and Others: No identified issues, but will be reconfigured to accommodate the rebuild. Upgrade to Station Inlet piping to accommodate a new horizontal gas separatos filters to prevent any liquids from the NEB 24 inlet from entering the station

Heating System: The heating system is in a hazardous area and must be moved. In addition, it has an obsolete control system that is no longer supported.

Pressure Control: One of the pressure control runs has a Kerotest inlet valve that is low to grade. There are concerns about the water table in the station and a redesign will address the issues. A Becker regulator will need to be added to provide remote control for the NPS 12 line - Network 2187.

Oduorant System: The odourant building does not include the injection panel and does not have complete containment if the injection panel has a rupture.

Telemetry/Electrical: The telemetry and electrical systems will be brought up to current standards and may include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, generator or TEG upgrades, modem and firewall upgrades, station lighting upgrades, weather station installation/replacement, and gas chromatograph installation. New generator to be installed, current generator is at end-of-life. Additional Control Tuning requirements needed for Network 2187 outlet NPS 12. This will include addition of DNGP controllers and associated Telemetry equipment within the new RTU Building.

Measurement: Existing turbine meter will be replaced.

Compliance/Civil: Site grading will be required. Recoat all above ground piping and fittings including fittings, station filter, etc. Insulation of new heating system inlet (boiler building or cold weather technologies) Remove existing east fence line. Move existing east fence line to align with TCPL fence. Replace south fence to replace gap in fence between EGI and TCPL. Remove tree on west end side of property (climbing hazard).

Assets: Station# 20101A, 20101B, 20101C

Related Program(s): N/A

Recommended Alternative Description

Scope Work:
Pipes and Valves: Excessive station piping will be shortened and/or removed.

Heating System: The obsolete Delta V controller will be replaced with new Honeywell controllers. The boiler building will also be relocated to an area outside of any hazardous areas. Install new CWT or conventional boiler System (new building, if required). New inlet/outlet piping including valves required. Remove existing boiler building and associated mechanical piping assets.

Pressure Control: The existing double boot style regulators will be replaced with new regulators sized to handle the future projected load. Replace Run 1 to table top design to remove run from water table (STN #20101A) Replace Run 2 to table top design to remove run from water table (STN #20101B) Upgrade STN #20101C due to Kerotest inlet valve to be raised.

Odourant System: The entire odourant system will be replaced with a new system meeting design standards. The new odourant building will contain both the tank and injection panel, complete with containment, fire suppression system, and CGI's. New odourant building required. This will include the removal of the existing “dog shed” building to make room for the new building.

Telemetry and Electrical: Remove existing RTU/Electrical Building. Install NEW RTU/Electrical Building (Repurpose existing RTU Equipment). Relocate new generator to location next to new RTU/electrical building. Remove expansion tank and generator pad. Relocate incoming power from Brampton Hydro authority. New electrical/telemetry connection for E+H Meter. New electrical/telemetry connection for micromotion meter. Upgrade all meter-run pipe Supports. Relocate all pressure and temperature transmitters to pipeline (x5). Account for new telemetry tower location.

Measurement: The existing turbine meter will be replaced with mass-flow meters.

Solution Impact: Rebuilding the station location will mitigate safety risks to employees, contractors, and the general public.

Resources: Company crews, contractor labour and third-party vendor suppliers

Project Timing and Execution Risk: Planning in Year 1, Execution in Year 2. Execution Risk - Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Distribution Stations - Gate, Feeder & A Stations
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	20 - Mississauga
	Asset Program (EGI)	DS - Gate, Feeder & A Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	RTU Building in Hazardous Area, Boiler Building in Hazardous Area, Containment on odourant. Canadian Electrical Code Section 22.1
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
7061	**2021**	**5**

Investment Name

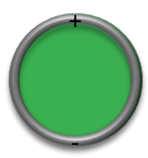
Brampton Gate Station Rebuild

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (2,362,000)	0.00	$ 2,547,760	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,507,760	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 12,500	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,362)	100%
Total	**(2,362)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	3609	2021	5
	Investment Name: CONSUMERS RD		

Investment Description

The Consumers Road Feeder station has heating concerns (to be addressed in 2020), piping and pressure control issues. Further information is described below for each sub-asset system.

Pipe, Valves and Others: The piping configuration has two different maximum operating pressures (MOP) that are not isolated by two valves and could potentially limit the operability of the station. In addition, the gas filter capacity is not sufficient and requires an upgrade.

Heating System: Not Required (being addressed in 2020)

Pressure Control and Odourant System: Not Required

Telemetry/Electrical: Not Required (being addressed in 2020)

Building: Removal of existing regulator building as Becker control valves will be designed below grade

Compliance/Civil: Fence replacement may need to be required. REWS to be consulted.

This project has high costs related to the turbo expander/fuel cell and piping configuration. The property has spacing issues that make the execution of the project difficult. The 2020 spend is primarily for the heating equipment (outsourced design and prefabrication).

Assets: Station #10471A

Related Program(s): N/A

Recommended Alternative Description

Scope of Work:
The station will be rebuilt in a phased approach (started in 2019).
- Pipe, Valves and Others: Replace inlet and out station valves (NPS 12 inlet) and (NPS 16 outlet) and station bypass valve (NPS 12). To execute the filter and inlet/outlet valve replacement will require tapping and stopping procedures outside of the station to isolate the flow of gas through the station.
- Replace the turbo expander components (Blade, etc.) utilizing the maintenance package (currently en-route from California, USA)
- Roof cover for the Hydro switch gear transfer building
- Roof cover for power cable tray from switch gear building to main electrical building (7 feet in length)
- Address Gear Body of Valve #33381
- Relocation + New Building for Boiler System (Potentially double the size of current building – x2 – 1 Million BTU System). This design will be a prefabricated system that will cost more upfront but will save execution resources on site.
- Proposed x3 Boiler System (x3 – 2 Million BTU Boilers)
- Annubar bar measurement + spool (designed by Lakeside)
- Relocation of the thermo sensor location (does not provide differential reading)
- Proposed + new building for RTU equipment due to heat issues within the current boiler build removal of fuel cell unit:
- Full removal of all fuel cell components
- Removal of power cable tray back to EGI electrical building including Tek cables into main disconnect equipment
- Removal of concrete pad
- Removal of glycol lines
- Draining of glycol fluid
- Upsize inlet and out isolation control valves (NPS 8 inlet) and (NPS 12 outlet).
- Install new monitor and operator (Qty. 6) (below-grade Becker control valves). Fiberglass huts will require Becker control valves.
- New design to include three monitor and operator.
- Abandonment of existing glycol lines if not captured in 2020.

Solution Impact: Rebuilding the station will mitigate safety risks to employees, contractors and the general public.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Project Timing and Execution Risk: Heating system in 2020 and balance of scope in 2021. Execution Risk - weather impacts, resource availability, procurement, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Distribution Stations - Gate, Feeder & A Stations
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	DS - Gate, Feeder & A Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
3609	2021	5

Investment Name

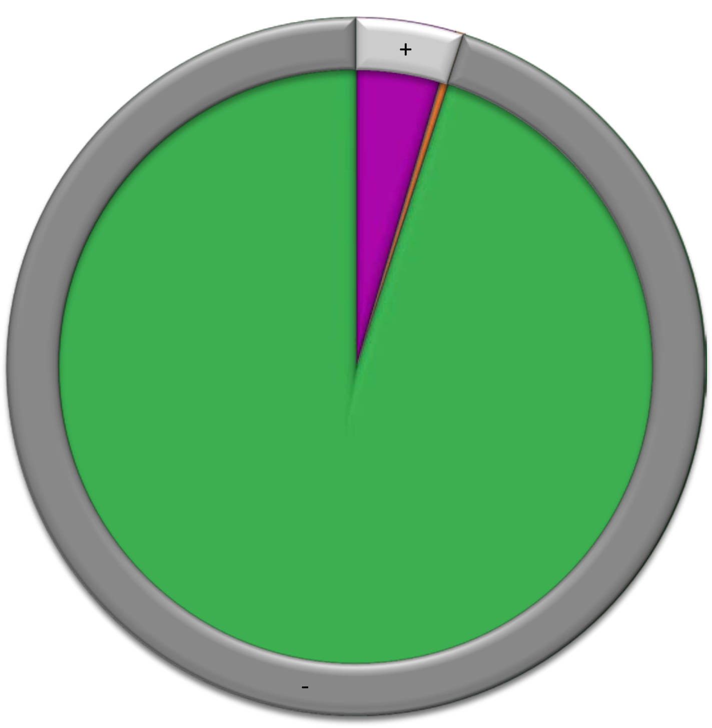
CONSUMERS RD

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,141,564)	0.00	$ 6,444,604	1/1/2018

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 4,110,865	$ 413,616	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 82,500	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Financial Risk	199	5%
Cost Avoidance OPEX (CA)	19	0%
Public Safety Risk	0	0%
Avoided GHG Emissions (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Cost Avoidance CAPEX (CA)	0	0%
Employee And Contractor Safety Risk	0	0%
Energy Efficiency (CA)	0	0%
Environmental Risk And Remediation	0	0%
Gas Storage Reliability (CA)	0	0%
Operational Risk	0	0%
Reputational Risk	0	0%
Revenue Impact (CA)	0	0%
Operational Disruption Risk (Gas) (CA)	0	0%
Operational Disruption Risk (Liquids) (CA)	0	0%
Total Investment Cost (CA)	(4,161)	95%
Total	**(3,943)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
3455	2021	5

Investment Name

Harmer District Station

Investment Description

Issue/Concern: EGI has an HP to IP district station located inside a building. The regulator station is located in the garage of a house and is not to current EGI standards. The station is located close to a school, hospital, shopping complex and dense residential population. The Integrity team is planning an in-line inspection of the Vital NPS 12 main (Network 6582) and additional space is required for a receiver.

Assets: Station# 6B005A

Related Program(s): N/A

Recommended Alternative Description

Scope of Work: Relocate Harmer District Station to Tunney's Pasture and complete rebuild as part of a system reinforcement. System reinforcement required for customer load increase request at Cliff Street and potentially required for future development at Tunney's Pasture.

Solution Impact: Relocating the station location will mitigate safety risks to employees, contractors and the general public.

Resources: Company crews, contractor labour and third-party vendor suppliers

Project Timing and Execution Risk: Planning in Year 1, Execution in Year 2 / Execution Risk - Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - DS - Station Rebuilds & B and C Stations - General Station Rebuilds
Investment Stage	Short Term Planning		

Investment Overview

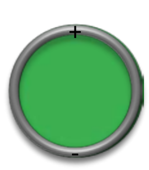
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	DS - Station Rebuilds & B and C Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (11,213,073)	0.00	$ 13,078,928	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 13,078,928	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 871,929	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(11,213)	100%
Total	**(11,213)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	8567	2021	5
	Investment Name: STJOHN SIDEROAD FEEDER		

Investment Description

Issue/Concern: The property on which St. John's Sideroad feeder station currently sits is insufficient for operation. It is located adjacent to a residential property and the area classification extends onto the adjacent private property. The boiler building is located in a hazardous area classification and the non-compliance needs to be remedied. Road widening of St. John's Sideroad currently has the sidewalk encroaching on our station. A land sale agreement with York Region was completed in 2016 and requires movement of the electrical meter.

As the area classification issue risks shutdown of the station by the Electrical Safety Authority, EGI is planning to resolve the movement of the electrical meter (on site) pending a new land purchase for relocation of the entire station. As a result of station relocation, a complete rebuild will be required. Maintenance on the boiler system piping, pumps and gauges, which are old and obsolete, suggest that the heating system needs to be replaced regardless of station relocation. The heating system is already undersized for the current demand. The FL regulators are difficult to work on due to their weight and ergonomic restrictions in a cramped building. These are to be replaced and upgraded. The old RTU 3330 telemetry system needs to be upgraded, including the backup power generator which is old and obsolete. The station was updated in 2006 and a new generator and boilers were installed in 2003. Source records do not indicate any regulator capacity issue .

Asset: Stn ID: 2944180

Related Programs: N/A

Recommended Alternative Description

SCOPE OF WORK:
2020 spend focused on land purchase. Reduced to $100k based on a deposit for preferred property location. If successful, property deal would close in 2020 for $1.1M. Uncertainty remains if the landowner will accept our offer to sell.
A new station and all supporting infrastructure will be constructed on a newly acquired parcel of land. The existing station will be removed from service and abandoned appropriately.
The new location will be in close proximity to the existing station just off of St. John's Sideroad, East of Leslie Street and west of Highway 404.
Pipes and Valves: All existing piping will have to be built as part of the station relocation. This includes station isolation and bypass valves as well as isolation valves required for the heating system and regulator runs. A new fuel gas station will be required that includes measurement of fuel gas consumption by the boilers and the generator.
Heating System: A new boiler and heat exchanger type heating system will have to be installed for gas preheat and all area classification requirements will be met.
Pressure Control: New regulator runs will have to be installed as the existing FL regulators are difficult to maintain.
Odourant System: No odourant system is required as this is a feeder station.
Telemetry and Electrical: The existing RTU panel will be replaced with a new unit in a new electrical building to meet area classification requirements. A new RTU cabinet and panel will be replaced with a Control Wave unit. The telemetry and electrical systems will be brought up to current standards and will include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, generator installation, modem and firewall upgrades, station lighting upgrades, and weather station installation/replacement.
Measurement: A new mass flow meter will be installed and connected to the SCADA system so that the Gas Control group can monitor station flows, pressures, and temperatures.
Compliance and Others: New land will have to be acquired to allow for the station relocation and there are currently two sites that are favoured. Either of these options will require significant civil work to ensure a suitable grade on which the station will sit and allow for adequate run off capabilities. The new station will require additional high-pressure pipe to be installed to connect appropriately to the existing network. The location will determine the length of pipe needed to be installed.
$1.2 million allotment for Land acquisition.

Solution Impact: Relocating the station location will mitigate safety risks to employees, contractors, and the general public.

Resources: Company crews, contractor labour and third-party vendor suppliers

Project Timing and Execution Risk: Planning in Year 1, Execution in Year 2. Execution Risk - Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Distribution Stations - Gate, Feeder & A Stations
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	30 - Richmond Hill
	Asset Program (EGI)	DS - Gate, Feeder & A Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Small compound, hazardous area classification issues
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,559,188)	0.00	$ 5,051,604	1/1/2018

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,947,995	$ 1,920,959	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE Investment Summary Report	Investment Code 8567	Report Start Year 2021	Number of Years 5
	Investment Name STJOHN SIDEROAD FEEDER		

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(4,559)	100%
Total	**(4,559)**	**100%**

Compression Stations

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	101995	2021	5
	Investment Name: Dehydration Expansion		

Investment Description

Issue/Concern:
This project is to fulfill EGI's obligation to meet Quality of Gas (Moisture Content) at Dawn and blending assumption of storage supplies and upstream pipeline supplies (Vector/Great Lakes). The Dawn Hub operational blends multiple sources of supply on a daily basis and is required to meet Gas Quality set out in C1 Tariff and Interconnect Agreements. The Dawn sendout moisture content is dependent on the daily supply balance (Upstream i.e Vector/Great Lakes), Storage (Dehydrated Supply/Dehy By-pass), and the moisture content of those respective supplies. EGI is responsible for blending all supplies and ensuring that gas supply leaving Dawn is within the Gas Quality Specification of 4 lbs H20/MMscf, as natural gas in combination with liquid water can form methane hydrate. The methane hydrates formed by cooling may plug the valves, the fittings or even pipelines.
Reference: Quality of Gas at Dawn (C1 Tariff and Interconnect Agreements)

Justification:
1. Operational Reliability:
EGI obligation to meet Quality of Gas (Moisture Content) at Dawn and blending assumption of storage supplies and upstream pipeline supplies. Storage design assumes a coincident transmission design in which upstream pipeline supplies are arriving at Dawn to balance the Dawn sendout.

2. Financial:
- EGI faces financial consequences if market supply needs to be replaced in a limited market or in the event of potential revenue loss and damage claims from customers.
- EGI is required to maintain its obligation of 4 lbs H20/MMscf under C1 Tariff and Interconnect Agreements.
- EGI must maintain firm service to all distribution customers, S&T and third party storage providers.

3. Inability to Meet System Growth beyond 2022-23

Assets: New

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Expansion of dehydration facilities by 1 BCF at the Corunna Compressor Station.

Work includes full project gating cycle due to scale and complexity including: stakeholder consultations, planning, detailed design, permit applications, environmental assessment, procurement, retaining a construction contractor, isolations erect buildings if required, prefabrication, hydrotesting, install new piping and auxiliary systems, NDE as required, coating, inspection, train staff, energize system, programming and records updates.

Resources:
Consultant resources for design
Contractor resources for construction and commissioning

Solution Impact: Blending of gas is not required to produce pipeline quality gas leaving Dawn.

Project Timing and Execution Risk:
Year 1: Pre-FEED and FEED study
Year 2: Regulatory, detailed Engineering work , Procurement activities
Year 3: Pre-Fabrication, Civil work
Year 4: Construction, Programming

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Compression Stations - Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	CS - Improvements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (34,457,904)	0.00	$ 41,000,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 4,100,000	$ 22,777,486	$ 12,807,569	$ 1,314,945	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
101995	2021	5

Investment Name

Dehydration Expansion

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(34,458)	100%
Total	**(34,458)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	100901	2021	5
	Investment Name: SCOR: K701/2/3 Reliability - Replacement		

Investment Description

Issue/Concern:
The operating reliability of K701/2/3 compressor units is poor. These three compressor units account for 20% of available compressor power and their failure frequency is five times greater than comparable - newer - units. Much of the reliability challenge stems from lean burn conversions. During the mid 1990s, EGI embarked on an emissions abatement program, which would see all units retrofitted with low NOx combustion systems. Lean burn (low emissions) systems were readily available for units K704 thru K710 (model KVR). The globally installed base for the KVR compressor model is large. K701 thru K703 are an earlier compressor model (KVT) with a much smaller number of units in the world. Indications from SMAs suggest that there are only four lean burned KVT units in the world, and EGI owns three of them. The KVT lean burn conversion kits have never been designed for mass production and have been plagued with problems. Reliability concerns related to K701/2/3 translate directly into peak day deliverability risk, because all three units are needed to achieve peak day flow rates.

Asset: Compressors K701, K702 and K703.

Related Program: N/A

Recommended Alternative Description

Scope of Work:
-Removal and abandonment of the three plants at the Corunna Compressor Station, associated piping and electrical and remediation of land back to level grade.
-Installation of 20 kilometres of NPS 36 Pipeline between Dawn and Corunna Compressor Station.

Work includes full project gating cycle due to scale and complexity including: stakeholder consultations, planning, detailed design, permit applications, environmental assessment. procurement, retaining a construction contractor, isolate system, demolition of structures/equipment to be replaced, erect buildings if required, prefabricating piping, hydrotesting, install new piping and auxiliary systems, NDE as required, coating, inspection, train staff, energize system, remediating site and records updates.

Solution Impact:
Alternative to provide 118 TJ/d of withdrawal capacity from K701, K702 and K703. Compression retirement identified in previous Asset Management Plan.

Resources:
Consultant resources for design
Contractor resources for abandonment, construction and commissioning

Project Timing and Execution Risks:
This project will need two years of design procurement and construction and requires environmental assessment and regulatory approval. In-service date slated for 2024.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Compression Stations - Replacements
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	CS - Replacements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
NPS 36 Pipeline	Recommended	$ (136,603,453)	0.00	$ 185,200,000	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 800,000	$ 9,300,000	$ 172,000,000	$ 3,100,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

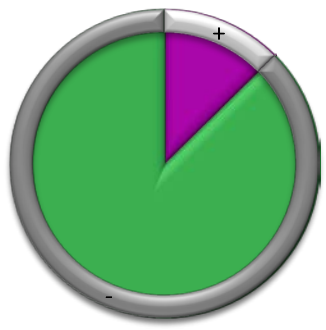
Investment Summary Report

Investment Code	Report Start Year	Number of Years
100901	2021	5

Investment Name

SCOR: K701/2/3 Reliability - Replacement

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Financial Risk	19,737	13%
Employee And Contractor Safety Risk	0	0%
Environmental Risk And Remediation	0	0%
Public Safety Risk	0	0%
Reputational Risk	0	0%
Total Investment Cost (CA)	(136,603)	87%
Total	**(116,866)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code: 12957	Report Start Year: 2021	Number of Years: 5
	Investment Name: SCOR:100MOD Hdr Valves-Replace		

Investment Description

Issue/Concern:
Operations has identified compressor station yard isolation valves that do not provide sufficient seal quality to provide isolation during normal maintenance activities or emergency situations. Valve condition is under investigation in the Asset Health Review. Condition assessment results are rudimentary. Leaking valve seals are not necessarily valves that leak to atmosphere or pose a loss of containment threat. The valves referenced in this investment are those that allow gas to flow, when in the closed position. These leaking valves pose:
(i) a process safety threat
(ii) a loss of system performance by creating recycle loops
(iii) decreased ability to provide a safe work environment for maintenance activities that require double lock and bleed.
If valve condition is not maintained at a reasonable level, the ability to isolate assets during an emergency will be compromised. Valves in question are sometimes used to separate piping with different MOPs. If these valves are allowed to leak, there is an increased threat of overpressuring lower MOP pipe as gas bleeds through the valve from higher MOP pipe.

Asset: K707 and 704 MOD header valves

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Solution/Cost Basis: Cost assumes that all MOD valves on the Transmission Header will be replaced. There are a total of 23 valves - all valves are PN100 pressure classification. It is assumed that valves sizes match the size of the Transmission Header (NPS24). Valves include: Project targets all MOD valves associated with K704 & K707.
Work includes design, stakeholder consultations, retaining a construction contractor, prefabricating piping, hydrotesting at shop, laying plates, isolate system likely with a full station outage, cut out existing valves, installing supports as required, install new piping coating as required, NDE, energize system and remediating site.

Resources:
Internal Resources: Engineering, Document Control, Lands Coordinator, Reservoir Group, Instrument and Electrical, Operations, Execution, Finance, Contracts, Warehouse, Safety
External Resources: Engineering Firm, Site Inspector, Construction Contractor & Sub Contractors, Non-Destructive Testing Contractor, Survey Contractor, Concrete Testing/Ground Testing Contractor, Community Engagement, Environmental

Solution Impact: Replacing the valves with new valves will stop the leakage issues. This ensures the MOD valves are capable of preventing mixing of gases at different pressures, directing gas as required and isolation can be obtained when required.
Risks Reduced:
(1) Safety - leaking valves can result in safety risks for all staff and contractors. In addition, leakage can result in damage to infrastructure in the event of ignition.
(2) Infrastructure reliability - Leakage or can interfere with the operation of the facility if valves are required for purposes such as over pressure protection. In the event that separate MOPS can not be kept isolated, derating of systems may be required having significant impacts pending the point in the injection/withdrawal cycle.
(3) Performance degradation. Leaking valves create re-cycle loops that reduce the effectiveness of compression.

Project Timing and Execution Risks:
Planning Year 1.
Execution in Year 2.
Execution Risk such as unavailability of the yard, weather, and injection/withdrawal schedule. Project impacts a crucial area of plant which can affect or be affected by numerous systems.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Compression Stations - Replacements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	CS - Replacements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,839,102)	0.00	$ 5,218,230	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 5,118,230	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
12957	2021	5

Investment Name

SCOR:100MOD Hdr Valves-Replace

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(4,839)	100%
Total	**(4,839)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	3460	2021	5
	Investment Name: SCOR:60007-Fdn Blk-Replace		

Investment Description

Issue/Concern: Due to the age of the compressor infrastructure, operating hours and oil contamination, engine block foundations are deteriorating. Industry benchmarks suggest that reciprocating engine block foundations degrade in 25 years or less for engines that run 24/7. Excessive bearing deflections place cyclic stresses on the crankshaft of the unit leading to increased frequency of bearing failure and increased potential for a crankshaft fatigue failure. Unit reliability will diminish dramatically if repairs are not performed. The worst case consequence is unit unavailability during a design day. Compressor foundations have been considered in the Asset Health Review. Condition assessment is largely visual. A telltale sign of poor foundation condition is the existence of cracks on the surface of the foundation, with oil seeping out of the crack. Cracks typically extend to a depth that is consistent with the bottom of the unit's anchor bolts. Without remediation, failing foundations will allow unit settlement, creating a misalignment of bearings. Frequency of bearing failures increases - reducing operation reliability. Collateral damage to the crankshaft is also common.

Asset: K707 Compressor foundation.

Related Programs: Not Applicable.

Recommended Alternative Description

Scope of Work: Solution/Cost Basis: Cost estimate is based on historical costs for similar projects and SMA review. The project will take approximately 90 days (two 10-hour shifts) to complete with EGI mechanics providing facilitation support to the manufacturer representative who will be contracted as the third party providing labour and execute the work.
Assumptions include:
1) Volumes of concrete removed and re-installed do not vary from previous foundations replaced.
2) No new additional work to support and secure the compressor unit is required.
3) Foundation blocks were installed at different times and are part of different vintages. It is assumed the vintage worked on is not more difficult to remove than foundations used for basis of the estimate. Scope: Remove and replace the foundation that is failing on K707. The manufacturers expected life span is approximately 25 years The foundation of this machine is not 40+ yrs old and is beginning to crack due to fatigue failure.
Task Breakdown:
1) Set the up the work area. Contractors are to remove the piping and cables that will interfere with the work area.
2) Remove the compressor cylinders and distance pieces.
3) Build the dust containment shelter around the machine and install the air filtration units.
4) Remove the foundation (cement and rebar block, "10'w x 8'h x 30'l).
5) Prepare the existing cement matt for the new foundation.
6) Install the new rebar and inspect.
7) Build the cement forms and reinforce. Pour the cement in one continuous pour. Remove the cement form and remove any high points.
8) Install compressor distance pieces and cylinders. Install piping and cables.
9) Complete PSSR with Operations.
10) Perform run tests and then return to Operations.

Resources:
One project lead for the duration of the project, one mechanic (days), one mechanic (nights), one Dresser Rand project manager, one Dresser Rand Field service representative, approximately four to eight contract MWs for the duration of the work, approximately six Dresser Rand mechanics for the duration of the work, a mechanical contractor team of four (two weeks for removal, three weeks for reinstallation), one electric contractor team of three (one week for removal, two weeks for reinstallation), four mechanics during final assembly for two weeks, crane company for heavy lifts (approximately five days)

Solution Impact:
This project replaces the entire foundation of the machine. Failure of a foundation can result in a crank failure that could take the machine out of service for more than a year and be as much as $10 million to complete the crankshaft replacement. The new foundation will provided an additional 25 years of life to the component of the machine. Risks Reduced: Increased reliability of the equipment reduces customer satisfaction risk. Another risk reduced is a long-term outage due bearing failures and possible (ensuing) crankshaft failure.

Project Timing and Execution Risks:
Installation Year 1:The scope will take ~90 days (two 10-hour shifts) to complete the work with EGI mechanics providing facilitation support. To complete the project, the contract will need to be awarded within the first two months of the year to ensure the required technical support, engineering, materials and labour can be secured for the project.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Compression Stations - Replacements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	CS - Replacements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
3460	2021	5

Investment Name

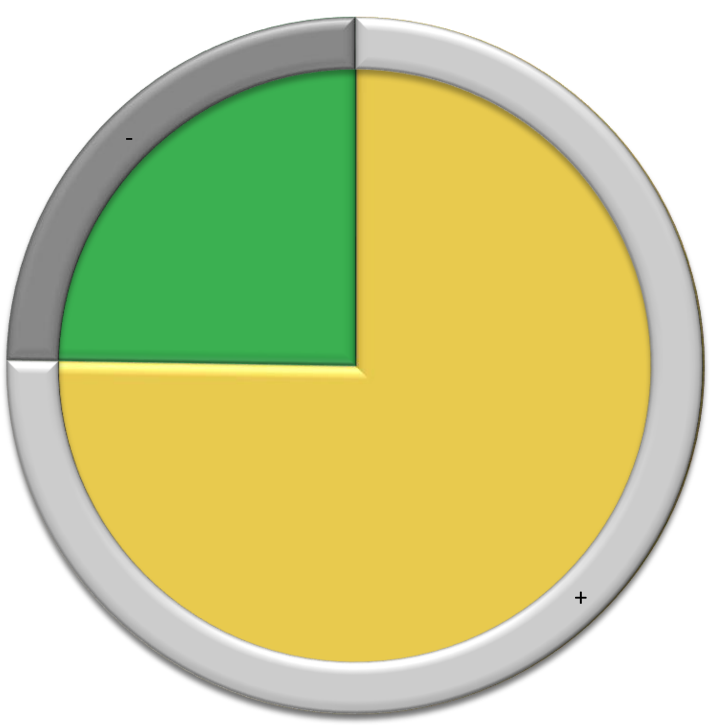
SCOR:60007-Fdn Blk-Replace

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (1,898,148)	0.00	$ 2,050,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,050,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Gas Storage Reliability (CA)	5,778	75%
Avoided GHG Emissions (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Cost Avoidance CAPEX (CA)	0	0%
Cost Avoidance OPEX (CA)	0	0%
Employee And Contractor Safety Risk	0	0%
Energy Efficiency (CA)	0	0%
Environmental Risk And Remediation	0	0%
Financial Risk	0	0%
Operational Risk	0	0%
Public Safety Risk	0	0%
Reputational Risk	0	0%
Revenue Impact (CA)	0	0%
Operational Disruption Risk (Gas) (CA)	0	0%
Operational Disruption Risk (Liquids) (CA)	0	0%
Total Investment Cost (CA)	(1,898)	25%
Total	**3,880**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	1811	2021	5
	Investment Name: SCOR:Meter Area-Upgrade (Phase 1)		

Investment Description

Issue/Concern: There are two drivers for replacement of the existing meter area:
- The existing cross flow header can be subjected to very high pipe velocities creating flow induced vibration.
- The meter area is no longer used to meter pool inventory and can be made safer by replacing with modern buried pipe designs.

The existing cross flow header allows interconnection of the DOW header (Maximum Operating Pressure (MOP) of 1550 psig) with all remaining headers (MOPs of 1200 psig and 900 psig). This interconnection is necessary during low-end withdrawal from DOW. Low-end withdrawal from DOW requires that the DOW header be allowed to flow into SCOR on first stage compression (MOP of 1200 psig). Due to the MOP differences between DOW and the remaining headers, the DOW header is unable to connect directly to lower pressure compressors on the suction side.

The cross flow header was added when the DOW reservoir was developed. The existing cross flow header interconnects DOW to the lower pressure headers by way of manual ball valves. The DOW pool pipeline and headers system is sized at NPS 24. Sizing of the cross flow header is such that DOW flows into 1200 psig headers through valves as small as NPS 12. This discrepancy creates a pinch point with excessively high velocities (>200 ft/s), causing flow-induced vibration. In addition to the sizing issue, CSA Z662 code requires that automatic over-pressure protection (OPP) be provided whenever pipe of dissimilar MOPs are connected. Suitable OPP does not exist on the current cross flow header.

Risk can be dramatically reduced by replacing the existing cross flow header with one that is appropriately sized and with over-pressure protection. The existing meter area is no longer used for inventory management - it is simply the flow path used to convey gas back and forth from reservoirs. Limited cross-flow functionality is provided in the current meter area piping. The pipe is of unknown material composition, with unknown strength characteristics, and is comprised of many flange connections in an area frequently accessed by personnel. Piping is also above-grade. Tolerance of damage risks related to above-grade piping is no longer warranted, and can be reduced by replacing with buried pipe.

Asset: SCOR header system and Meter Area

Related Programs: 500440; Resolution of this concern stands alone, but SCOR compressor replacement (replacement of K701/2/3; Inv# 100901) relies on resolution of this concern.

Recommended Alternative Description

Scope of Work: Install Electrical Control building, replace meter run piping and install new header cross-over and isolation valves for Ladysmith and Dow-Moore pool lines, install west section of new NPS 30 A, B, C headers.
New piping will be designed with pressure control and protection provisions needed to safely manage multiple pipeline and header MOPs ranging from 900 psig to 1550 psig. Work includes full gating cycle due to scale and complexity including: stakeholder consultations, planning, detailed design, permit applications, procurement, retaining a construction contractor, isolating the system, installing a temporary drainage system, demolition of structures/equipment to be replaced, erecting buildings if required, installing air system modifications if required, prefab piping, hydrotesting, demolishing meter runs, installing new piping and auxiliary systems, NDE as required, coating, inspection, training staff, energizing the system, remediating the site, and performing records updates.

Resources: Internal: Engineering, Doc Control, Lands, Reservoir Group, Instar and Elect, Operations, Execution, Finance, Contracts, Warehouse, Safety, EHS, Procurement
External: Engineering Firm, Site Inspector, Construction Contractor & Sub Contractors, Non-Destructive Testing Contractor, Survey Contractor, Concrete Testing/Ground Testing Contractor, Community Engagement, Environmental

Solution Impact:
(1) Replacement pipe will be welded in place. Replacement pipe will be a single run per header as compared to the current multiple runs. Fittings such as flanges, bolt in meters and bolt on valves will be eliminated. All these factors work to reduce the number of potential leak paths.
(2) Piping would be buried reducing risk of vehicle impact.
(3) Many valves in the existing meter run area are original installations and reaching the end of their life cycle with increased risk of internal bypass. Replacements will be able to fully seal.
(4) Diameter change at existing cross-flow header will be eliminated. This prevents piping from exceeding unsafe gas velocity.
(5) All new equipment would be purchased and installed to modern specifications designed specifically toward the high pressures the facility can experience. Replacement pipe will be designed to modern standards (CE, CVN testing, DWTT etc.).
(6) Replacement includes Pressure Control (PC) and OPP designed to address range of MOPs in EGI systems. Modifications that result in operational bottle necks installed over the history of EGI will be incorporated into a permanent, functional installation.

Project Timing and Execution Risks:
Year 1-Design work, permits, Approvals
Year 2-Procure, permits
Year 3-Construction
Challenges:
- The project is occurring in an area where modifications have been made for more than 50 years. Record keeping has gone through varying levels of detail during this time. Transfer between record systems creates a risk of unidentified pipe being discovered during execution. Should this occur during execution, short delays may be experienced.
- The work area has a significant amount of sand backfill. Combined with the water table, excavation will require shoring and drainage systems.
- This project replaces a vital section of plant piping execution delays will impact injection/withdrawal schedules.
- Material delays will impact execution of the project. Long lead items should be ordered in advance.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Compression Stations - Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	CS - Improvements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Investment Summary Report

Investment Code	Report Start Year	Number of Years
1811	2021	5

Investment Name

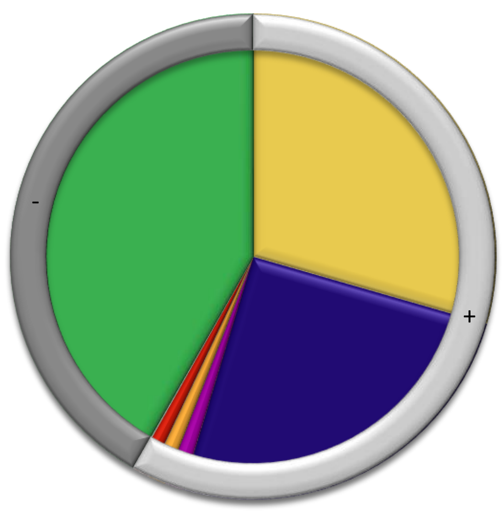
SCOR:Meter Area-Upgrade (Phase 1)

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,879,734)	0.60	$ 19,398,316	1/1/2018

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 12,898,501	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Gas Storage Reliability (CA)	8,708	29%
Cost Avoidance CAPEX (CA)	7,450	25%
Financial Risk	364	1%
Environmental Risk And Remediation	339	1%
Public Safety Risk	317	1%
Avoided GHG Emissions (CA)	22	0%
Budget Savings OPEX (CA)	12	0%
Cost Avoidance OPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(12,342)	42%
Total	**4,870**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
500440	2021	5

Investment Name

SCOR:Meter Area-Upgrade (Phase 2)

Investment Description

Issue/Concern:
There are two drivers for replacement of the existing meter area:
- The existing cross flow header can be subjected to very high pipe velocities, creating flow induced vibration.
- The meter area is no longer used to meter pool inventory and can be made safer by replacing with modern buried pipe designs.

The existing cross flow header allows interconnection of the DOW header (Maximum Operating Pressure (MOP) of 1550 psig) with all remaining headers (MOPs of 1200 psig and 900 psig). This interconnection is necessary during low-end withdrawal from DOW. Low-end withdrawal from DOW requires that the DOW header be allowed to flow into SCOR on first stage compression (MOP of 1200 psig). Due to the MOP differences between DOW and the remaining headers, the DOW header is unable to connect directly to lower pressure compressors on the suction side. The cross-flow header was added when the DOW reservoir was developed. The existing cross flow header interconnects DOW to the lower pressure headers by way of manual ball valves. The DOW pool pipeline and headers system is sized at NPS 24. Sizing of the cross flow header is such that DOW flows into 1200 psig headers through valves as small as NPS 12. This discrepancy creates a pinch point with excessively high velocities (>200 ft/s), causing flow-induced vibration.

In addition to the sizing issue, CSA Z662 code requires that automatic over-pressure protection (OPP) be provided whenever pipe of dissimilar MOPs are connected. Suitable OPP does not exist on the current cross-flow header. Risk can be dramatically reduced by replacing the existing cross-flow header with one that is appropriately sized and with over-pressure protection.

The existing meter area is no longer used for inventory management - it is simply the flow path used to convey gas back and forth from reservoirs. Limited cross flow functionality is provided in the current meter area piping. The pipe is of unknown material composition, with unknown strength characteristics, and is comprised of many flange connections in an area frequently accessed by personnel. Piping is also above-grade. Tolerance of damage risks related to above-grade piping is no longer warranted, and can be reduced by replacing with buried pipe.

Asset: SCOR Header system and Meter Area

Related Programs: 1811 (Phase 1); Resolution of this concern stands alone, but SCOR compressor replacement (Replacement of K701/2/3; Inv # 100901) relies on resolution of this concern.

Recommended Alternative Description

Scope of Work: Replace meter run piping and install new header cross-over and isolation valves for the Wilkesport, South Kimball, Seckerton, Corunna and Mid Kimball pool lines. Install east section of new NPS 30 A, B, C headers and tie in east and west header sections. New piping will be designed with pressure control and protection provisions needed to safely manage multiple pipeline and header MOPs ranging from 900 psig to 1550 psig. Work includes full gating cycle due to scale and complexity including: stakeholder consultations, planning, detailed design, permit applications, procurement, retaining a construction contractor, isolating the system, installing a temporary drainage system, demolition of structures/equipment to be replaced, erecting buildings if required, installing air system modifications if required, prefab piping, hydrotesting, demolishing meter runs, installing new piping and auxiliary systems, NDE as required, coating, inspection, training staff, energizing the system, remediating the site, and performing records updates.

Resources:
Internal: Engineering, Doc Control, Lands, Reservoir Group, Instar and Elect, Operations, Execution, Finance, Contracts, Warehouse, Safety. EHS, Procurement
External: Eng. Firm, Site Inspector, Construction Contractor & Sub Contractors, Non-Destructive Testing Contractor, Survey Contractor, Concrete Testing/Ground Testing Contractor, Community Engagement, Environmental

Solution Impact:
(1) Replacement pipe will be welded in place. Replacement pipe will be a single run per header as compared to the current multiple runs. Fittings such as flanges, bolt in meters and bolt on valves will be eliminated. All these factors work to reduce the number of potential leak paths.
(2) Piping would be buried, reducing risk of vehicle impact.
(3) Many valves in the existing meter run area are original installations and reaching the end of their life cycle with increased risk of internal bypass. Replacements will be able to fully seal.
(4) Diameter change at existing cross-flow header will be eliminated. This prevents piping from exceeding unsafe gas velocity.
(5) All new equipment would be purchased and installed to modern specifications designed specifically toward the high pressures the facility can experience. Replacement pipe will be designed to modern standards (CE, CVN testing, DWTT etc.).
(6) Replacement includes Pressure Control (PC) and OPP designed to address a range of MOPs in EGI systems. Modifications that result in operational bottle necks installed over the history of EGI will be incorporated into a permanent, functional installation.

Project Timing and Execution Risks:
Year 1-Design work, permits, Approvals
Year 2-Procure, permits
Year 3-Construction

Challenges:
- The project is occurring in an area where modifications have been made for more than 50 years. Record keeping has gone through varying levels of detail during this time. Transfer between record systems creates a risk of unidentified pipe being discovered during execution. Should this occur during execution, short delays may be experienced.
- The work area has a significant amount of sand backfill. Combined with the water table, excavation will require shoring and drainage systems.
- This project replaces a vital section of plant piping execution delays will impact injection/withdrawal schedules.
- Material delays will impact execution of the project. Long lead items should be ordered in advance.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Compression Stations - Improvements
Investment Stage	Executing		

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
500440	2021	5

Investment Name

SCOR:Meter Area-Upgrade (Phase 2)

Investment Overview

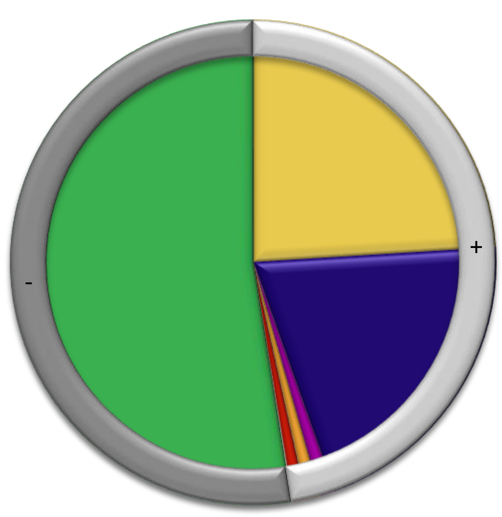
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	CS - Improvements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (11,568,698)	0.39	$ 25,122,575	1/1/2018

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,434,760	$ 18,884,388	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Gas Storage Reliability (CA)	8,708	24%
Cost Avoidance CAPEX (CA)	7,450	21%
Financial Risk	364	1%
Environmental Risk And Remediation	339	1%
Public Safety Risk	317	1%
Avoided GHG Emissions (CA)	22	0%
Budget Savings OPEX (CA)	12	0%
Cost Avoidance OPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(19,031)	53%
Total	**(1,819)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
13034	2021	5

Investment Name

SCRW:Station-Renewal In-Place

Investment Description

Issue/Concern: Due to the age of the facility, the compressor station experiences process safety concerns (lack of automation; unit valves, electrostatic discharge (ESD), dehydration and incinerator systems), obsolescence issues (compressor, building, electrical), code concerns (location of recycle valve/line), lack of auxiliary power, inability to support site security devices such as cameras, and setback concerns related to neighbouring occupied buildings and the nearby rail line.

Justification: Modernize the facility to comply with current code and design standards.

Asset: Crowland Compressor Station

Related Program: This project is under consideration in conjunction with an overall Crowland upgrade. Issues related to the wells and gathering system should be considered together with the compressor station's issues/concerns.

Recommended Alternative Description

Scope of Work: The compressor station will be rebuilt in place including:
- Installation of a new administration building, auxiliary building, compressor building, utilities, site safety and security system.
- Decommissioning of the compressor system
- Dehydration system instrumentation and controls upgrade

Work includes full project gating cycle due to scale and complexity including stakeholder consultations, planning, detailed design, community consultations, permit applications, environmental assessments, procurement, retaining a construction contractor, isolating the system, demolition of structures/equipment to be replaced, erecting buildings, prefabricating piping, hydrotesting at shop, installing new piping and equipment, NDE as required, coating as required, inspection, training staff, energizing the system, remediating the site, and performing records updates.

Resources:
Internal Resources: Engineering, Document Control, Lands Coordinator, Reservoir Group, Instrument and Electrical, Operations, Execution, Finance, Contracts, Warehouse, Safety, EHS, Procurement
External Resources: Engineering Firm, Site Inspector, Construction Contractor and Sub-Contractors, Non-Destructive Testing Contractor, Survey Contractor, Concrete Testing/Ground Testing Contractor, Community Engagement, Environmental

Solution Impact:
The new facility will be designed to current code requirements with remote operation capabilities.

Project Timing and Execution Risks: Project timing may be revised during the Front End Engineering Design (FEED) and detailed design phases. Current approach is to minimize potential station downtime.
Year 1 - FEED, Detailed Design, Permitting, Approvals, Permitting, Procurement, Construction Ramp up
Year 2 - Procurement, Prefabrication, Demolition and Construction
Year 3 - Restoration and Construction, Commissioning

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Compression Stations - Improvements
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	CS - Improvements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Operate Crowland without Compression	Recommended	$ (21,663,007)	0.00	$ 27,903,084	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 5,629,668	$ 12,171,192	$ 5,495,028	$ 4,607,196
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 1,765,906	$ -	$ -

Investment Summary Report

Investment Code	Report Start Year	Number of Years
13034	2021	5

Investment Name

SCRW:Station-Renewal In-Place

Alternative Value - Recommended

	Value Function Measure	Value	Value in Percentage
■	Financial Risk	648	3%
■	Total Investment Cost (CA)	(21,663)	97%
	Total	**(21,015)**	**100%**

Transmission Pipe and Underground Storage

ENBRIDGE Investment Summary Report	Investment Code 6377	Report Start Year 2021	Number of Years 5
	Investment Name PCRW:Wells-Upgrade		

Investment Description

Issue/Concern: Wells at Crowland are much older than other wells in EGI. Due to age, the wells were constructed to a production standard which would normally be retired after 10 years. Instead, the wells were converted to Storage service in the early 1970's and continue to operate ever since. Many wells have been relined, increasing the risk of leaks. Most wells possess only two casings - the current standard requires a minimum of three casings. The two-casing design at Crowland is comprised of an inner casing that runs from the surface to the reservoir (about 225m) plus a surface casing that runs from the surface to a depth of about 20 metres. Most wells do not have an intermediate casing with cement between the inner and intermediate casings, however, there is cement between the inner casing and the surrounding rock. This provides a poor barrier to gas flow should the inner casing fail. In addition, none of the wells at Crowland employ wellheads and master valves. Instead, the inner casing is simply connected to a flanged 1/4 turn valve without wing valves or wellhead vents. The surface casing is separated from the surface using cement. There are no casing vents and part of the inner casing (typically a length of 2 to 16 inches) is exposed at the surface. The lack of casing vents eliminates normal approaches to controlling a failed well. Vertilogs have been performed in the last 5 years, and indicated that the inner casing integrity is adequate, although two of 26 wells needed to be abandoned. Currently, there are 24 wells remaining. Bond logs have not been performed yet to determine the condition of cement at sulphur layers. Primary concerns are:
(1) Code compliance of the wells and wellheads. Technically, these wells were constructed before CSA Z341 came into force, and are grandfathered. However, a well failure would likely be viewed negatively by technical regulators.
(2) Risk to employees and the public - in the event of a loss of containment, there are insufficient barriers to gas flow. Public risk also extends to possible sulphur contamination of well water at surface levels. In addition to the wells, much of the gathering system is as old as the wells. The gathering system is operating at <30% SMYS, which means that they have not be considered for integrity inspections until recently and that the gathering system pipe condition is unknown after 50 to 100 years of operation.

Asset: Crowland wells and gathering system.

Related Programs: This investment is under consideration in conjunction with other Crowland investments in the Distribution Station asset class and Compressor Station asset class - Issues related to the wells and gathering system should be considered together with the additional distribution station and compressor station issues/concerns

Recommended Alternative Description

Scope of Work:
Solution/Cost Basis: Cost estimate allows for: drilling applications and well locations studies, design, materials, core sampling, drilling two new vertical wells (Vwells) and well heads/master valves to 12 existing Vwells, stimulate new wells and 12 existing wells, and upgrade wellheads for 12 existing wells. The majority of design and installation work will be performed by third parties.
Assumptions:
1) The project schedule is influenced by reservoir pressures, regulatory approvals and environmental factors.
2) Environmental findings may impact execution costs.
3) Crowland is located in a marshy area which may impact execution and costs.
Work sequence is as follows:
1) Drill a vertical well to core through the confining geological formations and the storage zone. The core will be tested and an integrity study will be completed to determine if stimulation operations can be performed in the sandstone storage zone. If the integrity tests are positive, they will be used as the basis for drilling permit applications for two Vwells.
2) Obtain permits to drill two new Vwells.
3) Obtain approval from MNRF to remediate remaining wells.
4) Install well pads.
5) Mobilize drilling equipment.
6) Drill new Vwells.
7) Stimulate Vwells
8) Replace Vwell wellheads.
9) Demobilize.
10) Remediate/restore.

Resources:
1) Gas Storage Reservoir Department - Project management, obtain MNRF and OEB permits, project execution
2) EGI Regulatory - Obtain permits
3) EGI EHS Department - Environmental assessment, species at risk and archeological study; final environmental reports
4) EGI Procurement Group - Contracts and purchasing for casing, wellheads and valves.
5) EGI - Aboriginal Affairs - Consultation
6) Third-party contractors - Wellsite supervision, drilling contractor, directional drilling contractor, core testing laboratories, well stimulation company, civil contractor (build pad and cleanup), mechanical contractor, logging contractors

Solution Impact: Results of the core integrity testing will verify that the confining geological formations are suitable for storage and provide inputs needed to simulate the Hwells. Up to eight existing Vwells will be abandoned, reducing risk.

Risks Reduced:
1) Loss of containment from exposed inner casing above the surface level of the well.
2) Effects of well casing corrosion, where exposed to corrosive sulphur, can be mitigated more readily with modern well heads and master valves. Limits pressurized gas, leaking through the well casing, and contaminating well water at surface with sulphur.
3) Effects of deteriorated cement, between the casing and rock, can be mitigated more readily with modern well heads and master valves. Existing cement is not resistant to the effects of sulphur and has reduced life expectancy. Compromised cement may allow well casing leaks to migrate to surface.

Project Timing and Execution Risks:
Year 1: Prep for Vwell permits - ER, SAR, Archeay, apply to MNRF/OEB, order long lead items - wellheads, master valves, casing, drill and core well, test core and report, plan well stimulations, apply to MNRF/OEB, order long lead items (wellheads, master valves, ESVs, casing) and drilling contracts.
Year 2: Drill wells, install pipelines, test wells and put wells in service.
Year 3: Abandon existing Vwells.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Transmission Pipe & Underground Storage - Replacements
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	70 - Storage
	Asset Program (EGI)	TPS - Replacements
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Wellhead requiring upgrade to be in compliance with Section 6.3.1 of CSA Z341-18.

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	6377	2021	5
	Investment Name: PCRW:Wells-Upgrade		

3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
6377	**2021**	**5**

Investment Name

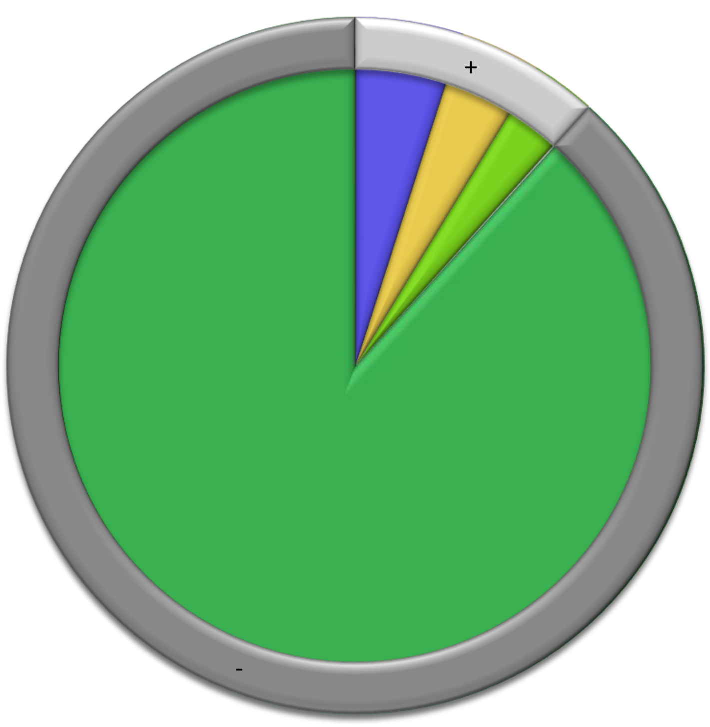
PCRW:Wells-Upgrade

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (7,207,017)	0.03	$ 11,648,011	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ -	$ 443,352	$ 1,290,371
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 3,000,000	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Avoided GHG Emissions (CA)	416	5%
Gas Storage Reliability (CA)	321	4%
Budget Savings OPEX (CA)	245	3%
Environmental Risk And Remediation	3	0%
Reputational Risk	3	0%
Employee And Contractor Safety Risk	1	0%
Budget Savings CAPEX (CA)	0	0%
Cost Avoidance CAPEX (CA)	0	0%
Cost Avoidance OPEX (CA)	0	0%
Energy Efficiency (CA)	0	0%
Financial Risk	0	0%
Operational Risk	0	0%
Public Safety Risk	0	0%
Revenue Impact (CA)	0	0%
Operational Disruption Risk (Gas) (CA)	0	0%
Operational Disruption Risk (Liquids) (CA)	0	0%
Total Investment Cost (CA)	(7,452)	88%
Total	**(6,463)**	**100%**

Real Estate and Workplace Services

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	8701	2021	5
	Investment Name: Kelfield Operations Centre		

Investment Description

Issue/Concern: The Kelfield office, owned by EGI, is in poor physical condition and is considered obsolete in its functionality and utilization. It is an old facility with an approximate age of 56 years.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 10.47%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 71%. Based on the FCI/AI graph, the current recommendation for the existing facility is to increase the site area by purchasing the abutting property, demolish existing building, and re-build the facility on the combined sites to accommodate current EGI standards.

Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation. The yard has only one point of access. The yard size is smaller than EGI standard yard size requirements. The current yard size is 0.3 acres. EGI standard yard size is 2.5 acres. The existing building requires expansion by approximately 7,200 square feet to meet the need for current staff and EGI functional requirements. Building addition on the property entails further reduction in the yard and parking areas. Both the building and site area are too small to meet current EGI standards. The current building is approximately 7,724 square feet and the ideal building size, based on EGI design standards, is estimated to be 14,924 square feet, with a site area of approximately five acres. There is no opportunity for building expansion at the current location. It is understood that the location of the facility works well for EGI operations.

Asset: 40 Kelfield Street, Etobicoke, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work:
The assets in scope are located at 40 Kelfield Street, Etobicoke, ON. The nature of work is the development of adjacent property, construction and fit-up of a new building.
Sell the existing property; purchase a property suitable in size to accommodate the required program. Required size of new property is approximately 3.5 acres.

Solution Impact: Purchasing the extra land will ensure adequate yard area for current activities and a new building will correct the identified operational deficiencies, using less energy and emitting less greenhouse gases. Once the new facility is occupied the old facility will be demolished. The service life of the new facility will be 25-40 years.

Timing and Execution Risks:
The Project duration is 36 months as described below:
0 – 3 months: Programming, design development
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit & tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
30 – 36 months: Disposition of the old property and remaining site activity

Risks include contractor delays and material delivery delays or defects.

Expenditures :
The total cost for the project is $6.8M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values are determined using marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources:
Professional resources for design and engineering will be contracted from the marketplace. EGI has historically retained architectural and engineering consulting services for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Investment Summary Report

Investment Code	Report Start Year	Number of Years
8701	2021	5

Investment Name

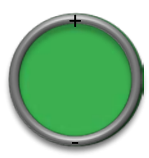
Kelfield Operations Centre

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (9,532,338)	0.00	$ 10,800,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 5,000,000	$ 4,700,000	$ 1,100,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 200,000	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(9,532)	100%
Total	**(9,532)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	3639	2021	5
	Investment Name: Kennedy Road Expansion		

Investment Description

Issue/Concern:
Overall, the existing building at the Kennedy Road facility is too small to meet current EGI standards. The separation of offices and warehouse into two separate buildings is not convenient for staff and causes operational and workplace difficulties and inefficiencies. The configuration of site functions and circulation is inefficient. The yard area is too small to meet current EGI standards. Building expansion on the same property will further reduce the size of the yard area and will cause additional pressure on parking and circulation. Based on the site deficiencies and space limitations, relocation to another property is recommended. This option may no longer be possible so further analysis is required depending on the ability to procure adjacent property or appropriately-sized property nearby. The analysis will look at the possible vertical industrial solution to meet the needs of the business.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a FCI of 0 to 5%. The current FCI of the facility based on this study is 6.51%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility AI is 95%. Based on the FCI/AI graph, the current recommendation for the existing facility is to increase the site area by purchasing the adjacent property, demolish existing building, and re-build the facility on the combined sites to accommodate current EGI standards.

Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation. Access and exit from Kennedy is difficult and poses operational inefficiencies. The yard size is smaller than EGI standard yard size requirements. The current yard size is 1.3 acres. EGI standard yard size is 2.5 acres. The existing building requires expansion by approximately 11,000 square feet to meet the need for current staff and EGI functional requirements. Building additions on the property entail further reduction in the yard and parking areas.

Asset: 3157 Kennedy Road, Scarborough, ON.

Related Program:N/A

Recommended Alternative Description

Scope of Work: Sell the existing property, purchase a property suitable in size to accommodate the required program. Required size of new property is approximately 5 acres.

The project will correct operational and workplace inefficiencies, using less energy and emit less greenhouse gases on the combined site. This strategy will leverage current site improvements and keep land acquisition costs to a minimum by joining the currently vacant neighboring property.

The assets in scope are located at 3157 Kennedy Road, Scarborough, ON. The nature of work includes development of the adjacent property and construction and fit-up of a new building.

Solution Impact: The service life of the new facility will be 25-40 years.

Timing and Execution Risks:
The Project duration is 36 months:
0 – 3 months: Programming, design development
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit and tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
30 – 36 months: Disposition of old property

Risks include contractor delays and material delivery delays or defects.

Expenditures:
The total cost for the project is $26.8M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and estimated land values are based on marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources:
External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	2nd floor office space not accessible for occupancy Barrier free accessibility is non-compliant to Ontario Building Code Building has exceeded allowable occupancy Kennedy 45 SF/person VPC average is 145 SF/person
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
3639	2020	5

Investment Name

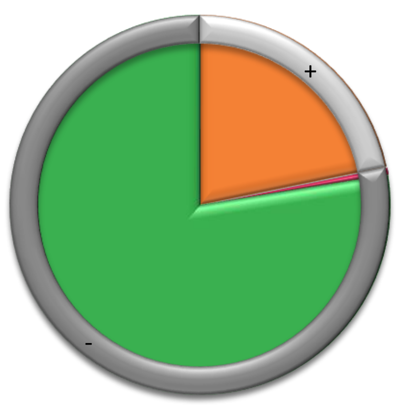
Kennedy Road Expansion

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 2	Recommended	$ (17,334,254)	0.28	$ 26,300,000	9/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 1,000,000	$ 12,000,000	$ 2,000,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 500,000	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	6,767	22%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Avoided GHG Emissions (CA)	(30)	0%
Energy Efficiency (CA)	(183)	1%
Total Investment Cost (CA)	(24,102)	78%
Total	**(17,547)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
6087	2021	5

Investment Name

MSB Demolition & New Administrative Parking

Investment Description

Issue/Concern:
The fleet garage (Mechanical Services Building) is located at VPC. Fleet services are now outsourced to third-party providers. As such, a review of remaining industrial activities within the building will be undertaken to determine appropriate facilities for relocation. It is expected when the building is vacant that it will be demolished for administrative parking on site. The capital funds have been re-purposed for the VPC Annex/Metershop Area Renovations project (500934).

Assets: VPC Mechanical Services Building

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Demolish Mechanical Services building.
The asset in scope is the Mechanical Services Building located at 500 Consumers Road, North York, ON. The nature of work is the demolition of existing building.

Timing: The Project duration is 12 months:
0 – 4 months: Programming
4 - 6 months: Perming and Tender
6 – 12 months: Demolition and parking construction

Risks include contractor delays and material delivery delays or defects.

Expenditures:The total cost for the project is $0.55 M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs. The project costs are based on a Class 5 estimate.

Resources: External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (5,430,811)	0.35	$ 9,000,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 9,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ 550,000	$ -	$ -

ENBRIDGE

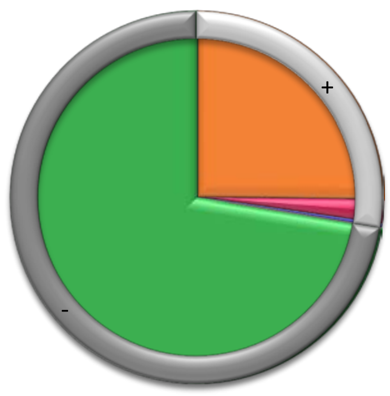
Investment Summary Report

Investment Code	Report Start Year	Number of Years
6087	2021	5

Investment Name

MSB Demolition & New Administrative Parking

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	2,903	25%
Energy Efficiency (CA)	238	2%
Avoided GHG Emissions (CA)	39	0%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(8,333)	72%
Total	**(5,154)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code: 3642	Report Start Year: 2021	Number of Years: 5
	Investment Name: SMOC/Coventry Facility Consolidation		

Investment Description

Issue/Concern:

Coventry Road
The office building in Ottawa is an owned facility that is in physically fair condition. The facility's functionality is sound but there is excess space. In addition, the furniture and finishings do not meet functional standards. The office is in a good location to serve the respective area, but there is duplication in coverage between the SMOC and Coventry Road facilities.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0, anything between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index is 43%, considered marginally correctable at current location without consideration of other factors including adequacy of land size and the Functional Condition Index.

Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation within the site. The yard size is smaller than EGI standard yard size requirements. The current yard size is 1.42 acres. EGI standard yard size is 2.5 acres. Building is in average condition and functionally sound (building has excess area). The site does not meet non-functional standards (furniture standards, finishes etc.) The site is in a good location but is no longer optimized for best use. There is potential for consolidation with the SMOC facility on 90 Bill Leatham Drive, Nepean, ON.

SMOC
SMOC is an owned facility in physically fair condition. The facility's functionality is sound, however, there is unused/excess space. In addition, the furniture and finishings do not meet non-functional standards (furniture standards, finishes etc.). The office is in a good location to serve its respective area, but there is duplication in coverage between this office and the office at Coventry Road.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. Anything between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index is 24% which is considered correctable at the current location, without consideration of other factors including adequacy of land size and the Functional Condition Index.

Functional Obsolescence – Site: The configuration of site functions and circulation is inefficient and poses a safety hazard. The yard area is too small to meet current EGI standards. The building is in average condition and is functionally sound (building has excess area). The building does not meet non-functional standards (furniture standards, finishes etc.) It is in a good location but there is potential for consolidation with the Coventry Road facility.

Assets: 400 Coventry Road, Ottawa, ON, and 90 Bill Leatham Drive, Nepean, ON (SMOC)

Related Program: N/A

Recommended Alternative Description

Eastern Region Consolidated Facility Project
Scope of Work:
This project requires selling both the SMOC and Coventry Road properties, purchasing a property suitable in size (approx. 7 acres) and building a new 70,000 sq. ft. building that will consist of administration, warehouse, welding, and fabrication facilities. The assets in scope are located at 400 Coventry Road, Ottawa, ON, and 90 Bill Leatham Drive, Nepean, ON (SMOC). The nature of work is development of a new property and the construction and fit-up of a new building.

Solution Impact: This option corrects operational and workplace inefficiencies by consolidating SMOC and Coventry redundancies. The new facility will use less energy and emit less greenhouse gases. The service life for the new facility will be 25-40 years.

Timing: The total Project duration is 30 months:
0 – 3 months: Programming, design development, location analysis
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit and tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
Post-occupancy disposition of property

Risks include contractor delays and material delivery delays or defects.

Expenditures: The total cost for the project is $23.8M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values using marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	60 - Ottawa
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
3642	2021	5

Investment Name

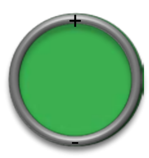
SMOC/Coventry Facility Consolidation

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (26,288,707)	0.00	$ 30,825,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 8,000,000	$ 12,000,000	$ 10,825,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 350,000	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(26,289)	100%
Total	**(26,289)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code: 3640	Report Start Year: 2021	Number of Years: 5
	Investment Name: Station B New Building		

Investment Description

Issue/Concern:
The Station B office on Eastern Avenue is an owned property in a good location, but does not meet current building standards or operational requirements. The physical condition is considered good, but the utilization and functionality is challenged. The office space no longer meets the needs of the staff currently working out of the facility. The new building will be able to provide the needed functionality and safety for the staff to carry out their tasks.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 12.28%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 49%.

Functional Obsolescence – Site: The property is divided into two separate parts. The first part consists of approximately 0.7 acres completely fenced off, including a secure gate station located adjacent to the site on the northwest corner. The reminder of the site consists of 3.2 acres and is used as an operations depot. The site does not meet operational requirements for size and vehicular circulation. One point of access is provided to the site which poses circulation difficulties and poses operational inefficiencies. The yard size is marginally smaller than EGI standard yard size requirements. The current yard size is 2.25 acres. The EGI standard yard size is 2.5 acres. It was noted by EGI staff that the existing yard size is adequate for current operations. The existing building requires expansion by approximately 8,000 square feet to meet the need for current staff and EGI functional requirements.

Asset: 405 Eastern Avenue, Toronto, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work: The project entails demolishing the existing facility and building a new single storey building with underground parking to ensure much needed yard requirements for core operational needs such as fleet and equipment parking, aggregate bunkers, and yard. Underground parking will ensure the site is maximized for operations yard needs as land in Toronto's downtown is limited and requires efficient use of property. This will expand the usable existing yard. The new building footprint of approximately 20,000 square feet will ensure adequate interior storage/warehouse and fabrication space for operations, an operations muster/meeting space, washroom/locker facilities appropriately sized for the operation, and and a larger office environment for site staff. The program will include currently missing elements such as a lunch room and meeting rooms. This new facility will correct operational and workplace inefficiencies, using less energy and emitting less greenhouse gases. The assets in scope are located at 405 Eastern Avenue, Toronto, ON. The nature of work is site improvements and construction and fit-up of a new building.

Solution Impact: The service life of the new facility would be 25-40 years, with the old building being demolished.

Project Timing: The project duration is 36 months.

0-3 months: Programming and design development
3-9 months: Site plan agreement, permit and tender documents
9-12 months: Permit and tender process
12-14 months: Contract award and winter contingency as required
14-28 months: Construction
28-30 months: Fit-up and occupancy
30-36 months: Old building demolition and remaining site improvements

Risks include contractor delays and material delivery delays or defects.

Expenditures: The total cost for the project is $6.5 M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI projects. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. Project costs are based on a Class 5 estimate.

Resources:
Professional resources for design and engineering along with a contractor will be retained from the marketplace. Historically, EGI has engaged architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
3640	2021	5

Investment Name

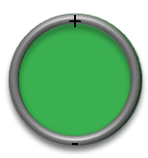
Station B New Building

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 2	Recommended	$ (15,851,852)	0.00	$ 17,600,000	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 15,500,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 350,000	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(15,852)	100%
Total	**(15,852)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code: 8782	Report Start Year: 2021	Number of Years: 5
	Investment Name: VPC Core and Shell		

Investment Description

Issue/Concern: The building shell and core for the VPC facility is over 50 years old. The tower building was constructed in or around 1968 as a two-storey building with an addition in 1978 that included floors 3 to 5. The VPC facility houses over 1,200 employees. It is an owned facility that is currently undergoing renovations.

Physical condition: Currently safe, ongoing periodic structural review required.

Functional condition: Failed performance as an insulator and barrier to the outdoors, water and vapor intrusion, comfort & energy efficiency is compromised.

Proposed activity: Envelope replacement - high performance curtain wall, new shell with very high levels of glazing allowing increased daylight and views; change from 30% today to 60-80% penetration of light.

Asset: 500 Consumers Road, North York, ON

Related Program:N/A

Recommended Alternative Description

Scope of Work: The assets in scope are located at 500 Consumers Road, North York, ON. The nature of work is the removal and replacement of the 50 year old exterior envelope on the tower and the replacement of core mechanical and electrical systems. This project calls for correcting physical and functional deficiencies by renovating and renewing the existing facility. This is the preferred strategy since the FCI and AI indices show the building and site deficiencies are correctable by the following activities:
-Renewing the building's main mechanical system
-Adding two elevators
-Renovating the 3 main staircases
-Replacing the building envelope

Solution impact: The renovation will correct operational and workplace inefficiencies by using less energy and emitting less greenhouse gases on the existing property. The service life of the renewed facility would be 40 years.

Timing: The project duration is 24 months:
0 – 3 months: Programming and design development
3 – 9 months: Permit and tender documents
9 – 12 months: Permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 24 months: Construction

Risks include contractor delays and material delivery delays or defects.

Expenditures: The total cost for the project is $20M net capital. Construction costs are determined from facility assessment reports and architectural consultant budget forecasts and use marketplace comparisons. Project costs are based on a Class 5 estimate.

Resources: External professional resources for design and engineering as well as a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (11,965,850)	0.15	$ 20,000,000	1/1/2024

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ -	$ 10,000,000	$ 10,000,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ 1,000,000	$ 1,000,000

ENBRIDGE

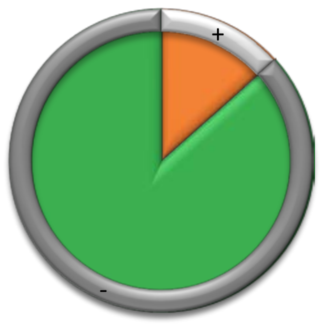
Investment Summary Report

Investment Code	Report Start Year	Number of Years
8782	**2021**	**5**

Investment Name

VPC Core and Shell

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	2,190	13%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(14,156)	87%
Total	**(11,966)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code 3634	Report Start Year 2021	Number of Years 5
	Investment Name VPC-1		

Investment Description

Issue/Concern:
The VPC facility is the largest EGI administrative facility. It is an owned facility that is currently undergoing renovations to address the physical condition and capacity concerns, as well as to replace legacy furniture and finishings. The first floor has not yet been renovated.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 5.59%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 11% which is considered correctable at the current location, without consideration of other factors including adequacy of land size and the FCI.

Functional Obsolescence – Site: The site area and parking provided are generally in compliance with EGI requirements.

Asset: First Floor, 500 Consumers Road Toronto, ON.

Related Program:N/A

Recommended Alternative Description

Scope of Work:The assets in scope are the first floor at 500 Consumers Road Toronto, ON. The nature of work is interior renovation and furnishings. The project corrects physical and functional deficiencies on the first floor of the tower by renovating and renewing the existing space. The current site has capacity to meet EGI functional requirements. Renovations to the building will correct operational and workplace inefficiencies, using less energy and emitting less greenhouse gases.

Solution Impact: The interior renovation will extend the asset useful life by 10 to 15 years.

Timing and Execution Risks:
The total project duration is 14 months and broken down as follows:
0 – 2 months: Programming and design development
2 – 5 months: Permit and tender documents
5 – 7 months: Award, permit and tender process
7 – 12 months: Construction
12 – 14 months: Fit-up and occupancy

Risks include contractor delays and material delivery delays or defects.

Expenditures:
The total cost for the project is $4.2M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values are determined using marketplace comparisons.
The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources:
External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	10 - Toronto
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	Building Code improvements such as OADA compliance and Fire code compliance.
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (5,925,926)	0.00	$ 7,950,000	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,700,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 350,000	$ -	$ -	$ -	$ -

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
3634	2021	5

Investment Name

VPC-1

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(5,926)	100%
Total	**(5,926)**	**100%**

Fleet and Equipment

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49980	2021	5

Investment Name

2021 - 485 Heavy Work Equipment

Investment Description

Issue/concern: In the EGD rate zone, heavy work equipment units which are much older and worn need to be replaced. Individual equipment is assessed using the Fleet Flagship Replace application.

Asset: Various Heavy Duty Equipment assets.

Related Program: N/A

Recommended Alternative Description

Scope of work: This Project provides EGI with the necessary heavy work equipment to safely and efficiently run business operations in the EGD rate zone. The goal is to maintain the integrity of all heavy work equipment assets for safe and reliable operation. To help achieve this goal, the Fleet department utilizes financial cost, risk analysis, and physical assessment information to drive replacement decisions. As the equipment ages and exceeds its useful life threshold, it can become an operational safety concern. Additionally, there are increases in maintenance costs and operational downtime which affects overall productivity.

Resources: Fleet and Equipment staff

Solution Impact: The fleet management analytical software tool Flagship Replace is used to make informed replacement decisions for rolling equipment such as backhoes. Replacement decisions for non-rolling equipment (i.e. welders) are primarily based on age, hour meter, and physical condition. Once heavy equipment assets reach an age of 10 years, a physical assessment is conducted to evaluate the equipment. A comparison of the maintenance history is used to determine refurbish or replace decisions.

Project Timing and Execution risks: Assets are ordered in January or February of fiscal year and delivered by December 31. Risk - delivery of assets not met by the December 31 deadline.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Fleet & Equipment - Equipment & Materials
Investment Stage	Short Term Planning		

Investment Overview

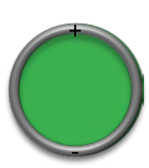
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	FLEET - Equipment & Materials
	Asset Class (EGI)	Fleet & Equipment
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	Yes

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (2,902,963)	0.00	$ 3,135,200	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,135,200	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,903)	100%
Total	**(2,903)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49978	2021	5

Investment Name

2021- 484 Light and Medium duty vehicles

Investment Description

Issue/Concern: In the EGD rate zone, light and medium duty vehicles are required to replace existing vehicles that are in poor operating condition.

Asset: Light duty vehicles and medium duty vehicles.

Related Program: N/A

Recommended Alternative Description

Scope of Work: This project provides EGI with the necessary fleet vehicles to safely and efficiently run its business operations in the EGD rate zone. The goal of the project is to maintain the integrity of all fleet assets for safe and reliable operation. This ongoing replacement strategy optimizes the asset life cycle, improves safety, and reduces risk for EGI and its employees. To help achieve this goal, Fleet utilizes financial cost analysis, risk analysis, and physical asset assessment to guide replacement decisions.

Resources: Fleet and Equipment staff

Solution Impact: In order to replace aging fleet assets, a report is generated by the fleet management analytical software tool Flagship Replace which uses raw fleet data to identify all vehicles meeting the replacement criteria. The direct impact is reduced O&M repair and maintenance costs, and improved driver safety.

Project Timing and Execution Risks: Assets are ordered in January or February of fiscal year and delivered by December 31. Risk - delivery of assets not met by the December 31 deadline.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - Fleet & Equipment - Vehicles
Investment Stage	Short Term Planning		

Investment Overview

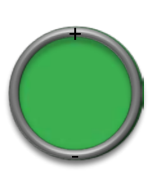
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	01 - All
	Asset Program (EGI)	FLEET - Vehicles
	Asset Class (EGI)	Fleet & Equipment
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	Yes

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,504,444)	0.00	$ 4,864,800	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 4,864,800	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(4,504)	100%
Total	**(4,504)**	**100%**

Technology and Information Services

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
101362	2021	5

Investment Name

IT - 00 - Microsoft Enterprise Agreement 2021

Investment Description

Issue/Concern: This is a contractual agreement with Microsoft that must be honoured. Three year Microsoft Enterprise Agreements are required to be able to continue using the Microsoft suite at EGI: Office, Outlook, SharePoint, Skype, etc.

Assets: TIS Software - packaged

Related Program: N/A

Recommended Alternative Description

Scope of Work:
This project is the annual payment of the Microsoft Enterprise Agreement (EA). The EA provides "software assurance" which allows us to upgrade EGI's Microsoft license assets as new versions of the software are released by Microsoft without additional cost. The EA is a three-year agreement. A payment is due in each of the three years based on the licensed assets owned by Enbridge at the beginning of the agreement. True-up payments are also made annually as new licensed assets are acquired, and are covered in this project. Contractual obligations and use of the software assets in the calendar year require payment in that year.

Resources:
This is a procurement project only, performed by Enbridge TIS, typically executed in February (payment) and December (true-up).

Solution impact: Allows for the usage of the Microsoft suite of products used by Enbridge users throughout the organization.

Timing and execution risk: if this spend is not executed, Enbridge would not be able to utilize some products, upgrade any of the products, and would likely be in violation of the license agreement if we are unable to true up based on actual usage

Benefits:
Microsoft EA allows for the use of the Microsoft licensed assets which include email, calendaring, servers etc… Essentially, this project allows for EGI personnel to use the Microsoft suite of products, which are key productivity tools, and to upgrade to current versions without re-purchasing the licensing. Products included are: Outlook, Word, Excel, PowerPoint, OneNote, Access, Publisher, Teams, Skype, Project, Visio, Windows operating system and various utilities that come with the operating system.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - TIS - TIS Infrastructure
Investment Stage	Short Term Planning		

Investment Overview

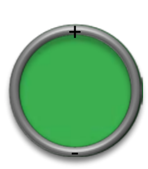
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	TIS Infrastructure
	Asset Class (EGI)	TIS
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	Yes

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (1,944,444)	0.00	$ 2,100,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,100,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(1,944)	100%
Total	**(1,944)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	8602	**2021**	**5**
	Investment Name: Operation Digital		

Investment Description

Issue/Concern: This project is to provide a solution for digitizing the Engineering standards documents,implementing software and developing a solution that will improve accessibility and consistency of records, resulting in :
-Ensuring that engineering documents (policies, procedures, standards, and processes) are compliant to both regulatory and standards that follow process safety policies and have well-defined procedures as it pertains to work on EGI assets.
-Reducing costs in creating, maintaining, and delivery of engineering documents while still remaining compliant. -Improving the readability of engineering documents so that they can be more easily understood and followed in order to reduce safety incidents. Improve the overall delivery and consumption of engineering document content to both internal and external EGI stakeholders.
-Establishing a governance structure so that engineering documents are kept up to date and meet regulatory standards and compliance.

Asset: TIS - Software - Packaged

Related Program: N/A

Recommended Alternative Description

Scope of Work:
The solution would include tools to perform the transformation of engineering documentation into a reusable format that is easy to update and with a consistent look and feel. In addition, the new engineering content framework will require a publishing mechanism to allow for consumption of the content in various situations faced by Operations personnel. The target audience also includes Extended Alliance partners.
Approach: Standard TIS project management approach, including a signed charter and approved project plan for each calendar year, encompassing the design, build, test and implementation phases.
Resources: TIS PM, BA, data architect, developers/support analysts and QA personnel.

Solution impact: This solution is of significant benefit to the Engineering department, and will help ensure safe and reliable operations of field workers.

Timing and execution risk: 2021 is the third year of this three-year project and if it is not executed then the benefits, which are significant, will not be realized.
2020: Funding requirements lowered from $3M to $1.5M. Primary driver for the reduction was a change in solution approach and utilizing a third party vendor that significantly reduced the costs associated with the documentation digitization.

Benefits: Avoided Printing Costs:
- In 2013 C&M Manuals - $235K into 1,500 pages to get the approximate cost per page: $156 + 15% Xerox markup = $180 per printed page.
- Assume 15,000 pages in the E&AM library in total but assume only 60% of that is printed.
- 9,000 pages x $180/pp = $1.62M. Even if we only print half of the total library it's still a $1.35M in savings
- Separate exercise with Xerox to look at what Engineering printed manuals, forms, etc. which verified the $1.35M approximate number:
2018 – 230K
2019 – 600k
2020 – 1.13 Million

Soft Benefits:
- Documentation to use unique procedural titles that communicate purpose, due to the related topics bread crumb
- Content is clear and at the right level of detail (involves rewriting documents to an audience-oriented standpoint)
- Tasks are assigned to the appropriate individual for procedures involving multiple operators.
- Consistent procedure format (using the DITA framework, all procedures would be consistently updated as changes to a procedure that affects multiple documents can be applied globally once the documentation set is republished).
- Overviews for lengthy procedures or activities involving multiple procedures (structured authoring enables consistency)
- Procedure documentation can be enhanced with interactive images, diagrams, or videos (a limitation of print media)
- Provision of accurate timely documents and data to the business (having one source of truth, with updates disseminated consistently to stakeholders). The proposed solution makes it easier to update content and publish content online.

Investment Type	Project (EGI)	Planning Portfolio	EGD - Core - TIS - TIS Business Solutions
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	00 - Head Office
	Asset Program (EGI)	TIS Business Solutions
	Asset Class (EGI)	TIS
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
8602	**2021**	**5**

Investment Name

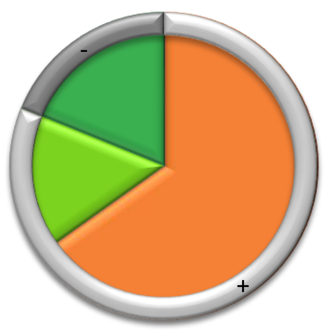
Operation Digital

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ 10,232,705	4.30	$ 4,090,000	1/1/2019

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	10,709	65%
Budget Savings OPEX (CA)	2,625	16%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(3,102)	19%
Total	**10,233**	**100%**

Growth

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100203	**2021**	**5**

Investment Name

Customer Stratford Reinforcement

Investment Description

Issue/Concern/Opportunity:
In order to support a significant load addition on the Forest, Hensall and Goderich Transmission System, a reinforcement is required from the end of the 2019 Stratford Reinforcement project to the inlet of Stratford Gate Station (17P-301).
This project allows EGI to continue to provide regular rate customers with gas while also serving a new glass plant with a known demand of 18,000 m3/h.

Justification: Reinforcement is required to add customer (a Glass plant) to the system.

Assets: This project will consist of two components:
1. Approximately 9.4 kilometres of NPS 12 high pressure transmission (6160 kPa MOP) steel natural gas main extending from the end of the Stratford Reinforcement Phase 1 project at Perth-Oxford Road and into Stratford Gate Station (along Crane Avenue).
2. Approximately 1 kilometre of NPS 6 (3450 kPa MOP) and approximately 700 metres of NPS 4 (3450 kPa MOP) heading south along Erie Street (Hwy 7) to the customer site at Erie and 29 Line.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Approximately 9.4 kilometres of NPS 12 high pressure transmission (6160 kPa MOP) steel natural gas main extending from the end of the Stratford Reinforcement Phase 1 project at Perth-Oxford Road and into Stratford Gate Station (along Crane Avenue).
Approximately 1 kilometre of NPS 6 (3450 kPa MOP) and approximately 700 metres of NPS 4 (3450 kPa MOP) heading south along Erie Street (Hwy 7) to the customer site at Erie and 29 Line.

Resources: Company crews, contractor labour and third-party vendor suppliers

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Project Timing and Execution Risk: Construction start March 2021- customer requires gas by April 2022.
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_04 - London
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Perth Road 113	Recommended	$ (12,109,054)	0.00	$ 13,300,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 10,300,000	$ 23,900,000	$ -	$ -	$ -
Contributions	$ -	$ (20,900,000)	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(12,109)	100%
Total	**(12,109)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48757	2021	5

Investment Name

HAMI: Dunnville Line Reinforcement (6.3 km of NPS 10)

Investment Description

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

System Reinforcement - Loop 10" reinforcement from outlet of Caledonia Trans, ending at Stoneman Road

Assets: 6.3 kilometres of NPS 10 outlet of Caledonia Trans, ending at Stoneman Road

Related Program: N/A

Recommended Alternative Description

Scope of Work: 8100 kilometres 10" ST in road allowance (yellow line) From Caledonia Station, north on Highway 6, west on Haldibrook Road, south on Abbey Road, running through easement to 10" loop.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Project Timing and Execution Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Short Term Planning		

Investment Overview

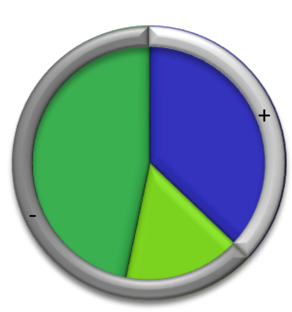
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_16 - Hamilton
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,337,382)	0.45	$ 9,100,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 600,000	$ 8,500,000	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



	Value Function Measure	Value	Value in Percentage
■	Revenue Impact (CA)	6,228	37%
■	Financial Risk	0	0%
■	Public Safety Risk	0	0%
■	Budget Savings OPEX (CA)	(2,722)	16%
■	Total Investment Cost (CA)	(7,843)	47%
	Total	**(4,337)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49774	2021	5

Investment Name

LOND: Goderich Transmission System, Reinforcement (11.4km of NPS 10)

Investment Description

Issue/concern: System Reinforcement: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Assets: 11.4 kilometres of NPS 10 pipe

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Loop existing NPS 8 Goderich Transmission pipeline with new NPS 10 steel pipeline (see red route) for 11.4 kilometres in road allowance of Huron Road (County Rd 8) from Hensall Road Valve Site to new Sanctuary Road.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Project Timing and Execution Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

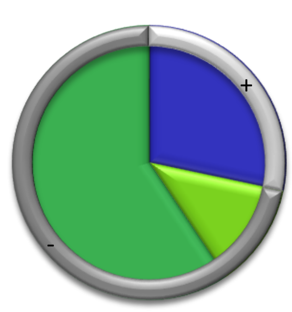
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_04 - London
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (11,557,680)	0.27	$ 25,000,000	1/1/2024

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ -	$ 67,341	$ 2,170,347
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Revenue Impact (CA)	7,539	28%
Financial Risk	0	0%
Public Safety Risk	0	0%
Budget Savings OPEX (CA)	(3,275)	12%
Total Investment Cost (CA)	(15,821)	59%
Total	**(11,558)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49004	2021	5

Investment Name

LOND: Upgrade Byron Transmission Stn (13N-501) Reinforcement

Investment Description

Issue/Concern:
The Byron Transmission Station Rebuild Project is required as a result of the rapid growth on the south and west sides of the London System which are supplied gas from the Byron Transmission Station. Due to the growth interest in markets fed by Byron Transmission Station and the abandonment of the London Lines, the Byron Transmission Station is projected to reach capacity in 2022.

Assets: Byron Transmission Station

Related Programs: N/A

Recommended Alternative Description

Scope of Work: The Byron Transmission Station Rebuild Project is required as a result of the rapid growth on the south and west sides of the London System which are supplied gas from the Byron Transmission Station. Due to the growth interest in markets fed by Byron Transmission Station and the abandonment of the London Lines, the Byron Transmission Station is projected to reach capacity in 2022.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Project Timing and Execution Risks: Scheduled to be energized and brought into service in 2021
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Executing		

Investment Overview

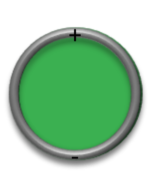
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_04 - London
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (7,953,704)	0.00	$ 8,550,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 8,050,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(7,954)	100%
Total	**(7,954)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49796	2021	5

Investment Name

LOND: Upgrade Ingersoll Trans (14R-102) Reinforcement

Investment Description

Issue/Concern: A rebuild of the Ingersoll Transmission Station (14R-102) is required due to inadequate capacity and will allow in-franchise growth on the Eastern Transmission System serving communities like Tillsonburg and Woodstock.

Assets: Ingersoll Transmission Station (14R-102)

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Complete station rebuild is required as the station is showing signs of wearing and load growth in the area is expected to exceed station capacity.

Resources: Capital Development with be managing this project. Company crews, contractor labour and third-party vendor suppliers will be used to complete the work.

Solution Impact:
Without the rebuild, low pressure downstream of the station could result in a loss of customers on peak winter days.

Project Timing and Execution Risks:
The project is to be completed by Nov. 2022
Weather impacts, resource availability, procurement issues, etc

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

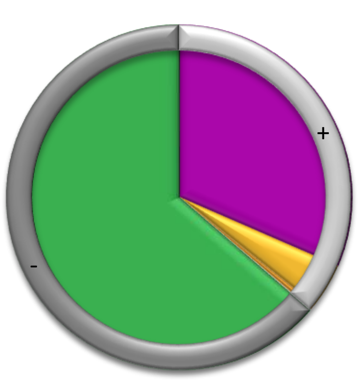
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_04 - London
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (7,210,219)	0.00	$ 8,370,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 500,000	$ 7,870,000	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Financial Risk	3,571	32%
Operational Risk	475	4%
Environmental Risk And Remediation	57	1%
Reputational Risk	11	0%
Employee And Contractor Safety Risk	0	0%
Public Safety Risk	0	0%
Total Investment Cost (CA)	(7,210)	64%
Total	**(3,095)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49116	2021	5

Investment Name

NBAY: Parry Sound Lateral Reinforcement (12.5 km of NPS 6)

Investment Description

Issue/Concern:
Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Description: Reinforcement project required due to the increased demand within the Parry Sound area. Residential and Industrial additions have currently accounted for most of the NPS 4 pipeline capacity since being installed in 1998 (the original OEB filing was for a 10-year life span). The 1998 forecasted and observed attachments align, the exception being the commercials which have been larger than forecasted. The 2015-16 FBP forecast suggested 12 commercials per year attaching. The Crofters load addition was equivalent to 41 such commercials in 1 year. The current system can only handle a total flow of ~4500 m3/h, and if the lateral was fully 6", it could handle ~12500 m3/h of flow. This increased flow capacity will ensure the system will continue to meet future growth demands, specifically future residential attachments, the identified industrial park in Seguin, and the potential future expansion if the McDougall community.
Assets: Parry Sound Lateral - 12. 5 kilometres of NPS 6 pipe.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: 12.5 kilometres main to be installed alongside existing 4" main to increase flows into Parry Sound. Alternatives to this project have not yet been fully vetted but are planned to be reviewed by the end of 2020.

Resources: Company crews, contractor labour and third-party vendor suppliers.

Solution Impact: Increased flow capacity will ensure the system will continue to meet future growth demand. The network adds about 100 customers per year - without the reinforcement customers would not be able to be added in violation of EBO 188.

Project Timing and Execution Risks: This project is scheduled to be in service in 2023. Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

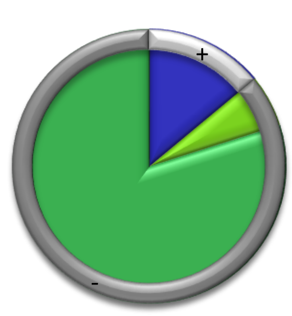
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_46 - North Bay & Orillia
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (10,730,406)	0.10	$ 15,000,000	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 15,000,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Revenue Impact (CA)	2,089	14%
Financial Risk	0	0%
Public Safety Risk	0	0%
Budget Savings OPEX (CA)	(912)	6%
Total Investment Cost (CA)	(11,907)	80%
Total	**(10,730)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49793	2021	5

Investment Name

SUDB: Marten River Compression, Reinforcement

Investment Description

The Sudbury system is supported by the Liquefied Natural Gas (LNG)/compressor facility at Hagar. However, the volume of LNG available is insufficient to maintain the system in the event a historical cold winter is experienced. Higher than contracted pressures from TC Energy would be required to offset LNG utilization. This proposed reinforcement project includes the addition of two 2100 HP compressors at Marten River to increase system pressures to support Sudbury system demand. However, alternatives are continuing to be assessed - alternatives include a lift and lay pipeline project from North Bay and upgrades at the Hagar LNG plant.

Assets: 2x 2100 HP compressors

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Option A: 2x 2100 HP Compressors at Marten River
Option B: Transmission Reinforcement plus compression
Option C: Lift and lay pipeline from North Bay.
Option D: Upgrade the Hagar LNG facility.

Resources: Company crews, contractor labour and third-party vendor suppliers

Solution Impact:This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth. Any of the options prevents a loss of customer if TCPL delivers tariff minimum inlet pressures - 15,000 customers could be lost on peak day if the reinforcement is not complete.

Project timing and Execution Risks: Scheduled to be in service in 2023.
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

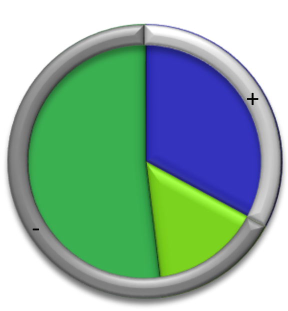
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_43 - Sudbury & S.S. Marie
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (27,030,191)	0.34	$ 51,600,000	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 51,600,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Revenue Impact (CA)	25,903	33%
Financial Risk	0	0%
Public Safety Risk	0	0%
Budget Savings OPEX (CA)	(11,971)	15%
Total Investment Cost (CA)	(40,962)	52%
Total	**(27,030)**	**100%**

ENBRIDGE Investment Summary Report

Investment Code	Report Start Year	Number of Years
49925	2021	5

Investment Name

THUN: Greenstone Mine, Geraldton (12km of NPS 6)

Investment Description

Issue/Concern:
Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

-12 kilometres of NPS 6 plus TBS (Town Border Station) and SMS (Sales Metering Station) installation
-Customer driven and funded: 1 customer (Mine) Compliance under EBO 188

Assets: 12 kilometres of NPS 6 pipe

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Install ~ 12 kilometres of NPS 6 pipe from the Geraldton TBS (at the existing TransCanada tap) to the customer's site. The majority of pipe will be installed on the current and old Hwy 584 and will require a new customer station and modifications to the existing Geraldton TBS.

Resources: Company crews, contractor labour and third-party vendor suppliers

Solution Impact:This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Project Timing and Execution Risks: This project is scheduled to be in service in 2021.
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (3,654,630)	0.00	$ 3,907,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,407,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(3,655)	100%
Total	**(3,655)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
103275	2021	5

Investment Name

TIMM: Macassa Mine New Shaft #3 SMS

Investment Description

Issue/Concern:
Macassa Mine (contract customer Kirkland Lake Gold) in Kirkland Lake is requesting additional load to mine Shaft #3. It has been identified by Network Analysis that the additional firm contract load requires reinforcement on the existing NPS 4 Kirkland Lake transmission line fed from Kenogami CMS (42501001). The additional load also triggers a new NPS 4 HP service to Shaft #3 and a new NPS 2 HP main installed to Shaft # 4. Stations engineering has identified approximate standard designs for shaft #3: 9.S 210 HP.

This project includes a new NPS 4 HP customer service and requires first stage cut at HWY 66 (48.122424, -80.083232) and runs along unnamed customer access road @ 1900 kPa MOP.

The tentative in-service date for the new SMS at Shaft #3 is November 1, 2021, as of May 2020.

Assets: Station ID 12500030 (station ID developed for the new Shaft #3 SMS)

Related Investments: C55 investment #103278 pertains to the new SMS at Shaft #4, also with a tentative date of November 1, 2021.

Recommended Alternative Description

Scope of Work: This project includes a new NPS 4 HP customer service. Requires first stage cut at HWY 66 (48.122424, -80.083232) and runs along unnamed customer access road @ 1900 kPa MOP. The tentative in-service date for the new SMS at Shaft #3 is November 1, 2021, as of May 2020.

Note that the cost estimate submitted in C55 in May 2020 is based on the feasibility-level, Class 5 estimate prepared by the Capital Development Team in 2019, plus a 40% contingency, and this total cost excludes any aid-to-construct (to be confirmed after the contract is signed). The budget-level estimate is still outstanding, and the costs and aid-to-construct amount contained in C55 will be revised and re-submitted after the exact terms of the contract are known.

Resources: To be confirmed - the construction work will be performed by company crew or an Alliance Partner.

Solution Impact: Increased revenue for EGI, as well as expanded company presence and increased market share.

Project Timing and Execution Risk: The tentative in-service date is set for November 1, 2021. Based on information from the Sales Account Manager, there is a high likelihood that Kirkland Lake Gold will wish to proceed with the proposed work; however, there is the possibility that the customer does not agree to the contract. Resources need to be confirmed. Potential execution risks include limited resources due to competing project priorities in 2021, or any timing or execution delays that may be imposed by the customer (Kirkland Lake Gold).

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_45 - Timmins
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	EBO 188 Compliance
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Construct New SMS at Shaft #3, including NPS 4 Service	Recommended	$ (2,111,667)	0.00	$ 2,280,600	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,280,600	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

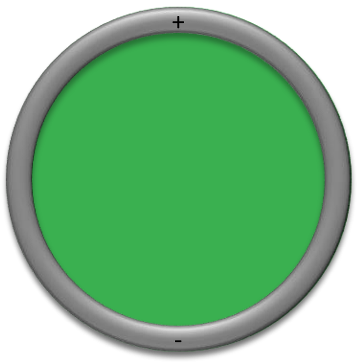
Investment Summary Report

Investment Code	Report Start Year	Number of Years
103275	**2021**	**5**

Investment Name

TIMM: Macassa Mine New Shaft #3 SMS

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Financial Risk	0	0%
Employee And Contractor Safety Risk	0	0%
Environmental Risk And Remediation	0	0%
Public Safety Risk	0	0%
Reputational Risk	0	0%
Operational Risk	0	0%
Total Investment Cost (CA)	(2,112)	100%
Total	**(2,112)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49929	2021	5

Investment Name

WATE - Owen Sound Reinforcement Ph 4

Investment Description

Issue/Concern: System Reinforcement
NPS 12 ST looping from Durham to Chatsworth of the Owen Sound transmission system for both EPCOR and general growth.

The Owen Sound area continues to grow as retirees move from the Greater Toronto Area. A current reinforcement is underway to supply increasing demands (including EPCOR) in the region - this project is the next phase in reinforcing this network to support forecasted growth. This project will install approximately 28 kilometres of NPS 16 pipe (replacing NPS 8 pipe) from Wellington Road, Harriston to the Durham gate station.

Assets: 28 kilometres of NPS 16 pipe from Wellington Road, Harriston to the Durham gate station

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Station Replacement Program: Proactive replacement program that targets stations based on obsolescence, condition and age. This project will install approximately 28 kilometres of NPS 16 pipe (replacing NPS 8 pipe) from Wellington Road, Harriston to the Durham gate station.

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth.

Resources: Company crews, contractor labour and third-party vendor suppliers

Project Timing and Execution Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Executing		

Investment Overview

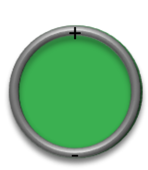
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_07 - Waterloo
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (56,481,627)	0.00	$ 56,623,896	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 1,920,625	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



	Value Function Measure	Value	Value in Percentage
■	Total Investment Cost (CA)	(56,482)	100%
	Total	**(56,482)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49773	2021	5

Investment Name

WATE: Owen Sound Transmission System, Reinforcement (28.8km of NPS 16)

Investment Description

Issue/concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

Assets: Owen Sound Transmission System - reinforcement of 28.8 kilometres of NPS 16 pipe.

Related Programs: N/A

Recommended Alternative Description

Scope of work: Lift and lay 28.8 kilometres of existing NPS 8 pipe with NPS 16 steel pipe. Cross country from approximately 9302 Wellington Road 6, Harriston to Durham Gate Station.

Resources: Company crews, contractor labour and third-party vendor suppliers

Solution Impact: This reinforcement project will ensure the system has adequate flow capacity in anticipation of projected customer growth. Approximately 1,300 customers are added annually in the region.

Project Timing and Execution Risks: Scheduled to be in service in November 1, 2025 or else customers could be lost from the system due to low pressure on peak day - the project will allow for a forecasted five years of growth.
Risks: Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Growth - System Reinforcement
Investment Stage	Long Term Planning		

Investment Overview

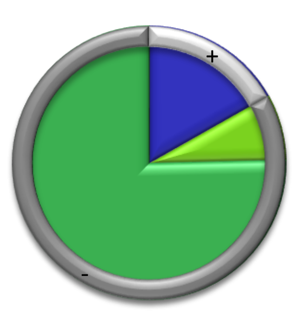
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_07 - Waterloo
	Asset Program (EGI)	GTH - System Reinforcement
	Asset Class (EGI)	Growth
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (50,149,743)	0.12	$ 83,551,000	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 141,000	$ 4,580,000	$ 77,000,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Revenue Impact (CA)	12,763	17%
Financial Risk	0	0%
Public Safety Risk	0	0%
Budget Savings OPEX (CA)	(5,876)	8%
Total Investment Cost (CA)	(57,036)	75%
Total	**(50,150)**	**100%**

Distribution Pipe

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
1791	2021	5

Investment Name

Augusta NPS 8

Investment Description

Issue/Concern:
Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30% SMYS. Any changes in class location need to be assessed to the current standard to determine if pipeline modifications are required. Urban development occurs in close proximity to EGI's pipelines which triggers annual class location changes; this work ensures EGI is compliant and fosters the safety of the public and the pipeline system.

Assets: Augusta 8 - 2400 metres of NPS 8, 2 roads Class 1 to 2.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replace 2400 metres of NPS 8, 2 road crossings.

Solution Impact: The NPS 8 Augusta line will be designed and installed to address the class location change in this area; this work ensures EGI is compliant to CSA Z662 and fosters the safety of the public and the pipeline system.

Resources: Engineering Construction will manage the planning and execution of this project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Class Location Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_22 - Kingston
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30 per cent SMYS. This work ensures EGI is compliant and fosters the safety of the public and the pipeline system.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Replacement	Recommended	$ (5,555,556)	0.00	$ 6,000,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 6,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(5,556)	100%
Total	**(5,556)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48691	2021	5

Investment Name

Bruce Lake Lateral

Investment Description

Issue/Concern:

General Concerns: The capital expenditure included in this category covers a variety of planned maintenance projects. The projects covered under this expenditure include low pressure system replacements, distribution pipeline replacements due to historical leakage and integrity concerns, pipeline casing replacements, bridge and water crossing replacements and repairs etc. These projects are often identified through planned inspections and pipeline surveys and would then be assessed and planned based on risk and resource availability.

Project Specific: The Bruce Lake Lateral Maximum Operating Pressure (MOP) Upgrade project has been ongoing since 2017. This project is required to address capacity constraints on this system and ensure that contractual obligations can continue to be met. Work completed in 2017 was primarily focused on make piggable work for planned in-line inspection during the winter of 2017/2018. The line was inspected with ILI in 2018 and then again inspected in the winter of 2018/2019 with the addition of a flare stack to create more control over flow in the system. This second inspection was fully successful and provided the Integrity team with the required data to assess required repairs on the lateral prior to pressure testing. A total of 69 defects were identified requiring remediation – 29 of those defects were remediated in 2019.

Assets: Bruce Lake Lateral

Related Programs: N/A

Recommended Alternative Description

Scope of Work: In 2020 the work plan is focused on remediating the remaining 40 defects in order to be in a position to complete the remaining MOP upgrade activities in 2021.

In 2021, the work plan includes segmenting the 127-kilometres Bruce Lake lateral into a minimum of five segments for pressure testing, trucking in LNG to maintain system supply during the pressure tests, and completion of any required remediation as a result of pressure test results Work will also include a leak survey of the lateral post completion of the pressure test and completion of any remaining outstanding Engineering Assessment requirements in order to document and obtain approval from the TSSA for the final MOP Upgrade.

Solution Impact: Bruce Lake Lateral MOP Upgrade will be completed and approved by TSSA.

Resources: Engineering Construction will manage the planning and execution of this project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - General Mains Replacement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (13,550,989)	0.00	$ 13,921,359	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 5,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(13,551)	100%
Total	**(13,551)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
1790	2021	5

Investment Name
Coniston Lateral Replacement

Investment Description

Issue/Concern:
General Concerns: Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30% SMYS. Any changes in class location need to be assessed to the current standard to determine if pipeline modifications are required. Urban development occurs in close proximity to EGI's pipelines which triggers annual class location changes; this work ensures EGI is compliant and fosters the safety of the public and the pipeline system.

Project Specific Concerns: Coniston Lateral Replacement - Replace 1100 metres of NPS 4, two roads Class 1 to 2.

Assets: Coniston Lateral

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replace 1100 metres of NPS 4 and two road crossings.

Solution Impact:The Coniston Lateral line will be designed and installed to address the class location change in this area; this work ensures EGI is compliant to CSA Z662 and fosters the safety of the public and the pipeline system.

Resources: Engineering Construction will manage the planning and execution of this project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Class Location Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_43 - Sudbury & S.S. Marie
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30 per cent SMYS. This work ensures EGI is compliant and fosters the safety of the public and the pipeline system.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Replacement	Recommended	$ (2,777,778)	0.00	$ 3,000,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,778)	100%
Total	**(2,778)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49459	2021	5

Investment Name

HAMI - 20" Shorted Casing on Hwy 5 - Phase 1

Investment Description

Issue/Concern: This project includes the replacement of approximately 40 metres of 20" main which is shorted to the casing around it under Highway 5 in Flamborough. A non-conformance was issued for this work by the Corrosion department. This is one of two shorted casings close to each other on the outlets of Hamilton Gate 1 and 2. The west-most one is of higher importance due to condition as identified by corrosion technicians.

Assets: FID 555217110 (Highway 5 crossing of Gate 1 outlet)

Related Programs: 49460

Recommended Alternative Description

Scope of Work:
The Corrosion Program includes the required expenditure to replace aging or obsolete rectifiers or any other general corrosion capital, excluding anodes, in order to reduce the amount of down plant within the system. These installations and replacements are based on the internal Standard Operating Practice established to maintain the appropriate level of cathodic protection on steel pipeline assets or are driven by business cases to improve efficiencies in the corrosion program.
This project includes the replacement of approximately 40 metres of 1900kPa MOP 20" pipe within a casing under Highway 5. This pipe is near the outlet of Gate 1 and feeds the Hamilton high pressure loop which surrounds and feeds all of Hamilton.

Solution Impact: Once this is completed, the risk of loss of containment on this line will be eliminated. This line is an extremely important feed to all of Hamilton. Gate 1 is being rebuilt and it is important that to be able to use the station and line to their full capacity.

Resources: Engineering Construction will complete the work. It will require outside contractors for stopping and tapping.

Timing and Execution Risks: The project can only be completed in the summer months as Gate 2 and 3 will need to act as back-ups while this section of the line is shut down. Gas from Gate 3 is purchased from TCPL and nominations need to be considered for the time that it will be used more than normal. Temporary land may be required from nearby land owners to allow for room to work. The city of Hamilton will need to approve the work under their right of way (ROW). Cost estimates continue to be refined as project design progresses and approaches construction.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Corrosion - Corrosion
Investment Stage	Short Term Planning		

Investment Overview

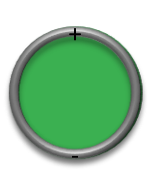
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_16 - Hamilton
	Asset Program (EGI)	DP - Corrosion
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
40m of 20" 1900kPa MOP pipe replacement	Recommended	$ (2,727,778)	0.00	$ 2,946,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,946,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,728)	100%
Total	**(2,728)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48252	2021	5

Investment Name

INTE: North Shore - Section A : Retrofit ECDA to ILI

Investment Description

Issue/Concern:

General: The Integrity Retrofit portion of the Integrity Management Program is to specifically capture retrofit work to make pipelines inline inspectable. The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of pipeline systems at EGI to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30% SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and remediation of pipeline segments with integrity issues that are identified through the inspections.

Project-specific concerns: External Corrosion Direct Assessment (ECDA) to ILI; no previous inline inspection. Associated 2021 O&M spend.

Assets: NPS 12 North Shore Lateral

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Retrofit North Shore Lateral by installing in-line inspection (ILI) launcher and receiver facilities, removing non-piggable valve installations and other fittings installed on the pipeline. Pipeline will be segmented into multiple sections for ILI to keep run duration manageable.

Solution Impact: This retrofit project will allow the North Shore Lateral pipeline to be inspected using in-line inspection. Performing ILI will enhance the quantity and quality of pipeline condition data available for integrity management purposes including risk mitigation activities and fitness for service assessments.
In-line Inspection is part of EGI's Integrity Management Program, a regulatory requirement designed to comply with all applicable codes and standards.

Resources: Engineering Construction will manage the planning and execution of the retrofit project.

Timing and Execution Risks: This project is scheduled for design in 2020 and execution in 2021. Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the retrofits, the work might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Integrity - Integrity Retrofit
Investment Stage	Executing		

Investment Overview

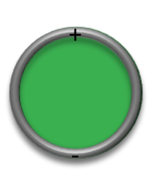
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_46 - North Bay & Orillia
	Asset Program (EGI)	DP - Integrity
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Retrofit	Recommended	$ (11,411,111)	0.00	$ 12,300,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 12,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



	Value Function Measure	Value	Value in Percentage
■	Total Investment Cost (CA)	(11,411)	100%
	Total	**(11,411)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
102211	**2021**	**5**

Investment Name

INTE: Norwich South: ECDA to ILI

Investment Description

Issue/Concern:

General: The Integrity Retrofit portion of the Integrity Management Program is to specifically capture retrofit work to make pipelines inline inspectable. The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of pipeline systems at EGI to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30% SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and remediation of pipeline segments with integrity issues that are identified through the inspections.

Assets: NPS 6 Norwich South Line

Related Programs: Integrity Management Program

Recommended Alternative Description

Scope of Work: Retrofit Norwich South Line by installing in-line inspection (ILI) launcher and receiver facilities, removing non-piggable valve installations and other fittings installed on the pipeline.

Solution Impact: This retrofit project will allow the Norwich South Line to be inspected using in-line inspection. Performing ILI will enhance the quantity and quality of pipeline condition data available for integrity management purposes including risk mitigation activities and fitness for service assessments.
In-line inspection is part of EGI's Integrity Management Program, a regulatory requirement designed to comply with all applicable codes and standards.

Resources: Engineering Construction will manage the planning and execution of the retrofit project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the retrofits, the work might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Integrity - Integrity Retrofit
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_06 - Brantford
	Asset Program (EGI)	DP - Integrity
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of Union's pipeline systems to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30 per cent SMYS
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Retrofit	Recommended	$ (2,546,296)	0.00	$ 2,750,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,750,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

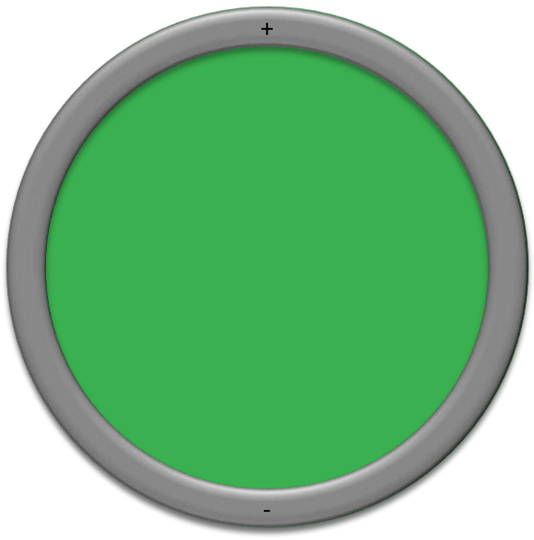
Investment Summary Report

Investment Code	Report Start Year	Number of Years
102211	2021	5

Investment Name

INTE: Norwich South: ECDA to ILI

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Financial Risk	0	0%
Employee And Contractor Safety Risk	0	0%
Environmental Risk And Remediation	0	0%
Public Safety Risk	0	0%
Reputational Risk	0	0%
Cost Avoidance CAPEX (CA)	0	0%
Cost Avoidance OPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Operational Risk	0	0%
Total Investment Cost (CA)	(2,546)	100%
Total	**(2,546)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48248	**2021**	**5**

Investment Name

INTE: Owen Sound Section 5: Replace Road Crossing for 2021 ILI

Investment Description

Issue/Concern:

General: The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of EGI's pipeline systems to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30 per cent SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and replacement of pipeline segments with integrity issues identified through the inspections.

Project Specific: Enhance piggability of Owen Sound line prior to next ILI in 2021. Associated 2021 O&M spend. Previous ILIs have encountered lodged tools at this location resulting in speed excursions and missing and degraded data.

Assets: Owen Sound line

Related Programs: N/A

Recommended Alternative Description

Project Specific: Enhance piggability prior to next ILI in 2021. Associated 2021 O&M spend. Previous ILIs have encountered lodged tools resulting in speed excursions, missing and degraded data.

Resources: Engineering Construction group to provide project management support from design and planning phase to project execution.

Solution Impact: Replacing this section of pipe will eliminate speed excursions and result in a more complete and accurate ILI data set for evaluation as part of the TIMP program.

Project Timing and Execution Risks: Project is planned for early 2021. Proposal is based on Class 5 level cost estimates.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Integrity - Integrity Retrofit
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_07 - Waterloo
	Asset Program (EGI)	DP - Integrity
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Retrofit	Recommended	$ (4,000,366)	0.00	$ 4,200,366	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,700,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(4,000)	100%
Total	**(4,000)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code: **102128**	Report Start Year: **2021**	Number of Years: **5**
	Investment Name: Kirkland Lake Lateral Replacement		

Investment Description

Issue/Concern:
The Kirkland Lake Lateral is 12 km of NPS 4 steel pipe of late 1950s vintage (1957/1958) operating at an MOP of 6895KPa / 1000psig (>30%SMYS) and is considered a transmission main under the Transmission Integrity Management Program (TIMP):
- Main runs through mostly bedrock with blasted main bed and rocky backfill.
- Depth of Cover (DoC) and backfill washout is a big concern- 2019 ECDA included a DoC survey and found over 1.3km of pipe with less than 0.6m of cover.
- One inoperable valve at Swastika.
- The main has 1 river crossing.
- Approximately 4 km of the 12 km of pipe was replaced for class location mitigation work.
- Lateral supplies Kirkland Lake and some mining customers and is looped with another NPS 8 main (Kirkland Lake Loop)
- Utilization for these two mains is nearing full capacity, especially when the addition of three new mines takes place:
    - When demand increases (i.e. addition of these three mines) this would eliminate the ability to use the NPS 8 system as a back feed / bypass to allow repairs on the NPS 4 mains, should additional leaks occur.
    - Repairs on the NPS 4 would then require local isolation via bypass, dramatically increasing leak repair costs and repair times.
- Since this is a transmission line operating >30%SMYS, any leaks must be repaired via cut-out replacements (no sleeves).
- This main was inspected by ECDA in 2007. The report gave an estimated 12-year life from that point in time and found 11 immediate dig locations.

- A leak was found in September 2019 (1st leak in at least 12 years) and was repaired via cut-out / replacement using the NPS 8 loop to isolate the NPS 4 as capacity demands allowed for this process. Repair cost was approximately $375K.
- ECDA inspection was performed in late fall of 2019:
    - 13 immediate digs in 12 locations were identified and require mitigation within 18 months (June 2021).
    - These digs are O&M expenses, if cut-out repair is required, this would be Capital (replacement of >1m of pipe)
    - An additional 40 indications were classified as "scheduled for investigation" and require investigation digs within 48 months (2023).
    - TIMP estimates a cost of approximately $100K per dig.
    - TIMP estimates that in total, approximately $6M in digs and repairs is required to mitigate these 53 indications.
- TIMP has imposed a pressure reduction to the main of 850 psig as a temporary mitigation.

Justification:
The NPV analysis for replace versus repair shows a strong recommendation towards replacing the main as the least costly option.

Assets: Kirkland Lake Lateral

Related Programs: TIMP Inspection Program

Recommended Alternative Description

Scope of Work: Due to the condition of the existing NPS 4 Kirkland Lake Lateral, a cost estimate has been requested for the replacement of the line. This is a result of the latest ECDA report on the pipeline. Portions of the line have recently been replaced in 2018 and 2019 as part of the Class Location program. The remaining sections are proposed for replacement (8.5 km total of NPS 4). This option is a size for size replacement.

Solution Impact:
Replacement with new pipe will remove the over 300 corrosion indications being found by ECDA and reduce the likelihood for corrosion leaks as well as damage, as the new main will be set to the correct depth of cover.

Resources:
2022 OTC - resources TBD

Project Timing & Execution Risk: A 2022 in-service date considering this option will most likely require OEB approval through a Leave To Construct (LTC) application.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_45 - Timmins
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	2019 ECDA identified 13 Immediate Dig / Repair features that need to be mitigated no later than 2021, with an additional 40 features requiring scheduled mitigation by 2023. There are a further 300 indications being monitored. TIMP is suggesting that replacement versus repair be a preferred option. If the pipe is replaced then TIMP will remain in compliance. Otherwise repairs will be required for the 13 immediate and 40 scheduled digs through O&M.
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Investment Summary Report

Investment Code	Report Start Year	Number of Years
102128	2021	5

Investment Name

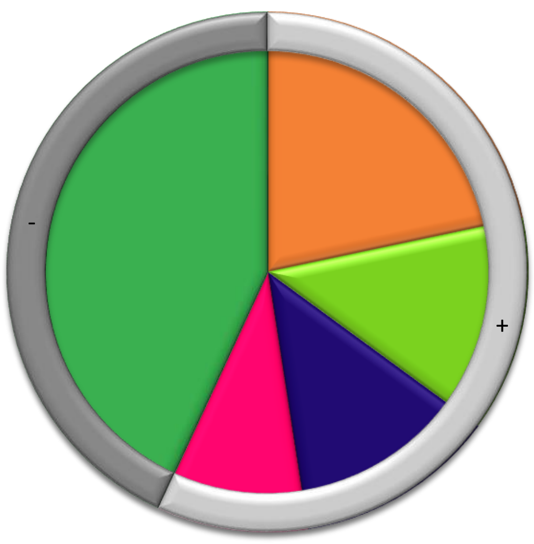
Kirkland Lake Lateral Replacement

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
NPS 4 Size for Size Replacement	Recommended	$ 4,614,115	1.32	$ 16,800,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 600,000	$ 16,200,000	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	7,263	22%
Budget Savings OPEX (CA)	4,490	13%
Cost Avoidance CAPEX (CA)	4,180	12%
Budget Savings CAPEX (CA)	3,126	9%
Financial Risk	0	0%
Employee And Contractor Safety Risk	0	0%
Environmental Risk And Remediation	0	0%
Public Safety Risk	0	0%
Reputational Risk	0	0%
Revenue Impact (CA)	0	0%
Operational Risk	0	0%
Total Investment Cost (CA)	(14,444)	43%
Total	**4,614**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49607	2021	5

Investment Name

LOND-London Lines Replacement

Investment Description

Issue/Concern:
The London Lines is a pair of high pressure distribution pipeline that connects Dawn to the City of London, and the multiple municipalities in between and spans approximately 80.9 km. The London Lines consists of two high pressure (HP) pipelines running in parallel and is considered a major feed supplying gas to the small communities between Dawn and London. The line located further north is known as the London South Line and is comprised mainly of NPS 10 steel pipeline coated in Barrett Enamel and installed in 1935. The line located further south is known as the London Dominion Line and is comprised mainly of NPS 8 steel pipeline coated in Durnite and installed in 1936, which was subsequently replaced in 1952. The materials used were reclaimed and refurbished steel pipe from the Windsor district with an average vintage of 1920 - 1930.

There are a number of business benefits to replacing the London Lines pipelines as soon as possible::
- Integrity– associated risks from numerous outstanding leaks and future leak potential eliminated through replacement:
  - Pipeline is constructed with unrestrained Dresser coupling fittings.
  - Aerial crossings at ditches which in some instances are bare and/or have unrestrained Dresser couplings.
  - Inoperable valves including valves installed at grade/in the ground
  - Current system operates below MOP to reduce number of leaks.
  - Both pipelines installed in the 1950s - one line constructed using reclaimed pipe from Windsor of 1920s vintage.
  - Depth of cover issues in multiple sections.
  - Non-standard supports at deep ditches to allow access for leak survey.
  - Increased difficultly of repairs including finding pipe suitable for welding.
- O&M resources - a reduction in the amount of O&M resources needed to address, monitor, and fix new and outstanding leaks is substantial. Estimated cost of a new repair is $15-60k.
- System flexibility – the connection of Strathroy to the Dawn to Parkway system in two locations will provide resiliency to the network.

Assets:
London Lines consists of two HP pipelines running in parallel (London South Line and London Dominion Line).

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
This project will install 83.5 kilometres of NPS 6 and NPS 4 steel pipe with a MOP of 3450 kpa (500 psi) from Dawn Compressor Station to Komoka Transmission Station, replacing the two pipelines known collectively as the London Lines. There will also be secondary new pipeline installed to connect the new NPS 6/4 pipeline to the town of Strathroy. The pipeline provides service, directly and indirectly, to approximately 8,500 customers.

Resources:
2021 - OTC and would be bid on by external contractors

Solution Impact:
Main replacement project identified by Operations - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results. This confirmed the timing for execution of this replacement project for 2021.

Timing and Execution Risks:
Risks: Moratoriums, third party developments, COVID-19 impacts, permitting and required easements.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - General Mains Replacement
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_03 - Sarnia
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (101,814,948)	0.00	$ 110,251,177	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 97,899,180	$ 8,302,453	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ 22,376,991	$ -	$ -	$ -

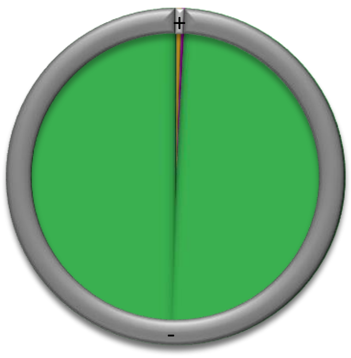
Investment Summary Report

Investment Code	Report Start Year	Number of Years
49607	**2021**	**5**

Investment Name

LOND-London Lines Replacement

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Operational Risk	520	1%
Financial Risk	357	0%
Reputational Risk	0	0%
Employee And Contractor Safety Risk	0	0%
Environmental Risk And Remediation	0	0%
Public Safety Risk	0	0%
Total Investment Cost (CA)	(101,815)	99%
Total	**(100,937)**	**100%**

ENBRIDGE **Investment Summary Report**	Investment Code **100295**	Report Start Year **2021**	Number of Years **5**
	Investment Name NPS 8 Port Stanley Replacement		

Investment Description

Issue/Concern/Opportunity:
The NPS 8 Port Stanley line is approximately 20 kilometres of NPS 8 built in 1959, with unknown grade and wall thickness, bare and protected, Dresser construction (some gas welded – such welds are usually susceptible to lack of fusion imperfections). There has been a history of a significant number of leaks due to corrosion on this single-feed system that provides natural gas to Port Stanley and St. Thomas, with about 13,000 customers including the St. Thomas hospital, a psychiatric hospital in St. Thomas and a retirement home in Port Stanley.

External corrosion has created difficulties with repairs due to the inability to weld. In one repair case, it took Operations three weeks to locate a suitable weld location for a repair. Repairs often require the use of split sleeves ($8K/ea). Depth of cover is a significant risk factor, with two exposed pipe sections being reported over creek crossings in December 2019. There are significant accessibility issues with locations of the pipe, making it difficult for emergency response and condition surveys. Some sections of pipe are heavily over-grown while other locations can be over 500 metres from the nearest road. There are three below-grade stations that are considered confined spaces and which often flood, and must be evacuated before inspections and maintenance can occur. Gas supply from Lake Erie (New Dundee Comp) was known to have high moisture content and may contribute to internal corrosion.

No isolation is built into the single feed system, so if supply needs to be shut down, all downstream customers would be affected. 6.8 kilometres of main were replaced in 2000 due to corrosion and exposed pipe. 230 metres were replaced in 2003 due to a Class B leak under a river crossing. Three casings on the system are known to be shorted. An attempted pressure increase in 1970 resulted in numerous leaks from compression couplings and pipe, therefore the pipe cannot be pressure elevated.

Assets: The Port Stanley line is approximately 20 kilometres of NPS 8 built in 1959.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Straight replacement of existing NPS8 utilizing right of way (ROW) only. This would involve the installation of 19.4 kilometres of NPS 8 steel gas main through ROW along existing roadway.

Solution Impact:
This option would eliminate access issues faced today with the gas main being installed through agricultural lands within easements.

Resources:
2024 - OTC and would be bid on by external contractors

Timing and Execution Risks:
Moratoriums, third party developments, COVID-19 impacts, permitting and required easements.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Long Term Planning		

Investment Overview

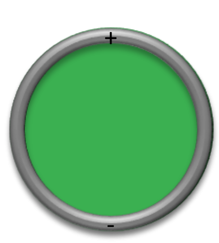
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_04 - London
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Port Stanley Replacement Option 1D	Recommended	$ (15,200,653)	0.00	$ 20,641,920	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 480,000	$ 20,161,920	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Financial Risk	0	0%
Public Safety Risk	0	0%
Total Investment Cost (CA)	(15,201)	100%
Total	**(15,201)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
2143	2021	5

Investment Name

Sudbury Section 1 - Yellek

Investment Description

Issue/Concern:

General Concerns: Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30% SMYS. Any changes in class location need to be assessed to the current standard to determine if pipeline modifications are required. Urban development occurs in close proximity to EGI's pipelines which triggers annual class location changes; this work ensures EGI is compliant and fosters the safety of the public and the pipeline system.

Project Specific Concerns: Sudbury Section 1 - Yellek - 2500m of NPS 10. 3 road crossings. Class 1 to 2.

Assets: Sudbury Section 1 - Yellek - 2500 metres of NPS 10 pipe.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replace 2500 metres of NPS 10, 3 road crossings

Solution Impact: The Sudbury Section 1 line will be designed and installed to address the class location change in this area; this work ensures EGI is compliant to CSA Z662 and fosters the safety of the public and the pipeline system.

Resources: Engineering Construction will manage the planning and execution of this project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Class Location Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

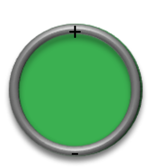
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_43 - Sudbury & S.S. Marie
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30 per cent SMYS. This work ensures EGI is compliant and fosters the safety of the public and the pipeline system.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Replacement	Recommended	$ (2,222,222)	0.00	$ 2,400,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,400,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,222)	100%
Total	**(2,222)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
2142	2021	5

Investment Name

Sudbury Section 1 Sturgeon River North Side

Investment Description

Issue/Concern - Replace 236 metres of NPS 10 steel transmission piping from the intersection of Delorme Street and Smilie Road to approximately 275 metres south of Smiley Road MLV. Chainage 43236 – 43472. Class 1 to Class 2 change. General concerns: Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30% SMYS. Any changes in class location need to be assessed to the current standard to determine if pipeline modifications are required. Urban development occurs in close proximity to EGI's pipelines, which triggers annual class location changes; this work ensures EGI is compliant and fosters the safety of the public and the pipeline system.

Assets: Sudbury Section 1 Sturgeon River

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replace 800 metres of NPS 10, two road crossings and a river crossing.

Solution Impact: The Sudbury Section 1 line will be designed and installed to address the class location change in this area; this work ensures EGI is compliant to CSA Z662 and fosters the safety of the public and the pipeline system.

Resources: Engineering Construction will manage the planning and execution of this project.

Project Timing and Execution Risks: Cost estimates continue to be refined as project design progresses and approaches construction. Depending on the location of the work, the project might require temporary land rights acquisition and special permitting ahead of execution, which could have an impact to the project schedule.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Class Location Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

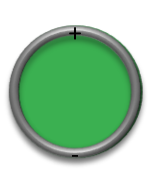
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_43 - Sudbury & S.S. Marie
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30 per cent SMYS. This work ensures EGI is compliant and fosters the safety of the public and the pipeline system.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Replacement	Recommended	$ (2,129,630)	0.00	$ 2,300,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,300,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,130)	100%
Total	**(2,130)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48670	**2021**	**5**

Investment Name

Windsor Line Replacement

Investment Description

Issue/Concern:
A significant portion of the Windsor Line was installed in the 1930s, 1940s, and 1950s. Although this pipeline one of the oldest operating assets within the Union rate zones, it is not age alone that is driving the need for replacement. There are many other factors related to its condition that are more relevant than its age in considering the need for replacement:
- History of leakage with significant costs to repair
- All joints prior to 2000s were made with unrestrained mechanical couplings; portions of the older vintage pipe are not weldable.
- Some sections of the line cannot be isolated because of inoperable mainline valves.
- The line has sections that have poor depth of cover with less than 0.6 meters.
- Sections of this pipeline are not located in easement.

Based on these concerns and the significant effort and resources spent already repairing leaks, the Windsor Line has been deemed an operational risk. To manage this risk, the line has been identified for replacement of those sections with the highest risk as identified above.

Assets:
Replacement of approximately 64 kilometres of the existing Windsor Line natural gas pipeline, (primarily a 10-inch diameter pipeline with some short sections of 8-inch pipeline), with a new 6-inch diameter pipeline.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: The proposed project will replace 61.4 kilometres of the existing Windsor 10” pipeline, and construct a new ~65-kilometres, 6” distribution line operating at a higher operating pressure, between Windsor and Port Alma, which is expected to be placed into service on November 1, 2020.

Resources:
OTC 2020 with external contractors

Solution Impact:
Main replacement project identified by Operations - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results.

Timing and Execution Risks:This confirmed the timing for execution of this replacement project for 2020. Risks: Moratoriums, third party developments, COVID-19 impacts, permitting and required easements.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - General Mains Replacement
Investment Stage	Executing		

Investment Overview

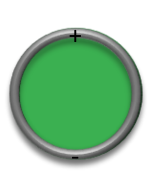
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_01 - Windsor
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (85,666,753)	0.00	$ 86,199,958	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 7,198,274	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ 1,920,518	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(85,667)	100%
Total	**(85,667)**	**100%**

Distribution Stations

ENBRIDGE Investment Summary Report	Investment Code: 101078	Report Start Year: 2021	Number of Years: 5
	Investment Name: HALT- Milton Gate, Milton, Boiler Replacement		

Investment Description

Issue/Concern/Opportunity:
Natural gas heating equipment is used in many stations across EGI to help mitigate failure of equipment due to the freezing of liquids in the gas stream as well as moisture that surrounds buried piping. Over the companies many years of operation, a variety of heating systems have been used resulting in many variations of equipment age, and the introduction of equipment obsolescence. This project includes ongoing maintenance to replace equipment that has reached end-of-life or has been deemed obsolete. This work will maintain system reliability, ensure operating costs for heating systems are minimized and reduce the potential for glycol spills. The heating system was identified during the Indirect Fire Heater assessment in 2019, and the recommendation was to replace the boilers. In addition, there are corrosion concerns of the station piping due to deteriorating/open piping insulation and there are heaving issues at this site.

Assets: Station #19X-301

Related Investments: N/A

Recommended Alternative Description

Scope of Work: Replace the aging heating system to improve efficiency and reduce operating costs of to mitigate the risk of equipment failures that could result in loss of customers and/or loss of glycol containment.

Solution Impact: Replacing the heating system at the station will mitigate safety risks to employees, contractors, and the general public.

Resources:Company crews, contractor labour and third party vendor suppliers

Project Timing and Execution Risk: Planning and execution in Year 1.
Execution Risk - Weather impacts, resource availability, procurement, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Distribution Stations - Gate, Feeder & A Stations
Investment Stage	Long Term Planning		

Investment Overview

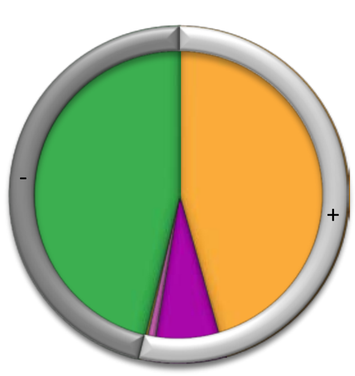
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_17 - Halton
	Asset Program (EGI)	DS - Gate, Feeder & A Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
replace Boilers	Recommended	$ (2,777,778)	0.00	$ 3,000,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,000,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Environmental Risk And Remediation	2,746	46%
Financial Risk	420	7%
Reputational Risk	52	1%
Operational Risk	21	0%
Employee And Contractor Safety Risk	0	0%
Public Safety Risk	0	0%
Total Investment Cost (CA)	(2,778)	46%
Total	**462**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49058	**2021**	**5**

Investment Name

WATE: Waterloo Gate Stn Rebuild, Waterloo, Growth

Investment Description

Issue/Concern:
The Waterloo Gate station configuration and condition of existing equipment is not functioning in a reliable manner.

- Pipe, Valves and Others: The filter condition requires replacement, the over pressure protection will be modified to include a monitor-operator setup, and the outlet piping requires upsizing.

- Heating System: The heating system requires an analysis and potential upsizing to meet the current station needs.

- Telemetry/Electrical: Reworking of electrical and additional heat trace to be investigated.

- Compliance/Civil: Access to the site can be improved.

Asset: Station # 19S-601

Related Program(s): N/A

Recommended Alternative Description

Scope of Work:
Build a brand new station behind existing station (ie. farther away from Fischer-Hallman).
Build the 9.S-147 new station (July-August 2021) with:
- Additional regulator run (3rd)
- All three regulator runs to be a monitor operator setup.
- Outlet piping increase from NPS 8 to NPS 10
- Inlet piping to stay current pipe size

To complete this, the following needs to occur:
- Install new 12” isolation valve on the HP inlet (potential that existing does not fit stopple or stopple train).
- Station needs to be on bypass during build of new station.
- Replace the existing filter.
- Potentially replace the heat exchanger (2012) but might be too small (evaluate during design).
- Abandon the 1900kPa cut leaving this station.
- Move the RTU and cabinet to the new station location.
- Move the boiler building with boilers to the new location.
- Move heat exchanger to new site – include concrete pad/support.
- Build new driveway along the side of the property.
- Trees along fence line of the property.

Solution Impact: Rebuilding the station will mitigate safety risks to employees, contractors, and the general public.

Resources: Engineering Construction will complete the construction. They have provided a feasibility level costing. In addition, the Integrity team has been asked to review whether the provision for the launcher and receiver should be built to a permanent launcher and receiver.

Project Timing and Execution Risks: N/A

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Distribution Stations - Station Rebuilds & B and C Stations
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_07 - Waterloo
	Asset Program (EGI)	DS - Station Rebuilds & B and C Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Full Station Rebuild	Recommended	$ (1,862,594)	0.00	$ 2,011,601	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,011,601	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
49058	2021	5

Investment Name

WATE: Waterloo Gate Stn Rebuild, Waterloo, Growth

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(1,863)	100%
Total	**(1,863)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48318	2021	5

Investment Name

WIND-03D-301 Leamington North Gate

Investment Description

Issue/Concern: The Gate and Feeder Station Replacement Program manages the proactive replacement of component groups with the highest probability of failure, non-compliant assets, and the realization of opportunities for multiple component group replacements per station location as required.

The Leamington North Gate station has obsolete heating equipment and there are two boilers (circa 1985) that are problematic and have experienced glycol containment issues. The boiler controls have malfunctioned several times over the last to years.

The station piping presents ergonomic concerns as some sections are at ankle height.

Justification: Rebuild part of the station at the existing site; build a new station at a new location (essentially breaking the station into two new stations).

Assets: 03D-301 Leamington North Gate

Related Programs: N/A

Recommended Alternative Description

Scope of Work: 03D-301 Leamington North Gate station will be rebuilt into two stations. One will be built at a new location, and the second will be rebuilt on the existing site. The existing site has several environmental concerns that will be addressed through the execution of this project. The break up of this station is necessary to provide adequate growth to the system; the station cannot be expanded upon due to location (residential neighbourhood) and property size. This is Phase 1 of the project which entails the removal of 420 kPa pipe cut from the existing station and building a new 420 kPa station at Mersea Road 3 and Morse Road. 1 kilometre of 12" 420 kPa pipe will also be installed to tie this new station into the existing 420 kPa network.

Resources: Alliance partners, company resources, and third-party vendor suppliers

Solution Impact: Relocating the station location will mitigate safety risks to employees, contractors, and the general public.

Project Timing and Execution Risk: Planning and execution in Year 1 (Planning Oct 2020 - March 2021; Construction June to August 2021) / Execution Risk - Weather impacts, resource availability, procurement issues, etc.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Distribution Stations - Gate, Feeder & A Stations
Investment Stage	Short Term Planning		

Investment Overview

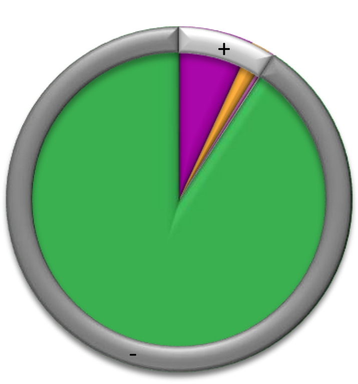
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_01 - Windsor
	Asset Program (EGI)	DS - Gate, Feeder & A Stations
	Asset Class (EGI)	Distribution Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (5,082,997)	0.00	$ 5,489,637	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 5,489,637	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Financial Risk	386	7%
Environmental Risk And Remediation	102	2%
Reputational Risk	23	0%
Employee And Contractor Safety Risk	4	0%
Operational Risk	2	0%
Public Safety Risk	0	0%
Total Investment Cost (CA)	(5,083)	91%
Total	**(4,566)**	**100%**

Compression Stations

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48715	2021	5
	Investment Name: Dawn Plant-C Compression Lifecycle		

Investment Description

Issue/Concern:
Dawn C Plant is one of the nine centrifugal compressors located at the Dawn Compressor Station. It is primarily used to lift from lower storage pressure levels, experienced later in the operations season, to intermediate pressure levels. The intermediate pressure level is typically elevated further in pressure by another compressor to reach the desired Dawn outlet pressure. Dawn Plant C and Plant D have a suction pressure rating of 195 psig, the lowest rating of the compressor fleet at Dawn. Considering the other compressors at Dawn have a 225 psig minimum inlet rating, Dawn Plants C and D become very critical when pool storage levels fall below 225 psig, as they typically do late in the operational season. Overall, compression can pose a very large consequence of failure as compressors are integral assets required to achieve the Dawn to Parkway Transmission System deliverability requirements throughout the year. The consequence of compressor failure is dominated by gas cost impacts to customers. Transmission System consequences associated with failure of a single compressor are heavily influenced by the time of year, weather severity and time to mitigate the failure. Siemens, the original equipment manufacturer (OEM) of the Dawn C compressor, has indicated that 40 years is the typical timeframe for supporting the supply of engine parts required to recover from a critical engine failure or to complete recommended overhauls. Dawn Plant C was installed in 1984, which indicates that the RB211- 24A engine in Plant C is reaching end-of-life.

Justification:
By continuing to comply with OEM-recommended Preventive Maintenance (PM) schedules and overhauls, compressor reliability risk is controlled to moderate levels but risk increases gradually over the 25,000-hour recommended interval between overhauls. Availability of parts is essential to repair internal engine failures and complete overhauls. Notably, the RB211-24A in Plant C has non-standard dimensions and cannot be retrofitted with more modern editions of the RB211 without significant plant retrofits. Similar to the 40-year old Dawn Plant B, which was replaced and retired in 2017 due to the risks associated with discontinued OEM support of critical engine parts, it is expected that Dawn Plant C will be exposed to a similar level of risk at the age of 40.

Assets: Dawn Plant C

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Removal and abandonment of the plant, associated piping and electrical, and remediation of land back to level grade. A new compression facility and its associated infrastructure will be developed and installed at the Dawn Compressor Station.

Work includes full project gating cycle due to scale and complexity including: stakeholder consultations, planning, detailed design, permit applications, environmental assessment. procurement, retaining a construction contractor, isolate system, demolition of structures/equipment to be replaced, erect buildings if required, prefabricating piping, hydrotesting, install new piping and auxiliary systems, NDE as required, coating, inspection, train staff, energize system, remediating site, and records updates.

Resources:
Consultant resources for design
Contractor resources for abandonment, construction and commissioning
Regulatory approval

Solution Impact:
This project will ensure the safe removal of infrastructure and the replacement of 32,000 hp of obsolete compression to support the storage to transmission requirements at Dawn.

Project Timing and Execution Risk:
Regulatory approval and planning - two years, abandonment and remediation 18 months.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Compression Stations - Replacements
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_53 - Union South Storage
	Asset Program (EGI)	CS - Replacements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1 - Direct Replacement	Recommended	$ (102,105,529)	0.00	$ 130,956,000	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 16,212,000	$ 69,636,000	$ 40,908,000	$ 4,200,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48715	2021	5
	Investment Name		
	Dawn Plant-C Compression Lifecycle		

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(102,106)	100%
Total	**(102,106)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48732	**2021**	**5**

Investment Name

Waubuno Compression Lifecycle

Investment Description

Issue/Concern/Opportunity: The Waubuno compressor elevates available pipeline pressure to the Waubuno Pool MOP. Compression increases the working inventory value of the pool by approximately $2.2 million (at $0.75 per GJ) based on top of what the pipeline alone can achieve. The compressor is operated approximately 45 days per year in late summer to early fall to top off the pool. The consequence of compressor failure is dominated by customer impact. Risk associated with failure of the Waubuno compressor is heavily influenced by the level of the pool at which the failure occurs and time to mitigate the failure.

The Joy Compressor (manufactured in 1985) was a used compressor package and installed at Waubuno in 1988. The Joy Compressor Company changed ownership approximately 20 years ago whereupon original equipment manufacturer (OEM) support for the compressor was discontinued. Although normal wear components are still available in the marketplace, replacement major compressor items such as cylinders, crankshafts, and rods, etc., required to support a critical failure are no longer available. In the event of a critical failure, sourcing used parts (which are rare) or aftermarket custom machining services would be the only options for repair. This was the case in 2007 when a discharge valve seat failed, resulting in catastrophic damage to cylinder 611. An extensive search across the used parts dealers was required to secure a viable used cylinder head. Other internal damage was repaired through custom machining services.

Justification: In the event of a future failure, if useable parts or custom machining are not available, the two options would be custom-designed aftermarket castings (if possible) or replacement of the entire compressor. However, both options would render the compression out of service for at least one operational season.

Assets: Waubuno Compressor

Related Programs: N/A

Recommended Alternative Description

Scope of Work: This project includes constructing 6.5 kilometres of NPS 16 wil between the Waubuno pool measurement station and the Bluewater, Airport, & Mandaumin NPS16 pipeline. The high-pressue pipe links Waubuno directly to Dawn compression. This results in increased operational flexibility, reduced cycle time and increased reliability.

Resources:
Consultant resources for design
Contractor resources for abandonment, construction and commissioning

Solution Impact:
New pipeline designed to meet injection requirements provided by compression.

Project Timing and Execution Risk:
This project requires two years of design, procurement, and construction and requires an environmental assessment and regulatory approval.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Compression Stations - Replacements
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_53 - Union South Storage
	Asset Program (EGI)	CS - Replacements
	Asset Class (EGI)	Compression Stations
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
NPS 16 Pipeline	Recommended	$ (6,150,055)	0.35	$ 12,889,800	1/1/2023

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ 867,043	$ 11,540,651	$ 482,106
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48732	**2021**	**5**

Investment Name

Waubuno Compression Lifecycle

Alternative Value - Recommended

	Value Function Measure	Value	Value in Percentage
	Financial Risk	14,015	52%
	Revenue Impact (CA)	3,349	12%
	Cost Avoidance CAPEX (CA)	0	0%
	Cost Avoidance OPEX (CA)	0	0%
	Budget Savings CAPEX (CA)	0	0%
	Budget Savings OPEX (CA)	0	0%
	Total Investment Cost (CA)	(9,499)	35%
	Total	**7,865**	**100%**

Transmission Pipe and Underground Storage

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48654	**2021**	**5**

Investment Name

Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)

Investment Description

Issue/Concern:
Incremental capacity is required on the Dawn Parkway System to meet in-franchise growth and customer demand bids received in the 2021/2022 Dawn Parkway Open Season from December 2018. All incremental demand bids are for 15 year terms with start dates of both November 1, 2021 and 2022.

This is an ICM-eligible project.

Assets: Dawn Parkway System Transmission Pipeline

Related Program(s): N/A

Recommended Alternative Description

Scope of Work: System Install approximately 10.2 kilometres of NPS 48 internally coated pipeline from Kirkwall Valve Site (17V-302) to Hamilton Valve Site (18W-601V) on the Dawn Parkway System.

Solution Impact: Capacity is available on the Dawn Parkway System to meet in-franchise growth and customer demand.

Resources: Projects group to provide project management support from design & planning phase to project execution.

Timing and Execution Risks:
-Proposal is based on Class 4 level cost estimates. There is risk that actual capital costs could exceed the estimate.
-Schedule delays due to right of way access for survey, environmental studies, permitting, and/or issuance of OEB Leave to Construct may put at risk the planned in-service date.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_16 - Hamilton
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (155,052,376)	0.00	$ 181,707,580	1/1/2018

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 171,097,289	$ 4,973,539	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(155,052)	100%
Total	**(155,052)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48257	2021	5
	Investment Name: INTE: Dawn - Cuthbert - ECDA to ILI Retrofit NPS 42, 34, 26		

Investment Description

Issue/Concern:
General concern: The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of EGI's pipeline systems to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30 per cent SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, repair and replacement of pipeline segments with integrity issues that are identified through the inspections.

Project-specific concern: The NPS 42, NPS 34, NPS 26 pipelines between Dawn Compressor station and Cuthbert Road receiver site has been inspected using external corrosion direct assessment (ECDA). Although it meets the intent of the TIMP, there are specific features that ECDA could not detect comparing to the inline inspection. ILI of these transmission lines are required to ensure continued safety and reliability of EGI's assets.

Assets: Transmission Pipeline (NPS 42, NPS 34, NPS 26 pipelines between Dawn Compressor station and Cuthbert Road receiver site)

Related Programs: Transmission Integrity Management Program (TIMP)

Recommended Alternative Description

Scope of Work: This project involves the replacement and conversion of transmission pipelines, so that they can be inline inspected between Trafalgar Valve Nest (TVN) at Dawn and the Cuthbert Measurement site.

Solution Impact: This project will enable the transmission pipelines between Dawn and Cuthbert to be in-line inspected to assess their condition.

Resources: Projects group to provide project management support from design and planning phase to project execution

Project Timing and Execution Risks: The projected in-service date for this project is in 2022.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage- Integrity
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_53 - Union South Storage
	Asset Program (EGI)	TPS - Integrity
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Required as per CSA Z662. (Sections 3.2, 10.3) and stipulated through EGD standards as listed in Integrity Manual Section 4.2.6.1.10 In-Line Inspection Re-Inspection Interval.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (21,559,122)	0.00	$ 24,600,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 1,000,000	$ 23,600,000	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(21,559)	100%
Total	**(21,559)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100086	**2021**	**5**

Investment Name

Panhandle Line Replacement

Investment Description

Issue/Concern:
EGI's Integrity Management team initiated work in 2019 to better understand the risk associated with the two NPS12 crossings that connect the Panhandle Eastern System owned and operated by Energy Transfer in Michigan with the EGI system in Ontario. These two crossings, installed in 1947, have never been inspected internally to provide direct assessment of the asset and to check for the presence of the primary threat of corrosion. A risk assessment was recently completed for the river crossings. The Risk Owner and Risk Approver reviewed the risk results and have decided the risk requires treatment with a permanent solution.

Assets: Transmission Pipeline (CER regulated crossing)

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replacement of the twin NPS 12 Crossings with a new NPS 20 pipeline.

Resources: Projects group to provide project management support from design & planning phase to project execution.

Solution Impact: The principal risk is the lack of ILI data needed to inform effective decision-making to mitigate a potential loss of pipeline containment (leak). Replacement with a new single pipeline, designed, manufactured and constructed to current standards that is ILI-capable can address this risk.

Project Timing and Execution Risk: In-service date is estimated to be Q3 2023. Overall project schedule highly dependent on regulatory process and discussion with joint partner (Energy Transfer).

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Replacements
Investment Stage	Short Term Planning		

Investment Overview

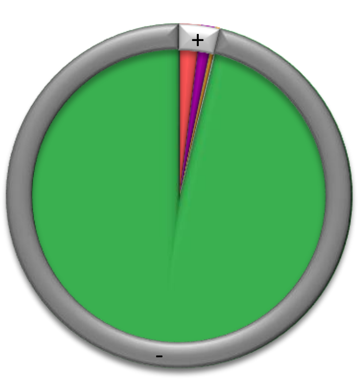
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_01 - Windsor
	Asset Program (EGI)	TPS - Replacements
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	Yes
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 2 - Replacement	Recommended	$ (23,536,717)	0.00	$ 29,771,279	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 1,619,900	$ 24,757,660	$ 3,393,719	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Operational Disruption Risk (Gas) (CA)	481	2%
Financial Risk	311	1%
Environmental Risk And Remediation	104	0%
Reputational Risk	45	0%
Public Safety Risk	0	0%
Employee And Contractor Safety Risk	0	0%
Total Investment Cost (CA)	(23,537)	96%
Total	**(22,595)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48658	**2021**	**5**

Investment Name

Sarnia Expansion - Bluewater Energy Park (Asset #1)

Investment Description

Issue/Concern:
EGI is forecasting 150 TJ/d of firm transportation growth primarily driven by industrial demand in Sarnia and surrounding areas requiring incremental Sarnia Industrial Line (SIL)System capacity.

Assets: SIL System Transmission Pipeline

Related Programs: 48659, 48660

Recommended Alternative Description

Scope of Work:
-Installation of ~7 kilometres of NPS 24/30 pipeline from existing LaSalle Pipeline Valve Site to Churchill Road Station (13F-503).
-Installation NPS 20 pipeline to a new multi-customer valve site in Bluewater Energy Park.

Resources: Projects group to provide project management support from design and planning phase to project execution.

Solution Impact:
Facilities will allow the SIL System to efficiently serve ~150 TJ/d demand and provide security of supply for the SIL System.

Project Timing and Execution Risks:
-Proposal is based on Class 5 level cost estimates. There is risk that actual capital costs could exceed the estimate.
-Schedule delays due to right of way access for survey, environmental studies, permitting, and/or issuance of an OEB Leave to Construct may put the planned in-service date at risk.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Long Term Planning		

Investment Overview

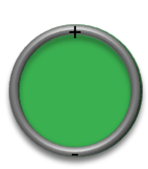
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (47,468,659)	0.00	$ 64,568,088	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 281,562	$ 281,562	$ 2,377,968	$ 58,606,438	$ 2,940,670
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(47,469)	100%
Total	**(47,469)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48660	2021	5

Investment Name

Sarnia Expansion - Bluewater Energy Park (Asset #2)

Investment Description

Issue/Concern:
EGI is forecasting 150 TJ/d of firm transportation growth primarily driven by industrial demand in Sarnia and surrounding areas requiring incremental Sarnia Industrial Line (SIL) System capacity.

Assets: SIL System Transmission pipeline

Related Programs: 48658, 48659

Recommended Alternative Description

Scope of Work:
Requires 1.5 kilometres of NPS 24 Pipeline between the Dawn Hub & SIL System.

Solution Impact:
Facilities will allow the SIL System to efficiently serve ~150 TJ/d demand and provide security of supply for the SIL System.

Resources: Projects group to provide project management support from design and planning phase to project execution.

Project Timing and Execution Risks:
-Proposal is based on Class 5 level cost estimates. There is risk that actual capital costs could exceed the estimate.
-Schedule delays due to right of way access for survey, environmental studies, permitting, and/or issuance of an OEB Leave to Construct may put the planned in-service date at risk.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (25,113,150)	0.00	$ 34,000,000	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 500,000	$ 1,500,000	$ 31,500,000	$ 500,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(25,113)	100%
Total	**(25,113)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48659	2021	5

Investment Name

Sarnia Expansion - Bluewater Energy Park (Customer Station)

Investment Description

Issue/Concern:
EGI is forecasting 150 TJ/d of firm transportation growth primarily driven by industrial demand in Sarnia and surrounding areas requiring incremental Sarnia Industrial Line (SIL) System capacity.

Assets: Transmission Pipeline

Related Programs: 48658, 48660

Recommended Alternative Description

Scope:
Install a new NPS 16 service line with a new customer station.

Solution Impact:
Facilities will allow the SIL System to efficiently serve ~150 TJ/d demand.

Resources: Projects group to provide project management support from design and planning phase to project execution.

Project Timing and Execution Risks: Proposal is based on Class 5 level cost estimates. There is a risk that actual capital costs could exceed the estimate. Schedule delays due to right of way access for survey, environmental studies, permitting, and/or issuance of an OEB Leave to Construct may put the planned in-service date of Nov ember1, 2021 at risk.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Long Term Planning		

Investment Overview

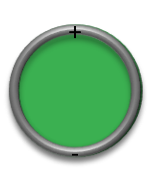
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_03 - Sarnia
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (8,599,463)	0.00	$ 11,730,139	1/1/2022

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ 10,110	$ 31,853	$ 11,217,088	$ 471,088
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(8,599)	100%
Total	**(8,599)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48661	2021	5

Investment Name

Sarnia Expansion (Novacor Stn)

Investment Description

Issue/Concern:
Enbridge Gas is forecasting 61.4 TJ/d of firm transportation growth primarily driven by industrial demand in Sarnia and surrounding areas to serve NOVA Chemicals (Canada) T2 growth for a November 1, 2021 in-service date.

Assets: Transmission Pipeline - customer station

Related Programs: 48657

Recommended Alternative Description

Scope of Work:
1.Novacor Corunna customer station modifications (12F-203I)
2.Novacor Corunna station modifications (12F-203)

Resources:
Projects group to provide project management support from design and planning phase to project execution.

Solution Impact:
Facilities will allow the Sarnia Industrial Line System to efficiently serve NOVA Chemicals (Canada) T2 growth (~61.3 TJ/d) demand for a November 1, 2021 ISD.

Project Timing and Execution Risks:
-Proposal is based on Class 4 level cost estimates. There is risk that actual capital costs could exceed the estimate.
-Schedule delays due to right of way access for survey, environmental studies, permitting, and/or issuance of OEB Leave to Construct may put at risk the planned in-service date of November 1, 2021.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (6,035,064)	0.00	$ 6,515,656	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 6,421,822	$ 34,357	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(6,035)	100%
Total	**(6,035)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48657	**2021**	**5**

Investment Name

Sarnia Expansion (NPS 20 Dow to Bluewater)

Investment Description

Issue/Concern:
EGI is forecasting 61.4 TJ/d of firm transportation growth primarily driven by industrial demand in Sarnia and surrounding areas to serve NOVA Chemicals (Canada) T2 growth for a November 1, 2021 in-service date requiring incremental Sarnia Industrial Line (SIL) system capacity.

This is an ICM-eligible project.

Assets: Transmission Pipeline

Related Programs: 48661

Recommended Alternative Description

Scope of Work: One NPS 20 pipeline reinforcement from existing Dow valve site (13F-501V) to existing Bluewater / Union Interconnect valve site (13F-502V)

Solution Impact:
Facilities will allow the SIL System to efficiently serve NOVA Chemicals (Canada) T2 growth (~61.3 TJ/d) demand for a November 1, 2021 in-service date.

Resources:
Projects group to provide project management support from the design and planning phase to project execution.

Project Timing and Execution Risks:
- Proposal is based on Class 4 level cost estimates. There is risk that actual capital costs could exceed the estimate.
- Schedule delays due to right of way access for survey, environmental studies, permitting, and/or issuance of an OEB Leave to Construct may put the planned in-service date of November 1, 2021 at risk.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Executing		

Investment Overview

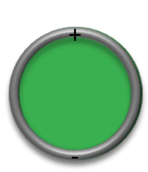
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (18,987,323)	0.00	$ 20,480,786	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 18,161,923	$ 1,038,370	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(18,987)	100%
Total	**(18,987)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48215	**2021**	**5**
	Investment Name: Trafalgar 26 - Branchton Class Location Replacement		

Investment Description

Issue/Concern:
General: Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30 per cent SMYS. Any changes in class location need to be assessed to the current standard to determine if pipeline modifications are required. This program replaces segements of pipelines with identified Class Location Change.

Project Specific: Replacement of 1.8 kilometres of NPS 26 pipe including pipe under Branchton Road (Regional Road 43).

Assets: 1.8 kilometres of NPS 26 pipe

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replace 1.8 kilometres of NPS 26 pipe.

Solution Impact: Remediate class location issue of the NPS 26 Dawn-Parkway transmission line near Branchton.

Resources: Engineering Construction group to provide project management support from design and planning phase to project execution

Timing and Execution Risks:
-Proposal is based on Class 5 level cost estimates. There is risk that actual capital costs could exceed the estimate.
-The Leave to Construct application and land right acquisition could have timing implications.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Replacements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	TPS - Replacements
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1: Replace class location segment	Recommended	$ (8,115,787)	0.00	$ 8,645,836	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 7,155,661	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(8,116)	100%
Total	**(8,116)**	**100%**

Real Estate and Workplace Services

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48606	2021	5
	Investment Name: 50 Keil Old 2nd Floor Renovations		

Investment Description

Issue/Concern: The 50 Keil facility is an owned facility that is currently undergoing renovations to address the physical condition and capacity concerns as well as to replace legacy furniture and finishings.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 12.91%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0%. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 11% which is considered correctable at the current location, without consideration of other factors including adequacy of land size and the FCI.

Functional Obsolescence – Site: N/A

Asset: 50 Keil Drive, Chatham, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work: The project corrects physical and functional deficiencies on the 2nd floor of the old tower by renovating and renewing the existing space. Renovations to the floor will correct operational and workplace inefficiencies, using less energy and emitting less greenhouse gases.

Solution Impact: The interior renovation will extend the asset useful life by 10 to 15 years.

Timing: The total project duration is 12 months and broken down as follows:
0 – 2 months: Programming and design development
2 – 3 months: Permit and tender documents
3 – 5 months: Award, permit and tender process
5 – 10 months: Construction
10 – 12 months: Fit-up and occupancy

Expenditures: The total cost for the project is $4.7 M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values are determined using marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources : External professional resources for design and engineering along with a construction company will be contracted for the Project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

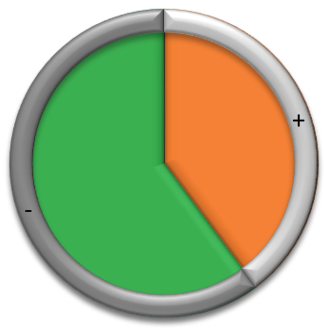
Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (1,471,316)	0.66	$ 4,700,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 4,700,000	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48606	2021	5
	Investment Name: 50 Keil Old 2nd Floor Renovations		

Alternative Value - Recommended



	Value Function Measure	Value	Value in Percentage
	Cost Avoidance OPEX (CA)	2,881	40%
	Cost Avoidance CAPEX (CA)	0	0%
	Budget Savings CAPEX (CA)	0	0%
	Budget Savings OPEX (CA)	0	0%
	Revenue Impact (CA)	0	0%
	Total Investment Cost (CA)	(4,352)	60%
	Total	**(1,471)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48607	2021	5

Investment Name

50 Keil Old 3rd Floor Renovation

Investment Description

Issue/Concern: The 50 Keil facility is an owned facility that is currently undergoing renovations to address the physical condition and capacity concerns as well as to replace legacy furniture and finishings.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 12.91%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0%. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 11% which is considered correctable at the current location, without consideration of other factors including adequacy of land size and the FCI.

Functional Obsolescence – Site: N/A

Asset: 3rd floor, 50 Keil Drive, Chatham, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work: The project corrects physical and functional deficiencies on the third floor of the old tower by renovating and renewing the existing space. Renovations to the floor will correct operational and workplace inefficiencies, using less energy and emitting less greenhouse gases.

Solution Impact: The interior renovation will extend the asset useful life by 10 to 15 years.

Timing: The total project duration is 12 months and broken down as follows:
0 – 2 months: Programming and design development
2 – 3 months: Permit and tender documents
3 – 5 months: Award, permit and tender process
5 – 10 months: Construction
10 – 12 months: Fit-up and occupancy

Expenditures: The total cost for the project is $4.7 M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values are determined using marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources : External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

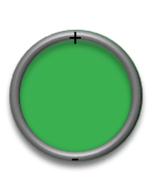
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (7,186,343)	0.00	$ 7,537,250	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 4,737,250	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(7,186)	100%
Total	**(7,186)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	48693	2021	5
	Investment Name: CS-Belleville PropertyPurch&En*C/O 2019*		

Investment Description

Issue/Concern:
The Belleville Operations Centre is located at 127 Enterprise Drive in Belleville, Ontario in a location that adequately services the Belleville market. The age of the building is not known as it is a leased facility. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.
In 2016, an operational performance assessment was conducted by EGI personnel which identified several deficiencies in the existing facility including but not limited to the inappropriate amount of space, inadequate storage, meeting space and site security, and legacy environmental concerns regarding water quality. The review also found the building to be deficient in several building code and life safety requirements.

Physical Obsolescence: The acceptable EGI standard for physical condition is a Facility Condition Index (FCI) score of 0% to 5%. An FCI score is not available for this facility. However, the physical condition of the facility does not meet EGI standards and is not considered correctable at this location as it is leased space.

Functional Obsolescence - Building: The acceptable EGI standard for functional condition is 0%. Anything between 0% and 50% is considered correctable at the current location. An AI score is not available for this facility. Based on the review, the building does not meet the functional requirements of the business and the conditions are not considered correctable at the current location as it is leased space.

Functional Obsolescence - Site: The site size is unknown. However, the site does not provide adequate traffic control, storage or security. These conditions are not considered correctable at the current location as it is leased space.

Furniture: Legacy furniture (20+ years old) does not meet EGI's current condition standards. At this facility, 53% of the furnishings are considered legacy and therefore not compliant with current standards.
The building and site deficiencies are numerous, and considered not correctable at this location due to the fact that this is a leased property.

Assets: Belleville Operations Centre located at 127 Enterprise Drive in Belleville, Ontario.

Related Programs: N/A

Recommended Alternative Description

Scope of Work:
Vacate current leased facility, purchase new property in Belleville (four acres) and build a new facility on the new site.

Resources: Company crews, contractor labour, and third-party vendor suppliers.

Solution Impact:
There are a number of consequences to EGI if the deficiencies at Belleville are not corrected. These include but are not limited to:
• Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
• Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
• Inadequate functionality resulting in productivity challenges for staff and visitors.

Timing and Execution Risks:
The Project duration is 36 months:
0 – 3 months: Programming, design development
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit and tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
30 – 36 months: Disposition of old property

Risks include contractor delays and material delivery delays or defects, weather impacts, resource availability, procurement issues, etc.

Expenditures:
The total cost for the project is $7.5 M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and estimated land values are based on marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48693	**2021**	**5**

Investment Name

CS-Belleville PropertyPurch&En*C/O 2019*

Investment Overview

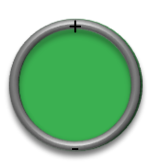
1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (6,993,599)	0.00	$ 7,500,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 5,833,333	$ 520,833	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(6,994)	100%
Total	**(6,994)**	**100%**

ENBRIDGE Investment Summary Report	Investment Code 100492	Report Start Year 2021	Number of Years 5
	Investment Name: Dryden Operations Centre		

Investment Description

Issue/Concern: The administrative office in Dryden is an owned property that is in physically good condition, but does not meet current building standards or operational requirements. The physical condition is considered poor and the utilization and functionality is challenged. The office space no longer sufficiently accommodates current and future staffing needs of the facility.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 11.33%. Therefore, the physical condition of the facility does not meet EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 87%.

Functional Obsolescence – Site: The site is serviced by one driveway off Kennedy Road. There is no separation of staff parking, visitor parking or yard. This is considered a safety and operational challenge. No trucks or fleet vehicles were observed parking in the yard. No pipe racks were observed. A material storage building is located to the south of the main building.
The following programmatic and functional deficiencies were observed during the walkthrough:
- There is no secure yard separated from staff and visitor parking.
- There is no site security present, including site fencing, access gates, yard perimeter lighting and security cameras.
- The yard storage is inadequate. Specifically, there are no aggregate storage bins or pipe racks.
- No parking spaces or other lines are marked on the pavement.

The following specific design principles were not met:
- Trucks, fleet vehicles, staff, and visitors enter and exit through one driveway.
- Sidewalks are narrow and unevenly paved.

Asset: 304 Kennedy Road, Dryden, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work: The preferred strategy is to purchase a new property in Dryden (approximately five acres) and build new facility on a new site.
The current facility and yard are too small for the district's current business needs with no room for expansion or growth. The site has inefficient access, configuration and does not meet the current EGI standards.

The assets in scope are located at 304 Kennedy Road, Dryden, ON. The nature of work for the project includes the purchase of a greenfield property approximately five acres, sell the existing and build a new facility to meet the business requirements.

The Project duration is 24 months as described below:
0 – 3 months: Land purchase, Programming and design development
3 – 9 months: Site plan agreement, permit and tender documents
9 – 12 months: Permit and tender process
2 – 14 months: Contract award and contingency as required
14 – 22 months: Construction
22– 24 months: Fit-up and occupancy

Risks include contractor delays and material delivery delays or defects.

Expenditures:
The total cost for the project is $4.6M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI projects. The project also leverages national pricing agreements with furniture, walls and flooring manufacturers. The project costs are based on a Class 4 estimate.

Resources
Professional resources for design and engineering will be contracted from the marketplace. Historically, EGI has retained architectural and engineering consulting services for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_33 - Thunder Bay
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100492	2021	5

Investment Name

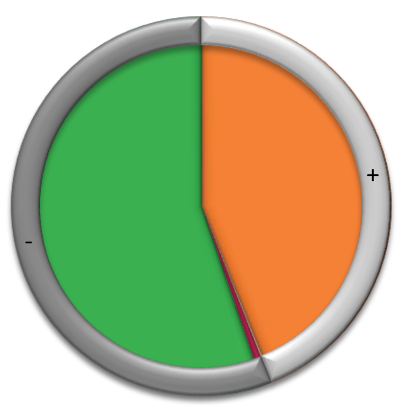
Dryden Operations Centre

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (726,942)	0.80	$ 3,850,000	1/1/2020

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,000,000	$ 500,000	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	2,830	44%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Avoided GHG Emissions (CA)	(8)	0%
Energy Efficiency (CA)	(47)	1%
Total Investment Cost (CA)	(3,556)	55%
Total	**(781)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
101136	**2021**	**5**

Investment Name

New Site No. 4

Investment Description

This project will allow for potential consolidation currently under review of four operational sites in the Union rate zones into a single facility.
Boundary analysis still ongoing and investment details will continually be updated as strategy progresses.

Functional Obsolescence – Building: N/A

Functional Obsolescence – Site: N/A

Assets: N/A

Related Program: N/A

Recommended Alternative Description

Scope of Work:
This project requires selling existing assets, purchasing a property suitable in size (approx. 7-10 acres) and building a new 44,000 sq. ft. building that will consist of administration, warehouse, welding and fabrication facilities. The preferred strategy is to correct physical and functional deficiencies by purchasing a new site and build a new facility on the new site.

Solution Impact: This option corrects operational and workplace inefficiencies by consolidating existing facilities. The new facility will use less energy and emit less greenhouse gases. The service life for the new facility will be 25-40 years.

Timing: The total project duration is 30 months:
0 – 3 months: Programming, design development, location analysis
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit and tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
Post-occupancy disposition of property

Risks include contractor delays and material delivery delays or defects.

Expenditures:
The total cost for the project is $28.8M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values using marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_46 - North Bay & Orillia
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (19,338,724)	0.22	$ 28,800,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 10,000,000	$ 10,000,000	$ 8,800,000	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

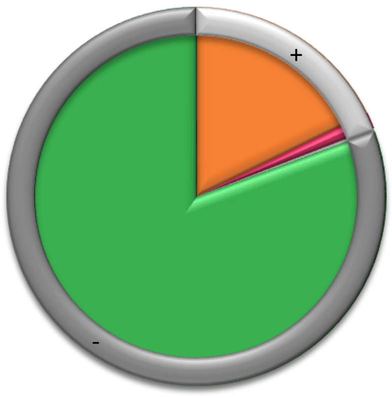
Investment Summary Report

Investment Code	Report Start Year	Number of Years
101136	**2021**	**5**

Investment Name

New Site No. 4

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	5,480	18%
Energy Efficiency (CA)	423	1%
Avoided GHG Emissions (CA)	69	0%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(24,818)	81%
Total	**(18,847)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
100607	2021	5

Investment Name

Thunder Bay Regional Operations Centre

Investment Description

Issue/Concern: The Thunder Bay depot on Amber Drive is an owned property in a good location. The physical and functional conditions of the building are considered good, but the utilization and functionality of the site is challenged.

Physical Obsolescence: The acceptable EGI standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 2.57%. Therefore, the physical condition of the facility meets EGI acceptable standards.

Functional Obsolescence – Building: The acceptable EGI standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 41%.

Functional Obsolescence – Site: The yard is smaller than EGI standard (2.5 acres), at approximately 1.86 acres. The building is serviced by a main entrance off Amber Drive through a circular drop off-area that leads to visitor and staff parking. An appropriate landscape buffer has been provided between the parking areas and building. The main entrance to the yard is provided off Amber Drive, with a power accessed gate. A chain-link fence meeting EGI's standard height requirements surrounds the perimeter of the yard. A secondary site entrance is provided through a northern driveway that leads to additional parking and yard access, with gates at the northern and southern boundaries. Pedestrian entries/exits are provided at the southern gate. Surveillance, security, storage and safety items located on the site all were observed to be in good condition and meet current EGI standards.

Asset: 1211 Amber Drive, Thunder Bay, ON.

Related Program: N/A

Recommended Alternative Description

Scope of Work: Correct physical and functional deficiencies by renovating the existing facility.
The renovation will ensure adequate interior storage/warehouse space for operations, operations meeting space, washroom/locker facilities appropriately fitted for the operation, and a new office environment for staff at site. The program will include currently missing elements such as a boot wash with washer/dryer, mustering area, hoteling, and gas monitor calibration facilities. This new facility will correct operational and workplace inefficiencies, using less energy and emitting less greenhouse gases.

Solution Impact: The renovation will extend the asset useful life by 15 years.

Timing: The Project duration is 12 months as described below:
0 – 2 months: Programming and design development
2 – 5 months: Permit and tender documents
5 – 7 months: Award, tender and permit process
7 – 11 months: Construction
11 – 12 months: Fit-up and occupancy

Risks include contractor delays and material delivery delays or defects.

Expenditures:Total capital expenditure for this project is estimated to be $10.2M which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. Project costs are based on a Class 5 estimate.

Resources: Professional resources for design and engineering will be contracted from the marketplace. Historically, EGI has retained architectural and engineering consulting services for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_33 - Thunder Bay
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (3,038,944)	0.56	$ 10,200,000	1/1/2024

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ -	$ 600,000	$ 9,600,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

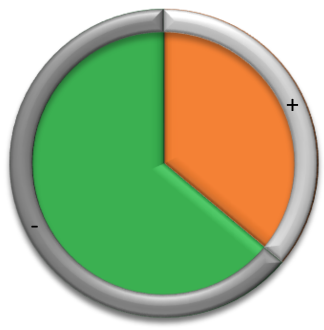
Investment Summary Report

Investment Code	Report Start Year	Number of Years
100607	2021	5

Investment Name

Thunder Bay Regional Operations Centre

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	3,936	36%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(6,975)	64%
Total	**(3,039)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
102392	2021	5

Investment Name

Union Rate Zones Micro Operations Sites Program

Investment Description

Issue/Concern:
The 16 Micro Operations Sites Program covers consist of 15 owned and one leased property. The sites are in aging physical condition, and due to their advanced age, do not meet required functionality. The properties are on average over 50 years old. The physical condition of the facilities does not meet EGI acceptable standards.

Generally, deficiencies are considered correctable at the current locations, without consideration of other factors including adequacy of land size and the Facilities Condition Index (FCI). Generally, the existing buildings are too small to meet current requirements. The undersized spaces, lack of proper locker/washroom, warehouse and fabrication areas are not sufficient for staff and cause operational and workplace difficulties and inefficiencies. Building expansions on the same property may further reduce the size of yard area, making it unusable and will impose additional pressure on parking and circulation.

Assets:
Micro Operations sites in Bracebridge, Haileybury, Huntsville, Iroquois Falls, Black River, Elliot Lake, Parry Sound, Atikokan, Kirkland Lake, Kapuskasing, Hearst, Geraldton, Englehart, Cochrane, Palmerston and Nipigon.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: The project corrects physical and functional deficiencies of the 16 properties by renovating and renewing the existing space. The current site has capacity to meet EGI functional requirements. Renovations to the buildings will correct operational and workplace inefficiencies, using less energy and emitting less greenhouse gases.

Solution Impact: The interior renovation will extend the asset useful life by 10 to 15 years.

Timing: The total project duration is 60 months and is recurring.

Expenditures: The total cost for the project is $10M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGI project costs and land values are determined using marketplace comparisons. The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources : External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Real Estate & Workplace Services - Furniture/Structures & Improvements
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	REWS - Furniture/Structures & Improvements
	Asset Class (EGI)	Real Estate & Workplace Services
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Default Alternative	Recommended	$ 14,494,855	2.82	$ 10,000,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 2,000,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE

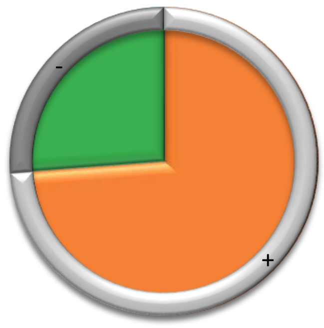
Investment Summary Report

Investment Code	Report Start Year	Number of Years
102392	**2021**	**5**

Investment Name

Union Rate Zones Micro Operations Sites Program

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	22,480	74%
Cost Avoidance CAPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(7,985)	26%
Total	**14,495**	**100%**

Fleet and Equipment

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
102181	2021	5

Investment Name

2021 - OS - Heavy Work Equipment

Investment Description

Issue/concern: In the Union rate zones, heavy work equipment units which are much older and worn need to be replaced. Individual equipment is assessed using the Fleet Flagship Replace application.

Asset: Various Heavy Duty Equipment assets.

Related Program: N/A

Recommended Alternative Description

Scope of work: This project provides EGI with the necessary heavy work equipment to safely and efficiently run business operations in the Union rate zones. The goal is to maintain the integrity of all heavy work equipment assets for safe and reliable operation. To help achieve this goal, the Fleet department utilizes financial cost, risk analysis, and physical assessment information to drive replacement decisions. As the equipment ages and exceeds its useful life threshold, it can become an operational safety concern. Additionally, there are increases in maintenance costs and operational downtime which affects overall productivity.

Resources: Fleet and Equipment staff

Solution Impact: The fleet management analytical software tool Flagship Replace is used to make informed replacement decisions for rolling equipment such as backhoes. Replacement decisions for non-rolling equipment (i.e. welders) are primarily based on age, hour meter, and physical condition. Once heavy equipment assets reach an age of 10 years, a physical assessment is conducted to evaluate the equipment. A comparison of the maintenance history is used to determine refurbish or replace decisions.

Project Timing and Execution risks: Assets are ordered in January or February of the fiscal year and delivered by December 31.
Risk - delivery of assets not met by the December 31 deadline.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Fleet & Equipment - Equipment & Materials
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	FLEET - Equipment & Materials
	Asset Class (EGI)	Fleet & Equipment
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	Yes

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (2,827,407)	0.00	$ 3,053,600	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 3,053,600	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(2,827)	100%
Total	**(2,827)**	**100%**

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
102060	2021	5

Investment Name

2021 - OS - Transportation-Replacements

Investment Description

Issue/Concern: In the Union rate zones, light and medium duty vehicles are required to replace existing vehicles that are in poor operating condition.

Asset: Light-duty vehicles and medium-duty vehicles.

Related Program: N/A

Recommended Alternative Description

Scope of work: This project provides EGI with the necessary fleet vehicles to safely and efficiently run its business operations in the Union rate zones. The goal of the project is to maintain the integrity of all fleet assets for safe and reliable operation. This ongoing replacement strategy optimizes the asset life cycle, improves safety, and reduces risk for EGI and its employees. To help achieve this goal, Fleet utilizes financial cost analysis, risk analysis, and physical asset assessment to guide replacement decisions.

Resources: Fleet and Equipment staff

Solution Impact: In order to replace aging fleet assets, a report is generated by the fleet management analytical software tool which uses raw fleet data to identify all vehicles meeting the replacement criteria. The direct impact is reduced O&M repair and maintenance costs, and improved driver safety.

Project Timing and Execution risks: Assets are ordered in January or February of fiscal year and delivered by December 31.
Risk - delivery of assets not met by the December 31 deadline.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Fleet & Equipment - Vehicles
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	FLEET - Vehicles
	Asset Class (EGI)	Fleet & Equipment
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	Yes

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (4,580,000)	0.00	$ 4,946,400	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 4,946,400	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(4,580)	100%
Total	**(4,580)**	**100%**

Technology and Information Services

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
102292	2021	5

Investment Name

Nominations Application Replacement (2024-2025)

Investment Description

Issue/Concern/Opportunity:
The Classification, Allocation, Reporting and Exchange (CARE) application is ~25 years old. To mitigate risk of failure and to ensure it is on a supportable technology platform, a replacement/modernization project needs to be initiated.
The CARE application is EGI's gas nominations and scheduling system. It processes both incoming nominations:
- EGI as a service provider to various customer groups and outgoing nominations
- EGI as a shipper on upstream pipelines to bring gas supply to Ontario

CARE checks all nominations against the related contract parameters to ensure the validity of each nomination as well as ensuring that EGI's system is balanced every gas day. CARE supports NAESB nomination cycles, TCPL STS nomination cycles, and EGI proprietary F24 (firm reserved) nomination cycles. Aggregated scheduled customer nominations are provided to Gas Control at each nomination cycle as a key input to the physical operation of the gas system. CARE also facilitates daily and monthly customer reporting as well as various month end accounting processes such as gas supply invoice verification, wholesale customer billing and gas inventory reconciliation. The CARE application supports both the in-franchise and ex-franchise wholesale business (large contract rate distribution, direct purchase and Storage and Transportation customers) and is deemed the system of record for all gas inventories owned by EGI and third parties. Every molecule of gas that enters or leaves the system, whether owned by EGI or others, is accounted for in CARE on a volumetric basis.
Additionally, GMS uses the CARE application to support the service level agreement that we have with the Energy Fundamentals Group (EFG) to operate their business on their behalf.

Assets: TIS Software (packaged)

Related Investments: N/A

Recommended Alternative Description

Scope of Work:
This project is to replace the CARE application, and must maintain the current functionality and continue to meet the needs of the clients and customers. Initially, solution design will analyze the current custom application, and determine if there is an off-the-shelf packaged application that can address the current capabilities and meet the clients needs ; a determination will be made if this will be a packaged or custom- developed solution. Once the solution has been identified, the project team will enter detailed design, followed by a build and configure phase, QA and testing, and implementation of the solution.

Resources:
TIS PM, TIS BAs, solution architecture, system integrator, vendor services, QA/testing resources

Solution Impact:
Due to the age of the CARE application, a replacement/modernization effort should be undertaken to mitigate risk of system failure. The business estimated the following impacts from a seven-day outage:
1. Money Management: Cash flow, delayed billing: $250 - $500
2. Income/Revenue: Incremental Day to Day S&T Optimization: $2,000 - $5000
3. Re-contracting risk, devalue S&T assets (storage, transport etc, Dawn HUB): $2,000 - $4,000
3. Regulatory/Legal/Contractual: contract breach/non performance, sanctions, fines, lawsuits: $500 - $1,000
4. Cost Overruns - mismanagement of OBA.LBA, Inventory, backstopping: 2,000 - $4,000

Project Timing and Execution Risk:
The project has been identified to begin in 2024 and 2025. The risk of not executing is that this application is extremely old, is increasingly prone to failure, and does not meet the evolving needs of the clients and users.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - TIS - TIS Business Solutions
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_54 - Head Office Support
	Asset Program (EGI)	TIS Business Solutions
	Asset Class (EGI)	TIS
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

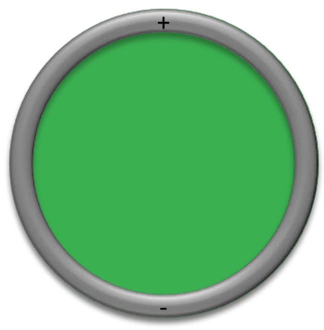
Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Default Alternative	Recommended	$ (17,695,163)	0.00	$ 25,000,000	1/1/2024

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ -	$ -	$ -	$ 12,500,000	$ 12,500,000
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	102292	**2021**	**5**
	Investment Name: Nominations Application Replacement (2024-2025)		

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance CAPEX (CA)	0	0%
Cost Avoidance OPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Budget Savings OPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(17,695)	100%
Total	**(17,695)**	**100%**

Asset Management Plan

2019-2028

uniongas
An Enbridge Company

November 2018

Contents

1 Executive Summary

1.1 Document Purpose

The primary purpose of this document is to outline the asset management plan for Union Gas Limited (Union) OEB-regulated assets for the years 2019 to 2028. This document also:

- Outlines the company's policy and strategies for achieving effective asset management.
- Demonstrates alignment with the company's Asset Management Program, which governs the approach to asset management at Union.
- Outlines and describes the inventory of assets within the various asset categories.
- Describes the 10-year prioritized expenditures in both capital investments and incremental operating expenses.

Definitions of key terms used throughout this document can be found in Appendix A.

Figure 1.1.1: Asset Management Purpose

1.2 Document Structure

The Asset Management Plan (AMP) is structured using the following framework. The AMP begins with a discussion of the background information that provides context for the forecasted capital and operating expenses over the 10-year period.

Figure 1.2.1: Structure of the Asset Management Plan

1.3 Advancing Asset Management

Over the past number of years, Union has identified the need to focus on asset management to achieve its goal of *Operational Excellence*. The ISO 5500X Standard for Asset Management has been applied to define the key guiding principles in the development of Union's Asset Management Program. The primary goal of asset management is to ensure that performance, cost and risk are balanced in delivering service to Union's customers, throughout the entire lifecycle of the asset. Continual improvements are regularly identified and acted upon to continue to drive effective asset management as identified in Section 3.5.

The Asset Management Plan is a key document that is used to outline the strategy and approach to asset management while summarizing the asset plans associated with all asset categories within the organization. The Asset Management Plan is filed as part of the Utility System Plan to support the company's rates application to the Ontario Energy Board (OEB) as per the OEB Filing Requirements For Natural Gas Rate Applications document (Section 2.2.6.1).

A number of key improvements to the Asset Management Program have been implemented and are further discussed in Section 3 of the plan.

1.4 Asset Management

The approach that Union has taken to implement asset management is illustrated in the following diagram from the Institute of Asset Management (IAM) document – *Asset Management an Anatomy*.

Figure 1.4.1: Asset Management – an anatomy, Version 3, page 16, Figure 3: The IAM's Conceptual Asset Management Model, theIAM.org

This diagram depicts the connections amongst many of the key elements and aspects of asset management, which without an overarching framework are otherwise disparate functions. By viewing all of these elements within a cohesive Asset Management Program structure, the company realizes significant gains from its efforts.

As outlined in the Section 1.1, the primary focus of this document is to outline the approach to asset management planning and the outcomes from this effort in the form of the capital and operating expenditures for the period from 2019 to 2028. This aspect of asset management falls into the *Strategy and Planning* subject group on the model for asset management depicted in Figure 1.4.1.

1.5 Portfolio Prioritization

The capital investment plan is prioritized for the 10-year period using a model that takes into account the following criteria to ensure that the best decisions are made to balance the competing priorities of cost, performance and risk:

- Customer engagement feedback/input.
- Company objectives.
- Risk.
- Workload and resource availability.

The prioritization model (further discussed in Section 4.2.1.1.4) uses the above criteria to develop a plan for capital expenditures to ensure that the optimal mix of projects is selected with the given constraints on capital funding.

1.6 About Union

Union is a major Canadian natural gas utility and has been providing natural gas services for more than 100 years. Union serves about 1.5 million residential, commercial and industrial customers in more than 400 communities in northern, southwestern and eastern Ontario. Union's franchise area is shown in Figure 1.6.1. Union also provides natural gas storage and transportation services for other utilities and energy market participants in Ontario, Quebec, and the United States (U.S.).

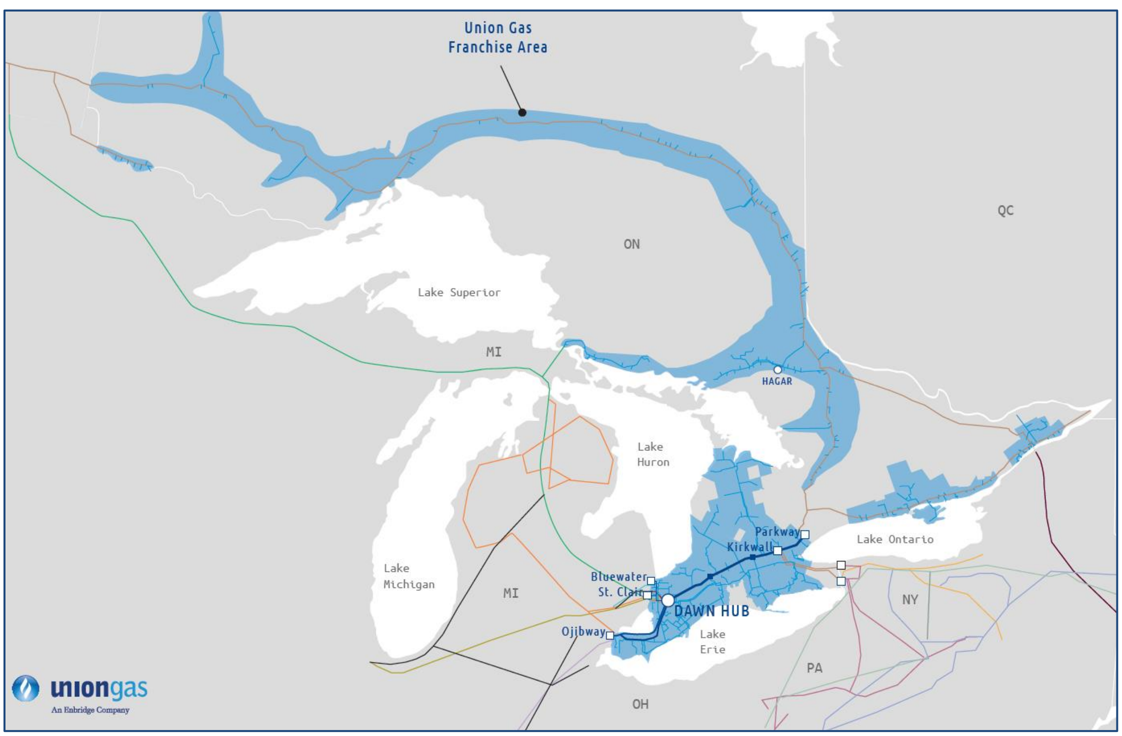


Figure 1.6.1: Union Franchise Area

1.6.1 Asset Base

Union has assets of approximately $8.9 billion and employs about 2,300 people. Union's natural gas assets include more than 70,000 kilometres of distribution, transmission, and storage pipelines, 2,980 system stations, about 1.4 million customer stations (including meters), 4,826 10^6m^3 (170.5 bcf or 188.1 PJ) of natural gas storage capacity, 760,000 horsepower of compression and one liquefied natural gas facility.

Union's supporting assets include service facilities, fleet vehicles and Technology and Information Services assets. The administration facilities include 74 buildings located across Ontario that support Union's functional business needs and activities, including an office located in Chatham that is the workplace for more than 680 people. Union's fleet includes about 800 trucks and 50 cars for the field workforce, plus trailers and equipment. The Technology and Information Services assets include 80 applications and technologies plus associated hardware that provide critical functionality to effectively run the business.

1.7 Asset Categories and Classes

Union has divided its assets into a number of different categories and classes (Figure 1.7.1) to align with unique design, operations and maintenance requirements.

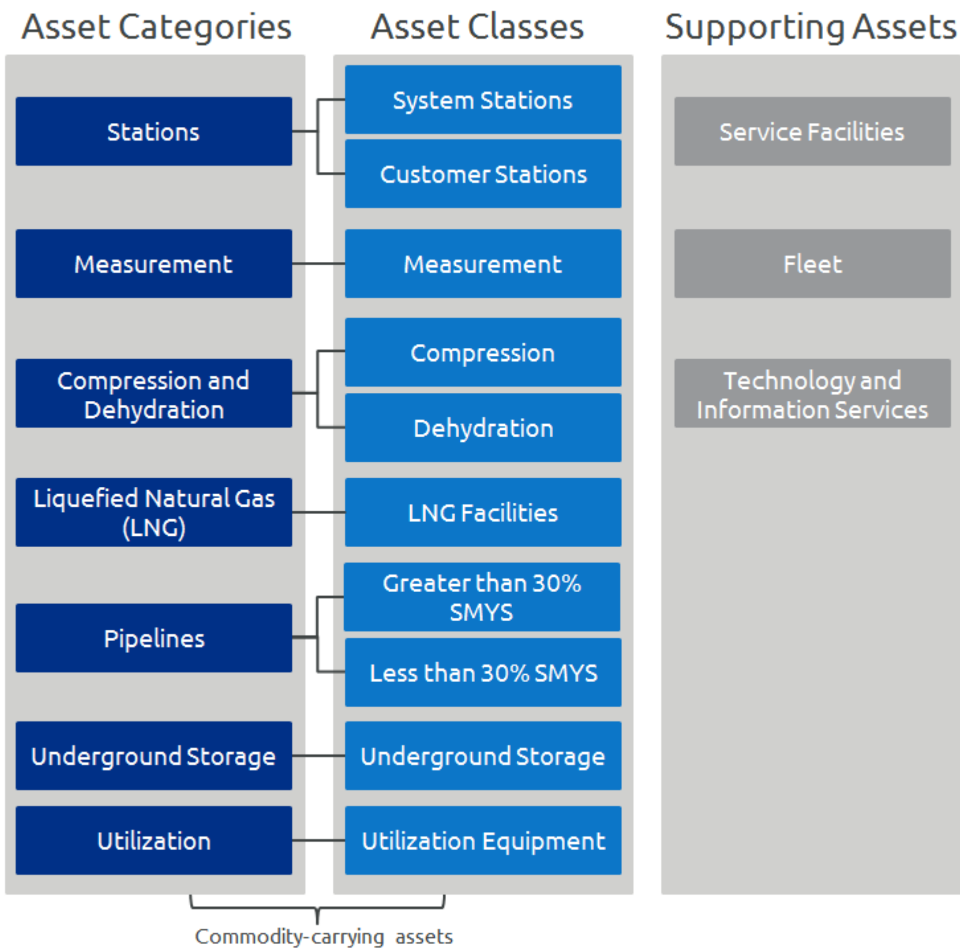


Figure 1.7.1: Asset Categories, Asset Classes and Supporting Assets

Each of the commodity-carrying asset categories is assigned an Asset Category Manager who is accountable for the overall performance of the category and the risks associated with the category.

1.8 Current Operating Environment

The discovery and production of shale deposits continue to impact the North American natural gas landscape. Prices are forecast to remain stable for the foreseeable future, as North American natural gas proven reserves are abundant and can meet the forecasted demand for the next 150 years.

Several new pipelines have been applied for, approved or have begun construction in the past year to move shale gas to liquid markets. The Rover Pipeline and Nexus Pipeline are both set to be online in 2018 delivering Appalachian shale to North American markets (including Union's Dawn Hub) to serve demand across the Great Lakes region, Eastern Canada, the Midwest United States (U.S.) and the Northeast U.S.

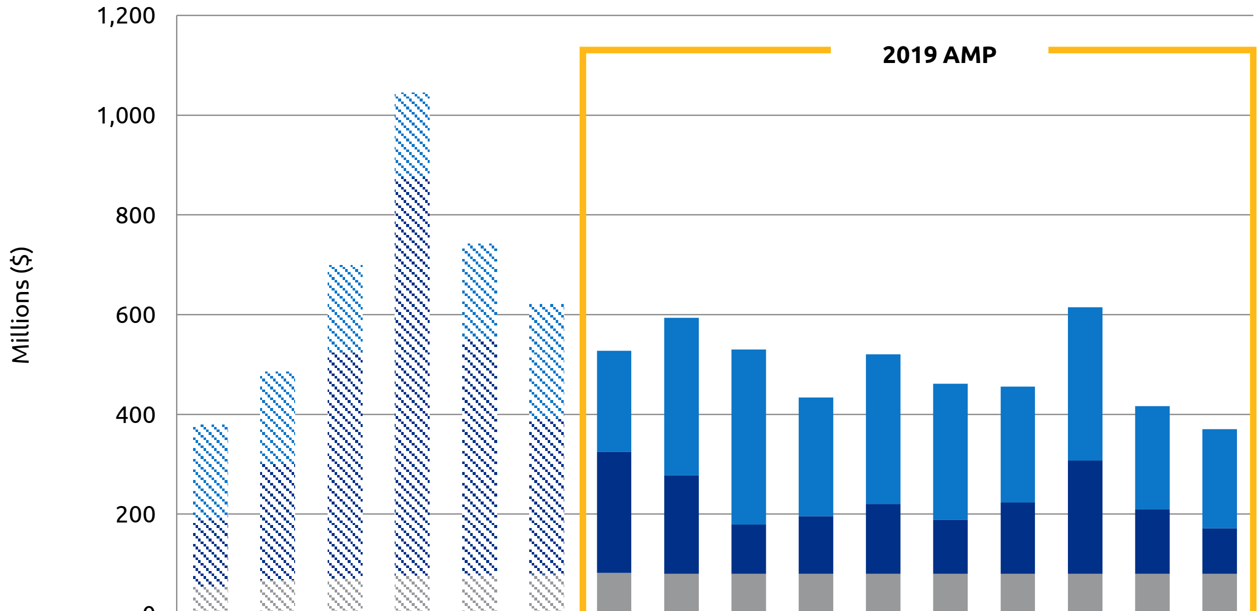
Communities served by natural gas use its availability and low cost as an important tool in their economic development. Many communities not served by natural gas are looking for service so that their constituents can enjoy the low-cost, clean-burning benefits of natural gas.

Natural gas is the cleanest burning conventional fuel producing almost no sulfur dioxide or particulate matter. Power generation by natural gas produces 45 per cent less carbon dioxide compared to power generation by coal. Natural gas produces up to 20 per cent fewer greenhouse gas (GHG) emissions than diesel or gasoline for transportation needs. It is also the ideal low-emission backup option when conditions are not optimal for solar and wind power generation.

Natural gas is also a safe energy choice. Stringent safety rules govern the production, transportation, storage and usage of natural gas. Pipelines provide a safe, reliable and efficient mode of transporting energy.

1.9 Capital and Operations & Maintenance (O&M) Forecast Summary

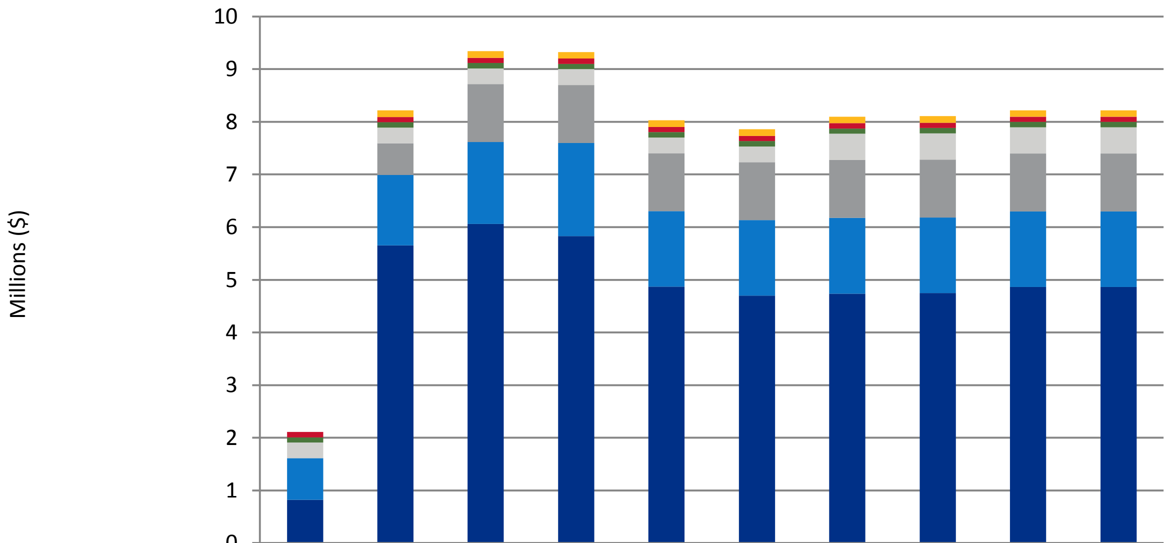
Figure 1.9.1 illustrates the forecast of capital required to meet growth needs and maintenance planning recommendations over the 10-year term of the Asset Management Plan. Some examples of major projects included in the maintenance plan include the Windsor Line Replacement (2020), London Lines Replacement (2021) and the replacement of the Dawn Compressor Plant C (2023-2024). Impacts can be seen in the growth plan from major projects including reinforcement of the Owen Sound System (2019), the Sarnia Industrial Line System (2020), and the Panhandle System (2026). These and other major projects are discussed in greater detail in Appendix D.



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Maintenance	188.2	183.7	173.5	168.3	191.2	229.3	202.5	315.4	351.0	238.3	300.1	272.7	232.1	307.0	206.1	199.0
Growth	135.7	233.7	454.2	799.4	472.2	312.3	243.1	198.1	99.1	115.8	140.3	108.6	143.6	227.6	130.2	91.4
Overheads	55.7	68.2	71.5	77.3	78.7	79.8	82.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0

Figure 1.9.1: Asset Capital 10-Year Forecast (all $ in millions)

Figure 1.9.2 illustrates the Operations and Maintenance (O&M) forecast incremental from 2018 based on maintenance plans. These changes include new facility greenhouse gas (GHG) abatement expenditures in support of new federal regulations, projects to support maintenance activities for major IT applications, increases to inspections of pipelines at water and bridge crossings, and an increased amount for inspections to support Integrity Programs.



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Stations	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Underground Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Measurement	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
CRES	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.5
IT	0.0	0.6	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Compression & Dehy	0.8	1.3	1.6	1.8	1.4	1.4	1.4	1.4	1.4	1.4
Pipelines	0.8	5.7	6.1	5.8	4.9	4.7	4.7	4.7	4.9	4.9

Figure 1.9.2: Incremental O&M 10 Year Forecast (all $ in millions, incremental to 2018)

2 Background and Objectives

2.1 Purpose and Objectives

Union is committed to using comprehensive asset planning to identify and prioritize expenditures over a long-term horizon; ensuring funds are appropriately allocated to maintain the delivery of natural gas safely and reliably to customers. This plan documents the effort and resources required to maintain and grow Union's Ontario Energy Board (OEB) regulated natural gas and supporting assets to meet customers' needs and preferences, to achieve a high degree of safety and reliability and to meet Union's goals, specifically to *deliver operational excellence*. This plan includes information about Union's asset planning processes and is a key input into short- and long-term financial planning. The primary purpose of this document is to outline the asset management plan for Union for the years 2019 to 2028. This document also:

- Outlines the company's commitment to and strategies for achieving effective asset management.
- Demonstrates the connection between the company's Asset Management Program, which governs the approach to asset management at Union, and its Asset Management Plan (AMP).
- Outlines and describes the inventory of assets within the various asset categories.
- Describes the 10-year prioritized expenditures in both capital investments and incremental operating expense.
- Demonstrates how Union strives to understand its customers' needs and preferences, and incorporate these into the long-term plan.

The AMP is a forecast of the growth and maintenance expenditures planned for Union Gas Limited (Union) assets. This plan demonstrates that Union will manage assets to serve its customers safely, reliably, and efficiently at the lowest cost.

2.2 Company Purpose, Vision, Goals and Values and Strategic Priorities

Asset management is a key component in achieving Union's Purpose, Vision, Goals and Values (Figure 2.2.1). Through asset planning and making informed, evidence-based decisions, this document specifically aligns with the goal to *deliver operational excellence.*

Figure 2.2.1: Union Purpose, Vision, Goals and Values

2.3 Organization and Structure

Union's parent company Enbridge Inc. carries out its activities through three core business units: Liquids Pipelines, Gas Transmission and Midstream, and Utilities and Power Operations (UPO) (Figure 2.3.1). The UPO business unit includes Enbridge Gas Distribution (EGD), Union Gas Limited (UGL), and other affiliate companies (Power Operations, Enbridge Gas New Brunswick Inc., Gazifère Inc., Niagara Gas Transmission Limited, 2193914 Canada Limited).

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

Within Ontario, Union is regulated by the OEB. This Asset Management Plan outlines the management of its OEB-regulated assets in Ontario.

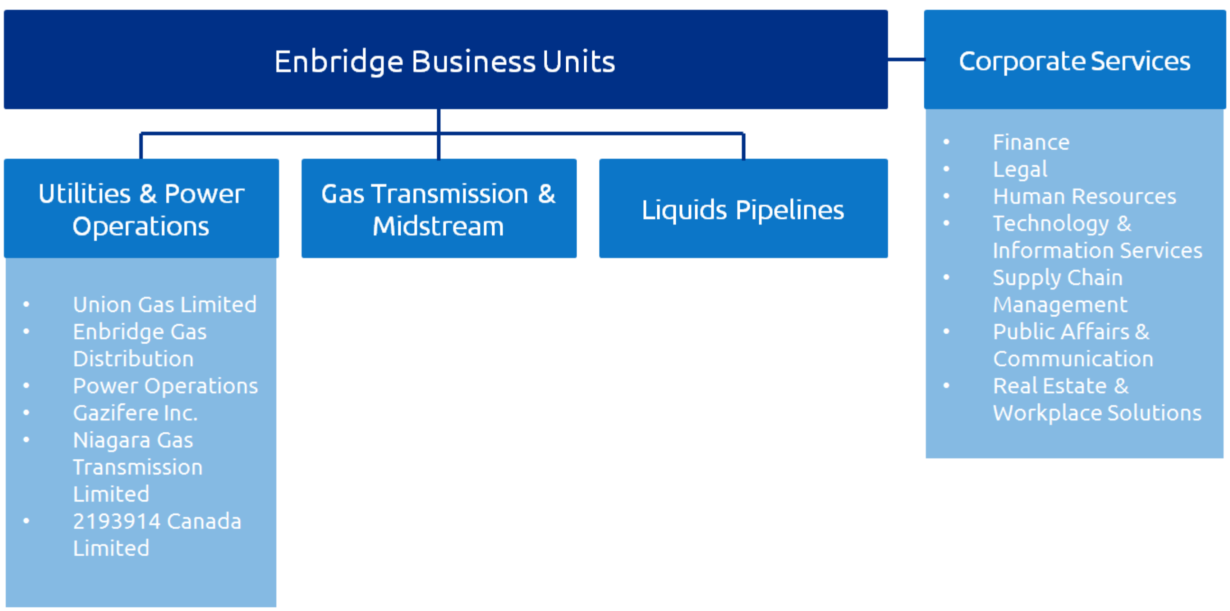


Figure 2.3.1: Enbridge Business Units

2.3.1 Union Gas Limited

Union is a major Canadian natural gas utility that provides energy delivery and related services to about 1.5 million residential, commercial, and industrial customers in more than 400 communities in northern, southwestern and eastern Ontario. Its distribution service area extends throughout northern Ontario from the Manitoba border to the North Bay/Muskoka area, through southwestern Ontario from Windsor to just west of Toronto, and across eastern Ontario from Port Hope to Cornwall. Union also provides natural gas storage and transportation services for other utilities and energy market participants in Ontario, Quebec, and the United States (U.S.). Union'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. Union has assets of approximately $8.9 billion and about 2,300 employees.

Union's assets include small diameter pipe, meters, and regulators at homes the franchise areas, transmission pipe of up to nominal pipe size (NPS) 48, which is used to transport natural gas across Ontario; five main compressor plants including 20 storage compressors 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.

Union's franchise area is divided into eight administrative areas, which divide the province both geographically and functionally. Union's Distribution Operations (DO) are divided geographically into the following seven districts:

- Windsor
- London
- Waterloo
- Hamilton
- Eastern
- Northeast
- Northwest

Figure 2.3.1.1: Union Distribution Operations geographic districts

The eighth area, Union's Storage and Transmission Operations (STO), consists of assets within various geographic areas throughout the province. The main operations centre for STO is the Dawn Hub, located in Dawn-Euphemia Township north of Chatham, Ontario.

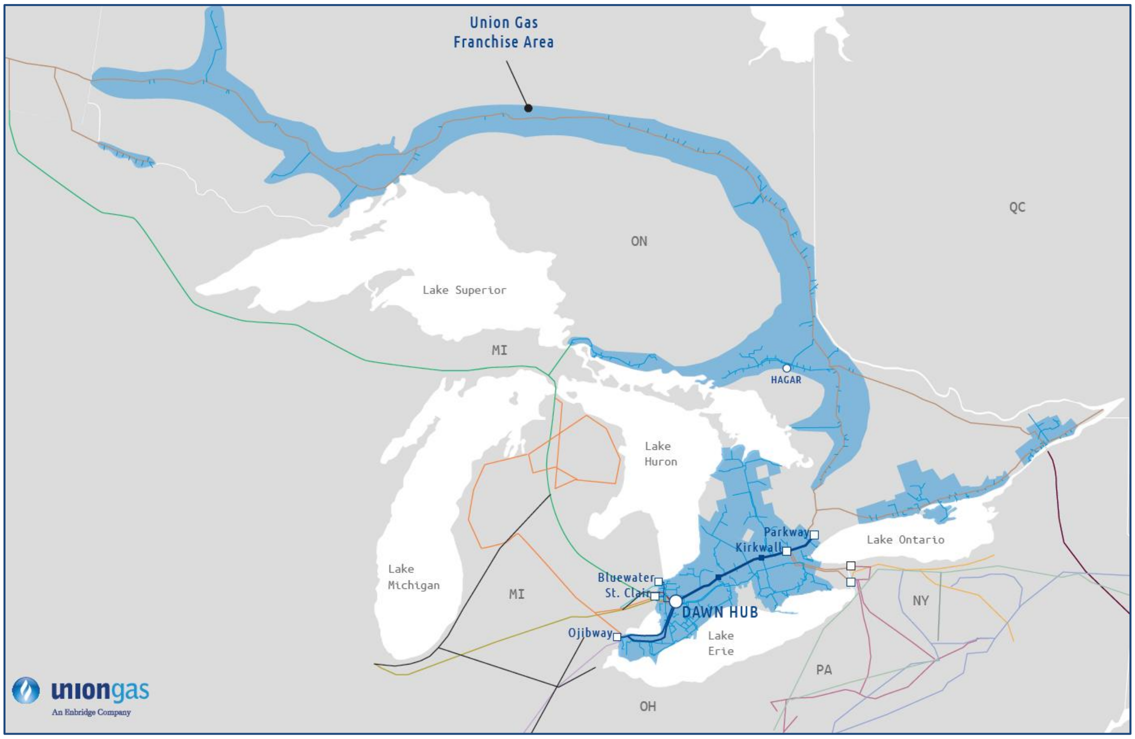


Figure 2.3.1.2: Union Franchise Area

2.4 Stakeholder Commitment

2.4.1 Customer Engagement

In 2017 Union engaged Innovative Research Group Inc. to assist in the design and implementation of an extensive customer consultation program in support of the development of Union's business planning. The objective of the consultation was to identify customer needs, identify and assess priorities among specific customer outcomes and explore customer preferences on some significant and illustrative choices before Union's planners of potential solutions, including the pace of investment.

This consultation complements Union's robust market research program that includes regular customer satisfaction surveys for all markets, as well as satisfaction tracking for all of the major transactions/touchpoints. Other customer engagement opportunities, such as focus groups and direct engagement from account representatives, are also undertaken on a regular basis to gather customer feedback on specific programs/services.

The key findings of the consultation include:

- Across all rate classes and all methodologies, customers consistently report high levels of satisfaction with Union.

- The top three most important outcomes for customers are price, safety and reliability. Minimizing environmental impact, customer service, making good use of rate monies and transparency are also important, but significantly less so.
- When asking customers to make business planning choices, there are times when they will choose system health, the environment or customer service over price.
- Customers want Union to spend what is needed to keep the system healthy in the long run even if it means higher prices.

Union has taken the customer preference for a steady pace of spend on assets into account within the 10-year maintenance capital outlook in Section 6. In addition, the project descriptions found in Appendix D provide more detail on how the results of the engagement consultation have been considered for specific projects/programs.

3 Asset Management Framework

3.1 Asset Management Program

The Asset Management Program is an additional program under Union's Integrated Management System (IMS). The program implements the systematic management processes and elements of the IMS to manage risk and assure compliance with internal and external requirements. The purpose of the Asset Management Program is to define the approach to asset management to ensure that that the company's assets are managed while balancing cost, performance and risk through the entire asset lifecycle.

Figure 3.1.1: Asset Management Purpose

The Asset Management Program document outlines the asset management framework and incorporates the Enbridge Management System Framework, Union's IMS requirements, and demonstrates alignment with the ISO 5500X Standard and IAM Subject Groups and Elements (Figure 3.1.2).

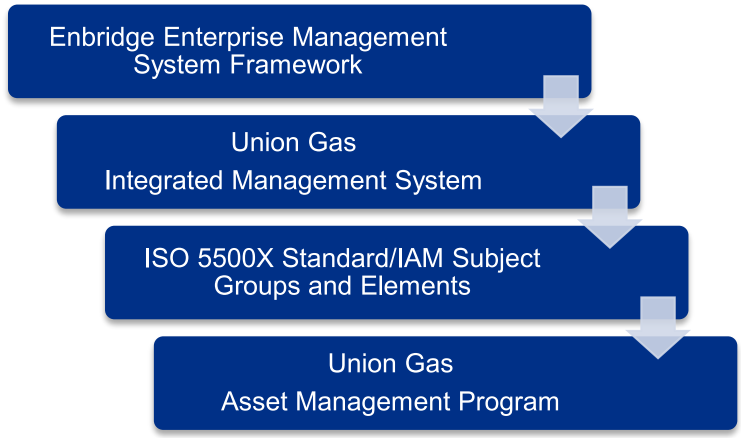


Figure 3.1.2: Alignment of standards and requirements

3.1.1 Scope of the Program

The Asset Management Program covers the full breadth of the asset portfolio that is managed by the operations groups within Union. This grouping of assets is often referred to as commodity-carrying assets, a term meant to distinguish them from assets which are operated and maintained by supporting groups such as Corporate Real Estate (CRES), Technical Information Services (TIS) and Fleet.

It is important to note that while the scope of the IMS is limited to commodity-carrying assets within the Distribution Operations (DO), Engineering, Construction and Storage Transmission Operations (ECS) functions, the scope of the AMP is expanded to encompass all OEB-regulated company assets (Figure 3.1.1.1).

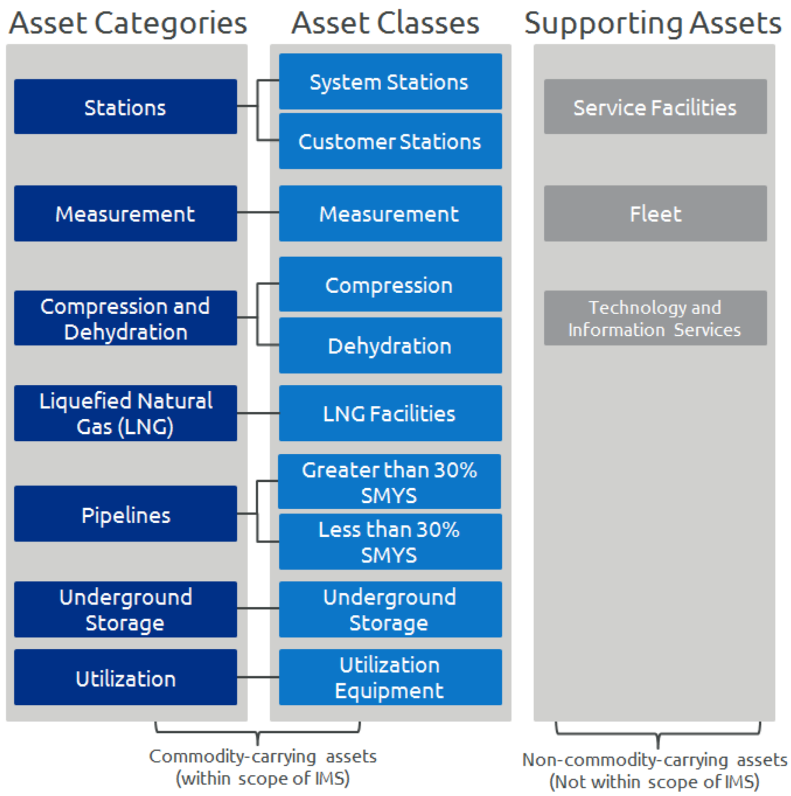


Figure 3.1.1.1: Scope of Assets for the IMS

The Asset Management Program encompasses all phases of the asset lifecycle (Figure 3.1.1.2), however, the business development and sales and marketing processes used to identify the need for new assets, or changes in performance requirements are not within the scope of this program. The need for new assets or changes in capacity is identified by the groups within the scope of this program using the inputs from the various business development and sales and marketing processes. New assets can also be identified by the groups within the scope of this program when the required asset performance can no longer be maintained with an acceptable balance of cost, performance and risk. The processes by which these asset renewal projects are identified are fully within the scope of the program.

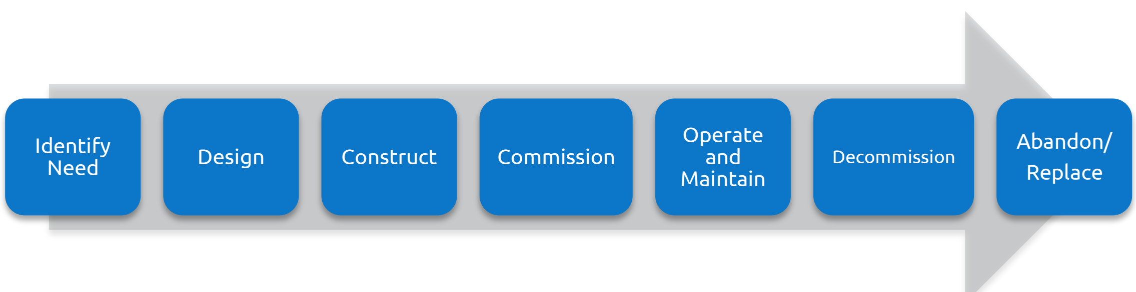


Figure 3.1.1.2: Asset Life Cycle Stages

3.2 Integrated Management System (IMS) Framework

Union implemented its first Operations Management System (OMS) in 2008, but introduced management elements and programs a full decade earlier. Since 2008, Union's IMS has evolved to include an increasing number of operational and personal safety and compliance programs, and has helped improve organizational performance.

In 2018, the OMS changed to the IMS to align with the Enbridge Safety and Reliability Policy. The IMS incorporates all dimensions of safety and reliability, including risk management and asset management. Union demonstrates its dedication to a zero-incident workplace through its commitment to managing risk and conducting business in a manner that protects the environment and the safety, health and security of its employees, contractors, customers and the public, and by driving continual improvement to deliver operational excellence. This commitment is outlined in a commitment statement (Figure 3.2.1) that is reviewed and signed by the Accountable Officer and communicated on an annual basis.

uniongas
An Enbridge Company

Union Gas
Integrated Management System (IMS) Commitment Statement

Commitment

Union Gas is committed to safe, reliable and compliant operations across the lifecycle of our assets. Leadership is dedicated to maintaining and continually improving our safety culture, our safety and reliability performance and our commitments to stakeholders. Union Gas' obligations include ensuring the safety and security of the public, employees and contractors, and protection of property and the environment.

To deliver on this commitment, Union Gas has established an Integrated Management System (IMS) that delivers compliance with the requirements of Enbridge's Enterprise Management System Structure, Safety & Reliability Policy, and Safety Principles.

Applicability

The Union Gas IMS applies to the lifecycle of Union Gas assets, including asset design, procurement, construction, operations, and abandonment and provides the governance structure for the organization's IMS framework and programs.

Figure 3.2.1: Union Gas IMS Commitment Statement

There are many benefits resulting from the implementation of the IMS, including:

- Structured, risk-based decision making.
- Clear roles, responsibilities and accountabilities.
- Compliance requirements are understood and met.

- Assurance that what needs to be managed is being managed.

Union's latest iteration of its management system in alignment with the Enbridge Enterprise Management System Framework and Standard was effective January 1, 2018. The current IMS Document includes 11 elements, and 9 operational and personal safety and compliance programs (Figure 3.2.2). Each of the management system programs incorporates the elements into their program design and each of the program leads is accountable for effective implementation.

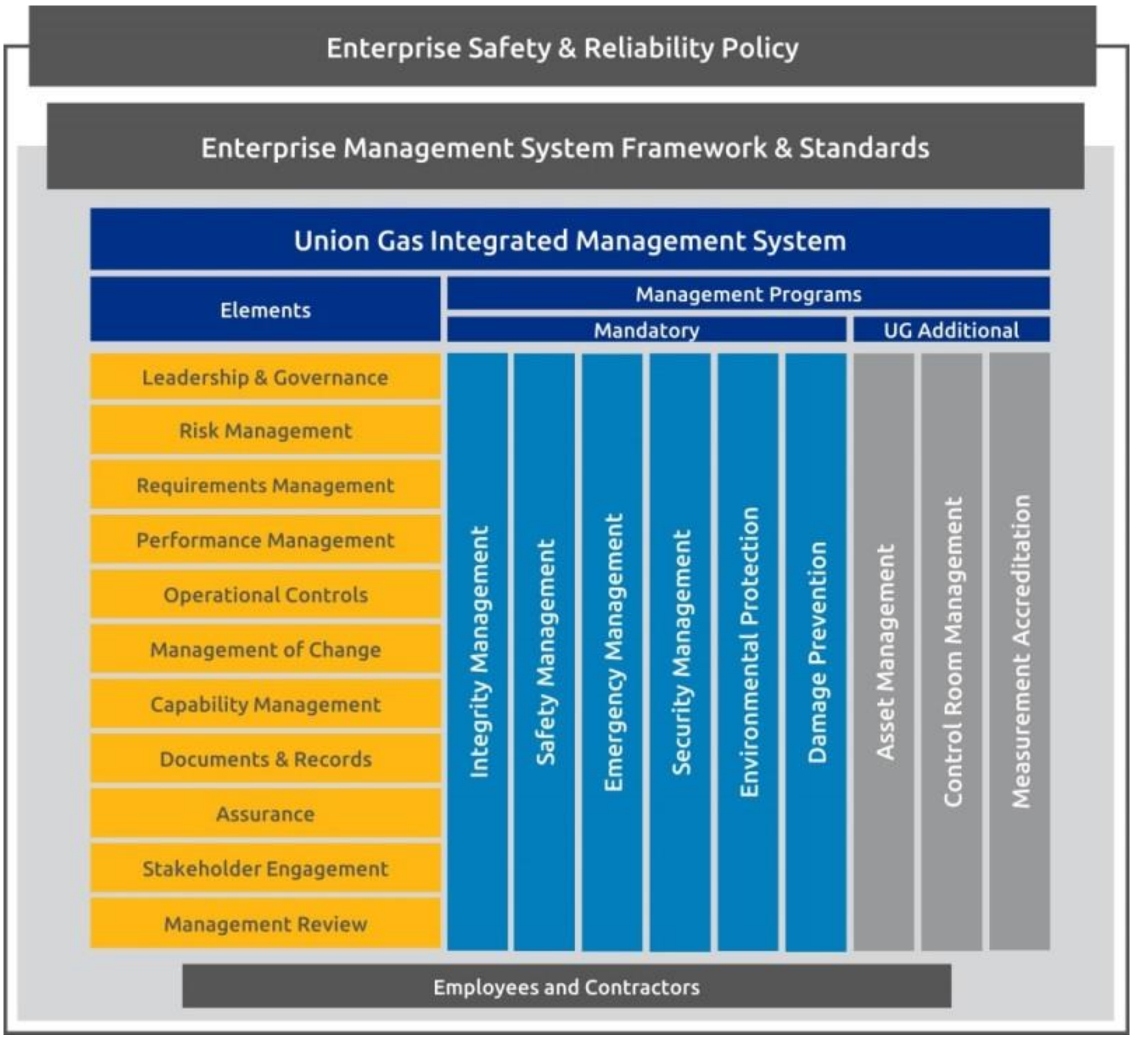


Figure 3.2.2: Union Integrated Management System (IMS)

Although the Asset Management Program is specific to asset management, there are aspects of asset management that are common throughout the other IMS programs. For example, the Integrity Management Program is focused on the Operations and Maintenance phase of specific asset categories.

3.2.1 The IMS and Continual Improvement

The IMS is predicated on the underlying principle of striving for continual improvement through the implementation of the Plan-Do-Check-Act quality cycle (Figure 3.2.1.1). Union's IMS Governance approach maintains the line of sight from front-line employees through to the executive leadership, and has been expanded to include the overall Enterprise level. Governance meetings occur on a quarterly basis and include a transparent and timely review of significant risks, compliance updates and performance metrics. The nine management programs and overall framework are each reviewed annually to ensure that goals, objectives and targets are being met effectively and to keep employees and the public safe. The IMS programs continue to evolve to include additional requirements such as personal and cyber security, abnormal operating conditions, public awareness, and to incorporate leading practices and consistent approaches across business units described in Figure 2.3.1 (Section 2.3). There are many IMS processes in place to drive continual improvement such as performance measurement, capability management, documentation review, formal incident reporting and investigation, and monitoring and tracking corrective actions.

Figure 3.2.1.1: Plan-Do-Check-Act quality cycle

Another way Union seeks 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) technical committees, participation in CGA and AGA surveys and workshops, and AGA peer reviews.

Union uses audits to ensure compliance with legal and regulatory requirements and improve on processes through corrective and preventive actions that are identified throughout. The audit strategy is reviewed through the IMS governance on a quarterly basis.

The following are examples of the internal audits that were conducted in 2017:

- Safety & Reliability (S&R) Verification of the Management of Change element identified four issues that have been resolved by updating reference documentation.
- S&R Verification of the Emergency Management Program identified one issue that has been resolved by updating program documentation.
- Systems audits performed on 30 contractors and material providers identified five non-conformances and 79 opportunities for improvement.
- Audit Services performed an audit of the Measurement Accreditation Program which identified three opportunities for improvement, which have been completed.
- The Field Quality Assurance Plan reviews details around assets and asset construction. In 2017 approximately 4800 reviews identified approximately 475 opportunities, all of which were responded to.
- The Safety Management Program and the Emergency Management Program were audited to the National Energy Board's Onshore Pipeline Regulations requirements with six identified improvements completed.

The following are examples of external audits that were conducted in 2017:

- The Integrity Management Program responded to eight recommendations from TSSA review.
- All emissions reporting was completed for 2017 with no issues.
- No issues were identified with the NEB Compliance Screening of the Safety Management Program.

3.3 Asset Management Roles and Governance

As part of the IMS framework, the Asset Management Program is subject to governance, oversight and coordination to meet the requirements as defined the IMS Document Section 1.4. Figure 3.3.1 represents the governance structure for the Asset Management Program under the IMS governance model.

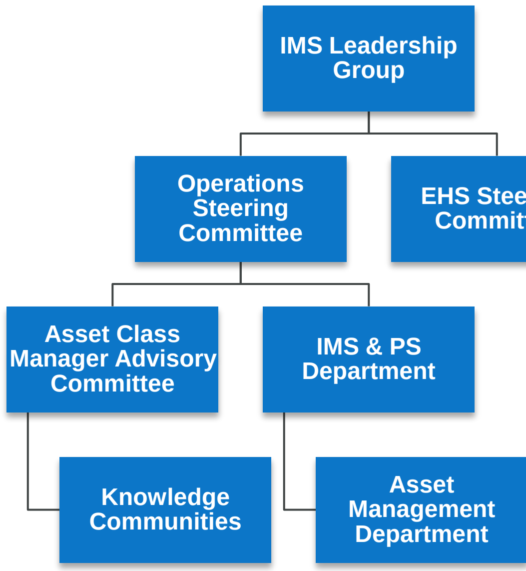


Figure 3.3.1: Asset Management Program Governance Structure

The Asset Class Manager Advisory Committee consists of Asset Class Managers who provide oversight and input into the Asset Management Program. This committee meets on a regular basis to build common understanding of asset management, share knowledge and guide decisions related to asset management. Two main functions are primarily responsible for the direction of the program as described in greater detail below:

1. Asset Category Managers and Asset Class Managers
2. Asset Management Functions

Asset Category Managers

Asset Category Managers are accountable to manage asset performance, support maintenance and operation, and are typically individuals at the director level with specific decision authority related to assets. This group does not have regular meetings, but is engaged to provide direction as required. The Asset Category Managers have overall accountability throughout the lifecycle of the assets within their category, including:

- Performance of the assets.
- Accountability for maintenance practices, including Standard Operating Practices (SOPs).

- Ensuring compliance to all applicable codes and regulations.

Asset Class Managers

Asset Class Managers are accountable to manage asset performance, support maintenance and operation and lead an asset knowledge community within their particular classes to identify risks and opportunities. The knowledge communities consist of subject matter experts (SMEs) in each asset category who support Asset Class Managers in risk assessments and the development of mitigations. These communities do not meet on a regular basis, but provide continuing support and knowledge to assist Asset Class Managers in delivering on their objectives. Asset Class Managers are individuals at the manager or supervisor level.

Asset Class Managers have accountability throughout the lifecycle of the assets within the class, including:

- Identification of required asset health information.
- Identification and definition of asset performance metrics.
- Definition and development of maintenance strategies, including SOPs.
- Addressing field-identified risks and issues related to the assets.
- Interpretation of codes and regulations as defined in the Operations and Environment Health and Safety (OEHS) Legal & Other Registry.
- Consultation with knowledge communities, as required.

Asset Category Managers and Asset Class Managers have additional assigned accountabilities related to asset management within existing roles in Operations and Engineering.

Asset Management Department

The Asset Management department is a group within the Integrated Management System and Program Support (IMS & PS) department that establishes asset management processes and provides support for reliability analysis and risk assessments.

The Manager Asset Management within this department provides leadership for the Asset Class Manager Advisory Committee and the application of, and alignment with, the ISO 5500X Standard for Asset Management. The Manager Asset Management has overall accountabilities for the Asset Management Program, including:

- Align with the IMS Commitment Statement and use systematic risk-based decision making.
- Develop program goals, objectives and targets to anticipate, prevent, manage and mitigate conditions that could adversely affect people, property, or the environment.
- Identify, assess, manage and mitigate risks to meet program goals, objectives and targets and to ensure compliance.
- Establish, implement and retain documented processes and procedures to meet the IMS Framework.

- Provide quarterly status reporting and an annual review of the program to identify continual improvement opportunities and corrective actions for endorsement by the IMS Governance.
- Develop and maintain the asset management framework, including the Asset Plan and Asset Class definitions.
- Facilitate the Asset Class Manager Advisory Committee.
- Provide resources to support Asset Class Managers, including:
  - Supporting asset health or metrics reporting.
  - Supporting the development of maintenance strategies, using techniques including Reliability Centred Maintenance (RCM) capabilities.
  - Analysis of asset data/information and support in closing gaps.

3.4 Review of Asset Management Practices

3.4.1 Target Operational Model (TOM) Process

In 2014 in conjunction with the implementation of the Enterprise Asset Management System (SAP PM), Union engaged a consultant to help develop a roadmap for the future of asset management at Union. The assessment involved a current state maturity analysis as well as determining the desired future state. The roadmap, entitled the Target Operating Model (TOM), specifies the various activities and initiatives required to achieve the desire future state.

The following graphic represents the various elements of asset management that formed the basis of the assessment. Representing asset management with this structure provides focus on the various elements that are most closely aligned with the strategic objectives.

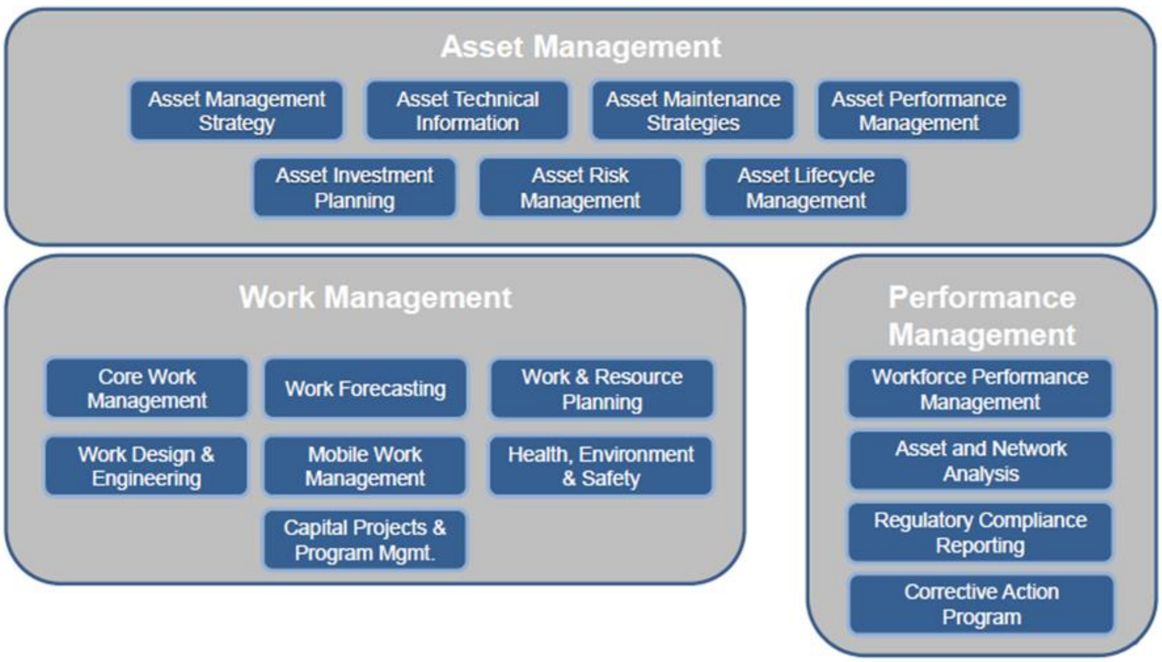


Figure 3.4.1.1: Enterprise Asset Management System structure

3.5 Continual Improvement

A key outcome from the TOM discussed in Section 3.4.1, was a series of improvement opportunities to be undertaken to achieve the longer-term vision for asset management. A detailed review and update to the TOM was undertaken in 2017 to ensure that Union continues to focus on the desired future state. Many of the asset management improvements have been realised through the completion of activities identified in the TOM.

Several of the key improvements achieved to date include:

- Integrated the Asset Management Policy with the IMS Commitment Statement and Framework.
- Established the asset planning process.
- Identified asset categories and governance.
- Introduced the treatment of maintenance as a business. This initiative centred on better maintenance planning and scheduling with the introduction of a function for maintenance planning within the Storage and Transmission Operations (STO) group.
- Implemented SAP PM as the Enterprise Asset Management (EAM) System (2015). This integrated system facilitates the gathering of data from maintenance processes, and provides the ability for greater understanding of costs, and materials requirements.
- Implemented a Technical Records and Information Management system.
- Introduced Hazard and Operability Studies (HAZOPs) and Reliability Centered Maintenance (RCM) for key assets.
- Developed Capital Project Operational Readiness processes.
- Standardized compressor station and customer station design.
- Implemented a mobile work management application and hardware platform for all operations employees.
- Implemented Legal Register process and governance.
- Developed a strong incident reporting and learning program.
- Developed a comprehensive Audit Strategy.

Although many significant improvements have been made over the past few years, Union continues to build on its successes by being driven by a strong culture of continual improvement. The TOM will remain an important roadmap to maintain focus on achievement of its vision.

4 Strategy and Planning

4.1 Asset Management Strategy

The Asset Management Program has been developed in alignment with the ISO 5500X Standard for Asset Management and the Institute of Asset Management's (IAM) Asset Management - an anatomy Version 3 document which provides a practical framework for an Asset Management System based on the ISO 5500X requirements. The approach to asset management at Union is to align with the ISO 5500X Standard for Asset Management, but not to certify to that standard.

Figure 4.1.1: Asset Management – an anatomy, Version 3, page 16, Figure 3: The IAM's Conceptual Asset Management Model, theIAM.org

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

1. Strategy and Planning.
2. Asset Management Decision-making.
3. Life-cycle Delivery.

4. Asset Information.
5. Organization and People.
6. Risk and Review.

The IAM model for Asset Management shown in Figure 4.1.1 has been used to build and implement an effective asset management framework at Union to balance cost, performance and risk through the entire asset lifecycle. By adopting the IAM model, Union can ensure alignment with the ISO 5500X Standard and demonstrate connections between the subjects of asset management and the elements of the IMS. This model also provides a simple visual representation of the complex discipline of asset management, showing the connections between the various elements and functions across the organization.

According to the IAM Model for Asset Management depicted in Figure 4.1.1, the subject of asset management planning falls under the subject group of *Strategy and Planning* (refer to Figure 2). It further defines asset management planning as the detailed activities, resources, responsibilities, timescales and risks for the achievement of the asset management objectives. This guidance has been used to develop the content and strategy of the AMP.

4.1.1 Asset Management Strategies and Objectives

4.1.1.1 Enbridge Enterprise Strategic Priorities

Union's asset management strategic framework includes the Enbridge Enterprise Strategic Priorities, Union's Purpose, Vision, Goals and Values and the Engineering, Construction and Storage Transmission Operations (ECS) and Distribution Operations (DO) Lines of Sight. These inputs help to determine and guide the asset management strategies and objectives.

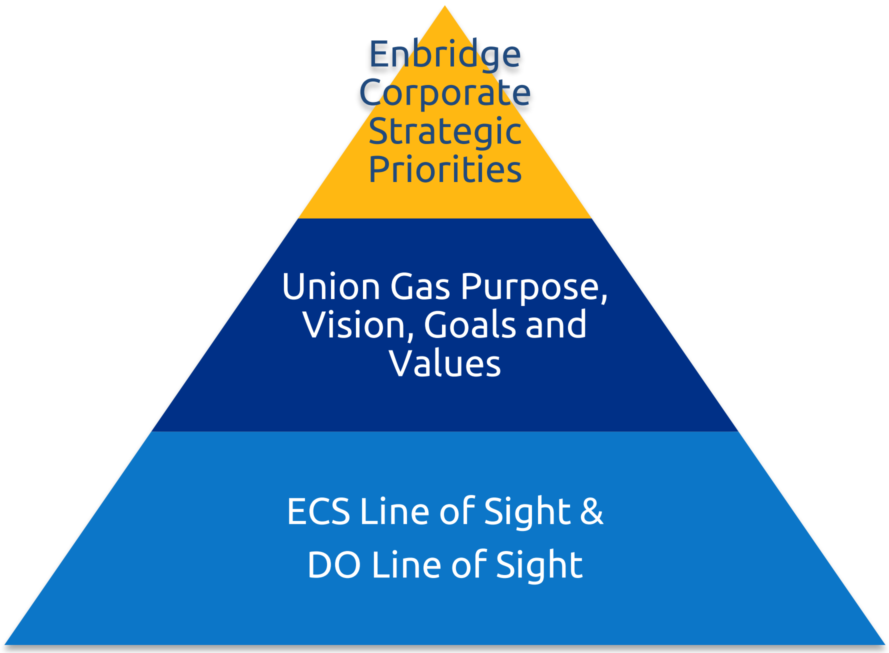


Figure 4.1.1.1.1: Hierarchy of inputs

The Enbridge Enterprise Strategic Priorities are defined to enable the enterprise to achieve its vision to be the leading energy delivery company in North America. Asset management actions and decisions align with these strategic priorities and contribute to Enbridge's success. They support the company's purpose of fueling people's quality of life, while maintaining the foundation of the business, and positioning the company for the future. This document directly supports and aligns with the priorities for *Safety and Operational Reliability*, *Execution of Capital Program*, *Position for Long-term Growth*, and *Stronger Financial Position*.

Asset management is a key component in achieving Union's Purpose, Vision, Goals and Values (Figure 4.1.1.1.2). Through asset planning and making informed, evidence-based decisions, this document specifically aligns with the goal to *Deliver operational excellence.*

Figure 4.1.1.1.2: Union Purpose, Vision, Goals and Values

4.1.1.2 Asset Management Goals

The goal of asset management at Union is to ensure that evidence-based decisions are made to balance performance, cost and risk in alignment with the ISO 5500X Standard for Asset Management. The following objectives support this goal and are in alignment with the purpose of Union' Integrated Management System (IMS).

Safety

- Enhance risk management processes with a focus on effective risk management and ensuring adequate layers of control.
- Facilitate identification of hazards at all levels and actively manage the operational risk registry.

Reliability and Integrity

- Implement Maintenance Optimization across Union operations, beginning with the most critical assets.
- Identify critical assets and ensure the correct data is collected and maintained in the correct system, with the right level of accuracy.
- Update Integrity Management Program documentation and associated Long-term Integrity Plans, leveraging risk management to address pipeline condition.

Compliance

- Complete the development and implementation of a comprehensive Technical Records program, compliant to legal, regulatory, and operational requirements.

Effective Asset Management

- Develop a comprehensive Asset Plan identifying the maintenance and growth requirements of gas carrying assets, taking into account asset health, and customer and shareholder requirements.
- Fully leverage the Geographic Information System (GIS) to support all Union business strategies that contain a Geospatial component, with a focus on data integrity, end user experience, and mobility.
- Enrich the understanding of assets through improved asset information governance to support asset maintenance tracking and analysis, with a focus on critical assets.

4.2 Asset Planning

4.2.1 Overview

The Asset Management Plan (AMP) includes information about the addition of assets to meet customer needs and maintenance requirements to ensure ongoing safety and security of supply for Union customers. Processes govern various phases of the asset lifecycle. The identification of the need for a capital expenditure can either be to satisfy a growth requirement or to resolve degraded condition or performance of an existing asset. In either case, the process to create a new asset is the same.

Growth includes adding assets to reinforce existing systems and to provide service to new customers. Growth is driven by increased in-franchise and ex-franchise demand as well as changes in the supply dynamics of natural gas. The process of determining maintenance requirements, referred to as Maintenance Planning in this Asset Management Plan, is completed for each asset based on asset health and compliance needs with a focus on delivering services reliably at the lowest lifecycle cost.

The asset planning process begins with the identification of need. The need for a new asset is typically driven by one of two primary causes:

- New demand on the system that cannot be satisfied by the existing asset base (growth); or,
- Asset performance degradation requiring asset renewal (maintenance).

In either case, the planning of the new asset is done in such a manner to allow the Company to continue to meet its strategic objectives. The following Section outlines the unique strategy and planning approaches associated with the two main categories of investments: growth and maintenance.

4.2.1.1 Identify Need

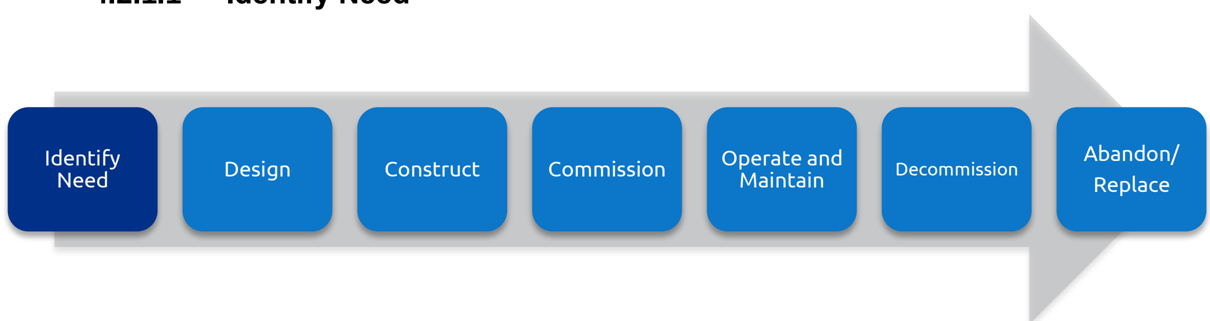


Figure 4.2.1.1.1: Asset Lifecycle Model

Projects are identified in a number of different ways. Union's risk management processes involve a number of formal steps to identify, mitigate, and monitor risks. Section 4.2.1.1.3 of this plan provides a detailed outline of Union's risk management process. Mitigation for the risks identified through this process is often projects to improve reliability or safety. Projects may also be identified or required as a result of regulation or code changes and when municipal projects result in conflicts with Union's infrastructure requiring relocations.

All potential projects are reviewed, evaluated, tracked, and monitored over time to determine if the risk level associated with a given item is increasing or stable. These potential projects, with a variety of priority levels, are used as a starting point for the annual budget cycle.

4.2.1.1.1 **Growth Planning**

Projects to accommodate new customers, to maintain adequate flow and pressure for all Union customers, and to meet storage and transportation needs of customers are planned by the Distribution Planning, System Planning, and Storage Planning groups. These projects include the installation of new mains, reinforcement of existing mains, as well as installation of new stations, and upgrades to existing stations as a result of in-franchise or ex-franchise growth. In-franchise growth at Union is defined as increased natural gas peak demand in the franchise areas of Union. Ex-franchise growth is the increased storage and transportation needs of customers primarily outside the franchise who provide or require natural gas services in Ontario, Quebec, and major U.S. natural gas consuming areas like the U.S. Northeast.

The Distribution Planning group makes asset planning recommendations for distribution systems, which are the pipeline and stations systems in regions throughout Union and include some of the transmission systems that supply these regions.

The System Planning group make asset planning recommendations for the three major transmission systems which include the Dawn to Parkway System, the Panhandle System and the Sarnia Industrial Line System.

The Storage Planning group makes asset planning recommendations for all underground storage facilities as well as for the Dawn Compressor Station.

Asset Growth – In-Franchise

In-franchise growth is driven by changes in the peak demand for new and existing general service and contract rate customers. The primary driver for this growth is the value proposition natural gas provides to Union's residential, commercial, agricultural, and industrial customers when evaluating their energy needs.

Union records indicate that in the general service, the total annual average use per customer has been declining since the early 1990s. This trend is expected to continue due to energy efficiency related activities, technology advancements, Demand Side Management (DSM) programs, and the potential impact of carbon policy initiatives.

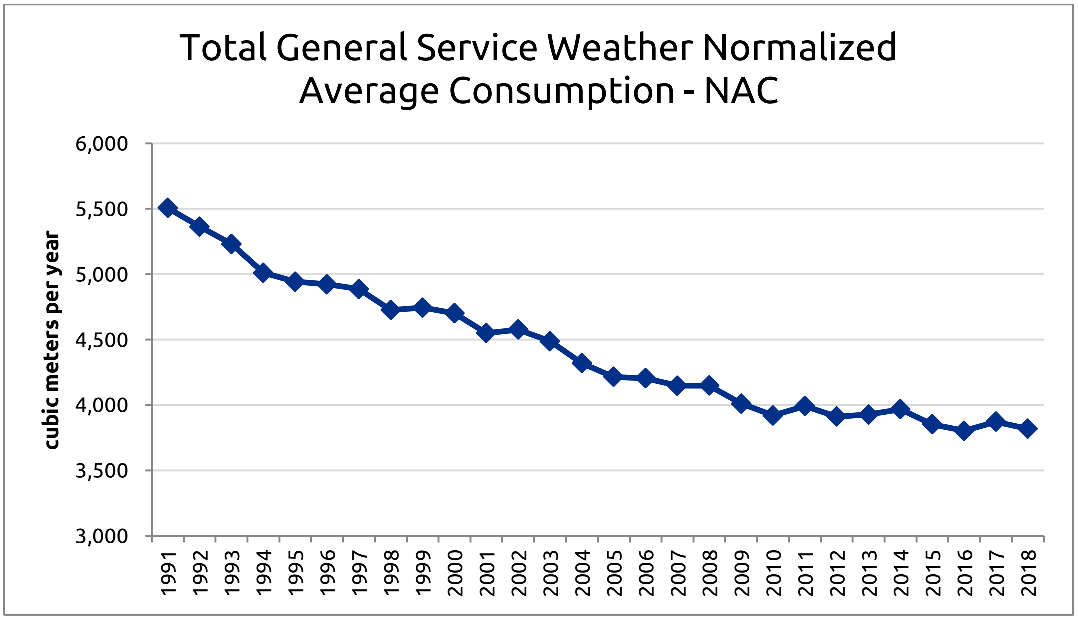


Figure 4.2.1.1.1.1: Normalized Average Consumption

While annual average use per customer is decreasing over time, the design day demand, which is the total average daily demand and peak hourly demand at the design weather condition, is increasing over time. The design day is the coldest potential winter day in Union's franchise.

General service growth is comprised of three areas which include new residential housing, commercial and small industrial businesses, and customers in these categories converting to natural gas. Customer growth in the general service market typically mimics the population growth of the franchise, however, area specific growth plans are used to ensure localized knowledge is considered when optimizing the gas delivery network.

Growth in the contract rate markets tends to be driven by a combination of population growth in the franchise as well as broad economic drivers. Typically, growth within the institutional markets is driven by community growth that spurs the need for new and expanding social services such as hospitals and universities. Natural gas demand is also increasing in these segments with the adoption of combined heat and power applications as a way to economize on their electricity costs.

The industrial contract rate market growth is driven by economic and investment factors such as exchange rates, tax rates, alternate fuel costs, cost of electricity, and proximity to markets.

The greenhouse contract rate market continues to grow at a faster than historic pace. Natural gas is the fuel of choice for these enterprises and growth in the greenhouse market continues to be strong with no signs of slowing down.

Future growth in the industrial rate contract market may come from chemical, mining, and steel segments. Currently significant uncertainty exists in some markets due to tariff and trade issues. Any future contract rate projects are subject to the economic tests identified in case EB-2017-0188.

Conversely, the power generation contract market has seen a decline in recent years as evidenced from customers opting to not renew their gas distribution contracts. This has been partially offset by TransCanada Energy's Napanee plant which is slated to be in commercial operations in Q4 2018. As the province's nuclear refurbishment plan is executed, additional generation may be required as various nuclear plants are taken out of service for major maintenance. However, according to the 2017 Independent Electricity System Operator (IESO) Long Term Energy Plan, incremental generation is not expected to be required until the mid-2020s. In addition, at this time it is not certain that this need would be met with natural gas fired generation since the Independent Electricity System Operator has indicated they are agnostic with respect to generation fuel type.

Growth in design day consumption has been modest in Union's franchise area. Increases in general service demand follow the population growth. A forecast of annual consumption and the number of customers can be found in Table 4.2.1.1.1 below. These projected growth figures, plus a forecast of contract growth based on historical contract growth, were used to create the forecasts in this plan.

Table 4.2.1.1.1.1: Forecast of Consumption and Customers

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Consumption (10^6m^3)	12,919	12,981	13,582	13,873	13,817	13,859	13,710	13,687	13,564	13,490
Customers (in 1,000's)	1,501	1,518	1,535	1,552	1,568	1,585	1,601	1,616	1,632	1,647

Asset Growth – Ex-Franchise

Growth in the ex-franchise storage and transmission business is driven by economic factors such as exchange rates, interest rates and gross domestic product, but the primary driver relates to changing North American natural gas market fundamentals such as demand and supply, natural gas prices, natural gas basis differentials (price differential between location), and North American-wide infrastructure projects.

The major contributing factor to Union's recent infrastructure expansion relates to the growth in natural gas production from the Marcellus and Utica shale basins which are within 300 km of Ontario and shippers that are accessing the Dawn Hub. As a result, the flow of natural gas on the Canadian and U.S. pipeline grid is changing and continuing to evolve.

Although difficult to forecast, going forward Union expects further growth along the Dawn Parkway System driven by further demand growth in the U.S. Northeast and Ontario Local Distribution Companies (LDCs), as well as natural gas fired generation due to Ontario's nuclear refurbishment plan, when executed.

Distribution Growth

Union's Distribution Planning group is accountable for making asset planning recommendations with regard to the sizing of mains, services, and station capacities in the Union franchise distribution systems. The distribution systems are designed to ensure the appropriate infrastructure is in place to supply natural gas to customers within the many towns and cities across the franchise. This is accomplished through the use of hydraulic modelling techniques.

Distribution Planning designs systems to meet peak hourly consumption to ensure there are no outages on the design day. Metered data is gathered and analyzed each year to calculate demand assumptions used for system design. Although annual consumption has been decreasing year over year, Union has not seen a decrease in peak hourly consumption.

The Facilities Business Plan (FBP) is an internal planning process used by Union for the identification of reinforcement facilities required to support forecasted growth over a specific geographic area. The FBP is developed for a geographic study area which provides an overall business case for the long range system expansion for the area. Union's franchise area has been divided into a number of specific FBP study areas based on operational areas, pipeline system configuration, and geographical features. FBPs provide a complete analysis of the study area based on a 10-year customer forecast, called the FBP forecast. Based on the FBP forecast, future facilities, both new and reinforcement, can be identified, economically evaluated, optimized, and scheduled to meet the future growth demands on the system.

The advantages of this FBP long range planning approach can be summarized as follows:

- Through the identification of future growth areas, Union can be more responsive to customer needs.
- Optimum, least-cost facilities can be identified to service the growth.
- Long-term security of supply to the overall system can be achieved.

The timing of the facilities is based on current customer attachments and demand forecasts which determine the need for additional facilities. Union updates each FBP as required to monitor the development of the system and to determine if the plan should be modified in any way. With Distribution System reinforcement, the timing of the proposed projects is based on the best available growth forecast information. When the proposed reinforcement plan results in significant peaks and valleys in the capital profile, opportunities are sought to attempt to pace the spend by either deferring projects or bringing them forward into earlier years.

It is Union's objective to provide adequate capacity to serve both current customers and new customers being added to the system. The system will be continuously monitored to better determine when and what reinforcement will be needed to keep the system above the required minimum pressure to serve Union's customers. Figure 4.2.1.1.1.2 shows an example of an FBP map depicting areas of growth within an FBP study area.

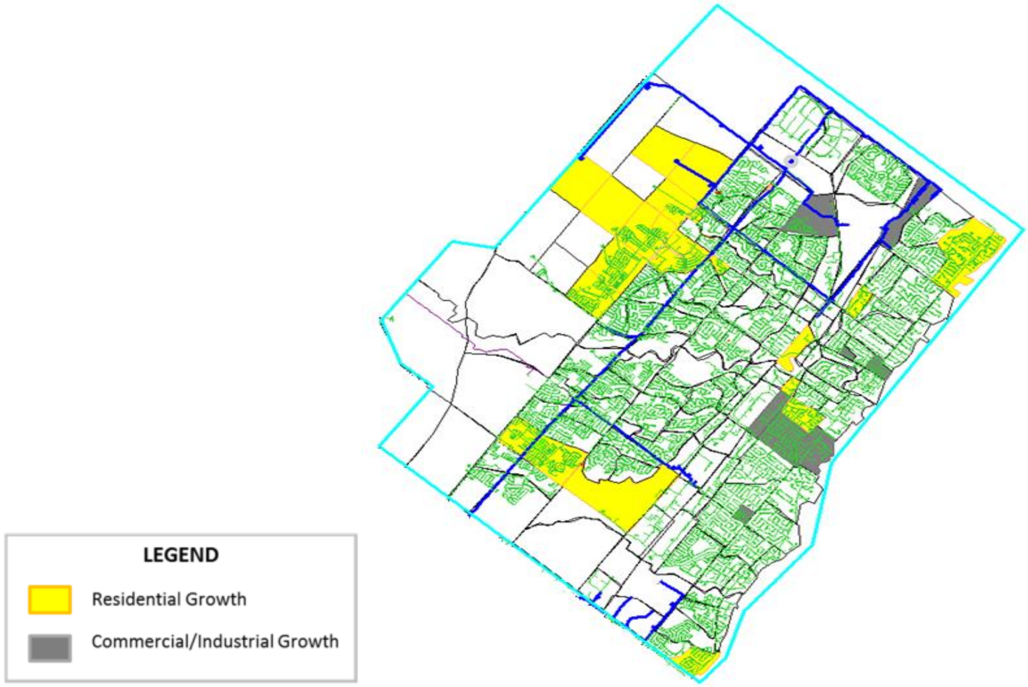


Figure 4.2.1.1.1.2: Example of an FBP Map Showing Residential and Commercial/Industrial Growth

System Growth

Union's System Planning group is accountable to make asset planning recommendations for the three major transmission systems: The Dawn to Parkway System, the Panhandle System, and the Sarnia Industrial Line System. These systems move natural gas from receipt points to delivery locations along the pipeline to meet the volumetric demands and pressure requirements of Union's in-franchise and ex-franchise customers. The pipeline system forms the foundation for future development as customers' needs grow, and represents the supply into the Union South Distribution Planning models as detailed in Section 5.2.1.

System Planning designs systems to meet peak daily consumption to ensure there are no outages on the design day. Metered data is gathered and analyzed each year to calculate demand assumptions used for system design. Although annual consumption has been decreasing year over year, Union has not seen a decrease in peak daily consumption.

Demand for additional long term capacity on Union's major transmission systems is typically met through installation of new pipeline, station, and/or compression. Non-facility options are also considered using gas supply on third party contracts for peaking service to optimize the resources used to provide service. Consideration of options will include evaluating the effect on system reliability, service quality, security of supply, and rates for service. Options are considered based on the "lowest cost per throughput" or highest economic benefit.

The Asset Management Plan provides a magnitude level estimate of future pipeline or compression facilities and does not include any non-facility alternatives or detailed economics for alternative comparisons. In the event that the projects identified in the asset plan proceed, Union will complete a Leave to Construct application where a detailed and rigorous examination of both the facility and non-facility alternatives, including detailed costs and economics will be completed when required.

Storage Growth

Union's Storage Planning group is accountable to make asset planning recommendations for all Underground Storage facilities, as well as the Dawn Compressor Station. The modelled deliverability required from Dawn is a direct output from the System Planning models previously defined and the Union system supply arriving at Dawn from the Gas Supply Plan.

The natural gas storage assets are expanded through either improving existing storage pools or developing new storage pools. Improvements are generally made by increasing the maximum operating pressure of the pool. New storage pools are typically developed by converting a depleted natural gas production field. An Ontario Energy Board (OEB) application and approval is required for developing or improving a storage pool.

In case EB-2015-0551 the OEB determined that Union is required to reserve 100 PJ of storage space to serve the needs of its in-franchise customers. On an annual basis the in-franchise storage space requirements are determined through a natural gas supply plan, using the aggregate excess methodology. The current 10-year forecast indicates that the in-franchise customer requirements are less than the 100 PJs of reserved storage space. This is primarily due to Demand Side Management (DSM) which has reduced the annual consumption of natural gas. Additional requirement for storage space for ex-franchise customers is determined by market demand, market prices, and the availability of economic projects.

Any deliverability shortfalls on Design Day indicate additional storage assets are required. Adding storage wells, compression and piping are typical methods to improve deliverability. Storage deliverability projects also require OEB approval for construction.

No storage growth is forecasted at this time.

Growth – Other

A new area of growth for Union is Compressed Natural Gas (CNG), Liquefied Natural Gas for vehicles (LNG), and renewable natural gas (RNG). Projects forecast in these areas will support low carbon fueling and production for Canada's Clean Fuel Standard.

4.2.1.1.2 Maintenance Planning

Maintenance Planning at Union is the planning of maintenance capital and operating and maintenance expenditures to ensure the safe, reliable, and compliant delivery of services over the life of the assets. Work that will result in maintaining and extending the life of an asset, typically identified as maintenance, is included in the asset maintenance plan. This includes capital and Operation and Maintenance (O&M) expenditures for projects ranging in complexity and scope, as well as a number of spend requirements to maintain tools and other support equipment.

Due to the complexity and variety of Union's assets, they are broken down into asset classes as further explained in Section 3. Asset health requirements and maintenance plans are developed for each of Union's asset classes. Union has a number of programs in place to ensure continued reliability of each asset, including, but not limited to: the Integrity Management Programs, Damage Prevention Program, defined maintenance plans, and robust operational monitoring of Union's critical stations.

The asset lifecycle planning process ensures that optimal decisions related to maintenance expenditures are made through proper prioritization of all identified issues and projects. The creation of a 10-year AMP ensures that issues are identified early allowing for proper risk assessment, project planning, and execution.

Maintenance is determined based on the unique requirements of the asset class to ensure optimal maintenance is being performed and compliance requirements are met. Basic maintenance strategies generally fall into several common categories ranging from run-to-failure to condition-based maintenance.

All assets pass through a number of phases throughout their lifecycle as depicted in Figure 4.2.1.1.1 Asset Lifecycle Model. The primary focus of this Section is to outline how projects to renew or replace assets are identified, selected for execution, and approved. The creation of the 10-year AMP is an important tool to ensure that capital resources are allocated to the highest priority items to reduce risk through improving reliability and safety.

Asset Condition or Health

Asset condition is monitored and impacts the need for a project to either replace an asset or to restore its performance to the required level. As asset condition and performance degrade, risks are raised through the risk management process. There are a number of factors that affect asset health and these generally apply to all asset categories.

The following are examples of some of these factors:

- **Third Party Damage** - When third parties perform work near Union's facilities, there is a risk that they may damage them, referred to as third party damage. Union has a number of strategies to mitigate this risk. All incidents of third party damage are tracked and assessed to determine improvement solutions. Mitigations include Union being a founding and contributing member of Ontario One Call, being a lead proponent to the Ontario Underground Information Notification Systems Act, and actively participating on the Ontario Regional Common Ground Alliance. Other mitigations for higher pressure pipelines include:

- Providing personnel to observe when others are working near Union's facilities (third party observation).
- Installing markers or signs along the pipeline which provide information about the presence of the high pressure pipeline.
- Establishing easements over certain pipeline and then monitoring (ground and aerial surveys) and maintaining these easements to keep them clear of excess vegetation and of third party structures.

- **Construction/Installation Practices** - Union has developed and maintains manuals and specifications which outline proper installation and maintenance methods and stringent quality control to ensure these requirements are met. All pipeline systems are designed by Professional Engineers and use Union approved materials which meet or exceed Code requirements. Union has high quality and safety standards that construction contractors must meet. Maintenance and major construction projects performed by contractors have an assigned inspector to ensure the quality of the installation, that it is constructed as per the design, and that proper construction procedures are followed.
- **Corrosion** – In addition to pipeline coatings, anodes and rectifiers are used to provide cathodic protection and reduce the chance of corrosion of pipelines. The level of cathodic protection is regularly checked to ensure adequate levels of protection. Pipelines that are identified to have inadequate cathodic protection will be assessed to determine the root cause of the inadequate protection and a solution will be implemented. Pipeline corrosion is also measured and assessed by either inline inspection runs or External Corrosion Direct Assessments and digs for pipelines greater than 30 per cent SMYS.
- **Age -** While age can be a factor in determining asset health or condition, on its own it is generally insufficient to make decisions related to replacement projects. There are some key areas in which age is used to drive maintenance requirements, primarily with respect to large rotating equipment such as gas turbines, power turbines and compressors. The Original Equipment Manufacturers (OEM) prescribe maintenance intervals that are based on machine run hours. Although the age of the asset may not have a direct impact on its condition, there comes a point where obsolescence becomes the primary risk. Whether it is an IT application or an aging compressor, as the asset ages beyond a certain point, vendor support for it declines to a point that the risk becomes intolerable.
- **Operating Conditions** - Operating conditions such as the flow profile of a station, magnitude of pressure differential, and equipment settings, can all impact the health of station assets. Equipment that is stressed due to "on/off" type operation or consistently operating at its maximum capacity can accelerate the degradation in performance of the asset and the frequency of maintenance interventions and/or failures. Natural gas quality can also have an impact on the health of the asset.

Debris, pipeline corrosion, and pipeline contaminants including moisture can cause damage to the equipment.

- **Operating Practices** - The conditions under which the equipment is operated is a significant determinant of asset health. Operating procedures, training and ongoing monitoring of key operational parameters are all used as a means to ensure the longevity of the equipment by ensuring that the asset is operated in a manner that is consistent with its capabilities and design.
- **Maintenance Program Effectiveness -** An effective maintenance program ensures that the essential care items such as lubrication, alignment, and filtration are completed as required to ensure the asset continues to perform its required performance. An effective inspection program will ensure that asset performance degradation is identified early to allow for proper planning and scheduling of not only maintenance interventions but also longer-term capital replacements.
- **Environmental Elements -** Environmental elements include factors such as ambient temperature, moisture, oxidation, lightning strikes, power surges, sunlight, and ultraviolet radiation.
- **Security: Industry Best Practices -** As cyber security and perpetrators become more prevalent and more sophisticated in how they attempt to exploit application and IT technology vulnerabilities, changes must be made and costs incurred to maintain an appropriate level of IT security. This is assessed in relation to IT industry best practices. Various reviews including application penetration testing are performed regularly to evaluate current security levels.
- **Asset Health: Pipelines greater than 30 per cent Specified Minimum Yield Strength (SMYS) -** In 2002, Union developed a software algorithm with the assistance of a third party consultant to aid in risk assessments for the pipelines greater than 30 per cent SMYS. This software algorithm, processed through an application called the Risk Analyst Tool, uses a number of probability and consequence factors to calculate a Total Risk Score for all pipelines greater than 30 per cent SMYS within Union's system. This tool was originally used to prioritize pipeline integrity inspections as part of the integrity management program at Union. As Union completed the inline inspections of its pipelines it began to focus more on managing the risks of the anomalies identified and used a risk based approach to prioritize the work. Going forward, Union will further leverage the Risk Analyst tool to focus on assessing asset health.
  - Union is now using the Risk Analyst Tool to assess the health of pipelines greater than 30 per cent SMYS. The Risk Analyst Tool analyzes a pipeline by segments of identical pipeline attributes. For each segment, a variety of factors are used to calculate both relative scores for probability of poor asset health and consequence of failures. This calculation is based on a number of different asset-related attributes for each segment that is assessed.
  - Examples of these attributes include pipe grade, wall thickness, coating type, per cent SMYS, Maximum Operating Pressure, depth of cover, and results from in-line inspection (ILI) and External Corrosion Direct

Assessment (ECDA). The Risk Analyst Tool can provide results for both individual pipeline segments as well as an entire pipeline. In addition to the scores for both probability and consequence, the tool also generates an overall risk score for both pipeline segments and entire pipelines.

- Moving forward, the Risk Analyst Tool will be used on an annual basis to generate updated asset health data for review and assessment. The highest probability and consequence factor scores as well as the highest total risk scores will be reviewed to identify if there are any potential asset health concerns which require further engineering review. The associated factors will be verified, and if deemed appropriate, an engineering review will be initiated for the specific pipeline. The engineering review will determine if any additional measures are required to assess the integrity of the pipeline, or if the inspection frequency of the pipeline needs to be adjusted. Once the engineering review is completed, if any remediation is required, the project will be risk-ranked in accordance with Union's risk management processes and will follow Union's budget process.

- **Asset Health: Underground Storage - Storage Wells -** In 2009, Union developed a semi-quantitative risk tool that evaluates the condition of Union's storage wells. This algorithm uses risk and consequence factors to determine a total risk score for each well that can be compared to other wells. Union has used a third party consultant to help in the various weightings and risk calculation of the algorithm. The risk tool helps prioritize remediation activities by indicating the greatest risk reduction for individual well workovers.
  - The risk tool analyzes each well's attributes to calculate a risk and consequence score. Examples of these attributes include pool location, casing wall thickness, presence of corrosion, wellhead construction, cement quality, maximum operating pressure, well deliverability, distance to nearest residence, and pool size. The risk tool is updated on an annual basis to generate an updated well risk score.
- **Asset Health: All Other Assets -** While there is no specific tool to assess asset health for assets excluding pipelines greater than 30 per cent SMYS and pipes in storage wells, the health of these assets is managed through Union's risk management processes and procedures as described in Section 4.2.1.1.3.
  - As Union identifies individual asset risks or systemic issues with particular asset classes across the franchise, these risks are brought to the risk workshops where Union's subject matter experts discuss the issues and risk rank them. The responsible Asset Class Managers will then begin to plan and prioritize the necessary work required to mitigate these issues.
  - As needed, additional data is used from corporate systems such as Union's Geographic Information System (GIS) to assess failure rates and failure modes, when available, to further quantify asset health to help support asset management related decisions and capital and operations and maintenance (O&M) spend. Union also leverages industry knowledge and experience to gain external perspectives on issues that may be prevalent with other

utilities across North America. As additional data and subject matter expertise is gathered and assessed, programs are created as needed to address specific asset health related risks over defined time periods determined by the associated risk severity of these issues. Many of these programs are highlighted in Section 5.5.

New or Changes to Existing Legal and Regulatory Requirements

Potential projects are identified when regulations change or Union's understanding of the regulations changes. This driver is not necessarily related to the actual condition of an asset, yet it is part of the maintenance capital budget as it is driven by a need to upgrade the asset to new standards set by changing regulations. Key standards that drive maintenance requirements are:

- Canadian Standards Association Z662–15 Oil and Gas Pipeline Systems and the Technical Standards and Safety Authority (TSSA) Code Adoption Document.
- Canadian Standards Association Z341 Storage of Hydrocarbons in Underground Formations, and the Oil, Gas and Salt Resources of Ontario Operating Standards.
- Ontario Building Code for Service Facilities.
- O.Reg.419/05 (Environmental Protection Act, R.S.O. 1990).
- Electricity Gas Inspection Act & Regulations and associated Measurement Canada specifications/bulletins.
- National Energy Board (NEB) Onshore Pipeline Regulations SOR/99-294.

The standards related to pipeline assets have resulted in the creation of a number of key Standard Operating Practices (SOPs) that address code requirements and outline how Union ensures compliance with Standards and Codes.

Contractual Obligations

Due to contractual agreements with municipalities, Union is required to relocate existing plant in cases where it conflicts with municipal infrastructure renewal projects. Union will strive to resolve conflicts by proposing alternative designs to avoid the need to relocate facilities where practical. In cases where no resolution can be achieved, Union will use this opportunity to renew facilities to ensure that an infrastructure renewal project in the near future does not result in additional disturbance to the municipality.

4.2.1.1.3 **Risk Management**

A number of risk management processes are leveraged to adequately assess, evaluate, mitigate, and monitor risks that are identified through a number of different channels. These processes also outline the approach to communicating these risks and seeking endorsement of risk mitigation actions to address them.

Union's risk management process uses a Risk Matrix (Figure 4.2.1.1.3.2) to provide a consistent basis on which to assess risks and prioritize mitigations. Items are raised through field input, input from subject matter experts, or evidence as derived from Union's asset systems of record (e.g., Geographic Information System). Mitigations may be in the form of process solutions or capital investments to reduce the risk to a tolerable level with a view to optimize resource expenditure.

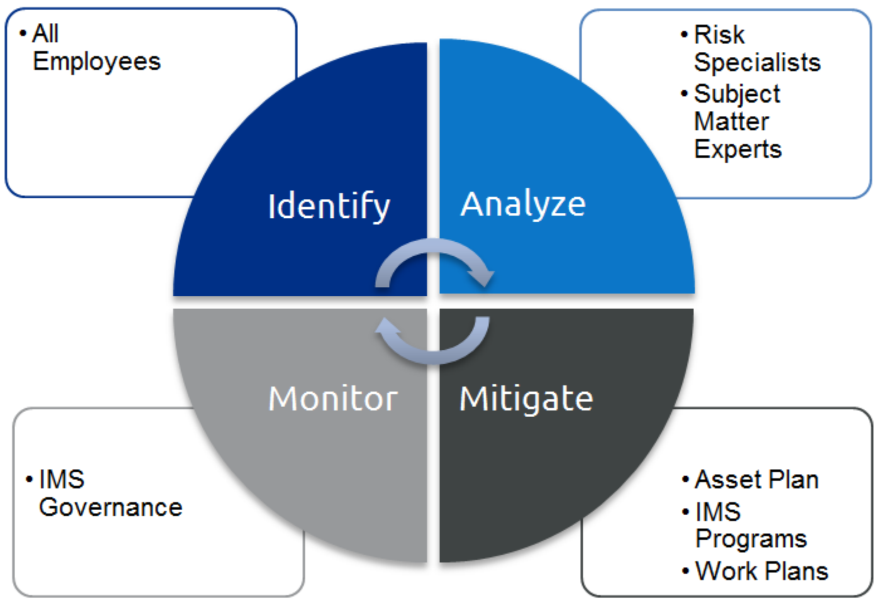


Figure 4.2.1.1.3.1: Risk management process

Hazard and Risk Identification

Operational hazard and risk identification occurs throughout each phase of the asset lifecycle. Hazards are identified through a number of different processes as identified in Table4.2.1.1.3.1. Items one to three are the primary processes used to identify hazards and risks that support asset management.

Table 4.2.1.1.3.1: Methods of Identifying Hazards and Risks

#	Source	Activity	Tactic	Description
1	Subject Matter Expert (SME)	Risk Workshops	Targeted Review	Targeted risk reviews for specific asset classes
2	SME	IMS Program Reviews	Targeted Review	Targeted reviews for specific IMS Programs
3	Asset class owners and operators	Capital Budget Process	Targeted Review	Targeted review for identified capital projects
4	All	Joint Health & Safety Committees	Targeted Review	Targeted review for occupational health and safety hazards
5	All	ILP	Reporting Tool	Specific mechanism to report hazards, concerns and issues
6	Leadership	IMS Governance	Leadership Reviews	Overarching review of hazards, risks and incidents
7	Front Line	Leak Tool	Work Management Database	Hazards identified as part of regular work for leak repairs
8	Front Line	Risk Tracker	Work Management Database	Hazards identified as part of regular work for line hits
9	Front Line	SAP PM	Work Management Database	Hazards identified as part of regular work for plant maintenance
10	Front Line	Distribution Operations Action Request (DOAR)	Reporting Tool	Specific mechanism to report hazards, concerns and issues
11	Front Line	Procedure, Equipment, Material Report (PEMR)	Reporting Tool	Specific mechanism to report hazards, concerns and issues

Newly identified hazards are reviewed and potential risks are evaluated. Based on the assessment results, a new risk may be added to the Operations Risk Registry or an existing risk may be updated. The Risk Registry is a database that is used to track all new risks that are identified and evaluated using the common risk assessment process underpinned by the Risk Matrix. All documented risks are tracked and managed in the Risk Registry through a cycle of continual reviews and updates.

Risk Analysis

Risks are assessed using a number of different approaches based on the types of hazards and assets that are under review. All risks are evaluated within the context of Union's Risk Matrix (Figure 4.2.1.1.3.2) to determine the likelihood of occurrence of the event in question and the consequence of the failure.

		Likelihood/Probability				
ALMOST CERTAIN	L5	III	II	II	I	I
LIKELY	L4	III	III	II	II	I
OCCASIONAL	L3	IV	III	III	II	II
RARE	L2	IV	III	III	III	II
REMOTE	L1	IV	IV	IV	III	III
		Consequence				
		C1	C2	C3	C4	C5

Figure 4.2.1.1.3.2: Union's Risk Matrix

Consequences are grouped into the following categories:

- Injury
- Regulatory
- Loss of containment
- Environmental
- Financial
- Reliability
- Reputation

The following is a list of the most commonly used types of risk assessments:

- Risk Workshops: Risk workshops are facilitated annually by the Engineer Specialist Risk Management during which SMEs in a given asset category are assembled to identify new risks and create a better understanding of previously-identified risks.
- Brainstorming: Group exercise to identify hazards and assess risks associated with a process or set of equipment. Used during regular reviews of the Risk Registry.
- Checklist review: Identify hazards, review general types of incidents, and evaluate impacts and controls in a systematic manner. Used during Risk Reviews in support of the Maintenance Capital Budget.
- Hazard and Operability Study (HAZOP): Systematic and detailed identification and evaluation of process facility safeguards with a multidisciplinary team. Used in the design phase for large capital projects.

- Reliability Centred Maintenance (RCM): Focused on required functions (based on the asset's operating context) and the functional failures that may occur. Used when focusing on developing or evaluating maintenance plan.
- Engineering Assessments: Detailed technical reviews performed by internal engineering staff or a third party consultant. Used for a detailed review of a possible systemic concern or risk.

New risks identified through these assessments are entered into the Risk Registry, and then significant risks (Risk Rank I and Risk Rank II) are presented to the accountable director, the Operations Steering Committee and the accountable vice president for endorsement.

Risk Treatment/Mitigation

Risk treatment is the mitigation of identified risks, ranging from day-to-day operations activities undertaken by operators and field personnel to inspect equipment, to a large capital project to replace an existing asset (Figure 4.2.1.1.3.3). Operating inspections, procedures and preventive maintenance activities are developed during the commissioning of an asset and are used to mitigate identified risks throughout the operations and maintenance phase of the asset lifecycle. The maintenance strategy for a facility or asset is established on the basis of Standard Operating Practice (SOP) requirements, the outputs of a maintenance strategy analysis (such as RCM) or Original Equipment Manufacturer (OEM) recommendations.

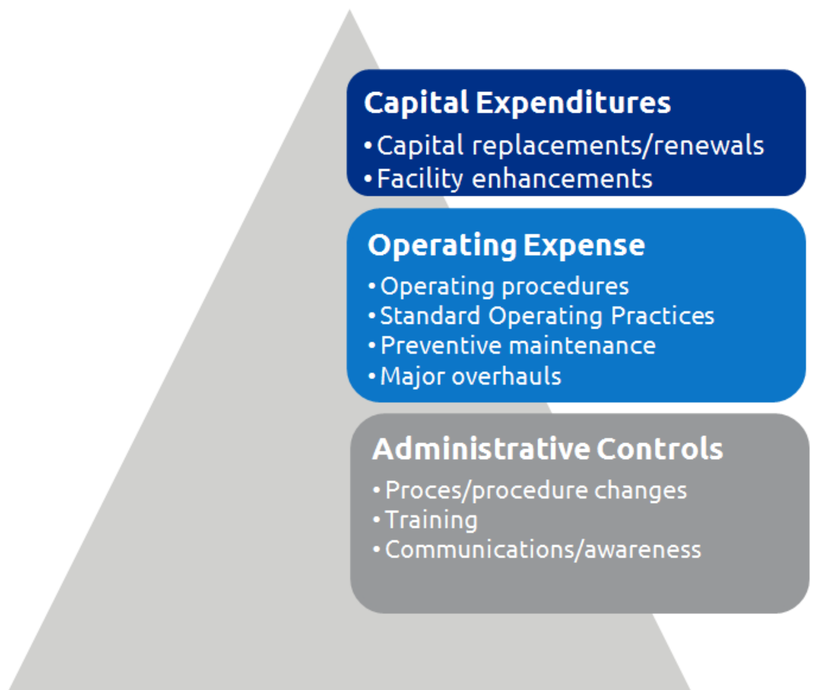


Figure 4.2.1.1.3.3: Spectrum of risk treatment options

4.2.1.1.4 Project Prioritization and Selection

The 10-year AMP is used as the starting point for the annual capital budget process, which determines the budget for the following year. Through the budget preparation process, the risks that each project is mitigating are re-evaluated and endorsed. It is at this point that new projects may also be identified to mitigate risk. Figure 4.2.1.1.4.1 outlines the budget cycle process with the AMP as the starting point.

Figure 4.2.1.1.4.1: Annual Budget/Asset Management Plan Cycle

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

Union has developed a consistent methodology for prioritization of all projects, as depicted in the figure below. The figure shows that there are projects of a higher priority nature at the top of the graphic to lower priority projects at the bottom. It is also important to note that the projects toward the high priority end of the spectrum have inherently less flexibility on the level of expenditure and timing. As we move down the priority spectrum, there is an increasing level of flexibility in expenditures and timing.

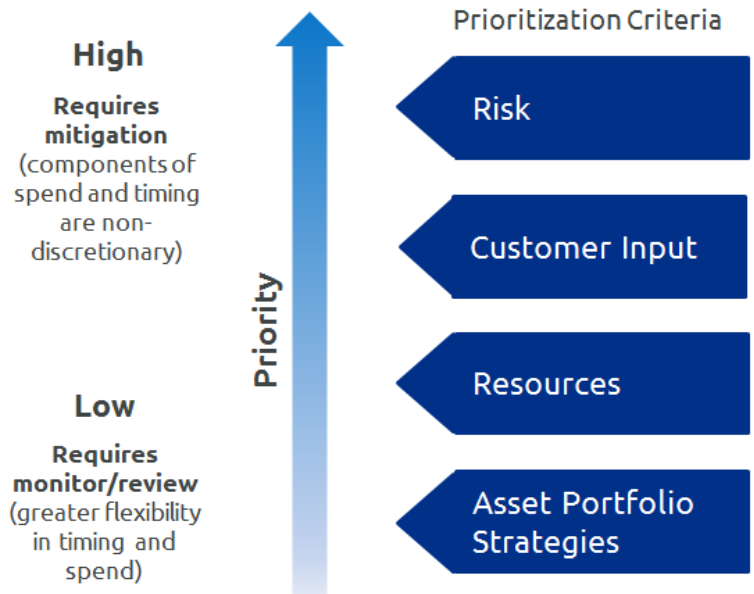


Figure 4.2.1.1.4.2: Asset Management Plan prioritization criteria

Maintaining a mix of high priority and low priority projects allows for adjustments to be made as circumstances change. If, for whatever reason, a high priority project is identified in a given budget cycle, a lower priority project may need to be displaced to provide needed capital resources.

Several criteria are used to consistently prioritize all projects and portfolio strategies within in the overall maintenance capital portfolio (Figure 4.2.1.1.4.2).

- Risk is one of the most important criteria, and is assessed using Union's risk management process. Risk is a combination of likelihood of the event and consequence of that particular event.
- Customer input and preferences, as obtained through various customer engagement activities, are carefully considered when making strategic asset maintenance decisions. Union's 2017 customer engagement survey showed that customers have an overwhelming preference to maintain a steady pace of spend to keep the system healthy in the long run.[1] Evidence of Union's commitment to a steady pace of spend on assets can be seen in the overall 10-year maintenance capital outlook in Section 5. The project descriptions found in Appendix D share more detail on how specific results of the customer engagement survey were considered.

[1] Unless otherwise stated, the results presented relate to residential customer feedback.

- Resource availability is also used to assist in project selection. Given a number of projects of equal priority (or risk), workload distribution is used to make final decisions of which projects will proceed in a given year.
- Asset portfolio strategies are important decision criteria that are used to select certain projects over others. These strategies are given higher priority to ensure continuity in addressing a broader issue holistically.

Union uses a simple priority ranking scale of 1 to 4 to help to organize the entire capital portfolio and to ensure that the highest priority work is identified and planned accordingly.

Table 4.2.1.1.4.1: Priority ranking scale

Priority Level	Examples
1	• Compliance-related items • Growth • Contractual obligations • Risk Rank I items
2	• Risk Rank II items • Specific portfolio strategies (bare and unprotected steel replacement) • Baseline maintenance spend (tools, emergency blanket spend)
3	• Risk Rank III items
4	• Risk Rank IV items • Other low-priority items

Items that are classified as Priority 1 are considered mandatory and timing is usually inflexible. Risk Rank I projects are considered a significant risk that is intolerable and requires notification to the president within 48 hours of discovery. Short-term mitigation plans must be put in place in less than four weeks and the target to implement long-term mitigations is less than six months. In cases where this is not possible, specific approvals must be attained. Although the Priority 1 category is comprised of more than just Risk Rank I items, all items in this priority level are treated with a high degree of urgency.

Projects that are rejected must be reprioritized to a subsequent year in the asset plan using the criteria identified in Table 4.2.1.1.4.2 Figure 4.2.1.1.4.3 outlines the decision process for prioritizing the budget and the subsequent years within the AMP. Projects that are rejected from the current budget are moved into the following year of the plan, reprioritized and ultimately accepted or rejected for that year of the plan. Projects that are subsequently rejected are moved into the following year, and the process is repeated for each year of the plan. This process ensures that the highest priority work is planned in each year based on the best information at the time the plan is created. In the case of a lower risk project, the process will continue to push the project to future years. This approach enables Union to track and monitor issues that have been raised so they are not missed and can be revisited to determine if the risk associated with the issue has changed.

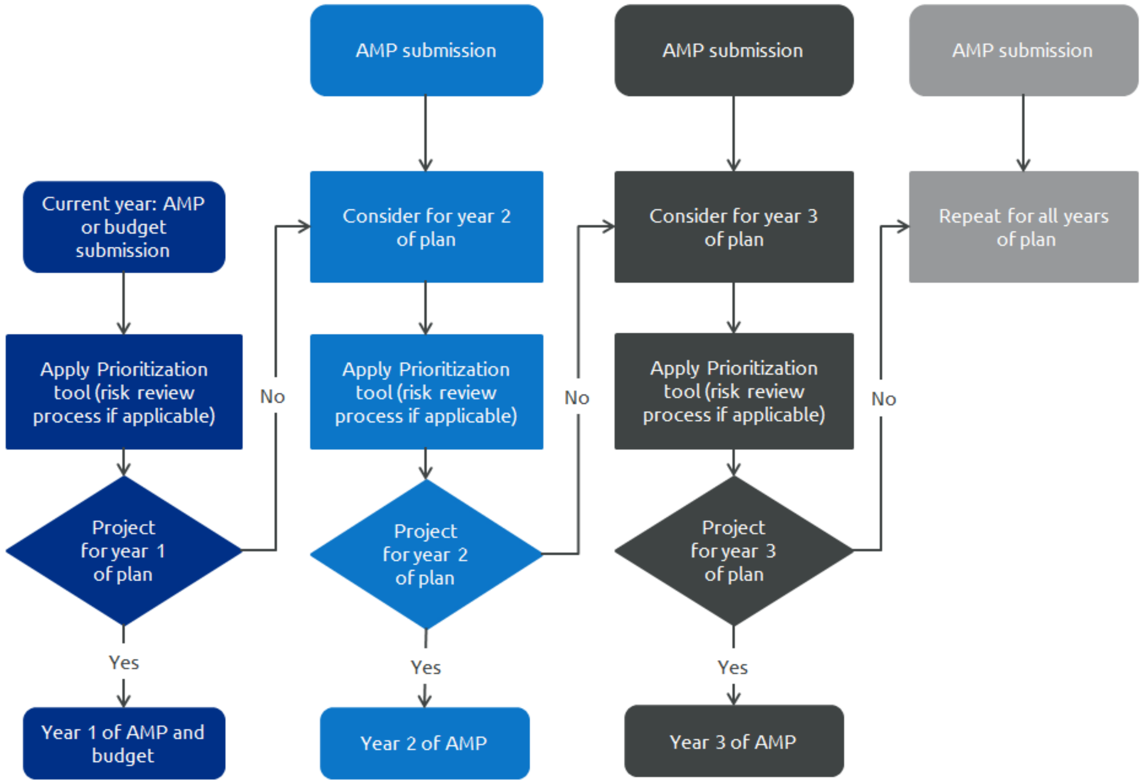
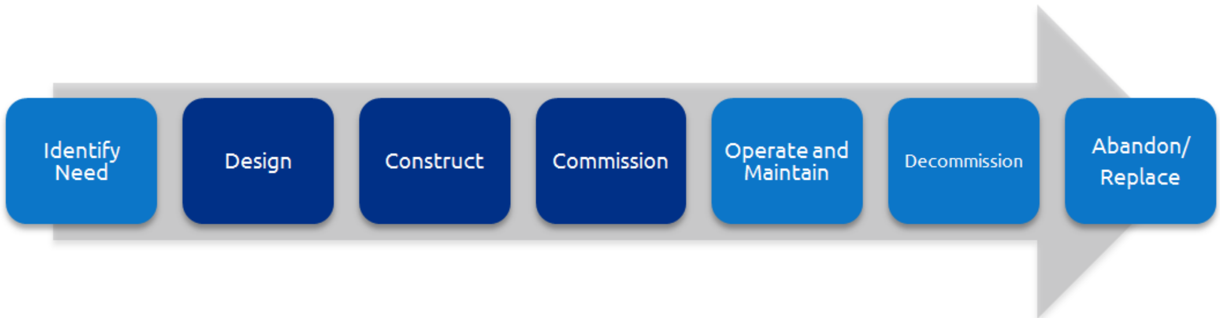


Figure 4.2.1.1.4.3: Annual prioritization flow of Asset Management Plan projects

4.2.1.2 Design, Construct and Commission



Whether it is a project that is designed by internal engineering resources or by external design firms, a strict set of design and construction specifications are followed. It is understood that the proper design, installation/construction and commissioning will affect the performance of the asset throughout the asset lifecycle. Decisions made in these phases will have a profound impact on the health and performance of the asset through the operation and maintenance phases.

4.2.1.2.1 **Integrated Resource Planning**

Consumers have the right to safe and reliable service, as well as the right to access available energy conservation programs. In response to the Ontario Energy Board's (OEB) case EB-2015-0029, Union has filed a Joint Transition Plan on how it anticipates integrating the supply and demand side processes. The Transition Plan lays the groundwork for a pathway to consider Integrated Resource Planning (IRP) over the coming years. This plan will aid in the coordination between distribution planning processes and analysis, and low carbon alternatives, including energy efficiency. IRP at Union refers to a multi-faceted planning process that includes the identification, preparation, and evaluation of all realistic supply-side and demand-side options to determine the least cost and lowest risk approach in addressing transmission and distribution infrastructure requirements. The IRP process could include:

- A review of a variety of different low carbon options such as energy efficiency to defer existing regional and local infrastructure.
- The impact of net-zero ready subdivisions and behind-the-meter solutions.
- Distributed energy resources (e.g., renewable natural gas).
- The interplay of these various energy options and the subsequent impact on infrastructure to meet system demand.

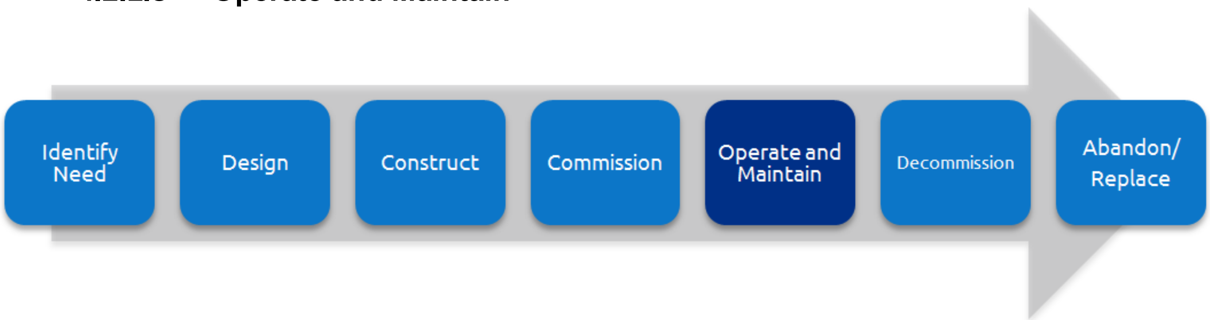
Although the supply and demand side options considered within IRP can be quite broad, in recent years, much of the discussion has focused on the impacts of Demand Side Management (DSM) and energy efficiency. At Union, DSM focuses on broad-based annual savings across the franchise areas that drive maximum bill reduction, versus a jurisdictionally-bound, peak-hour load reduction to influence supply planning. Currently, DSM plans account for potential savings in system-wide infrastructure (created by DSM savings through avoided distribution costs). On the other hand, infrastructure planning is based on a long-term load forecast intended to:

- Identify potential system constraints leading to incremental infrastructure requirements.
- Develop plans prior to the need for new infrastructure.

The primary goal of infrastructure planning is to ensure that the utility’s infrastructure is sufficiently robust to provide reliable and safe natural gas service that meets the design condition peak hour requirement forecast. The impact of broad-based DSM programs on infrastructure investment is inherently captured in the infrastructure planning process. Historical gas throughput is used as a base to predict future consumption and is updated each year. These historical forecasts include changes in gas usage resulting from implementation of historical DSM measures, as well as other natural conservation factors such as improved building codes and higher energy efficiency standards for natural gas equipment. The infrastructure plans do not explicitly factor in future projections of DSM program effects on peak day or peak hour demand as they are not known and therefore not certain.

As Union’s IRP and DSM programs evolve, there will be increased clarity around any subsequent impacts of these initiatives on peak period demand, further informing infrastructure planning and forecasting processes. IRP will continue to be monitored as part of Union’s Asset Management Plan to ensure advancements made are acknowledged and incorporated during asset investment planning.

4.2.1.3 Operate and Maintain



The operation and maintenance phase of asset's life is the longest, and the success of this phase largely determined by decisions made in the previous two phases (construct and commission). The manner in which the asset is operated and maintained will have a direct impact on its performance and longevity. Through this phase, incremental operation and maintenance (O&M) expenditures are typically identified to support changes in maintenance plans (e.g., new technology, new regulations).

4.2.1.3.1 **Asset Operation**

It is important that the operator of the asset understands its capabilities, as operating an asset in a manner that demands more than it was designed for will have a negative impact on its health and performance, resulting in premature degradation. Operating procedures are developed for physical assets to outline the acceptable range of operation and the limits of the asset performance. For many assets, there are controls in place to raise alarms when certain detrimental operating conditions occur.

4.2.1.3.2 **Asset Maintenance**

The purpose of maintenance is to preserve the required level of performance of the asset. This is accomplished through a variety of maintenance strategies that range from a simple run-to-failure strategy, to continuous condition monitoring and condition-based maintenance. The type of maintenance strategy used is selected to adequately address the consequence of failure of the asset, within the limits of technical feasibility of proactive tasks to identify potential failures.

Although maintenance tactics differ somewhat amongst the various asset categories, the same types of strategies are employed in each. All asset categories have two major groupings of maintenance activities: preventive and corrective. Generally, preventive maintenance consists of all activities performed to prevent a functional failure of the asset; whereas corrective maintenance describes all activities performed to restore the performance of the asset to its desired standard. Corrective maintenance can be either proactive, in the case where the corrective action is completed prior to point at which the asset can no longer perform its required function; or, reactive which is typically referred to as break/fix.

Pipelines greater than 30 per cent Specified Minimum Yield Strength (SMYS) are monitored using inline inspection (ILI) or External Corrosion Direct Assessment (ECDA) at a prescribed frequency as part of the Pipeline Integrity Management Program, Class

Location Surveys and Depth of Cover surveys. Any anomalies that are identified during an ILI run will be assessed using Union's Pipeline Integrity Engineering Reference Manual practices, which may drive pipeline maintenance. This program is an example of condition monitoring techniques to identify potential failures early allowing for good planning and scheduling of intervention at the right time.

Across the physical asset classes, there is generally a heavy reliance on inspections and condition monitoring to identify potential failures. There are a number of key Standard Operating Practices (SOPs) that are generally based on code requirements for inspection and maintenance of natural gas assets. These SOPs typically prescribe a required minimum inspection frequency, the scope of the inspection as well as the requirements to complete remedial actions to correct identified deficiencies.

In general, inspections are a form of condition monitoring with tasks and inspection points designed to identify certain expected failure modes that may be present. A repair or restoration task is only undertaken in the event that an impending failure is identified.

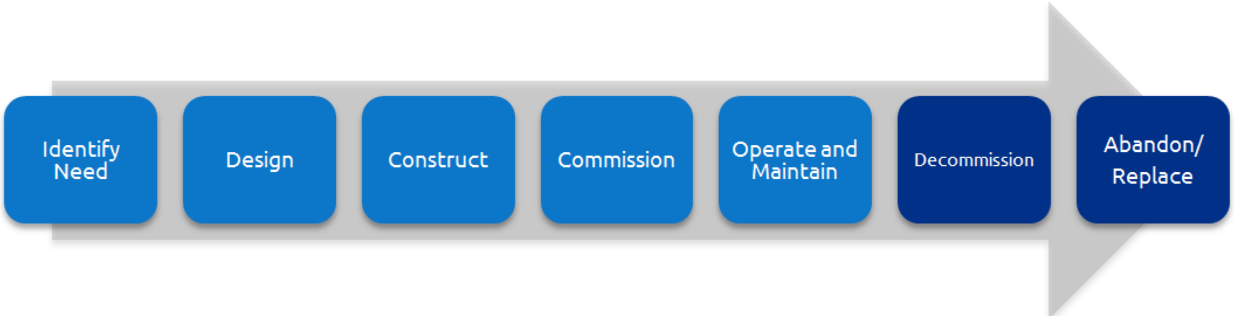
Time-based maintenance activities are those that occur at a pre-determined interval (either calendar time or run hours). Time-based activities are often referred to scheduled restoration, discard or renewal. Examples of scheduled maintenance tasks include:

- Scheduled replacement of diaphragm meters.
- Scheduled restoration of gas turbines based on Original Equipment Manufacturer (OEM) recommended overhaul interval.
- Technologies such as workstations, servers, network devices, databases and integration tools are upgraded every three to four years to maintain vendor support, performance, reliability and provide higher levels of security.

One approach to defining asset maintenance strategies that is seeing wider adoption at Union, particularly in the realm of rotating equipment, is Reliability Centred Maintenance (RCM). RCM is a very prescriptive approach to developing a maintenance program that begins with a clear understanding of the asset function. The maintenance tactics are derived as a means to preserve the required function of the asset. This is accomplished by identifying all functions of the asset and its functional failures and failure modes.

RCM then determines a consequence for each failure mode and applies a decision matrix that leads to the optimal solution or maintenance strategy to reduce or eliminate the consequence of each identified failure mode. This approach also requires the developer to question the economic business case of the suggested action to avoid over-maintaining the asset where the consequence does not warrant the effort to avoid it; a situation that results in the very legitimate maintenance strategy of run-to-failure.

4.2.1.4 Decommission and Abandon/Replace



When the asset reaches the end of its life, meaning the cost to continue to operate and maintain the asset are greater than the cost of replacing it, or the risk of continuing to operate and maintain it becomes too great, a number of alternative solutions are identified. These various alternatives are evaluated and one is ultimately selected and proposed in the AMP and subsequently included in the maintenance capital budget based on risk assessment and economic analysis. In the event that the selected solution is to retire, decommission or abandon the asset, there are a number of important considerations, including minimizing residual liabilities through the disposition of obsolete inventory, operating procedures, maintenance plans and records. These changes are managed using a number of tools such as the Management of Change (MOC) process.

4.3 Facility Greenhouse Gas (GHG) Abatement

Union is committed to the ongoing review of opportunities that will reduce greenhouse gas emissions from its natural gas transmission, storage and distribution operations in future years. Recent feasibility studies have identified several potential facility abatement opportunities that would lead to a reduction in methane and carbon dioxide emissions over the next ten years.

With recent changes in provincial government policy, Cap and Trade regulations are no longer the driving force for facility greenhouse gas (GHG) abatement. However, starting January 1, 2019 the Government of Canada intends to implement a carbon pricing system in any province that does not have a carbon pricing system that meets the federal benchmark. This federal legislation will implement carbon pricing that could support economic facility abatement initiatives in the future. Additionally, a new federal regulation targeting the reduction of methane will come into effect in 2020-2023 and a proposed Clean Fuel Standard is expected to come into effect in 2022 or 2023. The introduction of these new requirements will have impacts, which are yet to be determined, on facility GHG emission requirements. Union will continue to monitor these emerging issues and will adjust its long-term strategy and plans accordingly.

Results of Union's 2017 customer engagement study (telephone survey) showed that given the option of maintaining the status quo or paying an additional 50 cents per year for Union to reduce its GHG emissions beyond what is regulated, 58 per cent of residential customers would prefer to pay for the additional reduction. However, one third (33 per cent) say Union should not go beyond the regulated emissions requirement. Nine per cent either weren't sure or didn't have a strong opinion.

Results showed that commercial customers are not quite as willing as residential customers to pay for additional reductions in GHG emissions: almost half (49 per cent) would agree to a 2 dollars per year increase in rates for an additional 25 per cent in emissions reductions, but 42 per cent say Union should meet but not exceed the regulated requirement. Fewer than one-in-ten (8 per cent) did not offer an opinion.

Union will continue to develop criteria to appropriately evaluate potential facility abatement opportunities to ensure the implementation of initiatives effectively balances customer preferences, compliance obligations, anticipated future regulations, and other noteworthy benefits such as safety and operational reliability. This includes how the cost of carbon should be assessed, alongside other operational considerations, when evaluating system expansion alternatives.

4.4 Incremental Operations and Maintenance Expense

Within the scope of this plan are considerations related to incremental increases in operation and maintenance (O&M) expenses. For the purposes of identifying changes to the overall plan, only incremental changes relative to the base year (2018) are discussed. Specifically, the incremental O&M discussed in this plan are those items which have a direct connection to the asset management activities.

New programs or projects are directly attributable to items that require a change in how Union conducts its operation. Examples include new regulations resulting in the need for increased expenditures to maintain compliance; or, new programs to enhance inspection and maintenance programs to mitigate some identified risk.

A key input to Union's investment decisions is the trade-off between capital and O&M expenses. In cases where O&M and capital alternatives are available, both are evaluated to determine the solution that provides the best overall value. Section 5 details the incremental O&M expense associated with each asset category along with a description of the item and the driver for the increase. Union also needs to manage cost pressures on the base business. These pressures are typically not due to new programs or regulations driving the need for increased spending, rather they are the result of more gradual changes, such as inflation. Although these are not quantified in the Asset Management Plan, they are identified through the planning process, noted in the Plan, and factored into both the budgeting process, and into the asset management planning process as inputs into the costs used to assess alternatives.

5 Customers, Assets and Asset Categories

5.1 Overview of Customers and Asset Classes

Union has a network of natural gas assets that serve to receive, store, transport, and distribute natural gas. Assets illustrated in Figure 5.1.1 can be found at Union including underground storage, compression and dehydration, transmission and distribution pipelines, and the meters and regulator stations within Union's system and at customer's premises.

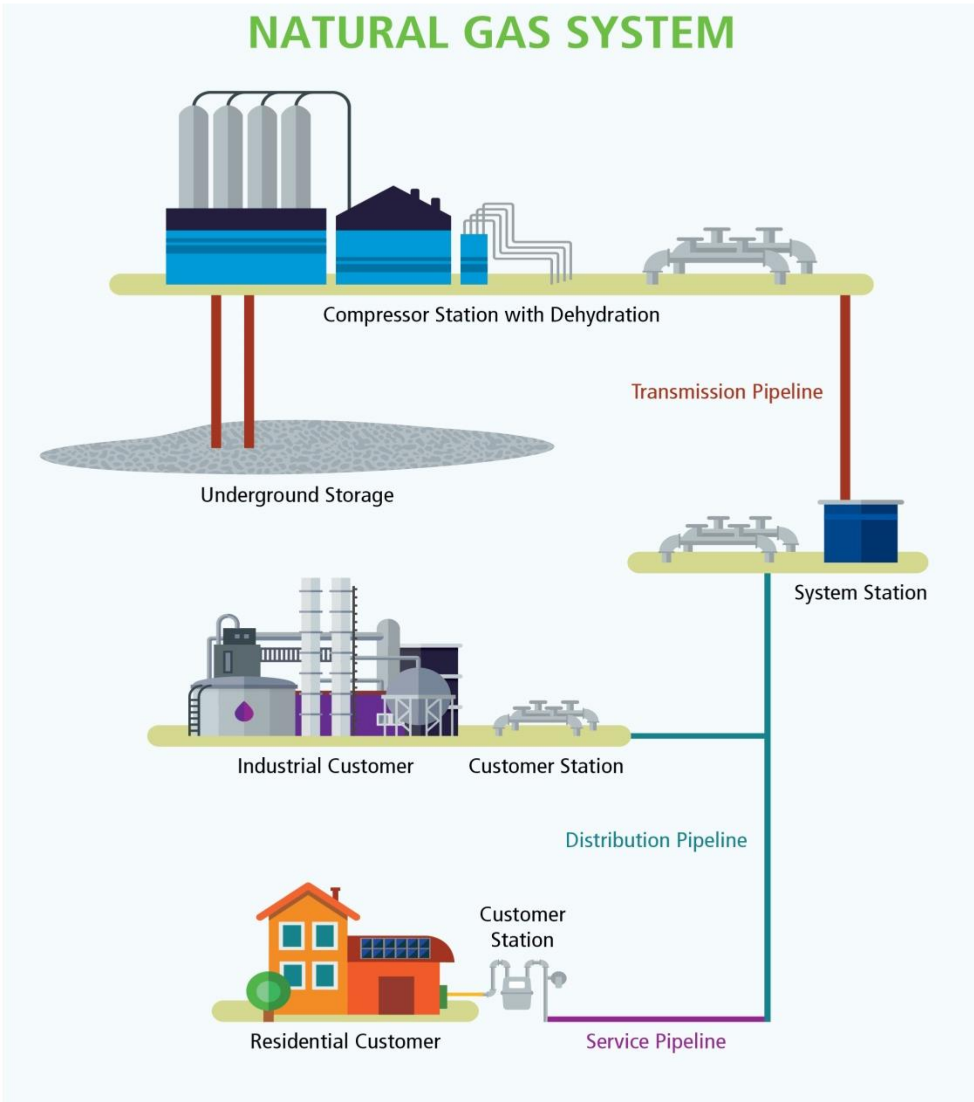


Figure 5.1.1: Components of a natural gas system

Customers, Assets and Asset Categories

To optimize maintenance and growth strategies, natural gas carrying assets are grouped into seven asset categories and ten associated asset classes as summarized in Figure 5.1.2. Additionally, there are three non-commodity carrying asset classes that support general operations for Union: Service Facilities (Corporate Real Estate Services CRES), Fleet, and Technology and Information Services (TIS). More detail about each asset class is summarized in Section 5.4.

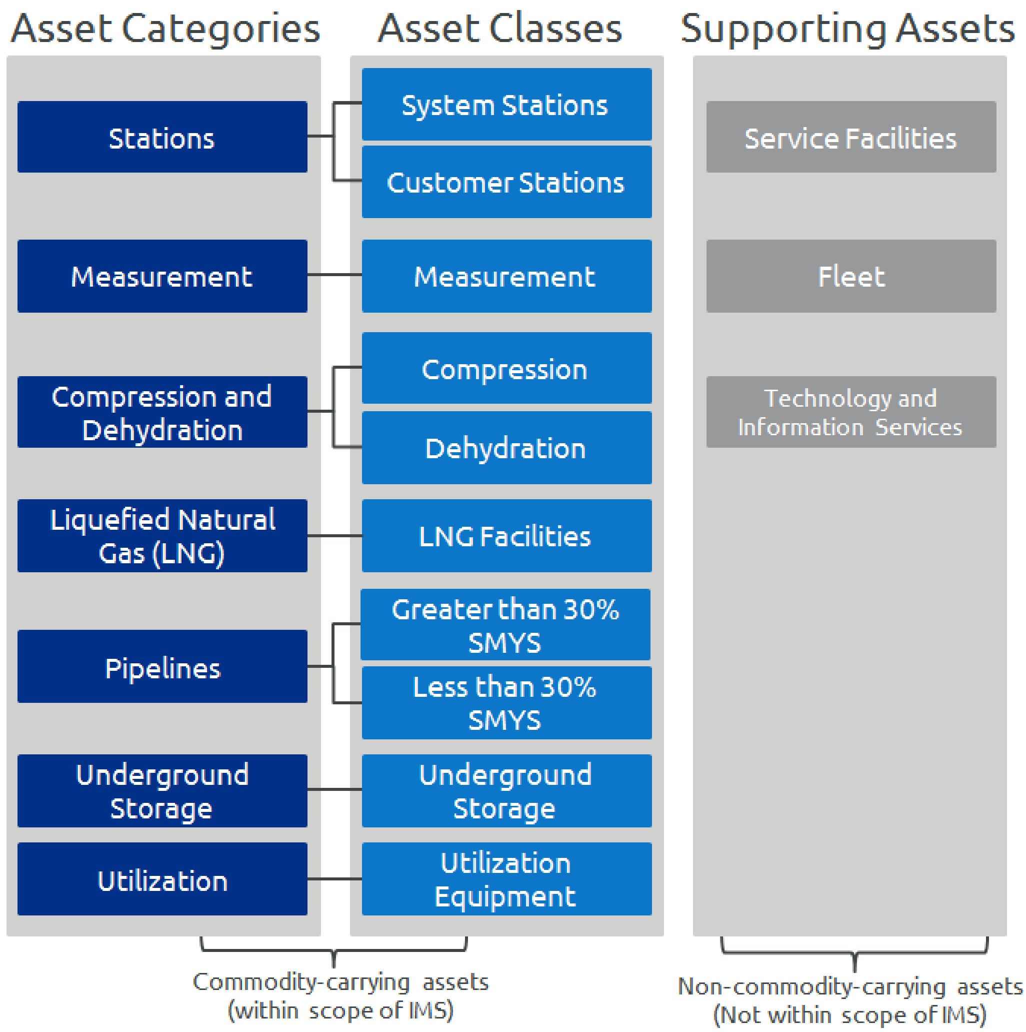


Table 5.1.2: Asset Categories, Asset Classes and Supporting Assets

5.2 Customers and Customer Growth

Union serves approximately 1.5 million customers in the Province of Ontario. These customers are referred to as in-franchise customers and are grouped into three main categories:

Residential

Residential customers are supplied for residential purposes in a single family dwelling or building, an individual flat or apartment within a multiple family dwelling or building, or a portion of a building occupied as the home, residence, or sleeping place of one or more persons.

When service for residential purposes is supplied to two or more families served as a single customer under one rate classification contract, that service is considered as commercial but is counted as only one customer. Residential premises also used regularly for professional or business purposes (e.g. doctor's office in a home or a small store in a home integrated with the living space), are considered as residential where the residential use of gas is half or more than half of the total service.

Commercial

Commercial customers are considered as customers who are engaged in selling, warehousing or distributing a commodity, in some business activity or in some other form of economic or social activity (also includes professions). The size of the customer's operation or volume of use is not a criterion for determining commercial service.

Industrial

Industrial customers are those engaged in a process which creates or changes raw or unfinished materials into another form or product, or who change or complete a semi-finished material into a finished form. All gas used on premises which qualify under the industrial classification is classified as industrial service. The size of the customer's operation or volume of use is not a criterion for determining industrial service.

Contract and Non-contract

In-franchise customers are served either by non-contract or contract rate classes. Customers in the contract rate classes tend to be larger volume consumers of gas who have made a term, volume, and storage commitments as part of their service. Non-contract customers are typically residential users and smaller commercial and industrial operations that have made no contractual commitment for service from the utility.

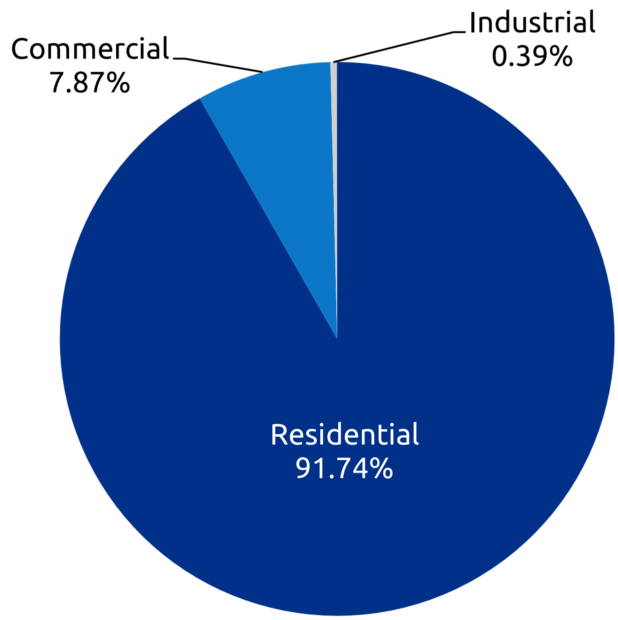


Figure 5.2.1: Breakdown of Union's customer base - by customer type

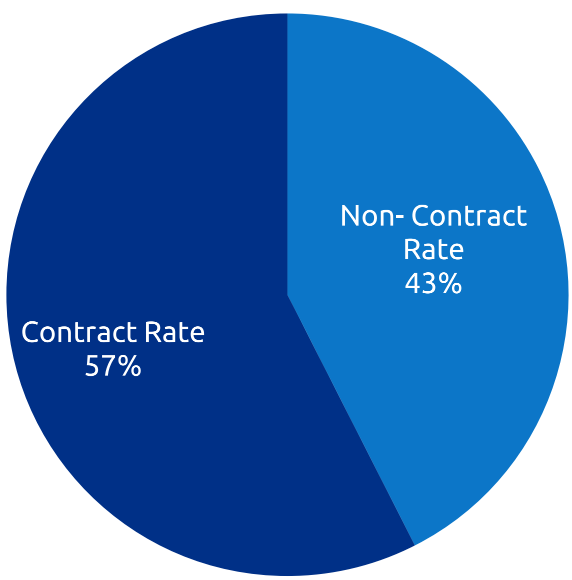


Figure 5.2.2: Breakdown of Union's customer base - volume per rate class

Figures 5.2.1 and 5.2.2 demonstrate that while the residential sector makes up the majority of the customers by count, the contract customer segment is by far the largest by volume. There are a large number of contract customers across the franchise representing a very important component of Union's business. Union manages these large contract customers through an account management process. Union regularly pursues growth in the contract rate customer growth segment, through the expansion of existing customers as well as the addition of new customers to the system.

Customer growth is grouped into two main categories:

- Distribution growth.
- System growth.

Distribution growth is associated with customer growth on the distribution system, whereas system growth is associated with customer growth on transmission systems. The following graphic depicts the breakdown of the Union's customers by type.

5.2.1 Distribution Growth

Table 5.2.1.1: Distribution Planning 10-Year Growth Summary (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
General Customer Growth	68.9	69.7	65.7	67.0	73.3	74.6	71.1	82.5	73.9	80.4	**727.1**
Community Expansion	6.8	0.1									**6.9**
CK Rural	16.2	0.4									**16.6**
Distribution Reinforcement	9.8	7.1	7.2	9.6	21.4	8.3	9.3	9.3	30.6	8.9	**121.6**
Station Reinforcement	1.4	3.9	10.8	21.4	35.8	18.7	1.7	1.7	0.4	2.1	**97.8**
Transmission Reinforcement	33.3	51.5	12.3	15.9	9.8	6.6	48.7	39.5	20.5		**238.0**
Distribution Planning Total	**136.3**	**132.7**	**95.9**	**113.9**	**140.3**	**108.3**	**130.8**	**132.9**	**125.3**	**91.4**	**1,207.9**

General Customer Growth

General Customer Growth is the forecast to attach new general service customers and new contract rate customers in the distribution systems and is based on the forecasts provided in Table 4.2.1.1.1.1. The forecast value is determined by applying a five-year historical average cost to attach customers to the forecast number of attachments as outlined in Table 5.2.1.1. The costs associated with general service include the mains and services to attach the customer as well as the costs associated with the meter and regulator installation at the customer's site.

This item also contains the forecast associated with attaching large contract customers. Historically, Union attaches one large contract customer every two to three years. At any given time there are a number of potential contract rate customers that are either seeking access to Union's system or are seeking an increase in their contracted volume. Based on discussions with these potential customers, a forecasted volume is calculated and used to estimate the capital requirements to attach the new customer or to increase the contracted volume.

Community Expansion

In response to the Ontario Energy Board's (OEB) initiative to address the Government of Ontario's desire to expand natural gas distribution systems to communities that currently do not have access to natural gas,[1] Union has filed proposals with the OEB designed to facilitate enhanced access to natural gas for non-served rural, remote and First Nation communities, and businesses in the province.

The availability of natural gas in community expansion project areas will create a number of benefits, both from a customer and community perspective. Not only will natural gas provide annual energy savings for customers, it will also result in reduced costs and increased efficiencies for existing businesses. The expansion of natural gas to these areas will help remove economic barriers.

Union's initial Community Expansion proposal[2] focused on four projects:

- Chippewas of Kettle and Stony Point First Nation and Lambton Shores.
- Milverton, Rostock and Wartburg.
- Prince Township.
- Delaware Nation of Moraviantown.

The OEB has granted approvals for the four projects and they will be in service by the end of 2018.

On July 30, 2017, Union submitted grant applications to the Government of Ontario (the Government) for 45 community expansion and five economic development projects based on funding from the Natural Gas Grant Program. On April 3, 2018, the Government announced grant funding for 11 projects, which includes up to $22 million in grant funding for four projects proposed by Union:

- Chippewas of the Thames First Nation.
- Delaware Nation of Moraviantown.
- North Bay (Peninsula and Northshore Roads).
- Saugeen First Nation.

The Delaware Nation of Moraviantown Project received rates approval from the OEB in 2017. In May 2018, Union filed an application with the OEB seeking approvals to serve the communities of the Chippewas of the Thames First Nation, North Bay (Peninsula and Northshore Roads) and Saugeen First Nation.

The recently elected provincial government indicated that the Natural Gas Grant Program would be terminated in the fall of 2018.[3] Union is awaiting the introduction of new legislation that is being developed by the provincial government to encourage private sector investment in the expansion of natural gas in Ontario. Union is seeking

[1] Minister of Energy correspondence dated February 17, 2015 and OEB invitation for parties to submit a community expansion proposal dated February 18, 2015.
[2] EB-2015-0179 updated application and evidence dated March 31, 2017.
[3] The funding agreement for Delaware Nation of Moraviantown was already executed and therefore was not withdrawn.

further clarification on intent and consequently notes that the above projects may be subject to deferral or cancellation as a result of restricted government funding. Depending on the mechanisms provided to incent private sector investment in similar projects, Union may make additional community expansion project proposals over the next few years.

In October 2016, Union and EPCOR Utilities Inc. (EPCOR) both filed Common Infrastructure Plan Proposals to serve the area covered by the South Bruce Expansion application. An OEB administered process to determine the successful competing project proponent was completed, and in April 2018, the OEB selected EPCOR to provide natural gas distribution service to the South Bruce Expansion area. EPCOR's proposal is expected to be supplied from Union's pipeline system and required reinforcement of the Owen Sound Line is under development.

Chatham-Kent Rural Expansion

In order to provide opportunities for economic growth within Chatham-Kent, Union is proposing to install a 500 m NPS 12 steel 6,040 kPa pipeline and a 13 km NPS 8 steel 6,040 kPa pipeline to boost system capacity across the Chatham-Kent region.

Distribution, Station and Transmission Reinforcement Projects

Reinforcement includes the reinforcement projects identified through the Facility Business Plan (FBP) process. These projects are important to meet the forecasted growth and will ensure Union is able to serve and satisfy those customers. For a detailed description of each of the projects in the distribution growth forecast, refer to Appendix D. The appendix is divided into the following Sections:

1. Growth
2. Pipelines
3. Stations
4. Compression and Dehydration
5. Liquefied Natural Gas
6. Measurement
7. Underground Storage
8. Service Facilities
9. Technology and Information Services (TIS)

The project descriptions include a discussion on the scope, the need for the project and timing and expenditures. There is also discussion regarding the alternatives that have been considered in in determining the solution that best meets identified needs and addresses the risk or opportunity. Alternatives and proposed solutions are still being investigated for projects that are projected to begin in coming years. As the need for the project grows and the estimated start date draws nearer, detailed analysis of alternatives and more precise cost estimates help to determine the optimal solution.

5.2.2 System Growth

5.2.2.1 Summary of System Growth Forecast

Table 5.2.2.1.1: System Planning 10-Year Growth Summary (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Kingsville Transmission Reinf Project	93.8	2.8									**96.6**
Panhandle	0.5					0.3	12.8	94.7	4.9		**113.1**
Sarnia Industrial System	3.0	60.4	1.3								**64.7**
Dawn Parkway System	8.5										**8.5**
System Planning Total	**105.8**	**63.2**	**1.3**			**0.3**	**12.8**	**94.7**	**4.9**		**282.9**

Kingsville Transmission Reinforcement Project and Panhandle System

The Panhandle System expansion is driven by in-franchise growth in Chatham-Kent, Windsor-Essex and surrounding areas, including the fast growing greenhouse market in the Leamington/Kingsville area. The forecast includes the Kingsville Transmission Reinforcement Project consisting of approximately 19 km of nominal pipe size (NPS) 20 pipeline which is driven by an increased growth forecast along the Panhandle System. The Panhandle System costs include clean-up costs in 2018 associated with OEB case EB-2016-0186 Panhandle Reinforcement Project. Additional Panhandle System facilities are planned for construction in 2024 and include the construction of approximately 14 km of NPS 36 pipe looping the existing NPS 20 from Dover Transmission Station towards Comber Transmission Station. These facilities will provide in-franchise customers in the Chatham-Kent, Windsor-Essex and Leamington/Kingsville areas increased access to low-cost natural gas for use in their homes and businesses.

Sarnia Industrial Line System

The Sarnia Industrial Line System expansion is driven primarily by in-franchise industrial contract rate growth. The forecast includes a project to directly serve new industrial customers in the TransAlta Energy Park and to serve increased demand for existing industrial customers. If demand continues to increase, additional reinforcement of the Sarnia Industrial Line System will be required. The costs and timing of these facilities has not been determined.

Dawn to Parkway System Expansion

Years 2018 and 2019 of the Dawn Parkway System forecast include the remaining commissioning and clean-up costs from the installation of the 2017 Dawn H, Lobo D and Bright C compressors. Future Dawn to Parkway System expansion is not currently forecasted as the expansion is primarily driven by changes to North American natural gas market fundamentals where shippers look to access economic natural gas supplies. Union will periodically conduct a transportation open season to gauge market demand. Should demand increase along the Dawn to Parkway System, it is anticipated that the next facilities required will be NPS 48 Kirkwall to Hamilton, NPS 48 Dawn to Enniskillen, and Milton to Parkway. The costs or timing of these facilities has not been determined. These facilities will provide ex-franchise customers additional access to the liquidity, storage, and transportation services available at the Dawn Hub to meet their market needs.

5.2.3 Growth – Other

A new area of growth for Union is Compressed Natural Gas (CNG) and Liquefied Natural Gas for vehicles (LNG). Projects forecast in these areas are expected to support low carbon fueling and production for Canada's Clean Fuel Standard.

5.2.3.1 Summary of CNG/LNG Growth Projects

Table 5.2.3.1.1 Summary of CNG Growth Projects 10-Year Growth Summary (all $ in millions)

Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
CNG Growth	1.0	2.3	1.9	1.9							**7.0**

Compressed Natural Gas (CNG)

Union's Highway 401 CNG project, which is being included under the unregulated Union Affiliate Union Energy Solutions (UES) Limited Partnership will establish key heavy-duty truck CNG refuelling infrastructure on Canada's busiest trucking corridor. It will be accomplished in conjunction with leading, Canadian industry providers of CNG solutions. The project scope will encompass all aspects of engineering, approvals, procurement, construction, commissioning, and ongoing operation and maintenance of three refueling stations at strategic locations along the Highway 401 corridor including Windsor, London and Eastern Ontario (Napanee).

The objective of this project is to provide the reliability and attractive pricing that is critical for the many fleets that regularly use the Highway 401 corridor to make long-term CNG adoption decisions for their operations. Growing CNG penetration in Ontario is strategically significant as it allows Union to grow natural gas consumption while simultaneously reducing Ontario's greenhouse gas (GHG) emissions. Moving forward with this project will allow Union to leverage federal government incentive funding and its early mover advantage.

Construction and operation of new CNG fueling stations by third parties is also expected to occur and Union will need to provide the gas distribution facilities (mains, services, meter stations) required to supply these CNG stations. The price of competing diesel fuel and availability of government incentive programs will be critical factors underpinning growth in this sector. The revenue forecast assumes these factors are conducive to growth and result in the following new stations and associated capital to supply natural gas service:

- 2019: Seven stations $1.00 million
- 2020: Six stations $2.250 million
- 2021: Five stations $1.875 million
- 2022: Five stations $1.875 million

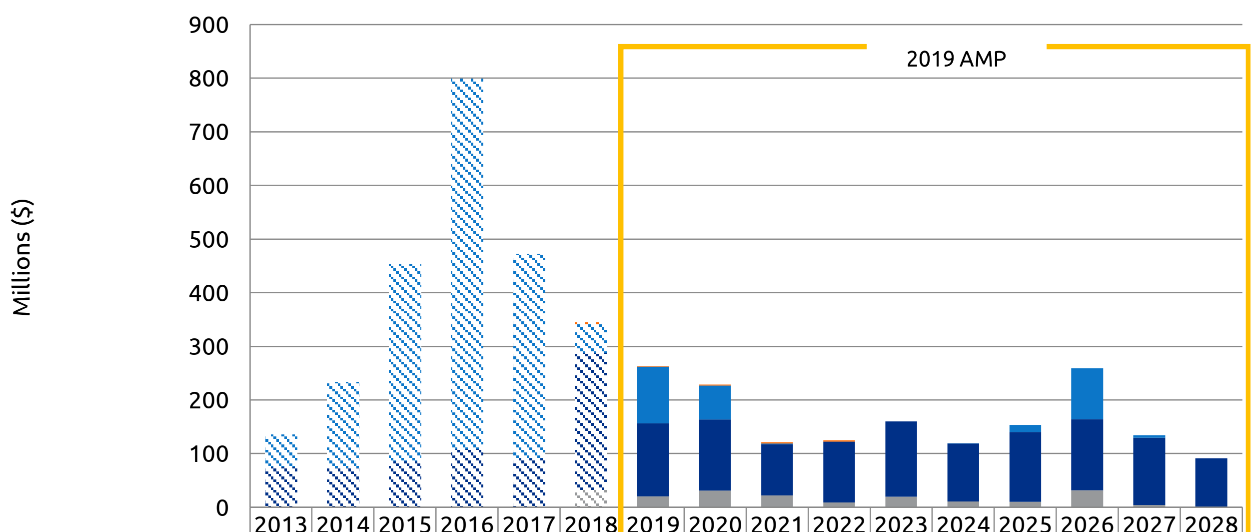
5.3 Asset Growth Recommendations

Table 5.3.1 and Figure 5.3.1 summarize the asset growth financial forecast to meet customer growth needs for the period of the AMP. Larger projects have an impact on certain years. Impacts can be seen from major distribution and system growth projects including growth from Community Expansion in 2018/2019, growth on the Panhandle System in 2019 and 2024, and growth on the Sarnia Industrial Line System in 2023.

Distribution growth is based on a forecast that incorporates historical growth with econometric factors. System and Storage Growth are based on a combination of an econometric forecast and ex-franchise growth. There is no ex-franchise growth forecast in this plan.

Table 5.3.1: Asset Growth 10-Year Capital Forecast (all $ in millions)

Project/ Program	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Other - CNG	1.0	2.3	1.9	1.9							**7.0**
Distribution Growth	136.3	132.7	95.9	113.9	140.3	108.3	130.8	132.9	125.3	91.4	**1,207.9**
System Growth	105.8	63.2	1.3			0.3	12.8	94.7	4.9		**282.9**
Growth Total	**243.1**	**198.1**	**99.1**	**115.8**	**140.3**	**108.6**	**143.6**	**227.6**	**130.2**	**91.4**	**1,497.8**



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Other - CNG						3.0	1.0	2.3	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0
System Growth	60.3	160.2	368.0	690.0	380.0	53.0	105.8	63.2	1.3	0.0	0.0	0.3	12.8	94.7	4.9	0.0
Distribution Growth	75.4	73.6	86.3	109.4	92.1	256.3	136.3	132.7	95.9	113.9	140.3	108.3	130.8	132.9	125.3	91.4
Overheads						32.5	20.0	30.7	21.7	8.6	19.4	10.4	9.7	31.4	3.9	0.0

Figure 5.3.1: Asset Growth 10-Year Capital Forecast (all $ in millions)

5.4 Asset Class Information

The following is a summary of the seven asset categories and ten associated asset classes identified in Figure 5.4.1, as well as the three non-commodity carrying asset classes that are considered supporting assets. Each asset class contains unique properties that can be managed through similar programs and oversight.

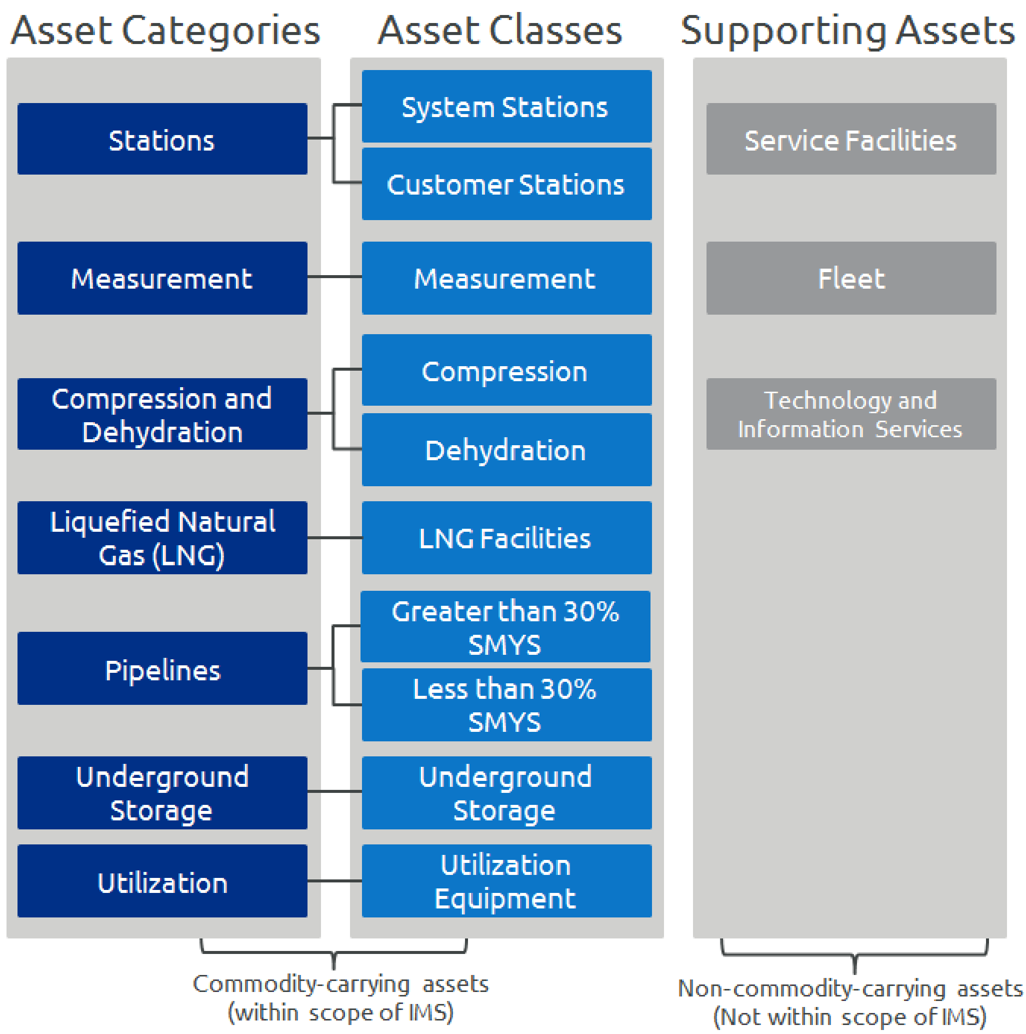


Figure 5.4.1: Asset Categories, Asset Classes and Supporting Assets

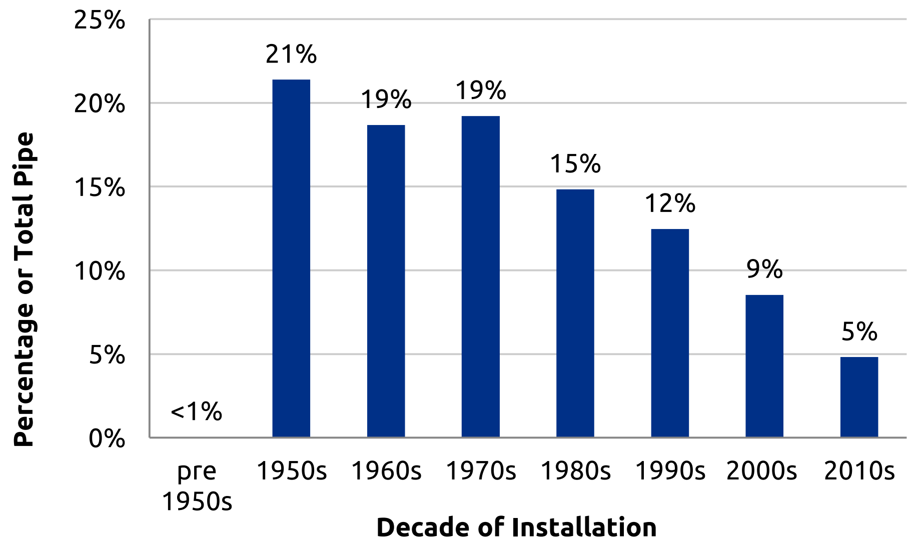
5.4.1 Pipelines

5.4.1.1 Overview of Pipelines greater than 30 per cent SMYS

This asset class contains pipelines and piping components (such as valves and fittings) that operate at or above 30 per cent of the Specified Minimum Yield Strength (SMYS) and all National Energy Board (NEB) regulated lines. This class, which includes 2,980 km of pipeline systems, consists of storage gathering systems, Union's major transmission systems and associated laterals connecting to the distribution networks, and the laterals feeding from the TransCanada pipeline system (Union's northern area) to the distribution systems and major customer stations. The majority of these pipelines have a maximum operating pressure (MOP) of 6,160 to 6,895 kPa and range in diameter from NPS 4 to NPS 48.

NEB regulated lines include the two NPS 12 Detroit River Crossing pipelines, the NPS 20 Bluewater pipeline, and the NPS 24 St. Clair pipeline. Although the two Detroit River Crossing pipelines operate at less than 30 per cent SMYS, they are included in this class to ensure they have the attention and maintenance required of National Energy Board lines. A large percentage of Union's pipelines greater than 30 per cent SMYS were installed over prior to 1980 as evidenced by the following age profile.

Figure 5.4.1.1.1: Percentage of total pipe by length versus decade of installation for pipelines greater than 30 per cent SMYS (Data used: December 31, 2017)



The major pipeline systems in this asset class are the Panhandle System, the Dawn to Parkway System, and the Sarnia Industrial Line System.

The Panhandle System consists of two parallel pipelines: NPS 12/20/36 and NPS 20. The two NPS 12 Detroit River Crossing pipelines connect the Panhandle Eastern Pipeline System to the Panhandle System and the Dawn Hub. This pipeline system supplies in-franchise customer demands from Dawn to Windsor.

The Dawn to Parkway System primarily consists of four parallel pipelines: NPS 26, NPS 34, NPS 42, and NPS 48. The NPS 26, NPS 34 and NPS 48 pipelines span the entire distance between Dawn to Parkway while the NPS 42 only runs from Dawn to Kirkwall. The Dawn to Parkway System was expanded with a second parallel section of NPS 48 from Hamilton and Milton.

The Dawn to Parkway System is used to transport natural gas to in-franchise customers located east of Dawn and west of Mississauga, and to ex-franchise customers at Dawn Compressor Station, Kirkwall Custody Transfer Station and the Parkway East and Parkway West Compressor Stations at the east end of Union South. These locations supply natural to Enbridge Gas Distribution, Gaz Métro Limited Partnership, utilities in the U.S. Northeast and others.

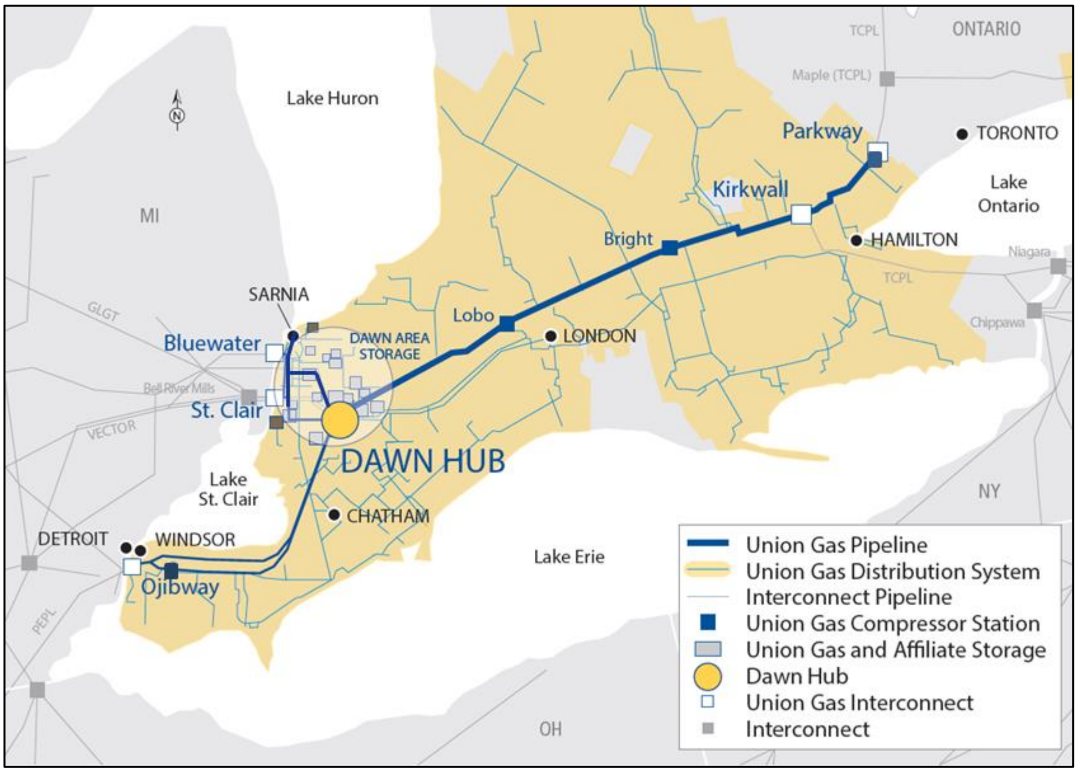


Figure 5.4.1.1.2: Panhandle, Dawn to Parkway, and Sarnia Industrial Line Systems

Union's Sarnia Industrial Line System consists of a network of pipelines ranging from NPS 8 and NPS 20, including connections to both the NPS 20 Bluewater Pipeline and the NPS 24 St. Clair Pipeline. This pipeline system serves in-franchise customers in Sarnia and St. Clair Township and ex-franchise customers via the St. Clair and Bluewater pipelines.

Union's 2,980 km of pipelines greater than 30 per cent SMYS cover a large operating area, comprised of a variety of unique operating conditions, including:

- 65 per cent of the pipelines operate at greater than 50 per cent SMYS, none are greater than 72 per cent SMYS

- 4 per cent are in Class 3 locations
- 10 per cent are in high consequence areas

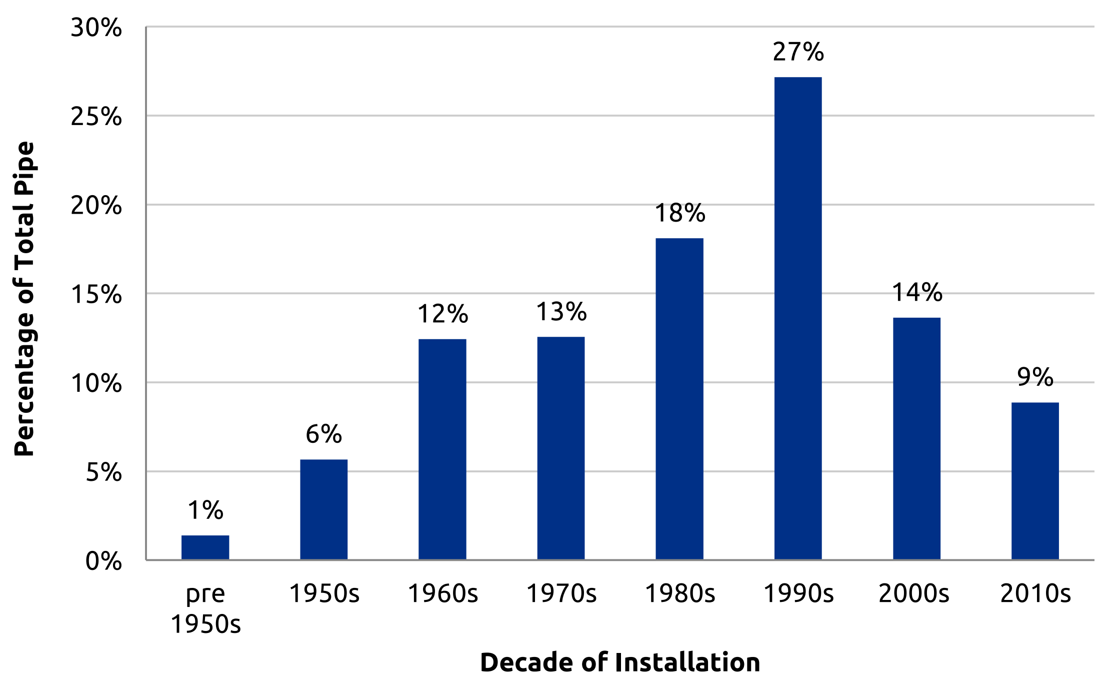
NOTE: *A Class 3 location is classified as an area (1.6 km along the pipeline) that has 46 or more buildings intended for human occupancy. A high consequence area is an area where a pipeline release would have greater consequence to health and safety or the environment.*

5.4.1.2 Overview of Pipelines less than 30 per cent SMYS

This asset class includes pipelines, services, and piping components that operate below 30 per cent of the Specified Minimum Yield Strength (SMYS). These assets are used to transport natural gas within Union's distribution systems or to end-use customers. This asset class includes 40,514 km of mains and associated valves and fittings. Of these mains, 53 per cent are plastic and more than 85 per cent operate at a pressure less than 700 kPa. This asset class also includes 1,363,000 services made up of 27,564 km of pipe and associated fittings. 72 per cent of these services are plastic and 98 per cent have an operating pressure less than 700 kPa (all values are based upon December 31, 2017 data).

Although distribution networks have been in place for over 100 years, the overall system is relatively new, as evidenced by Figure 5.4.1.2.1. Much of the older systems, particularly those that represented higher risk, have been replaced over time.

Figure 5.4.1.2.1: Percentage of total pipe by decade of installation for less than 30 per cent SMYS pipelines



5.4.1.3 Summary of Pipeline Maintenance Capital Projects

Table 5.4.1.3.1: Pipelines 10-Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Pipeline <30% SMYS	**31.4**	**115.3**	**141.6**	**38.0**	**28.0**	**27.8**	**19.1**	**19.4**	**19.3**	**20.1**	**460.0**
Cathodic Protection	8.0	7.0	9.9	9.9	6.6	6.6	6.6	6.9	6.7	7.4	**75.4**
Bare and Unprotected steel	9.1	9.2	10.7	12.9	9.1	8.8					**59.8**
Emo Sched 10	2.8										**2.8**
Leakage	2.2	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	**40.6**
Service Replacement	4.3	4.4	4.5	4.6	4.7	4.7	4.8	4.9	5.0	5.1	**47.0**
General Mains	2.0	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	**32.3**
Windsor Line	3.0	83.0	2.0								**88.0**
London Lines		4.0	107.0	3.0							**114.0**
Pipeline > 30% SMYS	**44.5**	**34.1**	**33.9**	**27.9**	**32.4**	**33.4**	**33.4**	**33.4**	**33.4**	**33.4**	**339.4**
Depth of Cover >30% SMYS						1.0	1.0	1.0	1.0	1.0	**5.0**
Integrity Management Program	14.6	14.1	13.9	12.9	12.4	12.4	12.4	12.4	12.4	12.4	**129.6**
Class Location	20.4	20.0	20.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	**165.4**
MOP Verification					5.0	5.0	5.0	5.0	5.0	5.0	**30.0**
Bruce Lake	9.5										**9.5**
Other	**26.2**	**37.4**	**34.2**	**32.8**	**31.0**	**33.2**	**33.0**	**106.3**	**32.0**	**31.7**	**397.8**
General Pipeline Maintenance	4.4	13.4	10.2	8.8	7.0	9.2	9.0	7.3	8.0	7.7	**85.0**
Municipal Replacement	21.8	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	**237.8**
Vintage Pipeline Replacement								75.0			**75.0**
Pipelines Total	**102.1**	**186.8**	**209.7**	**98.7**	**91.4**	**94.3**	**85.4**	**159.1**	**84.6**	**85.1**	**1,197.2**

Cathodic Protection

This program includes the required expenditure to install anodes and replace aging or obsolete rectifiers in order to reduce the amount of down plant within Union'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.

Bare and Unprotected

This program is to replace all the bare and unprotected steel mains within Union's franchise. These mains are more susceptible to leaks as they have not been cathodically protected since installation. About 60 per cent of these mains are in in urban areas, approximately 5 per cent of which are in highly-developed areas. The remainder of these mains are in rural areas. 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.

Union's 2017 customer engagement survey found that 50 per cent of those surveyed recommend prioritized replacements, while 41 per cent recommend following existing practices for replacement. The positive feedback supports Union's strategy for replacing bare and unprotected steel pipe over the next six years.

EMO Schedule 10

Union has approximately 14 km of Schedule 10 distribution main within two communities. This thin-wall pipe is very difficult to weld and requires special welding procedures. Removing this pipe from Union's system will reduce the chance of leaks due to failure of older welds.

Leakage

This expenditure accounts for the annual district capital blanket budgeted for unforeseen maintenance requirements arising from pipeline leakage identified throughout the year.

Service Replacements

This expenditure accounts for the annual district capital blanket budgeted for maintenance requirements associated with individual customer services that require replacement or repair due to their age and condition.

General Mains

This expenditure represents the annual blanket dollars required to fund maintenance work associated with distribution pipeline main that is identified with integrity-related issues that require replacement or repair.

London Lines and Windsor Lines

Both of these pipelines are nearing end-of-life and significant capital expenditures are required on a yearly basis in order to maintain these pipelines. Multi-year replacement strategies have been developed for both of these pipelines based on known risk factors. If these replacement spends are reduced or deferred, significant amounts will be required to continue to maintain these pipelines.

Depth of Cover

In compliance with the TSSA Code Adoption Document, Union has an annual depth of cover survey program for all 30 per cent SMYS pipelines. These surveys may identify locations were 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.

Pipeline Integrity Management

This expenditure is the result of the Integrity Management Program, a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of Union's pipeline systems to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30 per cent SMYS. 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.

Since the program was introduced in 2002, a number of opportunities for continual improvement have been implemented. Union has developed additional criteria and processes to inspect pipelines on a risk-based frequency that takes into account the operating characteristics and condition of the pipeline, and if its location has an impact on the potential consequence of a failure. Union also continues to retrofit some of the pipelines that were initially assessed through ECDA to accommodate ILI tools and improve the completeness of the integrity assessments. Further work has been completed to reconfigure some of the pipelines that were previously inspected with ILI tools to improve the quality of the data that is collected by the tools.

Class Location

Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30 per cent SMYS. Any changes in class location need to be assessed to the current standard to determine if pipeline modifications are required. Urban development occurs in close proximity to Union's pipelines which triggers annual class location changes. An annual budget is required for Union's pipeline system in order to meet the current standard requirements which generally involves replacement of pipe segments. Remediation includes pressure testing, installation of valves, remediating depth of cover issues, and in some cases pipeline replacement. This work ensures Union is compliant and fosters the safety of the public and Union's pipeline system.

Maximum Operating Pressure (MOP) Verification

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 Union has approximately 2,980 km 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.

Bruce Lake

The Bruce Lake/Ear Falls Lateral needs to be operated at an elevated pressure to maintain Union's system. Union has completed a detailed engineering review to validate the condition of this system prior to increasing the pressure on this lateral, which includes making the pipeline piggable, completing an inline inspection, and taking the line out of service to complete a pressure test. Deferring or reducing spend on this project will create risk of potential customer loss during high demand periods.

General Pipeline Maintenance

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.

Municipal Replacement

Projects in this 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 Union to avoid conflicts with municipal infrastructure early in the planning stage. If a conflict is unavoidable, Union's pipeline assets are typically relocated or replaced.

Vintage Pipeline Replacement

The capital identified in this category is a placeholder for a future major pipeline replacement. Similar to the Windsor and London Lines projects, Union expects to have another major replacement project in the next 10 years. Ongoing condition and integrity assessments are expected to identify pipelines that will elevate in risk in the future that will drive a more detailed plan for replacement.

5.4.1.4 Summary of Pipeline Incremental Operations and Maintenance (O&M)

Table 5.4.1.4.1: Pipelines 10-Year Forecast of Incremental O&M (all $ in millions, incremental to 2018)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
MOP Verification		1.6	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Class Location		-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Pipeline Integrity	0.5	3.7	3.2	2.9	2.3	2.1	2.1	2.1	2.2	2.2
Easement Clearing	0.3	0.5	0.6	0.6	0.3	0.3	0.3	0.3	0.3	0.3
Pipeline Incremental O&M Total	**0.8**	**5.7**	**6.1**	**5.8**	**4.9**	**4.7**	**4.7**	**4.7**	**4.9**	**4.9**

Maximum Operating Pressure (MOP) Verification

The MOP verification project is incremental work that will require incremental resources to complete. These resources will be tasked with completing records reviews and engineering assessments in order to validate the maximum operating pressures (MOPs) of Union's greater than 30 per cent Specified Minimum Yield Strength (SMYS) pipelines. In instances of insufficient records, validation digs may be required to determine potential remediation requirements, which is also part of this additional spend.

Class Location

The expenditure included in this program funds Engineering Assessments that are used to address changes in class location of Union's 30 per cent SMYS pipelines as an alternative to Pipeline replacement. The forecasted reduction reflects the expectation that Union will be moving into sustainment with respect to the Class Location program and that the number of identified Class Location changes should be declining.

Pipeline Integrity

This portfolio includes an increase to further the Pipeline Integrity Management Program in terms of External Corrosion Direct Assessment (ECDA) inspections, assessments for stress corrosion cracking, and increased inline inspection (ILI) inspection frequency requirements. Also included in this expenditure are additional programs related to distribution integrity, most notably the additional expenditure required for the inspection of water crossings and bridge crossings.

Easement Clearing

The historical spend with respect to Easement Clearing has been reviewed and is determined to be inadequate to maintain clear easements for Union's existing pipelines and the incremental addition of new pipelines and associated easements. The identified incremental funds will assist in accelerating Union's Easement Clearing program and add focus to this work.

5.4.2 System & Customer Stations

5.4.2.1 Overview of System Stations

System stations are typically above grade facilities designed to reduce the operating pressure of natural gas pipeline systems through pressure control and over pressure protection. These facilities are used to transmit and/or distribute natural gas to reduced operating pressure pipeline systems which supply natural gas to cities and towns.

System station components consist of piping, meters, regulators, valves, filters, separators, heaters, odourant, controls, and in some cases, structures. System station components can vary greatly depending on the station's application and design complexity. At Union, system stations are broken down into subclasses which drive design and operating practices as well as inspection requirements. A summary of the system station subclasses can be found in Table 5.4.2.2.1.

5.4.2.2 Overview of Customer Stations

Customer Stations, similar to System Stations, are designed to deliver a specific volume of natural gas at a reduced delivery pressure from natural gas pipelines as requested and/or required by individual customers for end-use consumption.

Typical delivery pressures can vary from 1.75 kPa to 1,380 kPa or higher depending on individual customer needs. The pressure and volume requirements for customers are driven by the customers' natural-gas-fired equipment requirements.

Typical components of customer stations can vary greatly based on the size and operating requirements of a particular customer. The smallest of customer stations (meter sets) are typically composed of small diameter piping, a single regulator and meter, and a single shut off valve. Larger customer stations can be composed of filter/separators, multiple regulators and meters, large diameter piping and headers, electrical, controls and telemetry, natural gas heating, odourant injection systems, and multiple valves. Customer stations are broken down into subclasses which drive design and operating practices as well as inspection requirements. A summary of customer station subclasses can be found in Table 5.4.2.2.1.

Union's largest in-franchise customer station facilities typically supply natural gas to major electric power producers. The subclass A customer stations also feed natural gas to major steel mills, chemical plants, smelters, and other process based industrial plants.

Table 5.4.2.2.1: Inventory of System and Customer Stations

Station Subclass	Operating Parameters		Systems Station Inventory	Customer Station Inventory
	Maximum Inlet Pressure	Inlet Size		
Subclass A	Over 3,450 kPa	NPS 3 and over	280	100
	Any Pressure	NPS 8 and over		
Subclass B	Over 3,450 kPa	NPS 2	770	1,500
	3,450 kPa and Under	NPS 3 to NPS 6		
Subclass C	3,450 kPa and Under	NPS 2	1,930	11,800
	All Pressures	Less than NPS 2		
Residential	All	All		1,382,500
		Total Number of Stations	2,980	1,395,900

5.4.2.3 Summary of System and Customer Stations Maintenance Capital Projects

Table 5.4.2.3.1: System and Customer Stations 10 Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Obsolete Heating Equipment	1.8	4.1	4.6	0.7	0.7	3.7	2.1	0.9	1.4	1.9	**21.8**
Hamilton Gate	2.0										**2.0**
Regulators/Reliefs		9.1	8.9	8.9	9.2	9.2	9.1	9.0	8.8	8.8	**81.0**
Replacement of Vaulted Stations		1.6	3.5	1.6	1.5	1.5	0.7				**10.4**
Station Painting	1.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	**19.5**
Stations Capital Maintenance	1.2	6.7	3.0	3.0	2.7	4.0	3.6	5.9	5.1	2.5	**37.8**
Frost Heave		0.9	0.6	0.1	0.5	2.5	1.4	2.0	0.4	0.1	**8.5**
Stations Total	**6.5**	**24.3**	**22.6**	**16.2**	**16.6**	**22.8**	**19.0**	**19.9**	**17.7**	**15.4**	**181.0**

Obsolete Heating Equipment

Natural gas heating equipment is used in many system and customer stations across the Union franchise to help mitigate failure of equipment due to the freezing of liquids in the gas stream as well as moisture that surrounds buried piping. Over Union's many years of operation, a variety of heating systems have been used resulting in many variations of equipment age, and the introduction of equipment obsolescence. This project includes ongoing maintenance to replace equipment that has reached end-of-life or has been deemed obsolete. This work will maintain system reliability, ensure operating costs for heating systems are minimized and reduce the potential for glycol spills. This forecast will improve efficiency in operating costs of aging systems and will mitigate the risk of equipment failures that could result in loss of customers and/or loss of glycol containment.

Hamilton Gate

Maintenance activities will be required for Hamilton Gate Station in 2019 in order for it to operate safely and reliably until the station is rebuilt in 2021. These maintenance activities include: boiler system upgrades at Hamilton Gate Station 2 due to current failure, replacement of steel access platforms to the heat exchangers, and engineering assessments of the building, piping and heat exchanger to support the 2021 to 2022 project.

Regulators/Reliefs

This capital spend represents the year-over-year cost of purchasing and stocking of natural gas regulators and relief valves to support ongoing maintenance work. As regulators and relief valves fail or require replacement due to age or obsolescence, (whether it be at the time of meter exchange or in conjunction with other maintenance projects) regulators are purchased and stocked for field representatives and technicians so that they can maintain the high reliability of Union’s system and customer stations. This forecast will mitigate shortages of equipment so that services to customers are maintained.

Replacement of Vaulted Stations

Union’s system station assets include a number of below grade vaulted stations. This project will replace all remaining vaulted stations with above grade facilities, reducing the risk of equipment failure and ensuring the reliability and integrity of these sites. These stations are advanced in age and present significant maintenance challenges due to their confined nature and a variety of risks with respect to asset deterioration and equipment failure. The vault design is prone to water ingress that can cause frost heave, accelerated corrosion of the assets and the vault itself, and can interfere with the proper operation of equipment. All of these factors have a negative effect on reliability and can create personal injury risks. As the solutions for each asset are developed, customer engagement results will be leveraged to select either a typical system station design with land purchase or an above grade enclosure station where land purchase is impractical. This forecast will decrease risk of equipment failure, improve system reliability and result in the stations being more safely and efficiently maintained.

Stations Painting Program

This is a centrally managed program 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 Union’s Corrosion Control Standard Operating Practice (SOP) and is its documented and committed practice with respect to how we comply with the applicable codes for corrosion control on above grade station assets. This work will improve compliance and ensure the safety and reliability of Union’s assets by reducing the risk of leaks and piping and/or equipment failure due to significant corrosion.

Stations Capital Maintenance

This category includes a number of risk remediation programs and general maintenance activities that are part of the core system and customer station maintenance work at Union:

- Obsolete equipment - As station facilities age, regulators and relief valves can become obsolete due to vendors no longer supporting specific types of equipment or simply that they have aged and created maintenance and reliability concerns. This project is an effort to remediate all currently identified obsolete equipment from

Union's system. The allocated cost is for installation and fabrication time; equipment cost is covered in the regulator/relief valve line item. This program will build on system reliability and generate field efficiencies due to reduced variability of equipment found in the field and simplified maintenance.

- Regulator Freeze offs - As natural gas supplies into the pipeline systems change, natural gas quality can also change. Existing system stations that experience significant pressure cuts combined with elevated moisture content in the natural gas stream can cause freezing of regulators and loss of downstream customers. Sites of concern will continue to be addressed as needed.
- Station Blankets - Spend is also allocated to each region to ensure they have capital available for unforeseen maintenance challenges. These challenges can be leaks or failures that require short turnaround times for remediation, particularly if there has not been a specific project identified for affected assets.

Frost Heave

Stresses imparted on station facilities due to frost formation in below grade soil are targeted for remediation in some cases. This can include the addition of station heaters or simply the excavation and leveling of station sites where heaving is less severe. This work ensures the risk of leaks and piping failures are reduced and therefore system reliability is maintained. This also ensures Union workers are not subjected to maintenance challenges where piping can spring out of place due to the stresses imparted from frost heave.

This forecast will improve system reliability and help ensure continued service to Union's customers.

5.4.2.4 Summary of Stations Incremental Operations and Maintenance

Table 5.4.2.4.1: Stations 10-Year Forecast of Incremental O&M (all $ in millions, incremental to 2018)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Stations Integrity		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

The primary driver for increased O&M activity in the stations category is for integrity assessment and mitigation of station piping and components.

5.4.3 Measurement

Measurement assets include a fully integrated family of devices that allow safe operation of the natural gas network, provide accurate and timely measurement, and monitor and control the flow of natural gas in real time. Measurement assets include the following subclasses:

- Natural Gas Meters.
- Electronic Volume Correctors.
- Odourization Systems.
- Gas Monitoring and Control Systems.

5.4.3.1 Natural Gas Meters

Natural gas meters are devices used in measuring the quantity of natural gas delivered. Meters can be further classified as custody transfer or non-custody transfer. The former are billing meters for gas purchased from suppliers or sold to customers and as such must meet the legal requirements of the Electricity and Gas Inspection Act. The latter are used for internal accounting of gas inventories.

Union uses a variety of gas meter types to fit different applications and requirements as outlined below.

Diaphragm Meters

Diaphragm meters use positive displacement technology and internal mechanical temperature compensation to calculate delivered natural gas volumes at base temperature and pressure.

The 200 class meter is the most common meter type in use. The 400 class meters are used for commercial and large residential loads and have incrementally more capacity than a 200 class. The 800/1000 class meters are used for large commercial, small industrial and estate residential loads.

Commercial Ultrasonic Meters

Commercial ultrasonic meters are used as a direct substitution for 800/1000 class diaphragm meters. They use inferential ultrasonic flow measurement and electronic temperature correction and consumption recording.

Rotary Meters

Rotary meters are positive displacement devices comprised of a meter body coupled with an electronic volume corrector. The two styles of rotary meters are temperature compensated and instrument drive. Rotary meters are used in commercial and industrial applications.

Turbine Meters

Large Turbine meters are inferential metering devices used at large commercial and industrial customer stations for high-volume metering. They are also used for volumetric measurement at interconnect sites between Union and other pipeline companies.

Large Ultrasonic Meters

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.

5.4.3.2 Electronic Volume Correctors

Rotary Temperature Compensated Modules

Rotary temperature compensation modules are directly attached to temperature compensated rotary meters. They correct meter volume to standard conditions based on temperature recorded at the meter.

Electronic Volume Integrators

Electronic volume integrators are directly attached to instrument drive rotary meters and turbine meters. They correct volume to standard conditions based on temperature and pressure recorded at the meter.

Automated Meter Reading (AMR)

AMR devices are installed on diaphragm, commercial ultrasonic, and temperature compensated rotary meters. These devices record and store meter consumption data after being corrected to standard units. They then transmit this information wirelessly to meter reading devices that upload the consumption to Union’s billing system.

5.4.3.3 Odourization Systems

Natural gas in its basic state is virtually odourless and can be difficult to detect if accidently released to the atmosphere. To protect the public and operate assets safely, natural gas is odourized at major stations to make it easier to detect as required by Canadian Standards Association Z662 – Oil and Gas Pipeline Systems.

5.4.3.4 Gas Monitoring and Control Systems

The natural gas monitoring and control system is comprised of field equipment for the Supervisory Control and Data Acquisition (SCADA) System for monitoring and control of natural gas flow and odourizing natural gas at large stations, custody measurement, and control of critical valves. This system is crucial to providing live natural gas measurement and operational information to various stakeholders.

The natural gas monitoring and control system is made up of Remote Terminal Units (RTUs - Bristol 3330/3310), which were installed from 1989 to 2006, with the majority installed between 1995 and 1999 in locations across Union's entire franchise. Communication devices are also included (satellite/cellular/radio modems), which were upgraded from 2008 and 2010 and again from 2015 to 2019 in locations across Union's entire franchise.

5.4.3.5 Asset Inventory Statistics and Geographic Locations

The following table summarizes information about asset classes, major components, and their inventory.

Table 5.4.3.5.1: Measurement Assets and Inventories

Measurement Asset Subclass	Device Type & Inventory
Natural Gas Meters	• Diaphragm meters (1.4 million) • Rotary meters (17,506) • Turbine meters (600) • Ultrasonic meters - commercial (7,850) and interconnects (80)
Electronic Volume Correctors	• Electronic rotary modules (16,023) • Electronic Volume Integrators (2,208) • AMR Devices (80,057)
Odourization Systems (Bypass & Injection)	• MOIS injection cabinets • Odourant injection tanks (approximately 71 sites) • Odourant bypass tanks (approximately 148 sites) • Environmental deodourizer units(at each injection site) • Level instrumentation(one at each odourant site)
Natural Gas Monitoring & Control Systems	• RTU (400) • Communication equipment(cellular, satellite, radio) – (300) • Transmitters (1,500) • Power supplies etc.

5.4.3.6 Summary of Measurement Maintenance Capital Projects

Table 5.4.3.6.1: Measurement 10 Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Meter Exchange Program	34.8	30.2	30.6	30.8	31.8	32.0	32.3	33.4	33.6	33.8	**323.2**
Measurement Electronics Upgrades	0.2	0.3	0.3	0.3	0.3	0.2	0.3	0.2	0.2	0.2	**2.6**
Obsolete RTU Equipment	1.4	3.1	3.1	2.5	2.0	2.0	2.0	2.0	2.0	2.0	**22.2**
Odourant Upgrades	1.0	1.4	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.0	**9.6**
Measurement Total	**37.4**	**34.9**	**35.0**	**34.7**	**35.2**	**35.3**	**35.6**	**36.6**	**36.9**	**36.1**	**357.6**

Meter Exchange Program

This program will remove meters and replace them with new meters as required to comply with the legal requirements of Measurement Canada. Batches of diaphragm meters are removed each year and tested to ensure the population of meters in the field meet regulatory requirements. Smaller meters are compliance-tested to meet regulatory requirements. Larger meters (rotary and turbine meters) and Electronic Valve Integrators (EVIs) are condition-tested in service to confirm adequate performance levels. If they do not meet adequate performance levels they are then removed, re-verified and returned to service.

The Meter Exchange Program budget forecast includes the procurement of all types of replacement meters, electronic volume correctors, AMR, regulators for 200/400 series replacement meters and labour cost of 200/400 series replacement meters.

The number of meter exchanges required beginning in 2019 is shown below. These exchange requirements are expected to continually grow as the overall in service population continues to grow.

- 200 series diaphragm meters – 54,402 exchanges.
- 400 series diaphragm meters – 4,851 exchanges.

Measurement Electronics Upgrades

This portfolio includes low-budget, small-scale capital projects to sustain and enhance operational support. These projects include Auto-Oilers, Turbo Correctors (TOC), lab upgrades, technician tools, industrial billing modems upgrades, billing communication modem lifecycle, and measurement replacement at low flow odourant sites. The benefit of these projects will be smooth and reliable operation.

Obsolete Equipment/SCADA RTU Lifecycle

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.

Odourant Upgrades

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.

5.4.3.7 Summary of Measurement Incremental O&M

Table 5.4.3.7.1: Measurement 10 Year Forecast of Incremental O&M (all $ in millions, incremental to 2018)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Meter Accreditation Internal Audit	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Increased O&M in this portfolio is due to increased requirements for internal audit of the Measurement Accreditation Program. As of 2019, Enbridge will no longer be providing Internal Audit Services of the Measurement Accreditation Program. It is a legal requirement to conduct an internal audit as per the Measurement Accreditation Standard. Union is currently seeking potential external service providers with the necessary experience for 2019.

5.4.4 Utilization

This asset class consists of the pipes, fittings, and equipment located downstream of the meter. As the components of this asset class are not owned by Union, the decisions about additions, maintenance and renewal are not made by Union and are not a part of this report. As the supplier of natural gas, Union plays a part in ensuring these systems are safe through inspections during customer visits. Union has a statutory obligation to inspect customer-owned equipment at the time of initial activation and when natural gas supply is interrupted for any reason as per the Ontario Regulation 212/01 Gaseous Fuels.

5.4.5 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. The facilities are usually natural geological reservoirs such as depleted oil or natural gas fields sealed on the top by an impermeable cap rock.

Natural gas demand for Union'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 Union's customers.

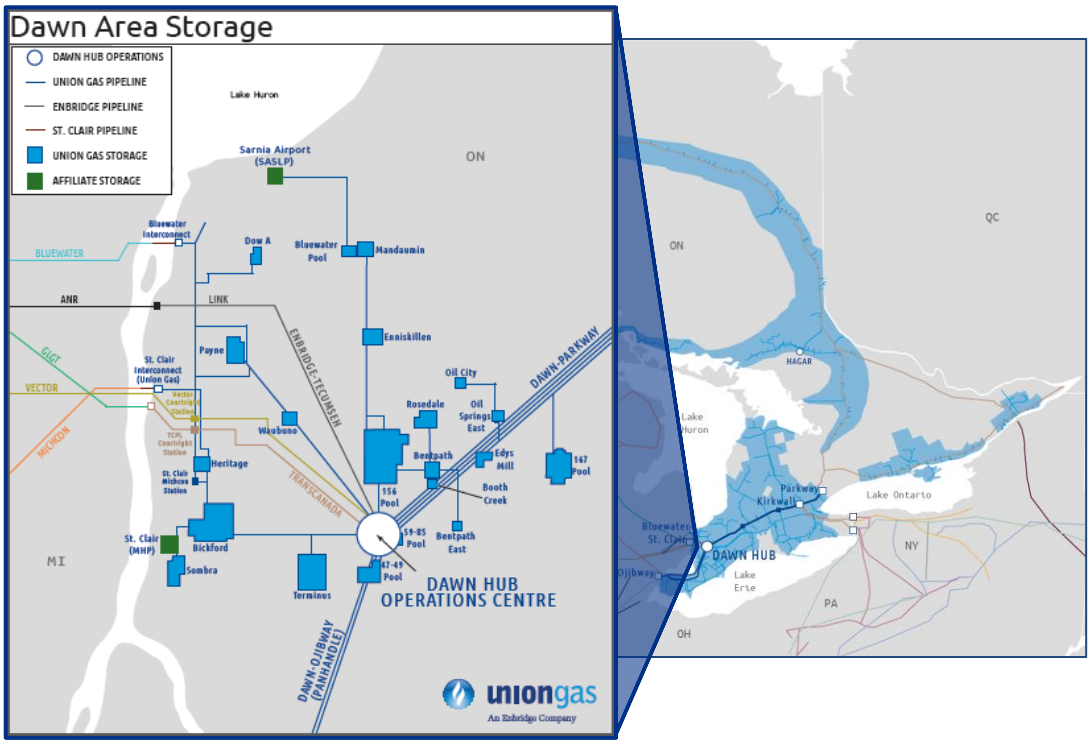


Figure 5.4.5.1.: Natural Gas storage pools (Lambton County)

Union (including Union Affiliates) stores natural gas in 23 company-owned storage reservoirs and four third party storage reservoirs. The storage capability of each reservoir is determined by the reservoir's maximum operating pressure, the cushion pressure, and the size of the pool. Capacities in the 23 storage reservoirs range from 31,000 10^3m^3 (1.2 PJ) to 830,800 10^3m^3 (32.0 PJ). Through Union's reservoirs, Union has a storage capacity of 4,744,500, 10^3m^3 (185 PJ) with cushion natural gas totaling 1,665,000 10^3m^3 (64 PJ).

Each reservoir is protected by a Designated Storage Area (DSA) as determined by the Ontario Energy Board (Board) to protect the reservoir from exploratory drilling. The land above each reservoir is leased from the landowners with storage leases. There are currently over 10,000 acres leased by Union for storage.

There are a total of 230 wells (as of September 2018) operated by Union to support the movement of natural gas into and out of the underground reservoirs. The 230 wells include 166 injection withdrawal wells, 63 observation wells, and one maintenance well.

5.4.5.1 Summary of Storage Maintenance Capital Projects

Table 5.4.5.1.1: Underground Storage 10-Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Storage Improvements	0.4	1.9		1.2	1.3	1.3	0.7	0.4	0.4	0.4	**9.2**
Storage Integrity	0.3	0.3	0.3	0.3	0.3	2.3	0.3	2.4	0.3	2.4	**8.7**
Underground Storage Total	**0.6**	**2.1**	**1.4**	**1.4**	**1.5**	**3.5**	**1.0**	**2.8**	**0.7**	**2.8**	**17.9**

Storage Improvements

These projects will improve the performance, condition and safety of the storage wells. The following are examples of storage improvement projects:

- Well testing to identify and remediate wells that have lost deliverability through ongoing operation.
- The installation of emergency shutdown valves on storage wells to provide the ability to remotely isolate each well.
- A wellhead pressure and flow monitoring project to identify flow restrictions, interference between flowing wells, and identify deliverability losses with the goal of maintaining and improving Union's total system deliverability.

Storage Integrity

Casing inspection logs are completed on a prescribed basis as per Canadian Standards Association Z341 Storage of Hydrocarbons in Underground Formations. The storage integrity projects include remediation requirements as a result of the casing inspection log. The remediation may include additional testing, well relining, repair or well abandonment. In some cases, additional wells may be required to replace the lost well deliverability as a result of the remediation.

Filed: 2018-12-14, EB-2018-0305, Exhibit C1, Tab 3, Schedule 1, Page 100 of 278

5.4.5.2 Summary of Storage Incremental Operations and Maintenance

Table 5.4.5.2.1: Underground Storage Incremental O&M (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Well Maintenance	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Increased O&M activity in the underground storage category is due to an increase in the casing inspection log survey that is required by code. The increase in logging expenditure is due to the following reasons:

- New requirements for cathodic protection profile logs.
- Additional wells.
- Labour and contractor price increase.

5.4.6 Compression and Dehydration

Union uses compressors to move natural gas throughout the natural gas transmission system by compressing natural gas into transmission pipelines designed for high flow. Compressors are also used to move gas in and out of underground storage reservoirs by providing a significant pressure increase at the expense of flow.

Dehydration facilities are also included in the compression asset category. Dehydration facilities remove moisture from natural gas to ensure that the natural gas entering the transmission system meets the contractual standard of moisture content, and to avoid operational problems related to high moisture content. The dehydration process involves contact between the natural gas stream and liquid glycol stream to remove excessive moisture from the natural gas stream. The resultant output natural gas that ensures pipelines are dry and customer quality for moisture content are met.

Union's main compressors are located at the Dawn Compressor Station, the site of the largest underground storage facility in Canada and a key natural gas trading hub. The Dawn Hub has interconnections to 10 major transmission pipeline systems including Vector, TransCanada Pipelines, Tecumseh Gas Storage, and Panhandle Eastern through the Union Panhandle Transmission system. The Dawn Compressor Station consists of nine compressors with a combined total of 252,350 ISO horsepower, a major natural gas dehydration plant and associated piping, large diameter valves, electrical components and other equipment required to support the operation of this station.

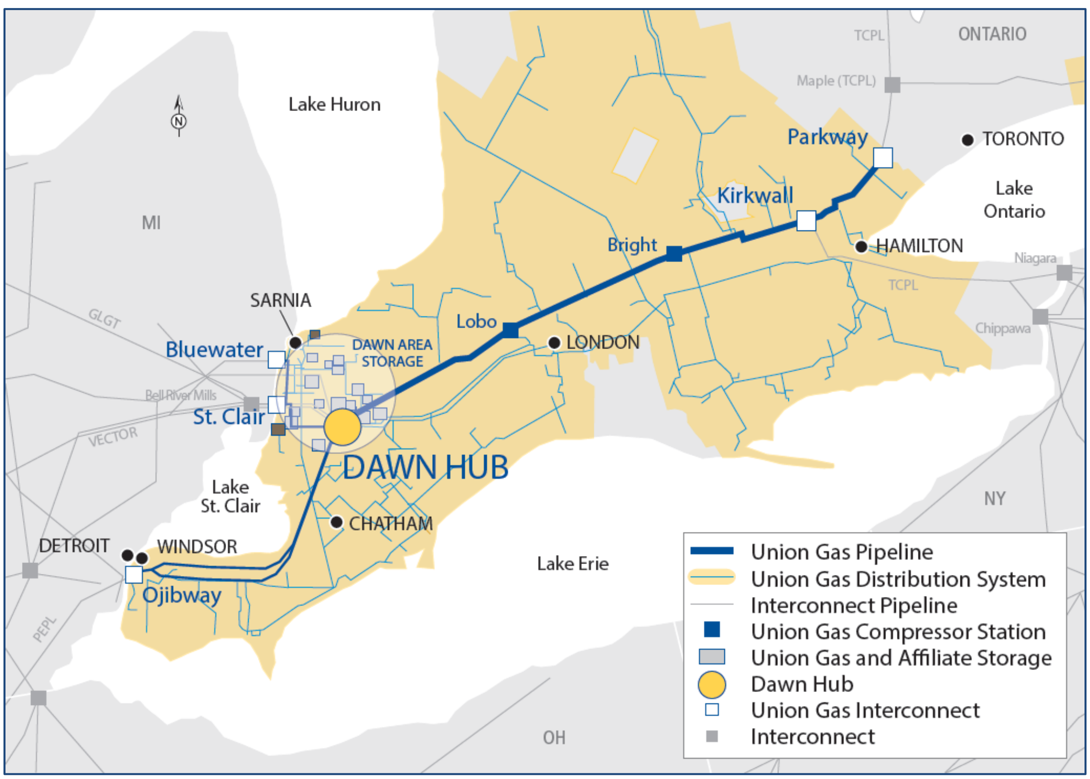


Figure 5.4.6.1.: Overview of Union's storage and transmission system, showing major compressor plants

There are four major compressor stations located along the Dawn to Parkway System located at Lobo, Bright, Parkway West, and Parkway East and can be seen in Figure 5.4.6.1. These stations consist of a total of 13 compressors with a combined total of 478,790 ISO horsepower.

Union maintains loss of critical unit coverage at Dawn and at the compressor stations located along the Dawn to Parkway System. Loss of critical unit coverage is required to provide compression to continue to provide services to customers if an unplanned compressor outage of a compressor that would create the greatest loss of system capacity if it failed on a design day.

Union has many other compressor stations located within the franchise including compressors located at underground storage facilities and in remote geographic areas.

Table 5.4.6.1: Compression Inventory

Location	Inventory	General Notes
Dawn Compressor Station	9 Compressors 1 Dehydration plant	Interconnects with pipelines from a number of other companies and Union's storage system. Provides supply to the Union transmission systems and loss of critical unit coverage for the Dawn Parkway System.
Lobo Compressor Station	5 compressors	Supports gas transmission from London towards Woodstock on the Dawn-Parkway system. It includes the current loss of critical unit coverage for the Dawn Parkway System.
Bright Compressor Station	4 compressors	Supports gas transmission from Woodstock towards Toronto (Parkway) on the Dawn-Parkway system.
Parkway Compressor Station	2 compressors	Acts as a custody transfer station to Enbridge and TransCanada Pipelines and provides required delivery pressure to TCPL.
Parkway West Compressor Station	2 compressors	Acts as custody transfer station to Enbridge and TransCanada Pipelines and provides required delivery pressure to TCPL as well as loss of critical unit compressor for Parkway.
Sandwich Compressor Station	1 compressor	Supports movement of gas from the Panhandle Eastern Pipeline system towards Dawn.
Hagar Liquefied Natural Gas Station	2 compressors	Supports the Sudbury System during peak periods, provides additional compression as required to maintain pressure.
Iroquois Falls Compressor Station	1 compressor	Supports required delivery pressure for industrial plant in Iroquois Falls.

Filed: 2018-12-14, EB-2018-0305, Exhibit C1, Tab 3, Schedule 1, Page 103 of 278

Location	Inventory	General Notes
Remote Storage Pool Compressor Stations	14 compressors	Supports storage facilities.

5.4.6.1 Summary of Compression and Maintenance Capital Projects

Table 5.4.6.1.1: Compression 10 Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Compressor Overhauls		1.9		0.4	8.9	1.9	2.4	6.4	1.0	2.5	**25.5**
Compressor Upgrade - Replace Plant C				19.3	82.9	48.7	5.0				**155.9**
Compressor Upgrade - Replace Waubuno		3.2	15.2								**18.3**
Compressor and Dehy Capital Maintenance	2.2	3.1	2.1	0.9	0.9	0.9	2.0	6.9	1.3	5.6	**25.9**
MSAPR Emissions Action Plan	0.2	0.2	0.2	0.1	0.1						**0.9**
Station Painting	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	**7.0**
Compression Total	**3.1**	**9.0**	**18.2**	**21.4**	**93.5**	**52.2**	**10.3**	**14.0**	**3.1**	**8.9**	**233.7**

Compressor Overhauls

These projects consist of the Original Equipment Manufacturer (OEM) prescribed scheduled maintenance/overhauls (engines, power turbines, and compressors). The overhauls satisfy the OEM recommendations to maintain equipment reliability. The project includes full internal inspections and replacement of wear items to maintain reliability and reduce the risk of failure. These projects ensure continued asset and system reliability. If the OEM recommended maintenance intervals are exceeded, the risk of reduced reliability and performance increases.

Compressor Upgrade – Replace Plant C

This project is the replacement of Dawn C Plant due to the obsolescence of a second-generation RB211-24A compressor unit that was installed in the early 1980s. The manufacturer has indicated the unit will be obsolete and no longer supported when it reaches an age of about 40 years. This means that parts and components required to support the ongoing operation of the unit may no longer be available. Union has experienced the unavailability of parts with a similar unit that has reached an age of obsolescence and was retired in 2017. Replacement of this unit in 2023 will reduce the risk of a long-term outage due to a failure and the related system reliability impacts.

Compressor Upgrade – Replace Waubuno

This project will replace the aging storage compressor at the Waubuno Station. This unit is used to inject natural gas into the Waubuno Storage Pool. The asset is over 30 years old and is becoming challenging to maintain due to difficulties sourcing replacement parts and uncertain manufacturer support. In order to ensure a reliable storage and withdrawal service, this unit will need to be replaced to avoid a significant outage.

Compressor and Dehydration Capital Maintenance

These projects consist of various compressor and Dehydration asset class replacements. These projects include replacement of uninterruptable power supply (UPS) battery banks with a finite life, light-emitting diode (LED) lighting upgrades as existing lighting ballasts fail. This forecast will improve system integrity and reliability.

Multi-Sector Air Pollutants Regulations (MSAPR)

The Multi-Sector Air Pollutants Regulations (MSAPR) came into effect in 2017. These regulations, enacted by the Ministry of Environment, Conservation and Parks Environment and Climate Change Canada (MECP) are dedicated to limiting nitrogen oxide emissions (NOx) from specific industries and equipment across Canada. Part two of the regulations are focused on stationary-spark-ignition gaseous-fuel-fired engines greater than 250k w, which specifically impacts large stationary reciprocating engines at STO. Environment, Health and Safety (EH&S) in conjunction with expert consultation and STO Engineering have developed a plan to review and address the emission exceedances. Emission allowances consider NOx emission from a fleet wide perspective and are broken into two compliance Phases.

MSAPR Phase One compliance date of Jan. 1, 2021:

- 2019
  - Dow A Compressor– install catalytic convertor - $110,000
  - Edy's Mills Compressor – install catalytic convertor – $110,000
- 2020
  - Dawn Aux 3 Generator – install catalytic convertor - $110,000
  - Dawn Aux 4-1 Generator – install catalytic convertor - $110,000

MSAPR Phase Two compliance date of Jan. 1, 2025:

- 2021
  - Oil Springs East Unit 1 Compressor – install catalytic convertor - $110,000
  - Oil Springs East Unit 2 Compressor – install catalytic convertor - $110,000
- 2022
  - 167 Compressor – install catalytic convertor - $110,000
- 2023
  - Dawn Aux 4-2 Generator – install catalytic convertor - $110,000

Station Painting Program

This is a centrally managed program 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 Union's Corrosion Control SOP and is the documented and committed practice with respect to how it complies with the applicable codes for corrosion control on above grade station assets. The benefit of this work is primarily the safety and reliability of Union's assets and ensuring code compliance. This forecast will improve compliance and reduce the risk of leaks and piping and/or equipment failure due to significant corrosion.

5.4.6.2 Summary of Compression and Dehydration Incremental Operations and Maintenance

Table 5.4.6.2.1: Compression 10 Year Forecast of Incremental O&M for (all $ in millions, incremental to 2018)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Catalytic Converters	0.1	0.1	0.1	0.1						
Emissions Testing	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Lubricants Sampling	0.2	0.4	0.4	0.4	0.1	0.1	0.1	0.1	0.1	0.1
Utilities	0.4	0.6	0.8	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Direct Leak Inspection Program	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Compression Incremental O&M Total	**0.8**	**1.3**	**1.6**	**1.8**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**

Catalytic Converters

Replace existing spent catalytic convertors plus annual maintenance.

Emissions Testing

Complete the annual greenhouse gas (GHG) emissions testing at compressor stations and Multi Sector Air Pollution stack emissions testing of the designated reciprocating engines.

Lubricants Sampling

Complete the annual engine lubrication and glycol maintenance program and increased lubricants sampling requirements to further enhance system reliability through better understanding of asset condition.

Utilities

Costs associated with power consumption are increasing due to changes in the power rates framework. Hydro assumption of 5 per cent increase annually in excess of inflation.

Direct Leak Inspection Program Requirements

The Federal methane regulations requiring direct leak inspections at compressor stations are changing and will require compressor stations be scanned three times per year going starting in 2019 and have prescribed timeframe requirements for leak repair. The default time to repair any leak that is identified is 90 days. There are, however, exceptions that may be granted under circumstances in which the volume of gas that must be vented from the pipeline in order to safely repair the leak exceeds the volume that will be saved by repairing the leak. In these cases, the leaks will be carried and tracked with maintenance work orders, until such time as the plant is shut down and the pipe evacuated for other necessary maintenance or construction activities.

In this way, the environmental impacts as well as the cost impacts are optimized. The cost to scan the compressor fleet is estimated at $110,000 based on the 2017 and 2018 work. With the recent change and the increased inspection interval to three times per year the estimated cost for this program is $330,000. There will also be a nominal increase in O&M leak repair to meet the prescribed repair timeframe considering repair timeframes may require the work to be planned and scheduled as standalone work as opposed to the historical practice of identifying and repairing leaks during plant shutdowns.

The incremental O&M forecast is to provide day to day maintenance and support of new compressor assets.

5.4.7 Liquefied Natural Gas (LNG)

Union operates one LNG facility, Hagar, located near Sudbury, Ontario, which has been in operation since 1968. Hagar is interconnected with Union's Sudbury Lateral System, which is within the TransCanada Pipeline delivery area known as Union Northern Delivery Area.

As an integrated storage and transmission system operator, Union requires the capacity to support the integrity of the system as a whole and the provision of service to all customers. This liquefied natural gas storage facility provides reserve capacity that allows for the operational balance necessary and ensures reliable supply through Union's Storage, Transmission, and Distribution systems during peak periods.

Hagar is used to support the Sudbury area during peak periods, supply shortfalls, and unplanned pressure drops or outages. As an example, Hagar was used for this purpose in 2011 when TransCanada Pipelines experienced a pipeline rupture near Beardmore, Ontario.

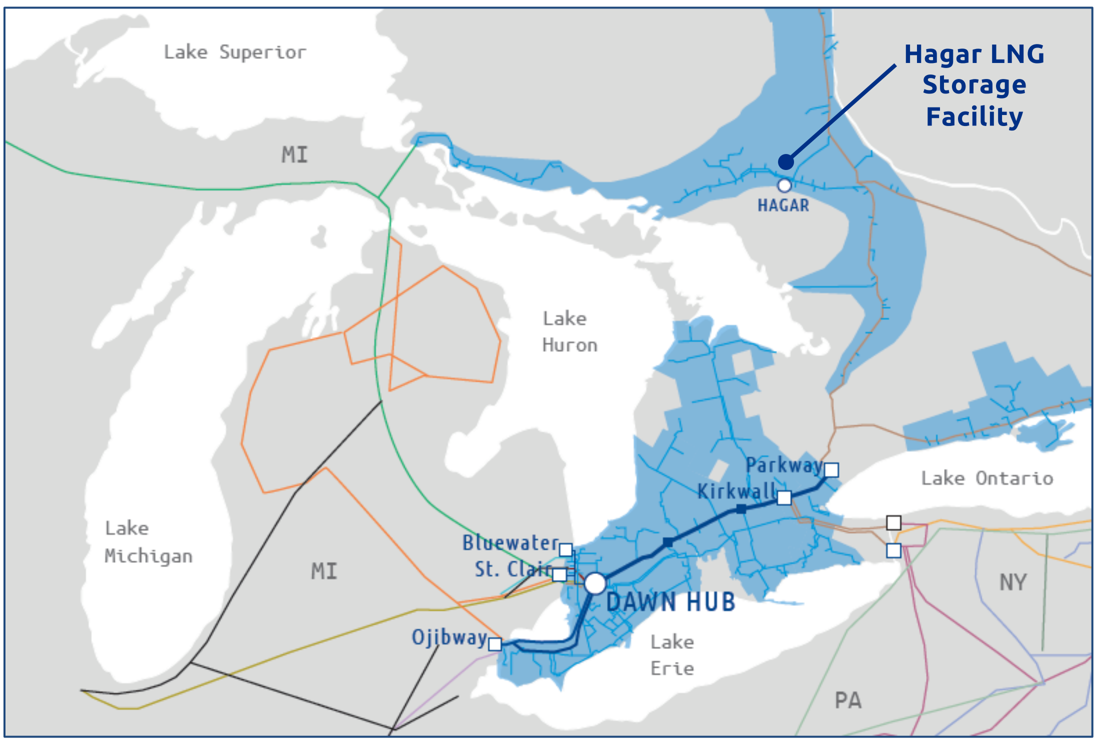


Figure 5.4.7.1: Hagar LNG Plant Location

5.4.7.1 Summary of LNG Maintenance Capital Projects

Table 5.4.7.1.1: Liquefied Natural Gas (LNG) 10-Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
LNG Capital Maintenance				6.2	0.1	2.1	6.4		0.5	2.4	**17.7**

These projects consist of improvements to the Hagar plant which are mainly required due to its age (1968 vintage). The upgrades will improve system integrity and reliability by reducing risk due to age and prepare for potential increased production demands.

5.4.8 Supporting Assets

This grouping of assets includes Service Facilities, Fleet and Technology and Information Services (TIS).

5.4.8.1 Service Facilities

Union's Corporate Real Estate Services (CRES) group manages (operation, maintenance and improvement) owned and leased facilities along with the furnishings within, in addition to owned parcels of land. In total, the CRES portfolio includes 74 properties, 1,245,291 square feet of building space and approximately 12,000 pieces of workspace furnishings. Union's Storage and Transmission Operations (STO) group manages eight additional facilities at three properties that are not part of the CRES portfolio, for a total of 82 properties.

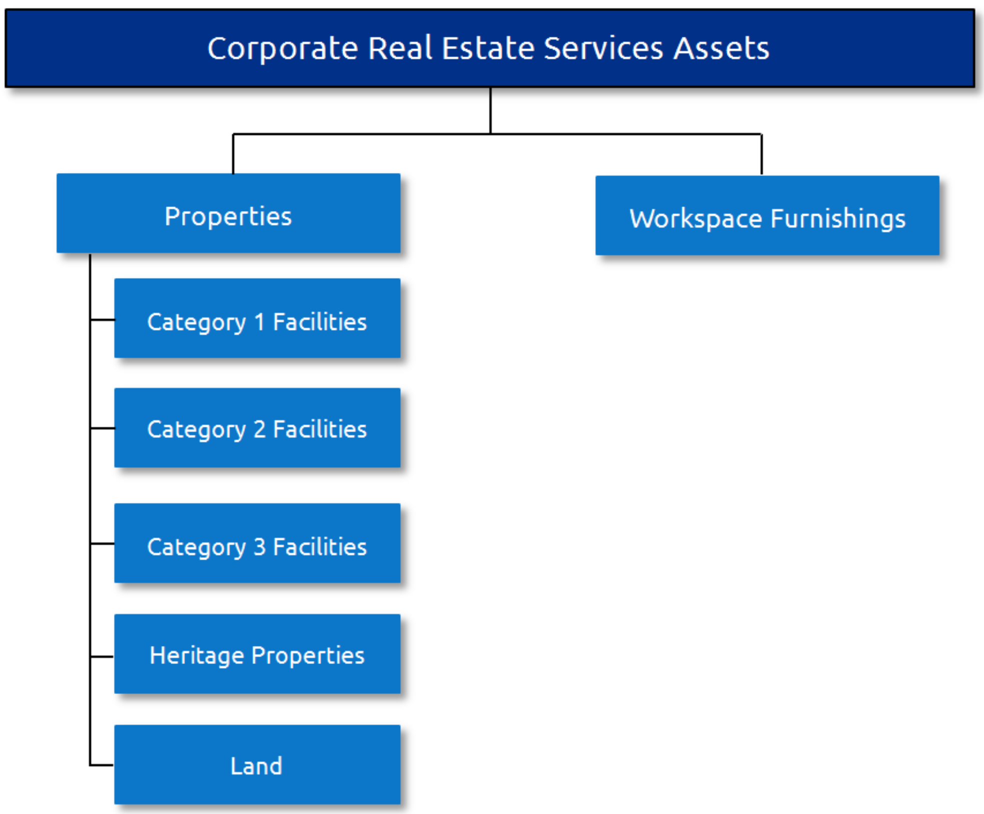


Figure 5.4.8.1.1: Structure of CRES Assets

Union's Service Facilities are divided into two subclasses: Properties and Workspace Furnishings. The Properties subclass is divided further into five categories as shown in Table 5.4.8.1.1. Inventory details are listed in Appendix C**.**

Table 5.4.8.1.1: CRES Asset Inventory

Service Facilities sub-classes	Quantity
Properties (Buildings / Land)	74
Category 1	8
Category 2	8
Category 3	52
Heritage Properties	2
Land	4
Workspace Furnishings	~12,000

Property Categorization

Category 1 Properties are operations or administration facilities located throughout the province that support the critical business needs of natural gas storage, transmission, distribution, central warehousing, customer service, revenue stream and public relations.

Category 2 Properties are operations facilities located throughout the distribution franchise area that provide field level support for natural gas distribution operations and may include a centralized support function such as a fabrication shop, call centre or drafting operations.

Category 3 Properties are field offices and small storage facilities for materials and equipment necessary to support natural gas distribution operations in remote areas of the distribution franchise area.

Heritage Properties are structures located on Union owned locations which may include significant heritage attributes. At this time, these properties are not being used for operational needs.

Land Union owns and maintains parcels of land where facilities have previously existed or where facilities will exist in the future.

5.4.8.1.1 Managed Facilities Ownership

Owned

CRES manages all aspects of building operations at owned facilities, and the occupying business function manages processes related to operations and material storage. Within the CRES portfolio, 67 of the 83 managed facilities are owned.

Leased

CRES manages only the building contents, grounds and property maintenance as required at leased facilities. The occupying business function manages processes related to operations and material storage. Unless otherwise specified, the property owner manages all aspects of capital improvements at leased facilities. 15 of the 82 managed facilities are leased.

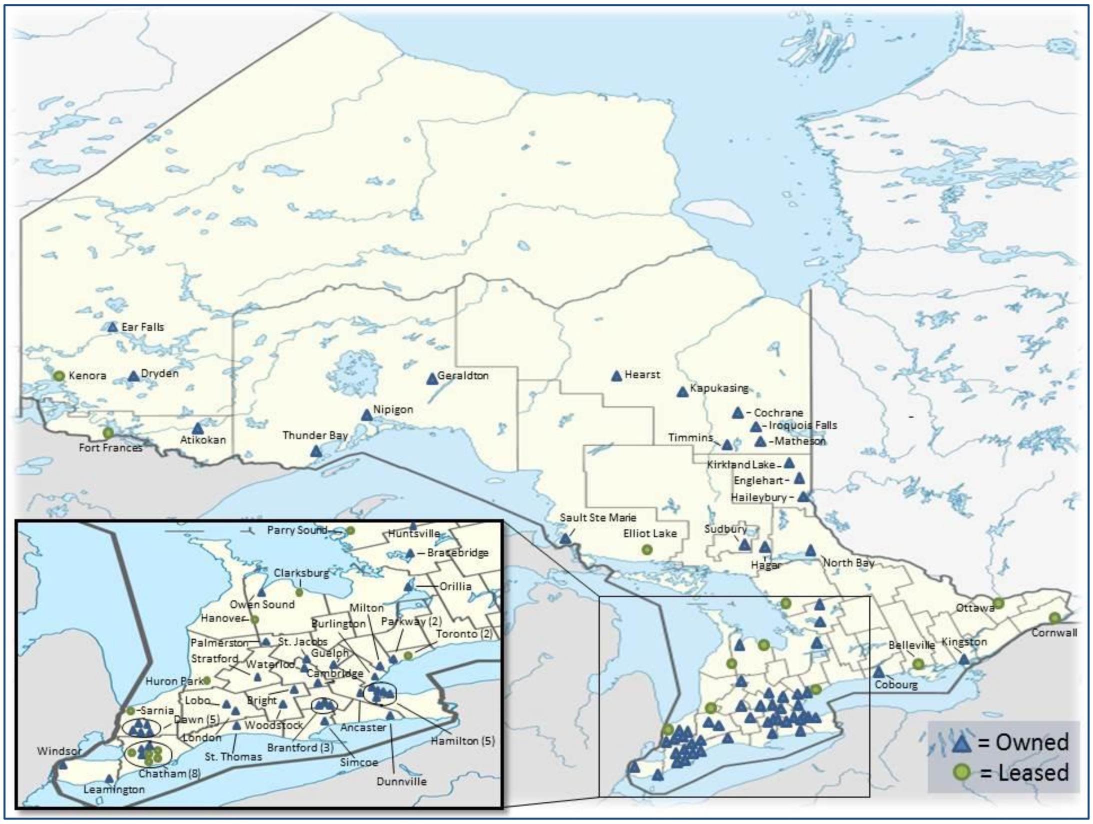


Figure 5.4.8.1.1.1: CRES-managed Service Facilities (owned and leased)

5.4.8.1.2 Asset Class Objectives

Table 5.4.8.1.2.1: Asset Class Objectives

Asset Class Objectives		Measure of success
Create and support safe, efficient, appropriate and collaborative environments for effective business function	Sustain the integrity of all facilities for safe and reliable use	• Physical Assessment: Facility Condition Index (FCI) • Functional Assessment: Adequacy Index (AI)
	Continuously evolve the understanding of condition and risk associated with real estate assets	• Cost per square foot (lease and building OpEx) • Utilization Rate • Risk Mitigated and LRROI • QRA completion %

To achieve these objectives asset investment decisions are governed by the Life Cycle Management policies outlined in Table 5.4.8.1.3.1.

5.4.8.1.3 Life Cycle Management for Real Estate Assets

Table 5.4.8.1.3.1: Life Cycle Management Policies

Life Cycle Stage	Activities
Acquire / Create	• Acquire and design facilities to suit business purposes and ensure safe business function. • Install and construct facilities to meet industry compliance and building standards. • Evaluate asset investment options to ensure best capital decisions are made for acquiring and/or creating real estate assets
Utilize	• Suitably commission real estate assets for safe and efficient use by employees. • Monitor the use of the assets over time to understand utilization and justify future life cycle decisions
Maintain	• Maintain the condition (integrity, longevity and efficiencies) of real estate assets for safe and reliable continuous operations

5.4.8.1.4 Real Estate Condition Methodology (Properties and Workspace Furnishings)

For the properties (buildings/land) asset subclasses, Union uses a Facility Assessment to evaluate and document the following:

- 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.
- Construct a 'bottom-up' capital plan.
- Create quality indoor environments with access to natural light and views which result in increased productivity, decreases 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 the functional needs, expressed as:

Adequacy Index (AI) Calculation

$$AI = \frac{\text{functional upgrade cost}}{\text{cost to replace the building with its functional equivalent}}$$

Scores between 0 per cent and 49 per cent are considered good. Scores of 50 per cent and above are considered critical.

The 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. Some Union properties have been inspected for the purpose of calculating an FCI and creating a long-term capital plan. The FCI is calculated as follows:

Facility Condition Index (FCI) Calculation

$$FCI = \frac{\text{cost to remediate immediate or short-term maintenance deficiencies}}{\text{current replacement value of the facility}}$$

Scores between 0 per cent and 5 per cent are considered good. Scores from 6 per cent to 10 per cent are considered fair. Scores between 11 per cent and 30 per cent are considered poor and scores greater than 30 per cent are considered critical.

Functionality and utilization are based on critical functional criteria (yard size, access, sufficient office area, tracked utilization, etc.) and are scored Good, Challenged or Obsolete.

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, the AI, FCI and recommended strategy for correcting the deficiencies were considered. Higher priority is given to facilities posing the larger more immediate financial and/or safety risk to the Organization.

OBC requirements must be met depending on the part, group and division each property falls under. These include (but are not limited to) barrier-free path of travel, barrier-free washroom facilities and universal washroom facilities. Furthermore, compliance with fire code regulation such as load bearing structure, fire resistance rating, sprinkler system and combustible/non-combustible construction are also considered. It is important to note that major renovations to a structure may require that area be brought up to current OBC standards, potentially requiring a substantial investment.

5.4.8.1.5 Property Condition Methodology

The CRES asset condition is governed by the AI and FCI indices, as well as the building-to-site area coverage (site functional obsolescence). The relationship between these metrics and how they lead to a particular strategic plan in regards to the assets future are visualized in two graphs (Figure 5.4.8.1.5.1).

The graph on the left represents the building adequacy and condition index. The black diamond in the graph indicates the facility assessment. The green area denotes that both the physical (FCI 0-5 per cent) and functional (AI 0-50 per cent) conditions are considered correctable at the current location. The corners on each graph are labeled to indicate the corresponding strategy for facilities that lie in that general area of the graph. The graph on the right represents the site assessment. The green area denotes that deficiencies are correctable on the existing property. The red area indicates the relocation/land acquisition is necessary to meet Union standards.

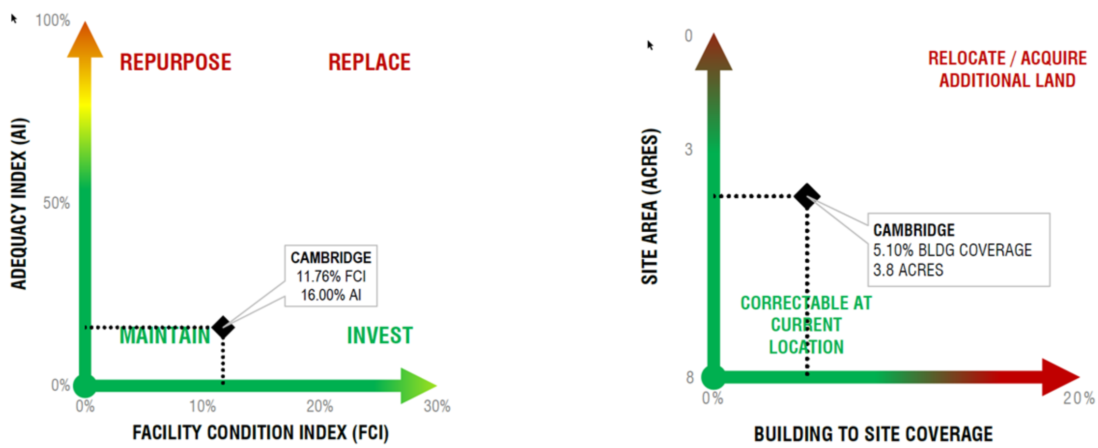


Figure 5.4.8.1.5.1: Sample graphs

A facilities condition is represented in the tables below to indicate if it meets Union's standards and whether the deficiency is correctable or not on the existing property.

Physical Obsolescence: The acceptable Union standard for physical condition is an FCI score of 0 per cent to 5 per cent. The current FCI score of the sample facility is 11.76 per cent. Therefore the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The current facility AI is 16 per cent. Therefore, the functionality of the facility is considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence – Site: The acceptable Union standard for functional condition is a 2.5 acre yard with dedicated traffic lanes for entry and departure. The Cambridge site currently does not meet operational requirements. The yard is 0.9 acres with a single access. However, the site has adequate space to accommodate future yard growth.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

5.4.8.1.6 Workplace Furnishings Condition methodology

Furnishings include workstations and office furniture. Furnishings are either considered current (meets current standards) or legacy (does not meet current standards).

Current furniture standards provide:

- Ergonomic support.
- Daylight and views for building occupants through the 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 allowing a broad range of administrative requirements without change.
- Designs that utilize materials and features to reduce the ‘cubicle feel’.
- Designs supporting power and network wiring.

Legacy furniture (greater than 20 years old) does not meet Union's current condition standards. Legacy furniture is comprised of furniture systems purchased prior to 1990 when the concept of system furniture was first implemented. The office environment and related standards have evolved immensely over the past 30 years. The systems still in use are high-paneled, impeding daylight into the environments. Legacy furniture has surpassed its 10-year warranty period (the anticipated use length) and is approaching 30 years in age.

In addition, ergonomic requirements have changed; supporting Union's goal of zero injuries in the office. The height of the existing fixed work surfaces is 29 inches, and a contributing factor to repetitive strain injury. Current standard workstations allow for adjustable height work surfaces, empowering employees to adjust their primary work surface to the appropriate height, or to stand if desired.

Ancillary furnishings are all support furnishings including (but not limited to) guest seating, informal and collaborative areas, conference room/common space furniture, filing cabinets and book cases. The condition of this furniture type is based on an assessment of age, physical condition and utilization, and is evaluated as either current (meets current standards) or legacy (does not meet current standards).

5.4.8.1.7 **Service Facilities Maintenance**

The service facilities maintenance activities, programs and best practices were established to ensure building, employee, and site safety, compliance, and reliability. Service facility maintenance activities are driven by a combination of several different maintenance programs and best practices to ensure building safety, legislative compliance, reliability, quality, value, and functional needs of each business unit are met in order to fulfil Union's core responsibilities as a natural gas utility.

These activities, programs and best practices include internal and third party assessments to critical infrastructure at predefined intervals, proactive and reactive maintenance and repair programs, and strategic renovation or replacement of service facilities to reduce the average age maximizing asset life while balancing costs.

Filed: 2018-12-14, EB-2018-0305, Exhibit C1, Tab 3, Schedule 1, Page 118 of 278

5.4.8.1.8 Summary of Service Facilities Maintenance Capital Projects

Table 5.4.8.1.8.1: Service Facilities 10-Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Service Facilities Maintenance											
Service Facilities Maintenance	5.8	4.1	3.2	3.2	3.5	3.5	3.5	3.5	3.5	8.5	**42.2**
New Service Facilities											
Belleville - New Building		3.5	4.0								**7.5**
CS-Belleville PropertyPurch&Eng.	3.5										**3.5**
Stratford - New Building								1.5	6.5		**8.0**
Service Facilities Modernization											
50 Keil CCHP Equipment	5.7										**5.7**
50 Keil Drive Modernization		4.0	5.0	5.0	5.0	3.5					**22.5**
Cambridge - Refurbishment		3.5									**3.5**
Dawn North Administration Modernization			2.9	5.3							**8.2**
Guelph - Refurbishment					1.5	6.5					**8.0**
London District Office Modernization							1.5	5.0	5.0	5.0	**16.5**
North Bay - Refurbishment						1.5	8.5				**10.0**
Orillia - New Building				1.5	5.0						**6.5**
Sault Ste Marie - Refurbishment							1.5	5.0			**6.5**
Sudbury - Refurbishment										1.5	**1.5**
Service Facilities Total	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**150.0**

Service Facilities Maintenance

These projects include mitigation to lifecycle risks including issues with grounds, pavement, roofs, walls, windows, door, interior finishes, heating, ventilation, air conditioning, plumbing, electrical, lighting, furniture, access and building automation systems. Projects in this grouping are also aimed at enhancing physical security to meet existing and new security risks in proactive approach.

Planned expenditures will aid in assuring business continuity, safe reliable natural gas service and potential significant operations and maintenance savings from Heating, Ventilation, and Air Conditioning (HVAC) replacements, Light-emitting diode (LED) lighting conversions and building envelope upgrades.

New Service Facilities

This category includes projects to build new service facilities that are better sized and are in a better location to accommodate the local operations. These also have improved lighting, heating and ventilation systems that will result in lower operating costs and improved security. This approach with a steady pace of spend is consistent with customer engagement feedback.

Service Facilities Modernization (Existing)

These projects will address lifecycle risks, optimize current business unit space layout and ensure compliance with current Ontario Building Code requirements including fire spread mitigation. These projects will also contribute to Union's efforts in conservation of energy at various locations, including Chatham District Office and 50 Keil Drive North, Dawn North Administration Building, and London District Office.

These 30 to 50 year old buildings have been maintained, but would benefit from modernization to aid in assuring business continuity and deliver safe and reliable natural gas service while reducing operating costs.

This approach with a steady pace of spend is consistent with customer engagement feedback.

5.4.8.1.9 **Summary of Service Facilities Incremental O&M**

Table 5.4.8.1.9.1: Service Facilities 10 Year Forecast of Incremental O&M (all $ in millions, incremental to 2017)

Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Additional Security Guards	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.5

Additional Security Guards

In support of the security management program, the addition of additional security guards at key facilities will result in increased O&M expenditure.

5.4.8.2 Fleet

Union owns approximately 1,280 vehicles, trailers, and equipment across Ontario from Windsor to Cornwall to Kenora to support Union's operational business needs. These assets include the vehicles listed in Table 5.4.8.2.1 as well as 312 pieces of equipment and 182 trailers.

The vehicles, equipment, and trailers can vary dependent on the operational needs. Vehicles are sub-divided further into heavy, medium, and light vehicles.

Table 5.4.8.2.1: Union Fleet Vehicles

Vehicle	Example	Inventory
Cars	Ford Focus/Escape	48
Light Trucks	Vans, Pick-ups, USR1 Truck	466
Medium Trucks	USR2 & USR3 Trucks, Cube vans etc.	228
Heavy Trucks	Dump Trucks	44

Preventive maintenance activities, processes, procedures and manuals for the fleet assets have been established to ensure asset and employee safety, compliance, and reliability. Maintenance activities are driven by a combination of programs and best practices to ensure vehicle, equipment and trailer safety, legislative compliance, reliability, quality, value, and to ensure the functional needs of each business unit are met.

Optimal replacement is determined by lowest total cost in vehicle's lifetime. The lowest cost is determined by analyzing cost curves for depreciation and maintenance.

Final asset replacement decisions are evaluated against the optimal replacement analysis plus age, mileage, condition, risk of failure and functional need. Each asset is ranked and evaluated annually. Maintenance dollars are spent based on risk with the highest risk items being completed first.

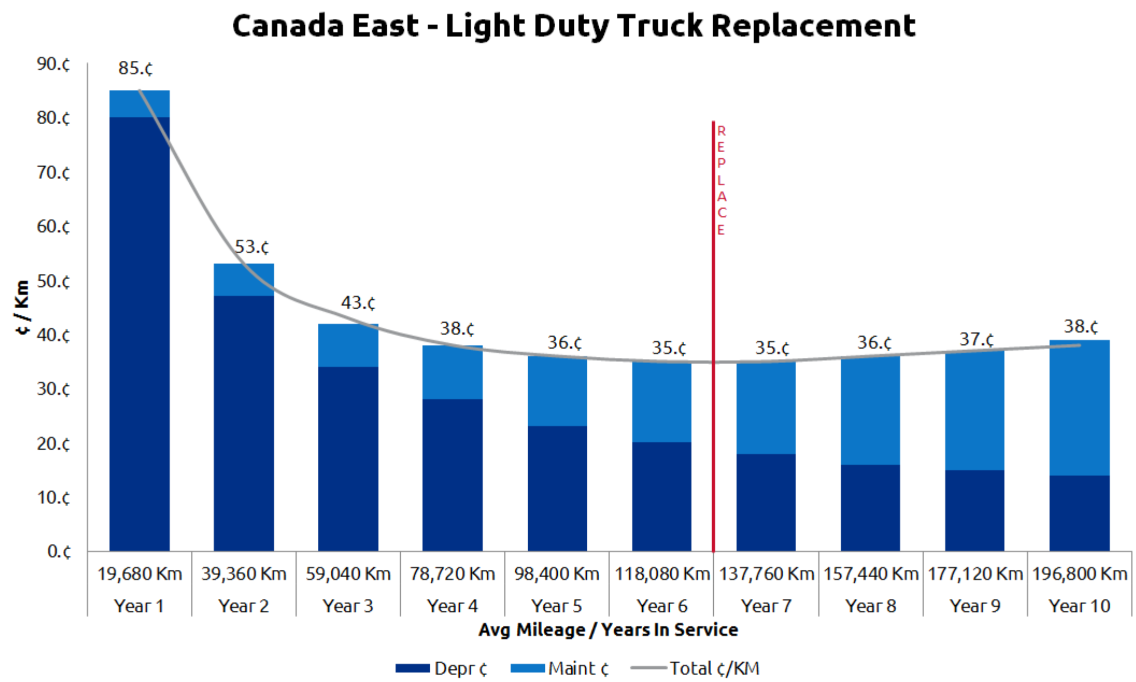


Figure 5.4.8.2.1: Optimal Replacement Analysis – Light Duty Truck

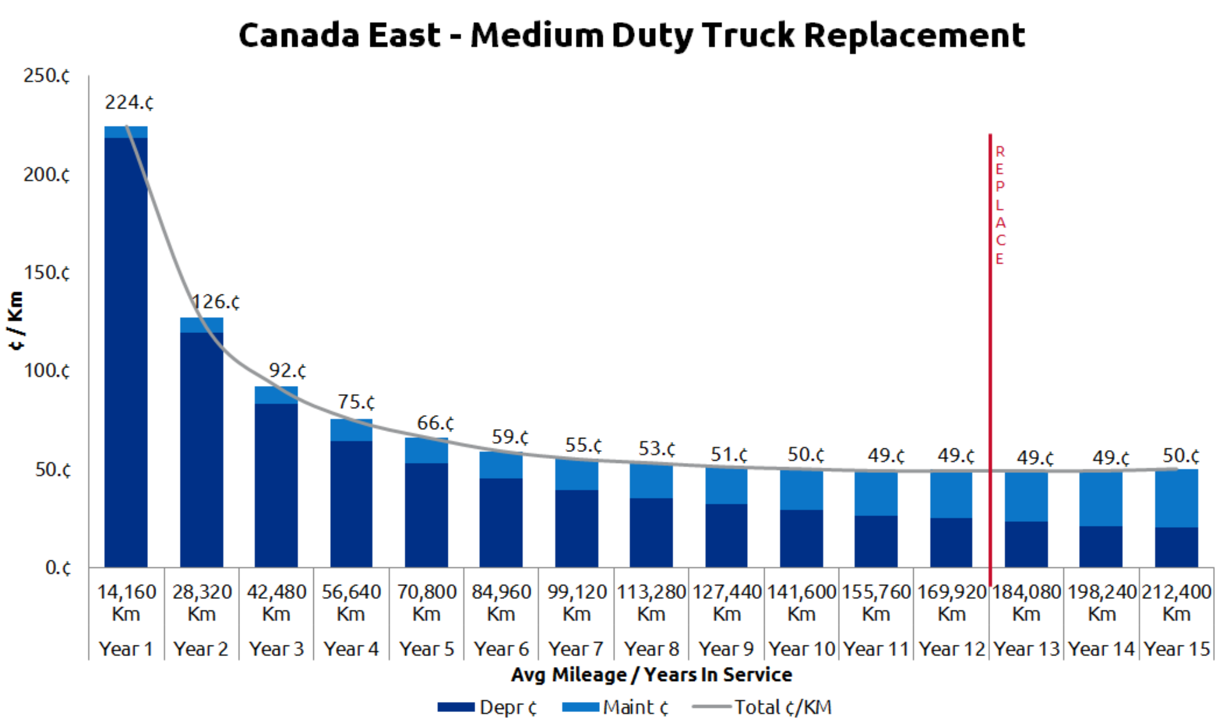


Figure 5.4.8.2.2: Optimal Replacement Analysis – Medium Duty Truck

5.4.8.2.1 Summary of Fleet Maintenane Capital Projects

Table 5.4.8.2.1.1: Fleet 10-Year Forecast of Capital (all $ in millions)

Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Fleet	10.0	12.0	12.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	**90.0**

Fleet Replacement

This forecast includes an increase in the years 2019 to 2021 to replace fleet vehicles that would have been replaced in the years 2015 to 2017. During the years 2015 to 2018, the fleet expenditures were reduced as the funds were allocated to higher priority projects. This approach with a steady pace of spend is consistent with customer engagement feedback.

5.4.8.3 Technology and Information Services (TIS)

Technology and Information Services (TIS) applications and related technology work activities are driven by a combination of enhancement projects and lifecycle upgrades/replacements. The overarching objective is to ensure that TIS applications and related technologies provide desired functionality, perform efficiently, and are usable, reliable, maintainable, and compatible with other applications/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.

Work activities include reviews of best practices, internal and third party assessments, development of technology roadmaps, maintenance and replacement of applications and/or technologies.

Business cases are developed for each TIS investment and are prioritized using compliance, lifecycle, financial strategic and reputational strategic drivers.

During the TIS application lifecycle, 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.

5.4.8.3.1 Hardware

Hardware includes general hardware used to support the entire business as well as specialized hardware specific to an application or area of the business. General hardware includes workstations, networks, servers, and security. Workstations include laptops, desktops, monitors and accessories, printers, and plotters. Networks consist of routers, switches, hubs, firewalls, devices required to maintain voice communication and video conferencing networks, as well as patch panels cabling systems that link internal local area networks to high-speed data circuits. Servers consist of the devices that operate Union’s applications and store data. Security involves the protection of control systems, business applications, computer infrastructure, and data networks.

Specialized hardware products are required to support specific business needs and include meter reading equipment, call centre network devices, and other communication devices that allow work to be completed in remote areas of the franchise as well as maintain the safety of field employees and equipment. The lifespan of hardware assets typically ranges between four and seven years depending on the device. The devices within each group vary in age. A portion of all the hardware assets are upgraded each year to ensure ongoing operational reliability.

5.4.8.3.2 Information Technology Applications

Information Technology (IT) applications include 16 key IT applications that provide critical functionality to Union employees and customers by contributing to the support and growth of Union’s natural gas storage, transmission, and distribution business. Key IT applications also rely on ancillary systems that have been added over time to provide additional functionality as the business needs change and grow. There are an additional

64 smaller IT applications that support specific functional business needs. The IT applications can be classified as Commercial-off-the-Shelf (COTS), internally developed solutions, or cloud services. The age range of the internally developed solutions can extend out as far as 20 years before a lifecycle replacement/significant upgrade occurs. Technology upgrades and enhancements may occur regularly to internally developed solutions. The age range of the COTS applications extends out as far as 15 years; however, the majority are within a 10-year range and rely on the vendor to maintain support. Lifecycle activities are based on risk factors identified for each application.

5.4.8.3.3 IT Technologies

The IT technologies asset class contains nine key technologies that are used within IT and are categorized as application integration systems, business intelligence systems, and database systems. Application integration systems allow the interconnection of processes and exchange of data among different business applications. Business intelligence systems allow business data to be queried, reported, and analyzed from Union's application systems to aid in corporate strategy planning and decision making. Database systems provide the back end relational database technologies for storage of business data, as well as related client software to allow applications to connect to these databases.

The age range of the all of the IT technologies extends to 20 years. However, plans are in place to decommission older IT technologies as more current technologies are available.

5.4.8.3.4 Summary of Technology and Information Services (TIS) Maintenance Capital Projects

Table 5.4.8.3.4.1: TIS 10-Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Key Applications											
Banner	2.0	3.5	2.1	2.1	2.3	12.1	32.1	37.3	27.1	2.1	**122.6**
CARE	0.1	6.1	11.2	10.2	9.2	0.2	0.2	0.2	0.2	0.2	**37.6**
CARS	0.1	0.3	7.2	7.4	7.4	2.0	2.3	0.3	0.4	0.8	**27.9**
ConTrax	11.6	0.1	0.4	0.3	0.1	2.4	0.1	0.1	0.1	2.4	**17.5**
Corrosion		1.5	2.3	0.3		0.2	0.3	0.3		0.2	**4.9**
GIS		1.5	0.8	6.0	6.1	6.0	0.6	0.3	0.3	0.8	**22.2**
Meters & Measurement		3.9	1.6	0.6	0.2	0.2	0.4	0.1	0.1	0.4	**7.5**
SCADA	1.0	1.0	1.0	1.0	1.1	2.1	4.2	2.0	1.0	1.0	**15.4**
Service Suite	3.8	0.5	1.0	0.5	0.5	2.5	0.5	0.5	0.5	3.0	**13.3**
Applications - Other	1.5	4.3	3.7	2.9	5.0	2.5	2.1	3.5	2.8	4.5	**32.7**
Hardware	6.3	7.4	4.6	4.6	5.7	8.2	7.6	5.8	5.9	9.3	**65.5**
IT Technologies	1.4	1.1	1.4	1.1	1.3	1.2	1.2	1.4	1.2	1.0	**12.1**
TIS Total	**27.8**	**31.3**	**37.1**	**36.7**	**38.7**	**39.5**	**51.4**	**51.6**	**39.6**	**25.4**	**379.1**

The detailed integration planning of the systems and processes of the two utilities is underway. The resulting integrated structure will influence the ultimate systems and processes spending.

Applications

Changes to TIS Applications are categorized into the following three types:

- **Enhancements** – Small to medium sized projects to add functionality and/or adapt the application to new business requirements.
- **Upgrades** – Primarily focused on applications that leverage vendor software. Regular version upgrades are required in order to maintain vendor support.
- **Lifecycle Projects** – Medium to large projects where the entire system is replaced with either a new in-house developed application or different vendor supplied software. COTS (Commercial-off-the Shelf) or vendor supplied applications are typically life cycled every 10 to 15 years to maintain support. In-house custom develop applications tend to have a longer life span and undergo a lifecycle replacement every 20 to 25 years.

The majority of the proposed TIS capital is for life cycling existing applications. Given there are 16 key applications and lifecycle projects typically take three to four years to implement, there will need to always be two to three active medium to large application projects in order for the systems to be properly working. This supports the desire expressed by Union's customers that costs are kept at a consistent, stable level.

Further, deferring some of the proposed TIS projects could result in outages that take several days to resolve, impacting Union's ability to provide safe and reliable operations – something that Union customers also indicated a strong preference for.

Key Application Projects

Banner – is used to bill Union's 1.5 million residential customers as well as the large commercial and industrial accounts. In 2019 and 2020, a $2.5 million enhancement to the on-line component referred to as My Account is required for compliance with the AODA (Accessibilities for Ontarians with Disabilities Act). During 2024 through to 2027, the application will undergo a major lifecycle replacement as the current version and underlying technologies will be over 20 years old. The other spending is on enhancements to enable the application to continue to meet business needs.

CARE – is Union's gas management system which handles both incoming and outgoing nominations. It validates these requests against Union's pipeline capacity. In 2020 to 2023, CARE will have a major lifecycle replacement to ensure it continues to operate effectively. It is an in-house developed application that was originally developed in 1994. The underlying technologies are no longer supported by the vendor and it's becoming increasingly difficult to maintain resources trained in the older programming tools.

CARS – allows customers and contractors to submit and track their requests to get gas service at their location. In 2021 to 2024, CARS will have a major lifecycle replacement to ensure it continues to operate effectively. It was developed in-house in 2009. The underlying technologies are no longer supported by the vendor and it is becoming increasingly difficult to maintain resources trained in the older programming tools. In 2025, the on-line user interface referred to as Get Connected, will be enhanced to ensure it continues to operate securely.

CONTRAX – provides billing of Distribution, Storage & Transportation services for large Commercial/Industrial accounts and Direct Purchase customers. A lifecycle replacement project was started in 2013 and will finish in 2019. The application had become difficult to support due to the outdated technology and the complexity of the application as a result of having undergone several disparate and complex enhancements since it was initially implemented in 1995.

Corrosion – provides asset-tracking, inspection and field data collection system for routine inspection, maintenance and regulatory compliance activities on Union's pipeline built on vendor provided software. The software is overly complex to use and therefore inefficient. Alternative packages will be investigated as part of the lifecycle project in 2020-21, including potential of consolidating its functions into an existing application.

GIS – is Union's geographic information system (GIS) application for storing spatial and attribute information primarily related to underground assets (e.g. pipe, valves, fittings, district boundaries, structures, intersections, etc.). It provides accurate data for planning and emergency response. The application consists of a suite of purchased software products that will need to be life cycled in 2022 to 2024 to maintain vendor support. The current software version was implemented in 2007.

Meter and Measurement – is a set of applications that captures meter readings from residential, commercial and high volume customers, passing the data onto the appropriate billing systems. In 2020, the residential meter reading application will be upgraded to incorporate reads from meters with AMR devices. It is expected that through the regular life cycling of meters, a sufficient number them will have this feature.

SCADA – the Supervisory Control and Data Acquisition System is used to monitor and control Union's pipelines and stations from a remote location, as well as to make important data accessible for other users for system planning. The software monitors pressures, flows and gas quality. A lifecycle of the SCADA application is planned for 2024 to 2027 with upgrades to both the host application and the telemetry throughout. The last major lifecycle replacement of the vendor software (Cygnet) was in 2011.

Service Suite – is vendor software configured to provide electronic work orders to Union's 400 Utility Services Representatives across Ontario. It is also used to dispatch workers in the event of a gas emergency. The application also accepts completion of work. The last major lifecycle occurred in 2007. A lifecycle project was initiated in 2016 to find a product that could better serve the requirements of the functional area and address the lifecycle issues of the aging software. The decision was made to complete a technical upgrade of the Service Suite system to the newest version of the software. This will address the lifecycle issues associated with the current version and return it to mainstream support with the vendor. The new system will go live mid-2019.

Hardware

These projects include the purchase of new and replacement hardware such as workstations, networks, servers and security components. Also included in this category are specialized devices such as meter reading handhelds, ruggedized laptops for use within the Utility Service trucks, and security cameras for monitoring remote facilities.

IT Technologies

These are projects to install new or upgrade existing IT technologies that include application integration systems, business intelligence systems, database systems, and web delivery systems. Application integration systems allow the interconnection of processes and exchange of data among different business applications.

5.4.8.3.5 Summary of IT Incremental O&M

Table 5.4.8.3.5.1: TIS Ten-Year Forecast of Incremental O&M (all $ in millions, incremental to 2017)

Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Maintenance Activities		0.6	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1

Maintenance Activities

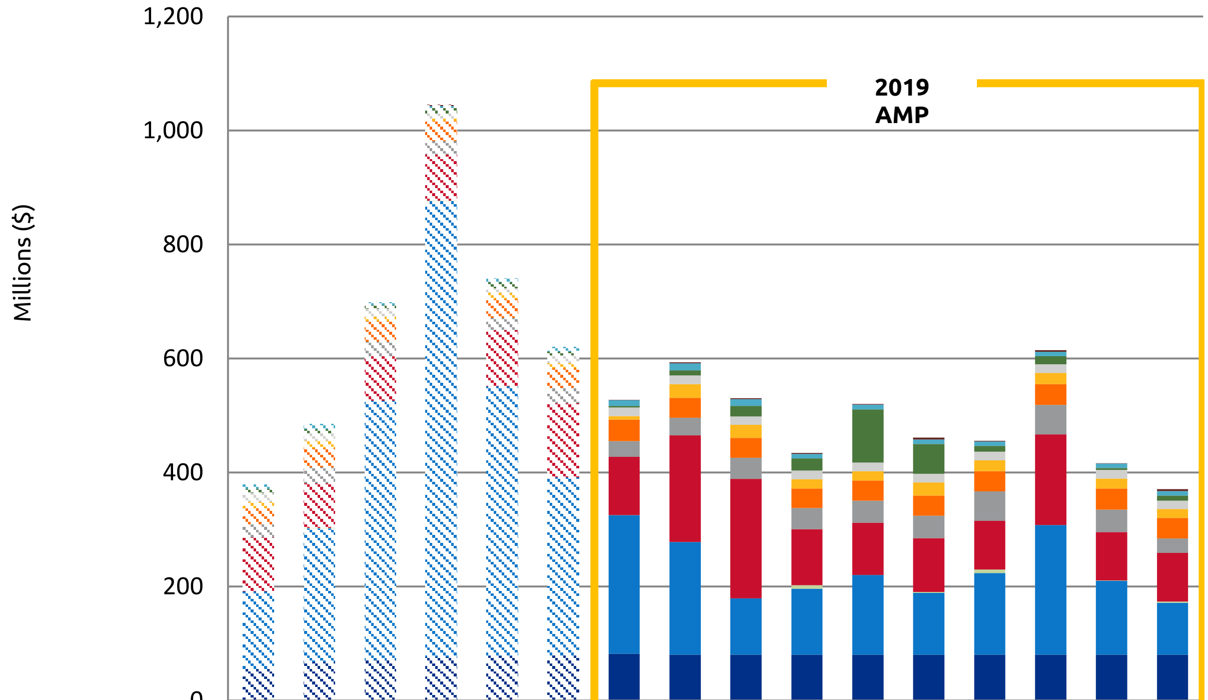
The incremental Operations and Maintenance forecast is maintenance activities for major IT applications. A majority of the incremental operation and maintenance cost is maintenance on new software licences.

5.5 Maintenance Planning Recommendations

The following Table and Figure summarize the maintenance capital forecast recommendations to mitigate risk, maintain integrity, improve reliability, manage integrity and meet compliance requirements. A significant portion of the forecast is for larger, long term projects such as the Meter Exchange Program and Integrity Programs. Larger investments have an impact on certain years. These include replacement of the Windsor Line replacement in 2020 and replacement of Dawn C Plant in 2023.

Table 5.5.1: Maintenance Capital 10-Year Forecast (all $ in millions)

Asset Category	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Pipelines	102.1	186.8	209.7	98.7	91.4	94.3	85.4	159.1	84.6	85.1	**1,197.2**
Stations	6.5	24.3	22.6	16.2	16.6	22.8	19.0	19.9	17.7	15.4	**181.0**
Measurement	37.4	34.9	35.0	34.7	35.2	35.3	35.6	36.6	36.9	36.1	**357.6**
Underground Storage	0.6	2.1	1.4	1.4	1.5	3.5	1.0	2.8	0.7	2.8	**17.9**
Compression & Dehy	3.1	9.0	18.2	21.4	93.5	52.2	10.3	14.0	3.1	8.9	**233.7**
LNG				6.2	0.1	2.1	6.4		0.5	2.4	**17.7**
Service Facilities	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	**150.0**
Fleet	10.0	12.0	12.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	**90.0**
TIS	27.8	31.3	37.1	36.7	38.7	39.5	51.4	51.6	39.6	25.4	**379.1**
Overheads	62.0	49.3	58.3	71.4	60.6	69.6	70.3	48.6	76.1	80.0	**646.1**
Maintenance Total	**264.5**	**364.6**	**409.3**	**309.6**	**360.7**	**342.3**	**302.3**	**355.7**	**282.2**	**279.0**	**3,270.3**

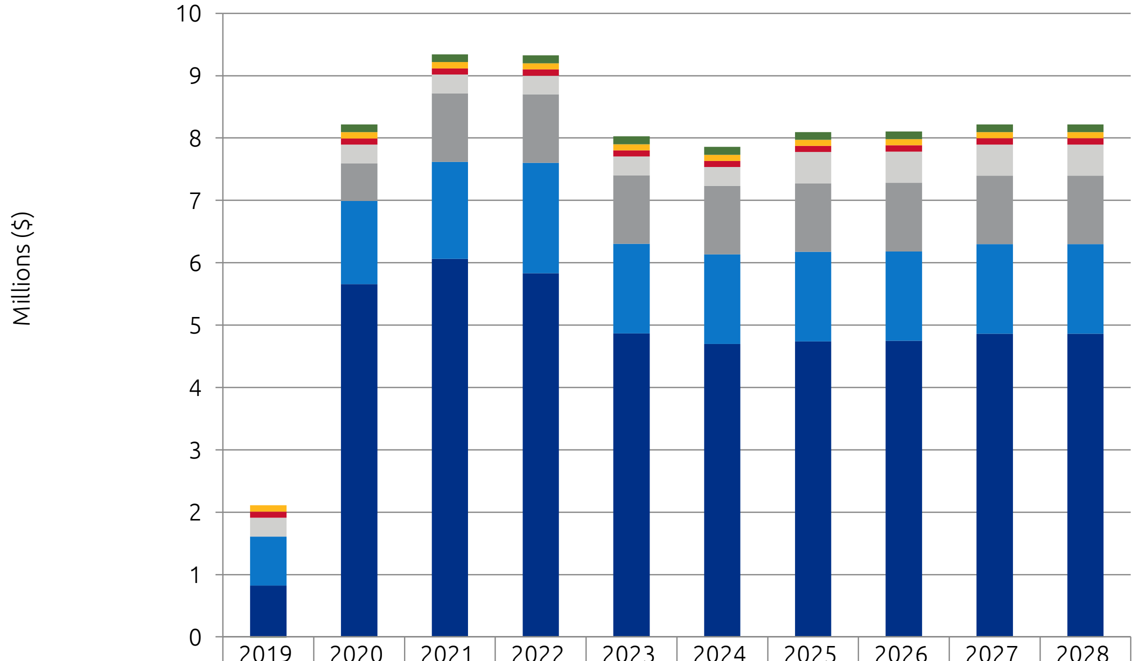


	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Underground Storage	0.5	0.5	1.1	1.7	1.9	0.9	0.6	2.1	1.4	1.4	1.5	3.5	1.0	2.8	0.7	2.8
Fleet	7.4	9.1	4.2	3.1	6.2	8.0	10.0	12.0	12.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Compression & Dehy	6.6	6.5	6.1	10.3	10.2	6.0	3.1	9.0	18.2	21.4	93.5	52.2	10.3	14.0	3.1	8.9
Service Facilities	16.5	13.5	14.2	8.3	8.0	14.4	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Stations	11.2	13.1	7.8	4.6	11.2	8.8	6.5	24.3	22.6	16.2	16.6	22.8	19.0	19.9	17.7	15.4
Measurement	27.8	33.1	35.6	34.7	32.3	33.6	37.4	34.9	35.0	34.7	35.2	35.3	35.6	36.6	36.9	36.1
TIS	22.9	28.6	26.0	24.0	22.4	27.3	27.8	31.3	37.1	36.7	38.7	39.5	51.4	51.6	39.6	25.4
Pipelines	94.9	77.7	78.1	80.6	97.7	129.8	102.1	186.8	209.7	98.7	91.4	94.3	85.4	159.1	84.6	85.1
LNG	0.5	1.6	0.3	1.2	1.2	0.5	0.0	0.0	0.0	6.2	0.1	2.1	6.4	0.0	0.5	2.4
Growth	135.7	233.7	454.2	799.4	472.2	312.3	243.1	198.1	99.1	115.8	140.3	108.6	143.6	227.6	130.2	91.4
Overheads	55.7	68.2	71.5	77.3	78.7	79.8	82.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0

Figure 5.5.1: Asset Maintenance Capital Forecast (all $ in millions)

Table 5.5.2: Incremental O&M 10 Year Forecast (all $ in millions, incremental to 2018)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Compression & Dehy	0.8	1.3	1.6	1.8	1.4	1.4	1.4	1.4	1.4	1.4
Service Facilities	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.5
Pipelines	0.8	5.7	6.1	5.8	4.9	4.7	4.7	4.7	4.9	4.9
Measurement	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
TIS		0.6	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Stations	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Underground Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Incremental O&M Total	**2.1**	**8.2**	**9.3**	**9.3**	**8.0**	**7.9**	**8.1**	**8.1**	**8.2**	**8.2**



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Stations	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Underground Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Measurement	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Service Facilities	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.5
TIS	0.0	0.6	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Compression & Dehy	0.8	1.3	1.6	1.8	1.4	1.4	1.4	1.4	1.4	1.4
Pipelines	0.8	5.7	6.1	5.8	4.9	4.7	4.7	4.7	4.9	4.9

Figure 5.5.2: Incremental O&M 10-Year Forecast (all $ in millions, incremental to 2018)

6 Summary of Capital and Incremental Operations and Maintenance (O&M) Expenditures

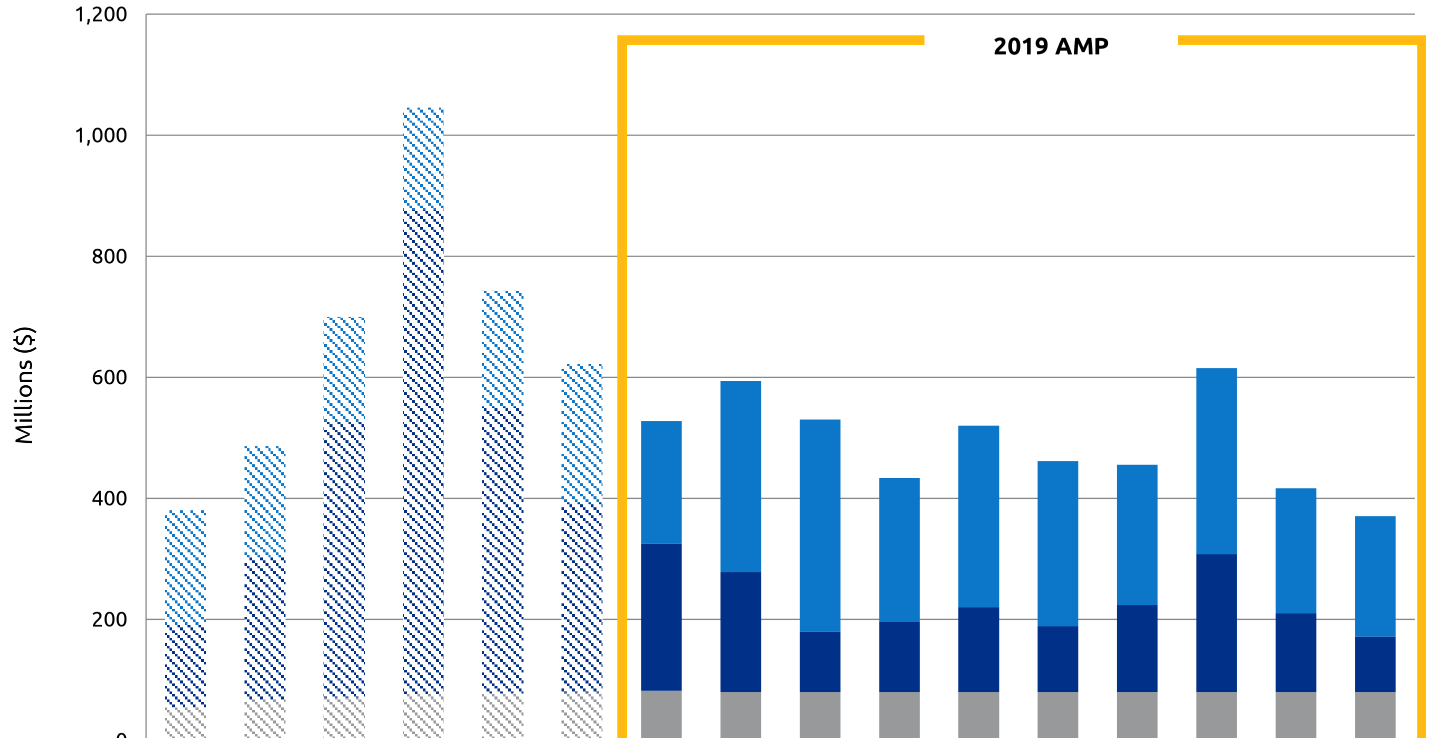
Using the methodology for prioritization and project selection outlined in Section 4, the following figures show the summary of the capital and incremental O&M expenditures required to meet Union's Purpose, Vision, Goals and Values, and to balance cost, performance and risk. Through careful consideration of the key inputs to the asset investment planning process (risk, customer engagement feedback, resource constraints), this plan provides critical direction for asset management for the next 10 years.

6.1 Total Capital Recommendations

6.1.1 Total Capital

The total capital expenditures are comprised of customer growth and maintenance capital with the associated overheads as calculated by the finance department. These expenditures are depicted in Figure 6.1.1.1. The table also shows the associated investment profile for the previous five years.

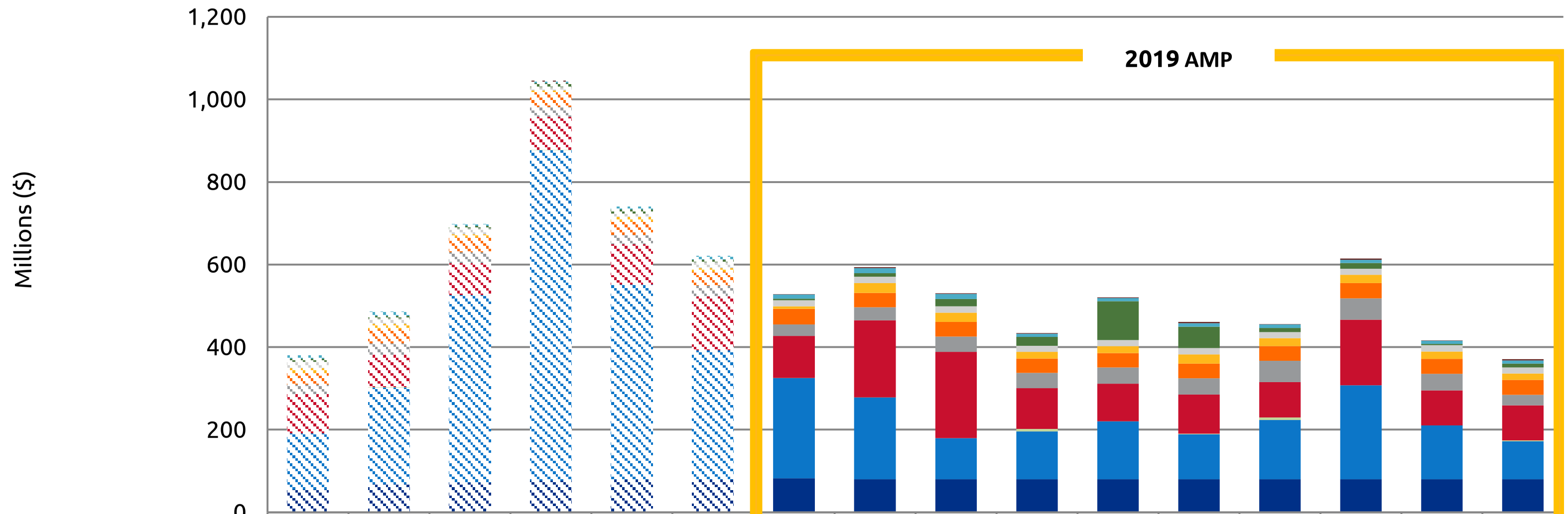
Summary of Capital and Incremental Operations and Maintenance (O&M) Expenditures



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Maintenance	188.2	183.7	173.5	168.3	191.2	229.3	202.5	315.4	351.0	238.3	300.1	272.7	232.1	307.0	206.1	199.0
Growth	135.7	233.7	454.2	799.4	472.2	312.3	243.1	198.1	99.1	115.8	140.3	108.6	143.6	227.6	130.2	91.4
Overheads	55.7	68.2	71.5	77.3	78.7	79.8	82.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0

Figure 6.1.1.1: Total Capital Expenditures – by Maintenance, Growth, and Overheads

6.1.2 Total Capital by Asset Category



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Underground Storage	0.5	0.5	1.1	1.7	1.9	0.9	0.6	2.1	1.4	1.4	1.5	3.5	1.0	2.8	0.7	2.8
Fleet	7.4	9.1	4.2	3.1	6.2	8.0	10.0	12.0	12.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Compression & Dehy	6.6	6.5	6.1	10.3	10.2	6.0	3.1	9.0	18.2	21.4	93.5	52.2	10.3	14.0	3.1	8.9
Service Facilities	16.5	13.5	14.2	8.3	8.0	14.4	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Stations	11.2	13.1	7.8	4.6	11.2	8.8	6.5	24.3	22.6	16.2	16.6	22.8	19.0	19.9	17.7	15.4
Measurement	27.8	33.1	35.6	34.7	32.3	33.6	37.4	34.9	35.0	34.7	35.2	35.3	35.6	36.6	36.9	36.1
TIS	22.9	28.6	26.0	24.0	22.4	27.3	27.8	31.3	37.1	36.7	38.7	39.5	51.4	51.6	39.6	25.4
Pipelines	94.9	77.7	78.1	80.6	97.7	129.8	102.1	186.8	209.7	98.7	91.4	94.3	85.4	159.1	84.6	85.1
LNG	0.5	1.6	0.3	1.2	1.2	0.5	0.0	0.0	0.0	6.2	0.1	2.1	6.4	0.0	0.5	2.4
Growth	135.7	233.7	454.2	799.4	472.2	312.3	243.1	198.1	99.1	115.8	140.3	108.6	143.6	227.6	130.2	91.4
Overheads	55.7	68.2	71.5	77.3	78.7	79.8	82.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0

Figure 6.1.2.1 Total Capital Expenditures – by Category and Growth

6.1.3 Total Capital by Priority Level

To provide some additional understanding of the composition of the capital investment plan, Figure 6.1.3.1 shows the expenditure profile by priority level. Priority 1 is classified as mandatory work for which there is little flexibility on timing. Priority 2 work, although having somewhat more flexibility than Priority 1, is still fairly inflexible in timing. From the standpoint of risk, Risk I (Priority 1) level projects (of which the company currently has none) and Risk II level projects (Priority 2) are considered to be intolerable risks and must have some form of mitigation action completed within a defined timeframe.

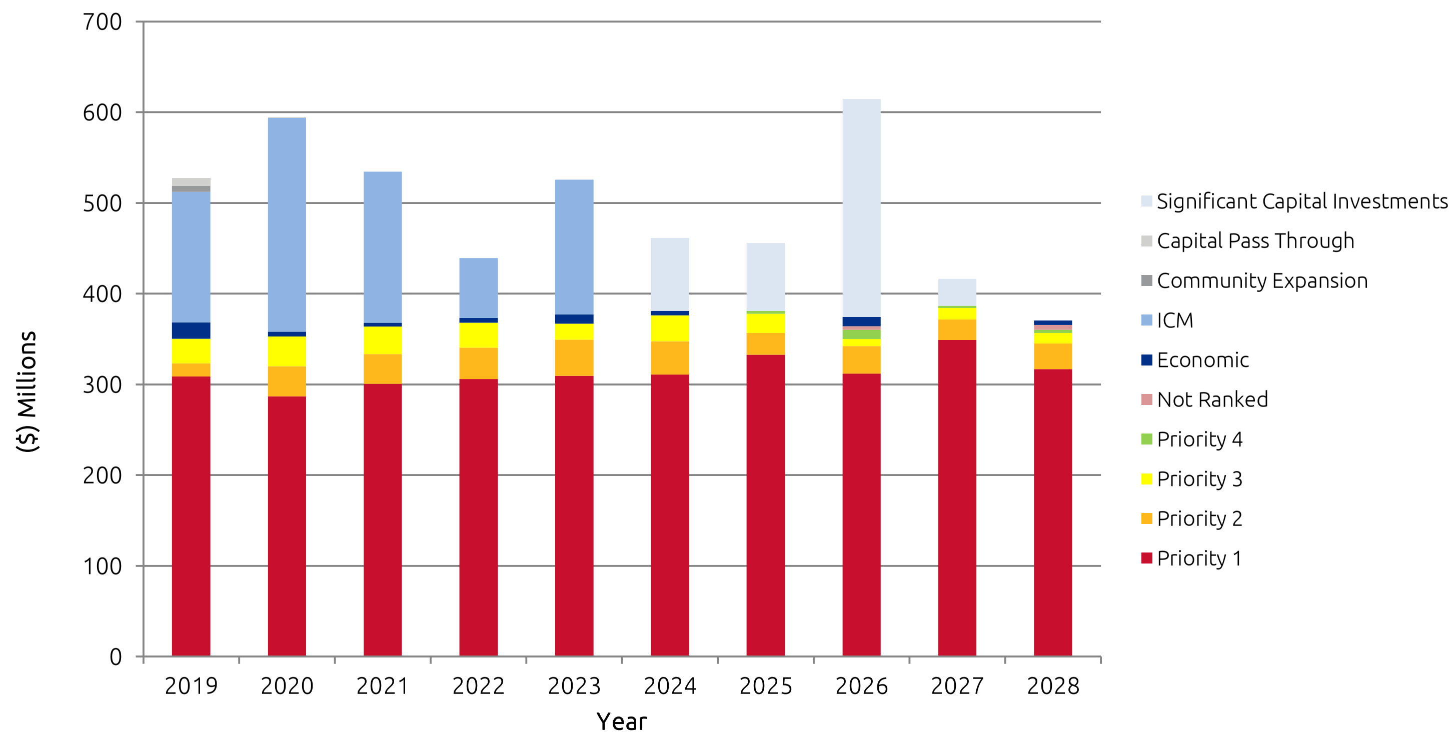
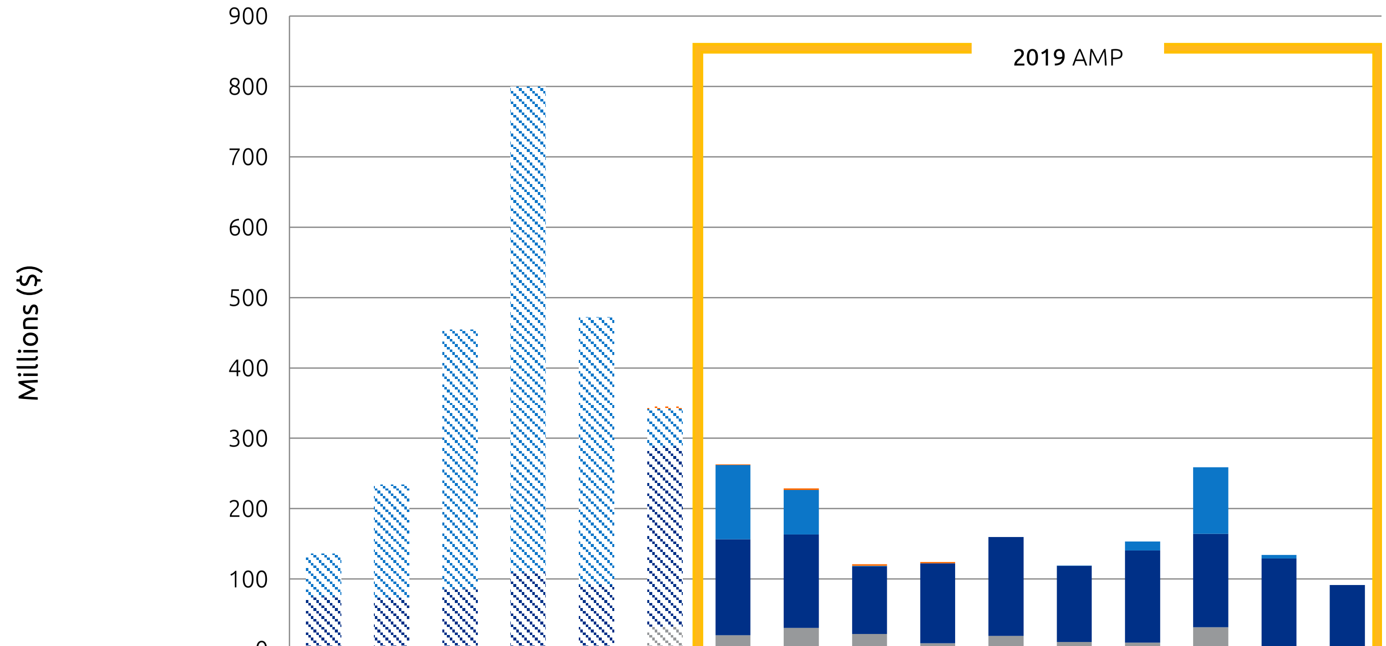


Figure 6.1.3.1: Total Capital Expenditures – by Priority Level

6.2 Asset Growth Recommendations

Within the customer growth plan are general customer growth, distribution reinforcement, transmission reinforcement, system reinforcement, as well as Compressed Natural Gas (CNG) growth opportunities. The following figure shows the growth capital profile for the 10-year plan with five years of history.

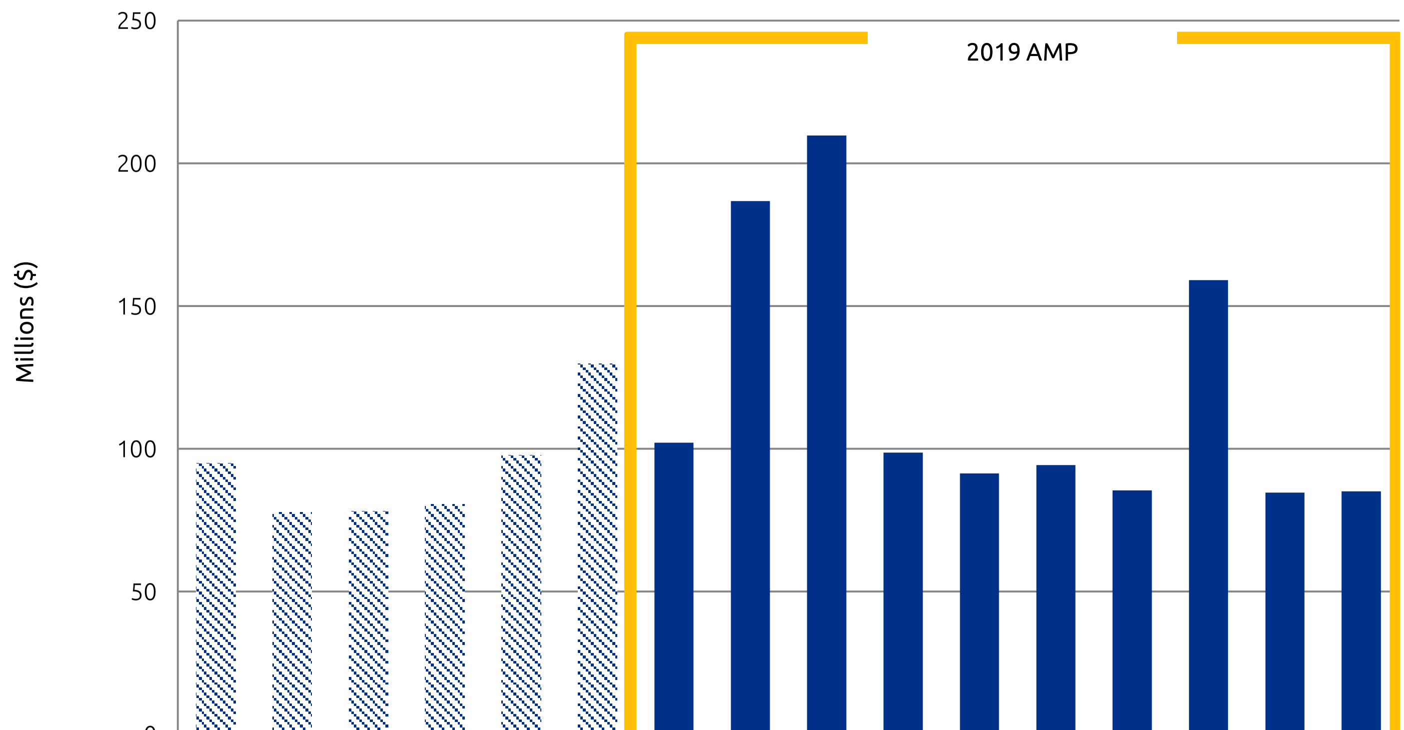


	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Other - CNG						3.0	1.0	2.3	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0
System Growth	60.3	160.2	368.0	690.0	380.0	53.0	105.8	63.2	1.3	0.0	0.0	0.3	12.8	94.7	4.9	0.0
Distribution Growth	75.4	73.6	86.3	109.4	92.1	256.3	136.3	132.7	95.9	113.9	140.3	108.3	130.8	132.9	125.3	91.4
Overheads						32.5	20.0	30.7	21.7	8.6	19.4	10.4	9.7	31.4	3.9	0.0

Figure 6.3.1: Growth Capital Profile – by System Growth, Distribution Growth and Other – CNG/RNG Growth

6.3 Maintenance Planning Recommendations

The maintenance capital plan contains all capital investments not associated with growth in the following asset categories: Pipelines, Stations, Underground Storage, Measurement, Compression and Dehydration, Liquefied Natural Gas (LNG), Service Facilities, Fleet and Technology & Information Services (TIS).



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Pipelines	94.9	77.7	78.1	80.6	97.7	129.8	102.1	186.8	209.7	98.7	91.4	94.3	85.4	159.1	84.6	85.1

Figure 6.4.1: Maintenance Capital Plan – by Pipelines

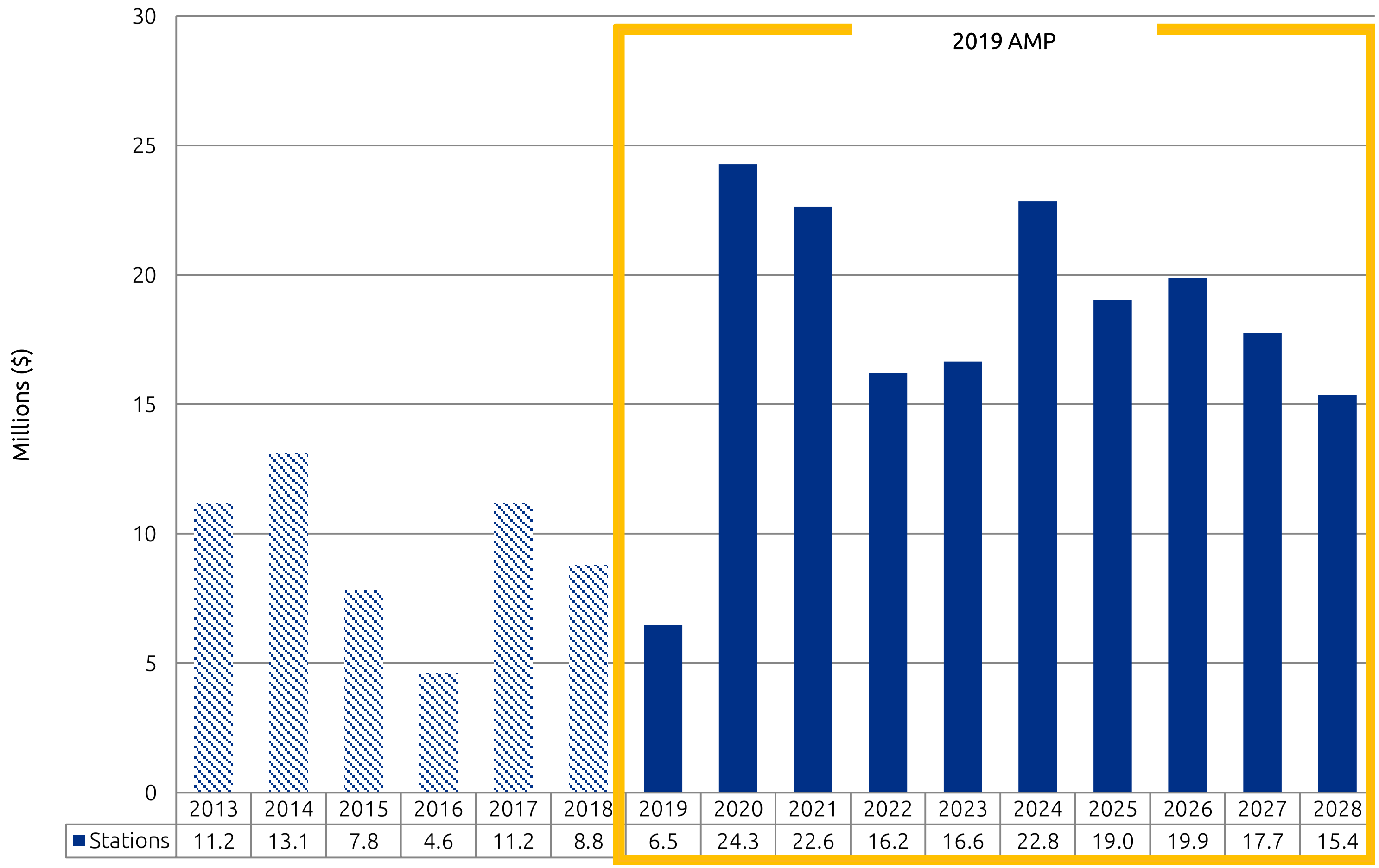
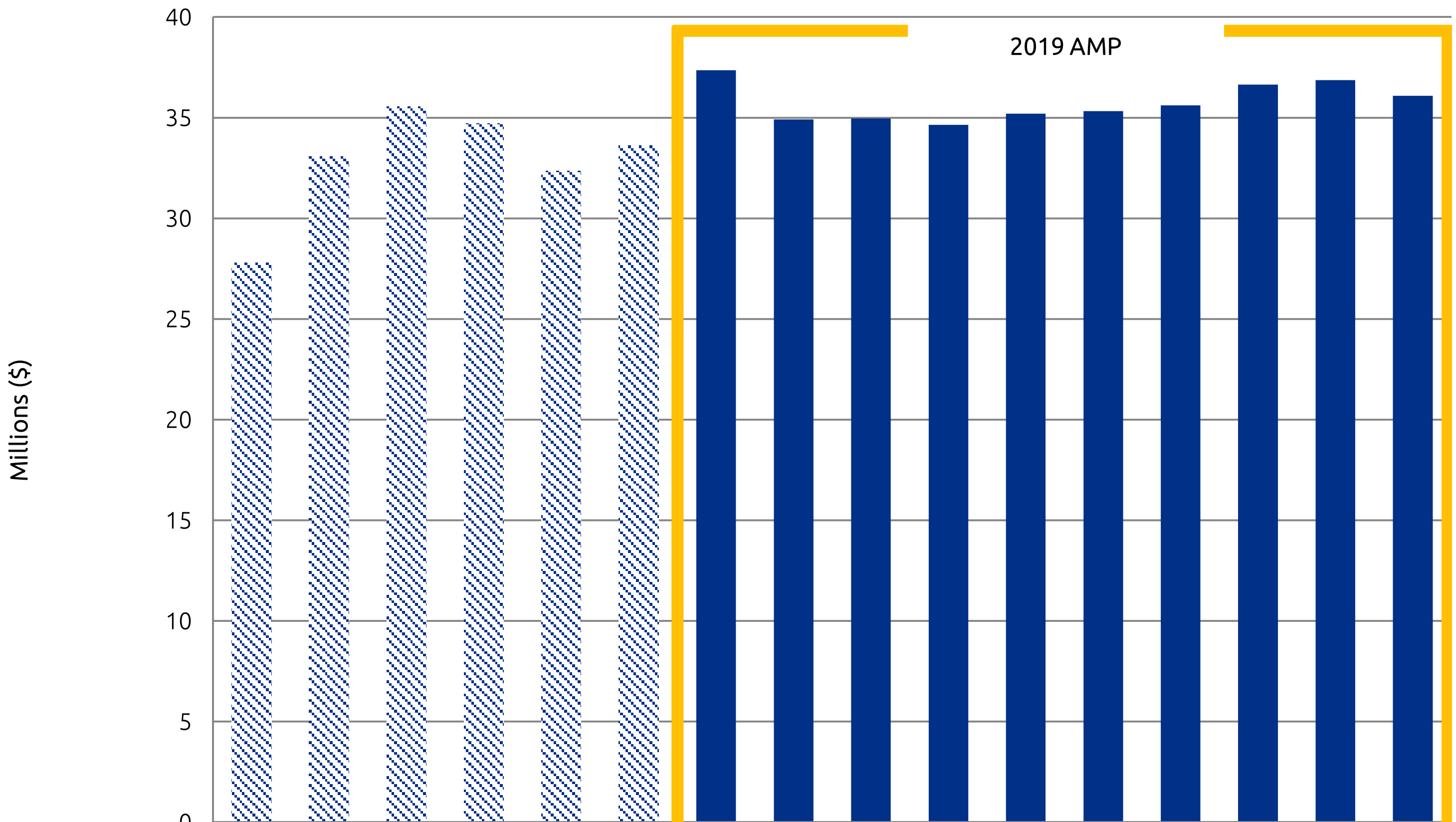
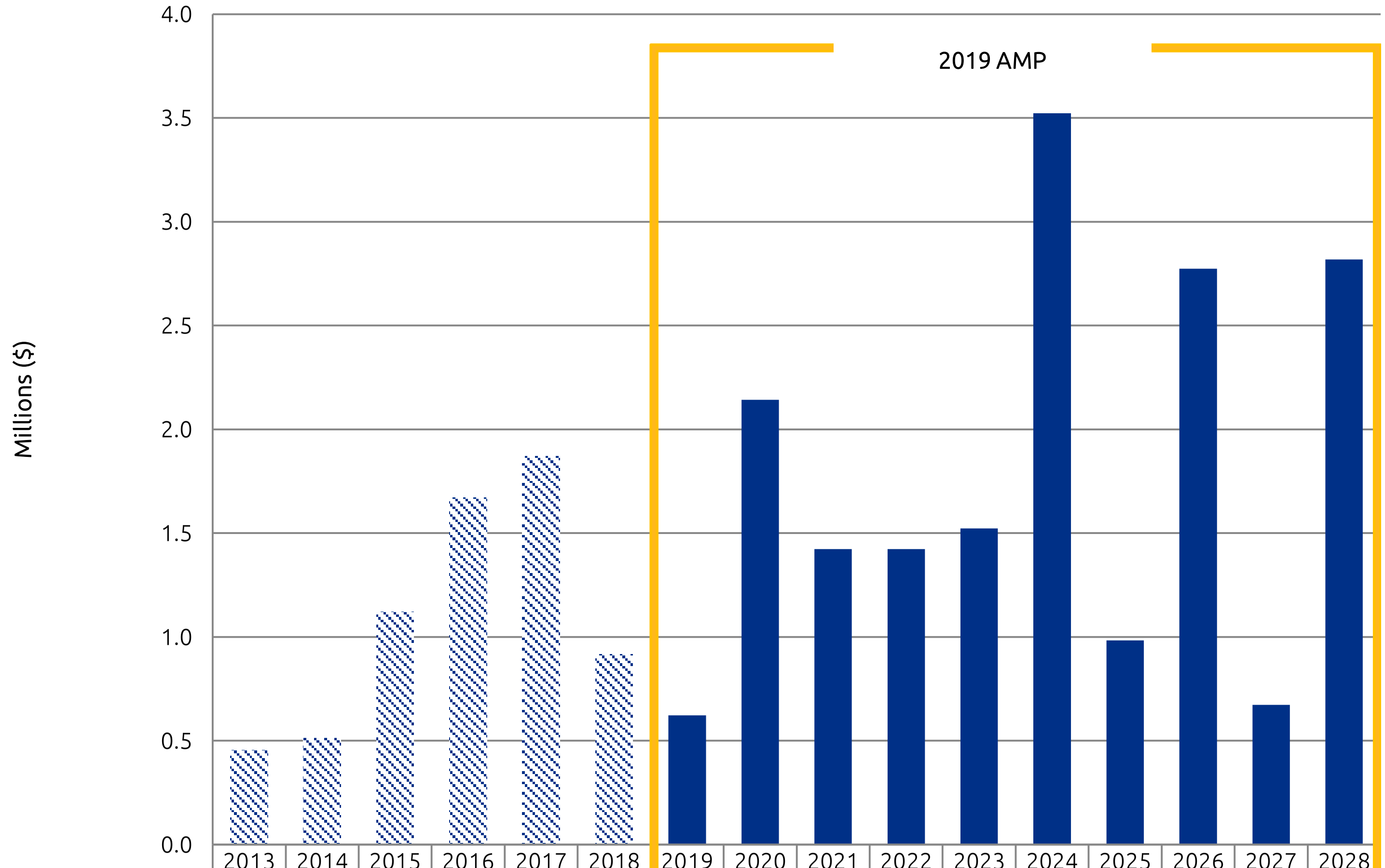


Figure 6.4.2: Maintenance capital plan – by Stations



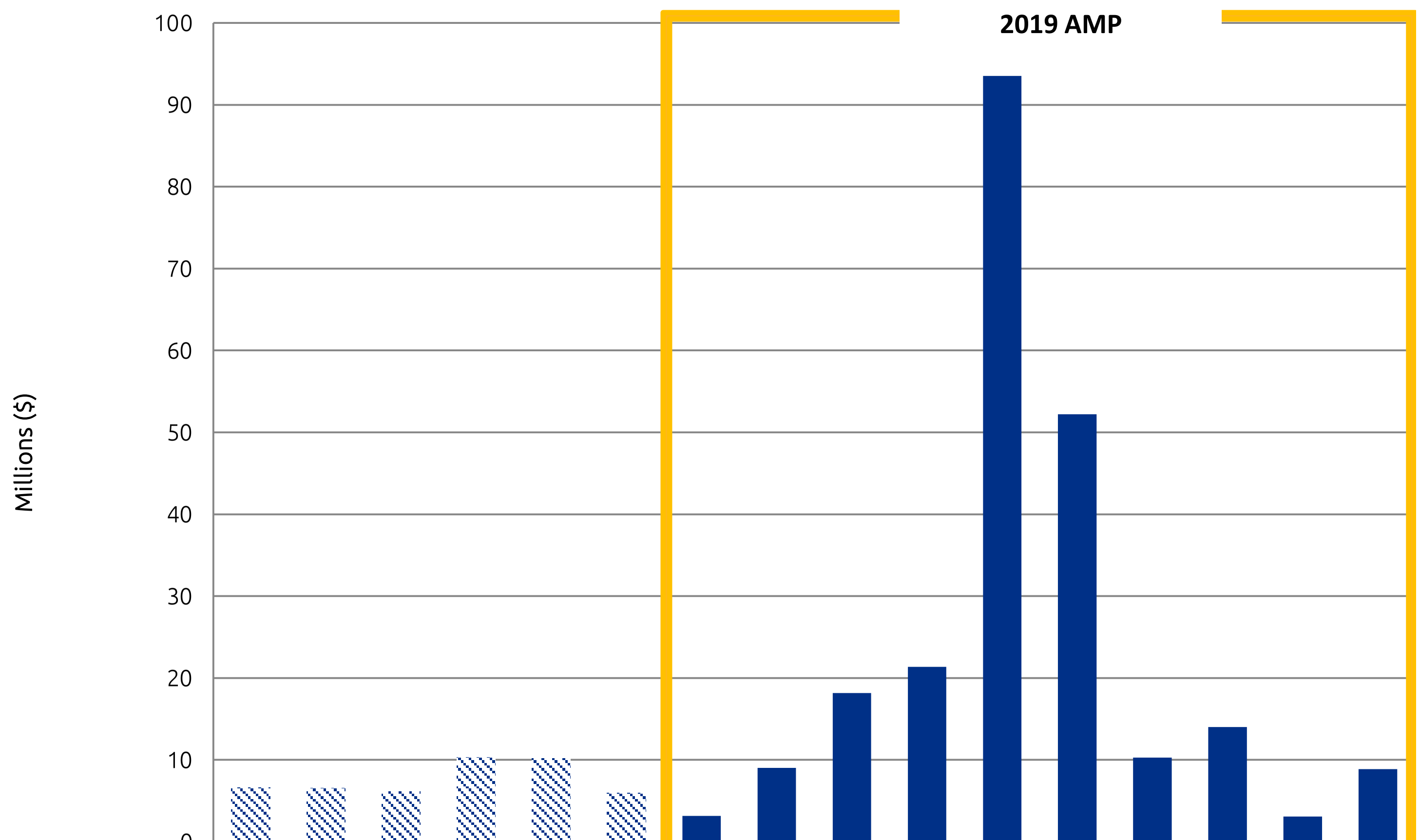
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Measurement	27.8	33.1	35.6	34.7	32.3	33.6	37.4	34.9	35.0	34.7	35.2	35.3	35.6	36.6	36.9	36.1

Figure 6.4.3.: Maintenance capital plan – by Measurement



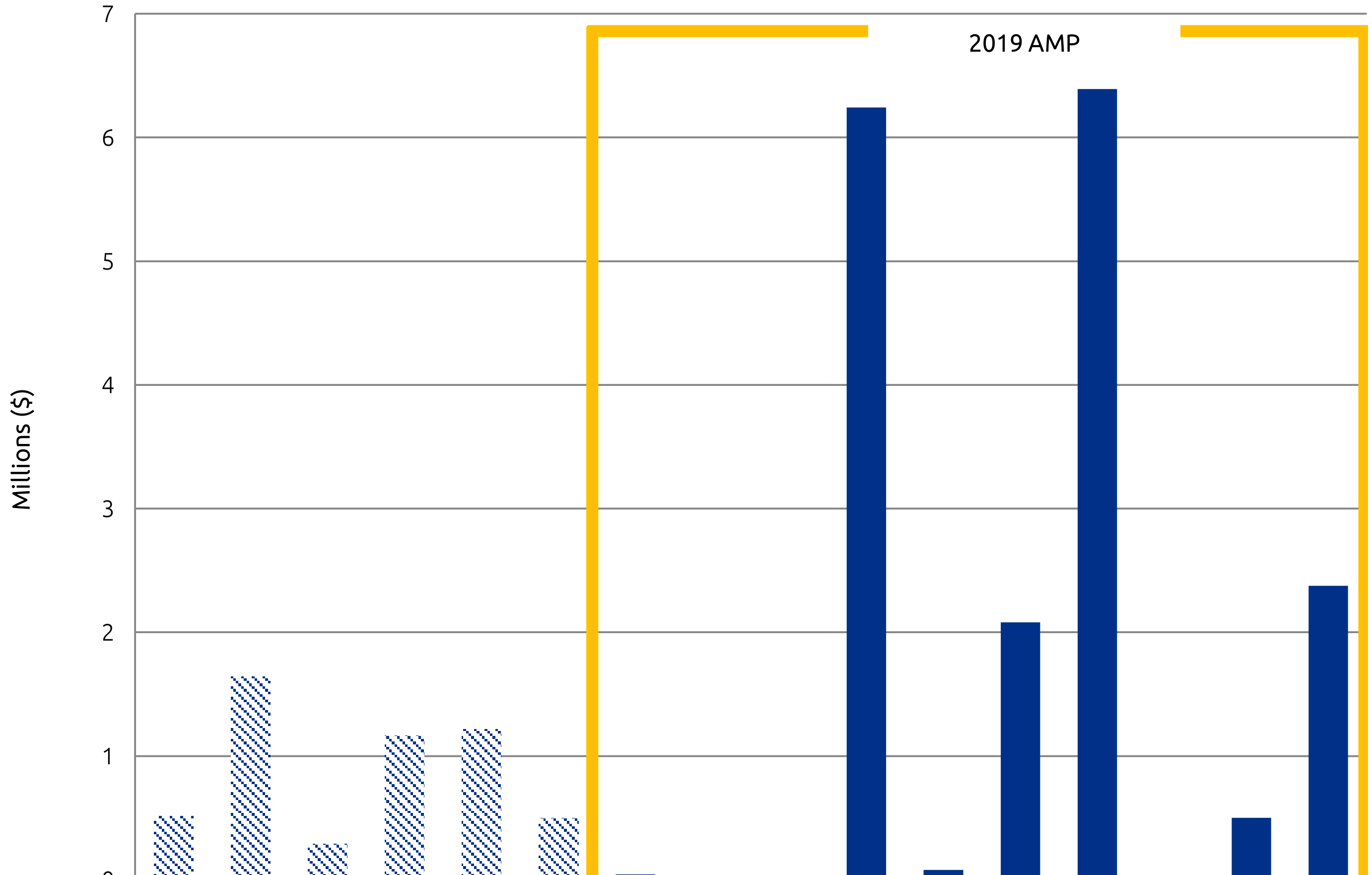
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
■ Underground Storage	0.5	0.5	1.1	1.7	1.9	0.9	0.6	2.1	1.4	1.4	1.5	3.5	1.0	2.8	0.7	2.8

Figure 6.4.4: Maintenance Capital Plan – by Underground Storage



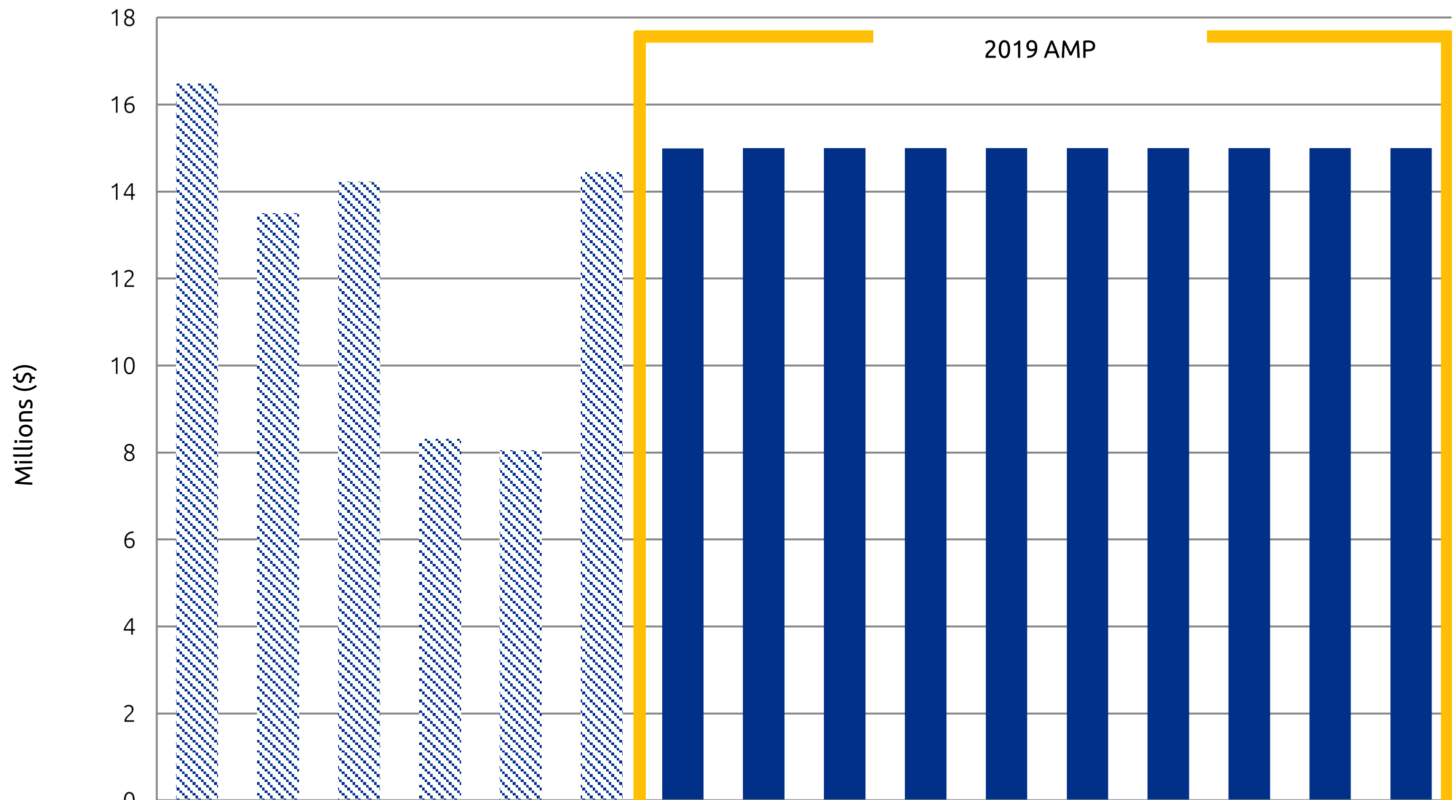
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Compression & Dehy	6.6	6.5	6.1	10.3	10.2	6.0	3.1	9.0	18.2	21.4	93.5	52.2	10.3	14.0	3.1	8.9

Figure 6.4.5: Maintenance Capital Plan – by Compression and Dehydration



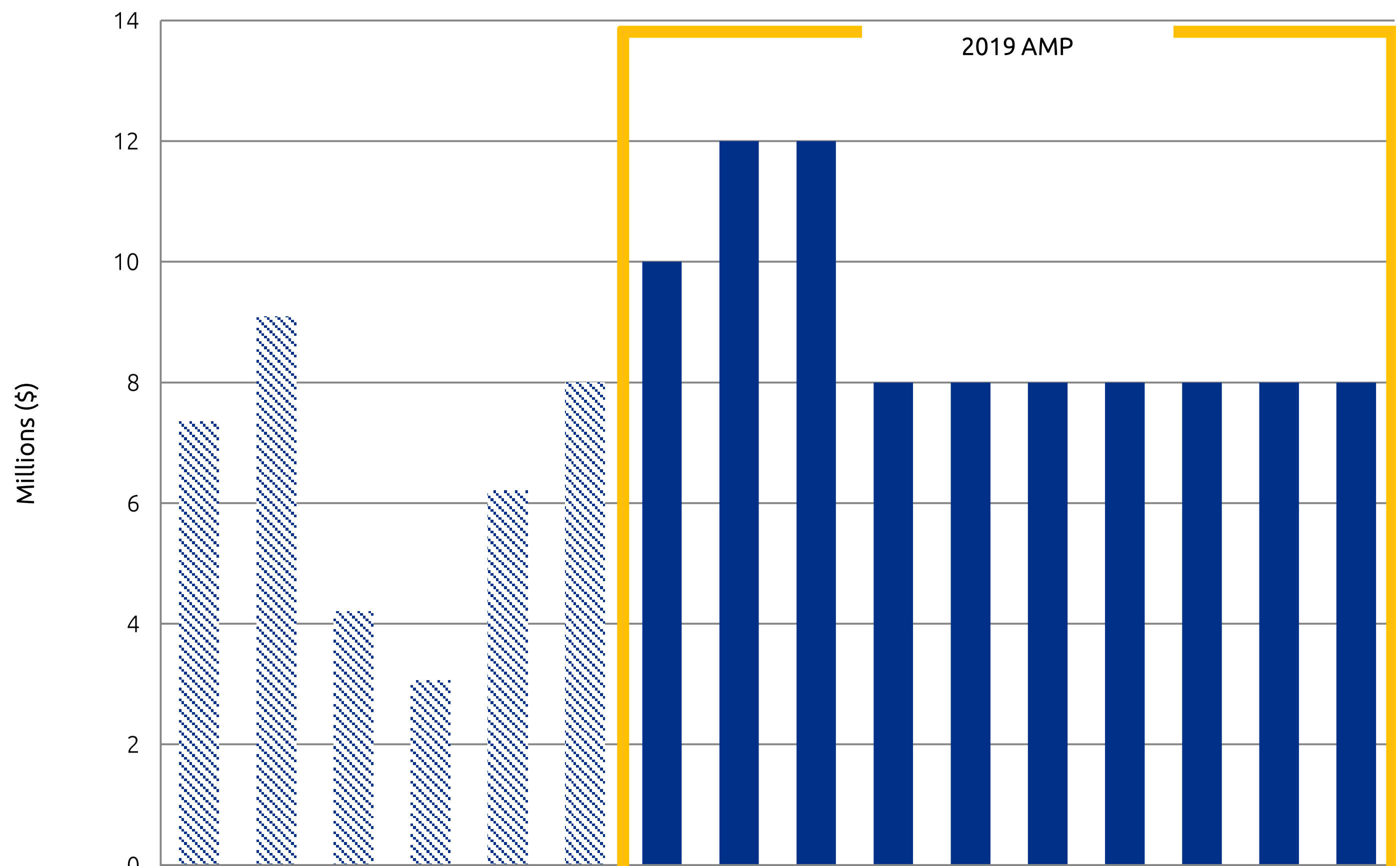
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
LNG	0.5	1.6	0.3	1.2	1.2	0.5	0.0	0.0	0.0	6.2	0.1	2.1	6.4	0.0	0.5	2.4

Figure 6.4.6: Maintenance Capital Plan – by Liquefied Natural Gas (LNG)



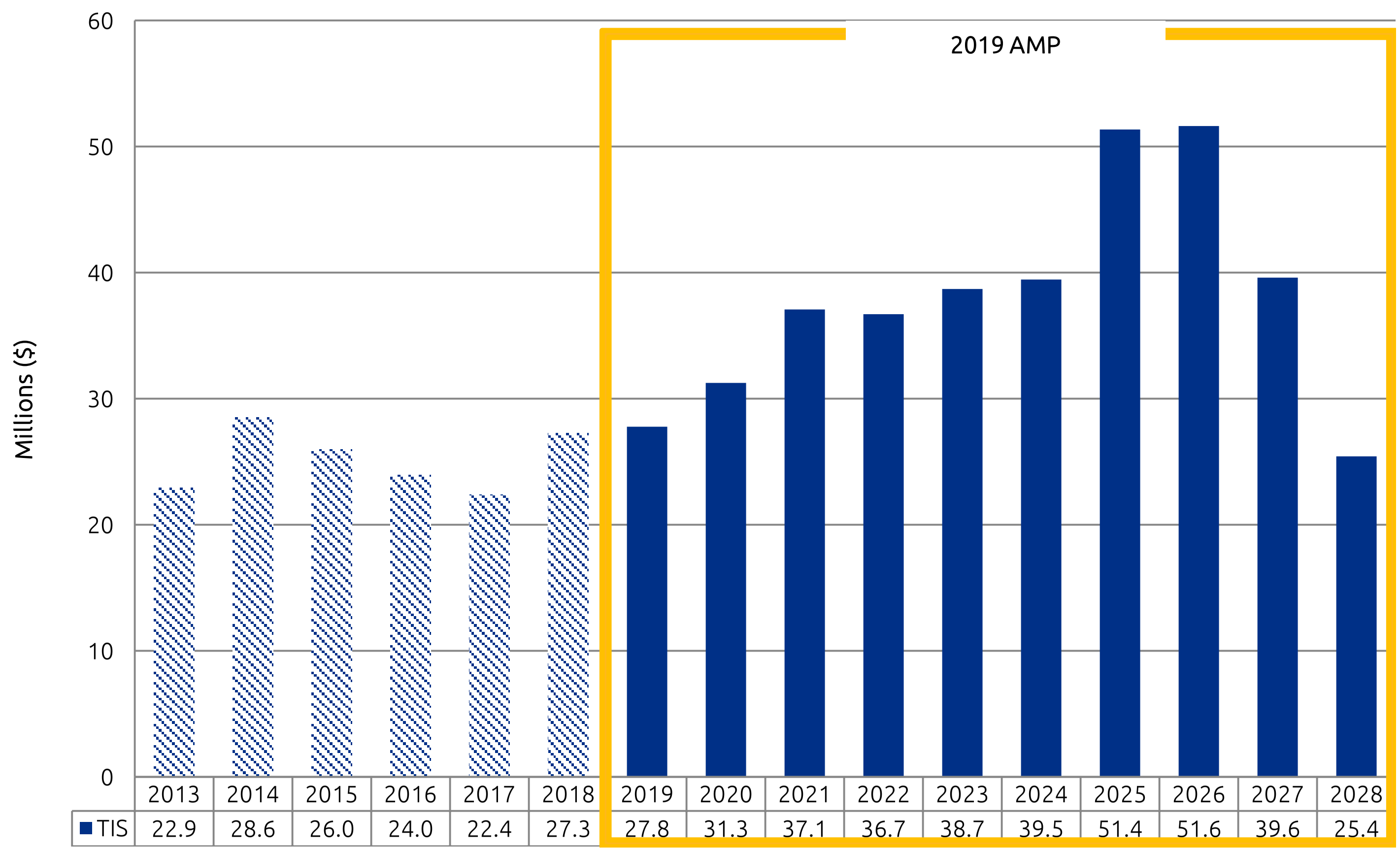
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Service Facilities	16.5	13.5	14.2	8.3	8.0	14.4	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0

Figure 6.4.7: Maintenance Capital Plan – by Service Facilities



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Fleet	7.4	9.1	4.2	3.1	6.2	8.0	10.0	12.0	12.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0

Figure 6.4.8: Maintenance Capital Plan – by Fleet

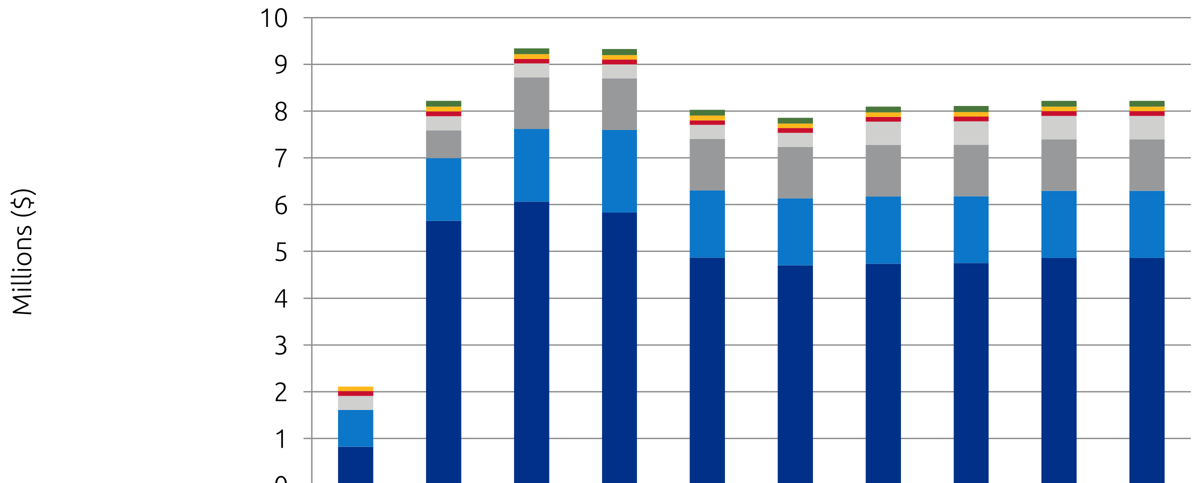


	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
TIS	22.9	28.6	26.0	24.0	22.4	27.3	27.8	31.3	37.1	36.7	38.7	39.5	51.4	51.6	39.6	25.4

Figure 6.4.9: Maintenance Capital Plan – Technology & Information Systems (TIS)

6.4 Incremental O&M

The following figure outlines the proposed incremental operating expenditures required to maintain the required level of safety and reliability over the ten-year period. Incremental O&M expense in this context is relative to the current budget year (2018). While it is being shown as incremental O&M, it is expected that any increases in O&M in support of specific programs herein will be offset by O&M reductions in other areas, resulting in no overall increases in O&M expenditures.



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Stations	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Underground Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Measurement	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
CRES	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.5
IT	0.0	0.6	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Compression & Dehy	0.8	1.3	1.6	1.8	1.4	1.4	1.4	1.4	1.4	1.4
Pipelines	0.8	5.7	6.1	5.8	4.9	4.7	4.7	4.7	4.9	4.9

Figure 6.5.1: Incremental O&M Expenditures

6.5 Assumptions

The 10-year capital plan is based on the best available information at the time of optimizing the portfolio. Key assumptions, as detailed in the following tables provide a basis for interpretations.

Table 6.6.1: Assumptions for All Categories

Assumption	Basis for Assumption (Union)
Future costs are valued at 2018 Present Value.	Current practice forecasts projects based on 2018 rates. An annual inflation factor has not been applied to asset classes (with the exception of customer growth and the meter exchange program, which assumes a 1.73 per cent annual inflation).
All cost estimates are based on available information as of July 2018.	
All Risk Assessments are based on risk models and methodology as of March 2018.	Using Union's risk management processes in alignment with the IMS risk element, risks are reviewed and updated accordingly.
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.
Capital overhead costs are included in the Asset Management Plan.	The plan also includes the following costs: interest during construction, labour and benefits, Alliance Partner overhead costs.
Historical actual costs are valued at execution years' actual value.	Historical values are not adjusted to be expressed in present value.

Table 6.6.2: Renewal Assumptions

Assumption	Basis for Assumption (Union)
Asset Health provides a reasonable representation for asset condition and remaining asset life for forecasting purposes.	Reliability Engineering is used to understand the health of assets. Based on projected life cycles, consequences of failure, tacit knowledge, and asset data, risk is determined. Renewal projects are planned to reduce this risk to the lowest practicable level.
Optimization of renewal projects produces a forecast that maintains an acceptable level of risk to the organization.	

Table 6.6.3: Customer Growth Assumptions

Assumption	Basis for Assumption (Union)
In-franchise Customer growth is forecasted using historical trends and economic projections for the planning period.	The Customer Growth Forecast considers new housing starts, meetings with builders and developers, municipal growth forecasts. Facilities Business Plans are completed and validated against econometric forecasts. Contract customer growth includes a combination of customer commitment and historical growth trends.
Ex-Franchise customer growth is forecast using historical trends, as well as customer and market intelligence.	The ex-franchise Growth forecast considers the opportunity for growth in various customer market locations using external consultants and individual ex-franchise customer interactions and discussions. The forecast also takes into consideration projected customer turn-back as an offset to growth.
Load Gathering and Simulation is based on current understanding of temperature inputs and estimated customer consumptions.	Distribution planning uses peak hourly rates while system planning uses peak daily rates for design to ensure that the design day requirements are met. The Company is evaluating the scope of its Carbon Strategy and subsequent impact on customer growth forecasts. Various technologies (e.g. smart thermostats) and Energy Efficiency programs (e.g. Demand Side Management) are being assessed to determine potential impacts on peak hour demand in the ongoing Integrated Resource Planning (IRP) study as directed through EB-2015-0029. These potential impacts to peak hour demand and customer growth forecasts have not been incorporated in this Asset Management Plan due to the current uncertainty. Any outcomes resulting from the IRP study will be factored into future Asset Management Plans.

Table 6.6.4: Solution Planning Assumptions

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

Appendix A - Key Terms

Per cent (%) SMYS: Based upon Canadian Standards Association Z662 – Oil and Gas Pipeline Systems:

$$S_h = \frac{P*D}{2*t} \qquad \% \text{ SMYS} = (S_h/\text{SMYS})*10$$

Where: S_h is the design operating stress,
P is the MOP of the pipe,
D is the outside diameter of the pipe,
t is the nominal wall thickness of the pipe
SMYS is the specified minimum yield strength of the pipe

Compressor: A mechanical device for increasing the pressure of natural gas for purposes of transmission or for storage in underground storage facilities

Compressor Station: Permanent facilities which contain one or more compressors used to supply the energy needs to move natural gas through the pipeline systems at increased pressures.

Dawn: Located southeast of Sarnia, Ontario, Dawn is referred to as a Hub as it represents the point where Union's supply, underground storage and transmission systems meet. A number of other ex-franchise pipeline systems (e.g. TCPL, Vector) are interconnected to Union's system at Dawn

Dehydration Plant: A natural gas processing facility that removes water vapour by passing natural gas through a glycol contactor, which absorbs water vapour from the natural gas stream and dries the natural gas

GHG: Greenhouse Gas

LDC: Local Distribution Companies

NPS: Nominal Pipe Size – approximate exterior pipe diameter in inches

Remote Terminal Unit (RTU): a dedicated electronic controller used for data acquisition and processing.

Supervisory Control and Data Acquisition System (SCADA) – the system used to monitor and control systems from a remote location, as well as to supply important data and make it accessible for casual users.

sm^3/hr: A gas measurement of standard cubic meters per hour of gas volume passed through a meter is converted to standard units applying pressure and temperature factors.

SMYS: Specified Minimum Yield Strength - The minimum yield strength prescribed by the specification under which the material is purchased.

TC: Temperature Compensate

Appendix B - Measurement Maintenance Tactics

Measurement Asset Sub-Class	Device Type	Maintenance Drivers	Maintenance Strategy & Tactics
Gas Meters	• Diaphragm meters (1.4 million) • Rotary meters (17,506) • Turbine meters (600) • Ultrasonic meters (commercial and interconnects) (7850 & 80)	• Compliance • Life cycle	• Diaphragm meters – Compliance sampling. Repaired or retired when removed. • Other meters - Planned maintenance as per company procedures. Condition based monitoring/time triggers. Seal expiry – out of date removal. Preventive maintenance - repair and redeploy or retire
Electronic Volume Correctors	• Electronic rotary modules (16,023) • Electronic Volume Integrators (2208) • AMR Devices (80,057)	• Compliance • Battery replacement • Life cycle	• Planned maintenance as per company procedures. Condition based/time triggers. Seal expiry – out of date removal. Preventive maintenance - repair and redeploy. Proactive battery replacement program
Odourization Systems **(Bypass & Injection)**	• MOIS injection cabinets • Odourant injection tanks (approximately 71 sites) • Odourant bypass tanks (approximately 148 sites) • Environmental deodourizer units(at each injection site) • Level instrumentation(one at each odourant site)	• Safety • Compliance • Reliability • Life cycle	• Visual inspections • Planned and unplanned maintenance • Monitoring alarms and diagnostics
Gas Monitoring & Control Systems	• RTU (400) • Communication equipment(cellular, satellite, radio) – (300) • Transmitters (1500) • Power supplies etc.	• Safety • Compliance • Operational sustainability • Reliability	• Visual inspections • Planned and unplanned maintenance • Monitoring alarms and diagnostics

Appendix C - Service Facilities Location Information

Facility Category	Ownership Status	Location Name	Address	Building Area (sq ft)	Age of Facility	Total All Furnishings
1	Own	Brantford	348 Elgin St., Brantford, N3T 5M4	45,330	23	484
1	Own	Bright	866139 Township Rd 10 - Bright N0J 1B0	10,213	1	99
1	Own	Chatham 50 Keil	50 Keil Drive North, Chatham, N7M 5M1	193,533	53	3434
1	Own	Dawn North Admin	3333 Bentpath Line, Dresden, N0P 1M0	17,417	48	267
1	Own	Lobo	11025 Ivan Drive - Ilderton N0M 2A0	13,768	2	83
1	Own	London	109 Commissioners Rd, London, N6A 4P1	66,840	50	699
1	Own	North Bay	36 Charles Street, North Bay, P1B 8K7	50,600	54	387
1	Own	Parkway West	6699 8th Line - Milton L9E 1A4	10,206	3	87
2	Own	Burlington Office	4475 Mainway, Burlington	23,000	10	303
2	Own	Chatham 20 Bloomfield	20 Bloomfield Road, Chatham, N7M 5M1	50,599	4	1002
2	Own	Chatham 555 Riverview	555 Riverview Drive, Chatham, N7M 5M1	60,000	46	415
2	Own	Kingston	1653 Venture Drive. Kingston, K7P 0E9	30,850	9	326
2	Own	Stoney Creek	918 South Service, Stoney Creek L8E 5M4	54,500	5	798
2	Own	Thunder Bay	1211 Amber Drive, Thunder Bay, P7B 6M4	44,285	22	420
2	Own	Waterloo	603 Kumpf Drive, Waterloo, N2J 4A4	40,032	7	430
2	Own	Windsor	3840 Rhodes Drive, Windsor N8W 5C2	35,725	9	503
3	Own	Ancaster	1474 Sandhill Dr., Ancaster, L9G 4V5	5,524	26	51
3	Own	Atikokan	426 O'Brien St., Atikokan, P0T 1C0	1,338	51	8
3	Leased	Belleville	127 Enterprise Dr., Belleville, K8N 4Z5	13,750	30	74
3	Own	Bracebridge	342 Eccleston Drive, Bracebridge, P1L 1V5	934	51	4
3	Own	Cambridge	221 Avenue Road, Cambridge, N1K 7Z1	8,530	56	71
3	Leased	Chatham 496 Riverview	496 Riverview Drive, Chatham, N7M 5M1	9,153	45	132
3	Leased	Chatham 745 Richmond St	745 Richmond St, Chatham N7M 5J5	21,800	N/A	456
3	Leased	Chatham 750 Richmond St.	705 Richmond St, Chatham N7M 5J5	12,130	N/A	0
3	Leased	Chatham Airport Hangar	14th. Line (R. R. #2)+B43, Blenheim,	5,758	N/A	10
3	Leased	Chatham King St.	100 King St. W, Chatham, N7M 6A9	32,000	38	0
3	Own	Clarksburg	369 Clark Street, Clarksburg	880	3	2
3	Own	Cobourg	520 Thompson St, Cobourg K9A 0E9	7,186	12	60
3	Own	Cochrane	156 Fifth Ave., Cochrane, P0L 1C0	1,442	52	20
3	Leased	Cornwall	2910 Copeland, Box 157, Cornwall, K6H 6W2	6,980	22	111
3	Own	Dawn Mechanics Building	1409 Dawn Valley Rd	10,500	N/A	40
3	Own	Dryden	304 Kennedy Road, Dryden, P8N 2Y8	1,798	39	14
3	Own	Dunnville	1202 Pine Street, Dunnville, N1A 2M9	6,994	28	47
3	Own	Ear Falls	5 Mills St, Ear Falls, P0V 1T0	960	4	8
3	Leased	Elliot Lake	14 Oakland Blvd., Elliot Lake, P5A 2T1	2,100	39	16

uniongas
An Enbridge Company

Appendix C - Service Facilities Location Information

Facility Category	Ownership Status	Location Name	Address	Building Area (sq ft)	Age of Facility	Total All Furnishings
3	Own	Englehart	137 Third Street, Englehart, P0J 1H0	400	N/A	4
3	Leased	Fort Frances	851 McIrvine., Fort Frances, P9A 2Y8	3500	N/A	33
3	Own	Geraldton	1017 Main St., Geraldton, P0T 1M0	1,464	55	17
3	Own	Guelph	10 Surrey Street, Guelph, NIH 3P5	6,659	61	109
3	Own	Haileybury	450 Meridian Ave, Haileybury,P0J 1K0	2,428	53	14
3	Own	Hamilton Park Street	133 Park Street N., Hamilton, L8N 1E7	1,428	58	19
3	Own	Hamilton Pritchard Rd	335 Pritchard Road, Hamilton	7,186	11	65
3	Leased	Hanover	69-14th Ave Unit 2, Hanover	1,600	N/A	33
3	Own	Hearst	51 Eighth St., Hearst, P0L 1G0	848	45	19
3	Own	Huntsville	184 Main Street West, Huntsville, P1H 1Y1	590	49	19
3	Leased	Huron Park	420 Quebec Avenue Huron Park ON	1,455	78	17
3	Own	Iroquois Falls	522 d'Iberville Ave., Iroquois Falls, P0K 1G0	1,650	52	6
3	Own	Kapuskasing	47 Burnelle Rd., Kapuskasing, P5N 2M1	4,330	28	27
3	Leased	Kenora - Keewatin	4091 Hwy #17 West, Keewatin, P0X 1C0	2,500	N/A	38
3	Own	Kirkland Lake	14 Kirkland St. E., Kirkland Lake, P2N 3H7	2,411	54	13
3	Own	Leamington	357 Oak St. Centre, Leamington, N8H 4W8	4,803	57	54
3	Own	Matheson	413 Park Lane, Matheson, P0K 1N0	565	50	6
3	Own	Milton	8015 Esquesing, Milton, L9T 2X8	7,000	24	52
3	Own	Nipigon	2 Wadsworth Dr., Nipigon, P0T 2J0	1,282	55	9
3	Own	Orillia	425 Memorial Ave, Orillia, L3V 6K2	12,254	44	89
3	Own	Owen Sound	1602 23rd St. East, Owen Sound,	7,300	12	63
3	Own	Palmerston	206 Whites Rd. Palmerston	720	N/A	7
3	Leased	Parry Sound	12 Seguin, Parry Sound P2A 2M5	730	5	5
3	Own	Sarnia	140 Business Park Dr., Sarnia	11,485	2	97
3	Own	Sault Ste. Marie	10 Industrial Court, Sault Ste. Marie, P6B 5W6	9,479	40	86
3	Own	Simcoe	RR #7 Hillcrest Rd., Simcoe, N3Y 4K6	11,594	62	58
3	Own	St. Thomas	25 Sparling Road, St. Thomas, N5P 3T5	6,638	39	56
3	Own	Stratford	827 Erie St., RR #3, Stratford, N5A 6S4	6,996	50	61
3	Own	Sudbury	828 Falconbridge Rd., Sudbury, P3A 4S3	36,717	34	174
3	Own	Timmins	615 Moneta St., Timmins, P4N 7X4	13,681	59	165
3	Leased	Toronto 2300 Yonge St	2300 Yonge St, Toronto, M4P 1E4	2,650	13	53
3	Leased	Toronto 777 Bay St	777 Bay Street, Toronto, M5G 2C8	10,581	13	354
3	Own	Woodstock	350 Beards Lane, Woodstock, NAS 3C2	8,832	36	33
Heritage	Own	McCurdy Farmhouse	6689 Eigth Line Milton ON	N/A	128	0
Heritage	Own	Tomas Robinson House	6603 Eigth Line Milton ON	N/A	150	0

Appendix C - Service Facilities Location Information

Facility Category	Ownership Status	Location Name	Address	Building Area (sq ft)	Age of Facility	Total All Furnishings
Land	Own	Belleville (land purchase 2017)	Jack Ellis Way, Belleville ON	0	0	0
Land	Own	Brantford Colborne St	315 Colborne Street, N3S 3N1	0	N/A	0
Land	Own	Brantford East Ave	11 East Ave, Brantford, N3S 7P4	0	N/A	0
Land	Own	Hamilton Strathearne	360 Strathearne Ave. Hamilton	0	N/A	0
STO	Own	Dawn EOC Building	1390 Dawn Valley Rd	6,810	N/A	75
STO	Own	Dawn Sewage Lagoon	1362 Dawn Valley Rd	270	N/A	0
STO	Own	Dawn South Admin	1380 Dawn Valley Rd	13,500	N/A	116
STO	Own	Dawn Warehouse	1362 Dawn valley Rd	16,000	N/A	16
STO	Own	Hagar	317 Northern & Central Rd - Hagar P0M 1X0	2,314	N/A	N/A
STO	Own	Parkway East	6626 9th Line - Mississauga - L5N 0C1		N/A	N/A
STO	Own	Parkway Healing Garden	6699 Eidth Line Milton ON L9E 1A4	0	3	0
STO	Own	Parkway Snake Habitat	6699 Eidth Line Milton ON L9E 1A4	0	3	0

Appendix D – Project Descriptions

1 Growth

1.1 Byron Transmission Station Rebuild Project (AMP ID 1518)

The Byron Transmission Station Rebuild Project is required as a result of the rapid growth on the south and west sides of the London System which are supplied gas from the Byron Transmission Station. Due to the growth interest in markets fed by Byron Transmission Station and the abandonment of the London Lines, the Byron Transmission Station is projected to reach capacity in 2022.*

NOTE: **Only regular rate growth is available until 2022, assuming all previously identified contract customers bring on their requested loads. If contracts fall through or are decreased, capacity is freed up on the system.*

1.1.1 Scope

The Byron Transmission Station Rebuild Project is a full rebuild currently scheduled to be completed in 2022.

- Purchase of land is in the plans for 2018 as additional land will be required.
- As part of the rebuild, the existing station will provide gas to the customers fed off of Byron Transmission Station, acting as temporary regulation.
- The regulations runs will be split so that the 6,160 kPa MOP feeds the 3,450 kPa MOP system and the 1,380 kPa MOP system will feed the 420 kPa MOP system.
- A new heating system (boiler system) will replace the existing inefficient and large volume glycol boilers. As a result of splitting the regulation runs, heating load requirements are reduced and efficiency of the system is increased.
- Monitor/operator regulation runs will replace the current design and position the station for future growth as existing regulators are at maximum capacity. This will also result in lower emissions (token relief versus existing full relief) and reduce noise (station situated in densely populated and growing neighbourhood).
- Existing orifice meters will be replaced by turbine meters to ensure accurate area measurement as well as measurement used for odourization purposes.
- The majority of station piping installed in 1968 will be removed and replaced with new pipe sized for future growth eliminating current velocity concerns.

All of the modifications to be completed as a result of this rebuild enhance station safety, reliability, and maintainability, positioning the area for growth out to 2044, assuming reinforcement is completed upstream and downstream as needed. There is potential for additional capacity with relatively minor station changes in 2044 and beyond.

1.1.2 Expenditures

Total capital expenditure for this project is $349 thousand in 2021 and $15.2 million in 2022.

1.1.3 Resources

These larger full station rebuild projects are traditionally planned and designed by the Major Projects department. Planning has a team of dedicated full-time employees that will continue to manage and execute major projects such as the Byron Transmission Rebuild. The construction work will be managed by Major Projects and a contractor will execute the work. Depending on the scope, the construction contractor resourcing will be managed through a combination of existing Environmental Assessment (EA) contractors and bid process to source out additional contractor resources where required (see Table 2.5.2.1 for estimated costs).

1.1.4 Leave to Construct

Not applicable.

1.2 Chatham-Kent Rural Expansion Project (AMP ID 854)

In order to provide opportunities for economic growth within Chatham-Kent, Union is proposing to install both a 500 metre (m) NPS 12 steel 6,040 kPa and a 13 km NPS 8 steel 6,040 kPa pipeline to boost system capacity across the Chatham-Kent region.

The Chatham East Pipeline and the Sarnia South Pipeline feed the majority of customers across the Chatham-Kent region. The Chatham-Kent Rural Expansion (CKRE) Project will reinforce both of these systems, providing much needed capacity to numerous communities across Chatham-Kent.

Pressures along the Chatham East Pipeline are expected to reach minimums in 2019/2020, while the Sarnia South Pipeline is already at its maximum capacity.

If not completed, there is a risk of falling below minimum pressures along the Chatham East Pipeline in 2019/2020, while also not being able to accommodate any significant growth on the entire Chatham-Kent system.

The benefit of this project is that it will serve a significant number of years of regular rate growth while also providing opportunities for large commercial, industrial and greenhouse customers to expand current operations or to build new sites within Chatham-Kent.

1.2.1 Scope

The project scope includes:

- Installation of 500 m of NPS 12 steel pipe designed to 6,040 kPa along Bear Line Road from the Dover Valve Site to Dover Centre Station.
- Installation of 13 km of NPS 8 steel pipe designed to 6,040 kPa along Kent Bridge Line from the Simpson Road Valve Site to a new station to be located at Kent Bridge Line and Base Line Road.

The following alternatives are to be evaluated:

- Installing a different diameter pipeline.
- Running a new lateral from the Panhandle to support the Chatham East Pipeline.
- Joining two previously independent distribution systems.
- Obtaining supply from nearby non-Union pipelines.
- Looping pipe in a different location.
- Implementing demand side management.

The project construction is estimated to start in 2019.

1.2.2 Expenditures

The total cost is $19.1 million.

1.2.3 Leave to Construct

A leave to construct has already been filed with the Ontario Energy Board (OEB).

1.3 Compressed Natural Gas (CNG) Project (AMP ID 1439, 859)

1.3.1 Scope

Non-regulated

Union's Highway 401 Compressed Natural Gas (CNG) project will establish key heavy-duty truck CNG refuelling infrastructure on Canada's busiest trucking corridor. It will be accomplished in conjunction with leading, Canadian industry providers of CNG solutions. The project scope will encompass all aspects of engineering, approvals, procurement, construction, commissioning, and ongoing operation and maintenance of three refueling stations at strategic locations along the Highway 401 corridor including Windsor, London and Napanee in Eastern Ontario.

The objective of this project is to provide the reliability and attractive pricing that is critical for the many fleets that regularly use the Highway 401 corridor to make long-term CNG adoption decisions for their operations. Growing CNG penetration in Ontario is strategically significant as it allows Union to grow natural gas consumption while simultaneously reducing Ontario's greenhouse gas (GHG) emissions.

Moving forward with this project will allow Union to leverage federal government incentive funding and our early mover advantage.

Regulated

Construction and operation of new CNG fueling stations by third parties is also expected to occur and Union will need to provide the gas distribution facilities (e.g., main, service, and meter stations) required to supply these CNG stations. The price of competing diesel fuel and availability of government incentive programs will be critical factors underpinning growth in this sector.

1.3.2 Expenditures

Non-regulated

Union will build three stations at an estimated cost of $9 million in 2018. $3 million of this will be funded by an interest free, forgivable loan from Natural Resources Canada.

Regulated

2018	3 stations	$1.1 million
2019	7 stations	$1 million
2020	6 stations	$2.3 million
2021	5 stations	$1.9 million
2022	5 stations	$1.9 million

1.3.3 Resources

Non-regulated

Union will use third party contractors to design, build, operate and maintain the three new stations.

Regulated

Union will use internal resources for design and our alliance partners for construction.

1.3.4 Leave to Construct

Non-regulated

Leave to Construct is not required.

Regulated

Leave to construct is not anticipated for any of these projects as they are relatively small in size.

1.4 Dunnville Transmission Reinforcement Project (AMP ID 1202)

Due to in-franchise growth on the Eastern Transmission System, inlet pressures into Rymer Road Station (12Z-301) will reach minimums in 2021 on a design heating degree day (35 DD ION). Pressures are expected to be below minimum inlet pressures of 700 kPa into Rymer Road Station on a design day.

To meet minimum inlets into Rymer Road Station, reinforcement is required on the Eastern Transmission System between the outlet of Caledonia Trans and Dunnville.

If not completed, there is a risk that falling below minimum pressures at Rymer Road Station will result in this station not being able to serve customers downstream. This station is the only feed into the city of Dunnville.

1.4.1 Scope

This reinforcement will install 8.4 km of NPS 10 steel
1,900 kPa main from the outlet of Caledonia Transmission Station and end at Stoneman Road.

The benefit of the project is that it will support more than eight years of in-franchise growth on the Dunnville Distribution System based on forecasted growth.

The project construction will start in 2021.

Alternatives will be evaluated in 2019.

1.4.2 Expenditures

The total cost is $11 million.

1.4.3 Leave to Construct

This project requires application in 2020.

1.5 Greenstone Gold Mine Project (AMP ID 848)

Greenstone Mine is an open-pit gold mine (brownfield site) with up to 30,000 tpd processing, recovering gold using cyanide recovery methods. The mine has a fifteen-year life. Natural gas access to the Greenstone Gold Mine is required to accommodate mine expansion. Mine expansion is not possible without this infrastructure expenditure.

1.5.1 Scope

Union will install a dedicated high-pressure line from the TransCanada Pipeline (TCPL) to the Greenstone Gold sales meter station. The project will include:

- 14 km of NPS 6 pipe installed along Hwy 584, through the town of Geraldton and continuing along Old Arena Road to the customer station location. The route is based on verbal approval from the municipality.
- Customer delivery request of 11,000 m^3/hr for operations (including Cogen).
- Minimum Gauge Pressure of 2,757 kPa (400 psi).
- The project assumes using existing TCPL tap, but potential TCPL tap modification may be required (not included in current cost estimate).

The project construction will start in spring 2020 and be in service by May 2021.

1.5.2 Expenditures

The construction cost estimate is $28.5 million with $25.5 million for Aid to Construct.

1.5.3 Resources

The majority of the work will be done by a contractor.

1.5.4 Leave to Construct

This project requires application in September 2019.

1.6 Guelph Transmission Reinforcement Project (AMP ID 1201)

Due to in-franchise growth on the Guelph Transmission System, pressures into Puslinch Transmission Station (19V-401) will reach minimums in 2027 on a design heating degree day (43.1 DD). Pressures are expected to be below minimum inlet pressures of 3,700 kPa into Puslinch Transmission station on a design day.

Reinforcement of the Guelph Transmission System between the Dawn-Trafalgar Guelph Takeoff and Puslinch Transmission Station is required.

If not completed, there is a risk that falling below minimum pressures at Puslinch Transmission Station will result in this station not being able to serve customers downstream. This station is the only feed into the entire city of Guelph.

1.6.1 Scope

This reinforcement will loop the existing NPS 10 main between the end of the previous looping (43.450628, -80.210186) to Puslinch Transmission Station. This will be approximately 4 km of NPS 12 steel pipe, 6,160 kPa along the existing road allowance.

The benefit of this project is that 40+ years of in-franchise growth can be added to the system.

The project construction will start in 2027.

Alternatives will be evaluated in 2025.

1.6.2 Expenditures

The total cost is $9.7 million.

1.6.3 Leave to Construct

This project will require application in 2026.

1.7 Hamilton Gate Station Refurbishment Project (AMP ID 2304, 2353)

The Hamilton Gate Station Refurbishment Project is a maintenance project, driven primarily by the condition of existing assets at both Hamilton Gate #1 (17X-401) and Hamilton Gate #2 (17X-402). As the two major feeds into the Hamilton District Distribution System, it is imperative that these stations be maintained to ensure safe and reliable operations in the future.

In addition to maintenance drivers, growth interests in the Hamilton District Distribution System serve to reinforce the need for refurbishing equipment at both Hamilton Gate Stations. These stations are projected to reach capacity in 2022, after which the flow throughput through each station will need to be increased and the outlet pressure from Hamilton Gate #1 will need to be increased to 1,830 kPa to defer downstream pipeline looping requirements.

1.7.1 Scope

In 2019, maintenance activities to support operation of Hamilton Gate #2 until refurbishment will include replacement of a boiler and the steel platforms providing access to the heat exchangers. Engineering assessments of the building, piping and heat exchanger will also be conducted at this time.

The Hamilton Gate Station Refurbishment Project is a partial rebuild at both Gate #1 and Gate #2 scheduled to be completed in 2022.

It will begin with refurbishing equipment at Hamilton Gate #2 in Summer 2021. This will be accomplished by:

- De-energizing Hamilton Gate #2
- Demolishing the existing transmitter and storage building (existing building is infested with rodents and its foundation is compromised due to frost heave)
- Rebuilding Gate #2 station inlet and replacing existing filter (to increase capacity)
- Demolishing and replacing existing boiler building, boilers, and boiler control system
- Installing new remote terminal unit (RTU) and telemetry equipment specific to Hamilton Gate #2

NOTE: *During the Summer 2021 construction window, Hamilton Gate #1 will feed both Gate #1 and Gate #2 station outlets (i.e. the Downtown feed and the Mountain feed). Hamilton Gate #3 will serve as a backup feed to the Hamilton loop in the event we the construction window needs to extend into Fall 2021.*

After completing refurbishment work at Hamilton Gate #2, the partial rebuild scope at Hamilton Gate #1 will commence in 2022 by:

- Completing induced AC mitigation study for the entire Hamilton Gate Station site
- De-energizing Hamilton Gate #1
- Demolishing old buildings on site including the regulator building, boiler building, RTU building (some of which were built with asbestos containing materials)
- Demolishing existing station equipment and associated piping including heat exchangers, boilers, regulation, and D/S orifice metering
- Remediating mercury impacted soil on site
- Installing new U/S metering, heat exchanger, and regulation

- Installing new heating system including new boiler buildings, boilers and associated control system
- Installing new telemetry equipment and RTU building specific to Hamilton Gate #1

NOTE: *During the Summer 2022 construction window, Hamilton Gate #2 will feed both Gate #1 and Gate #2 station outlets (i.e. the Downtown feed and the Mountain feed. Hamilton Gate #3 will serve as a backup feed to the Hamilton loop in the event the construction window needs to extend into Fall 2022.*

1.7.2 Expenditures

Total capital expenditure for this project is $23 million (magnitude level estimate, w/ +50 per cent/-25 per cent range ability). This estimate is split between:

- $1.9 million in 2019 for maintenance and engineering assessments.
- $7 million in 2021 for refurbishment scope at Hamilton Gate #2.
- $20 million in 2022 for refurbishment scope at Hamilton Gate #1.

1.7.3 Resources

A project of this magnitude is traditionally designed and constructed by Union's Major Projects department. The construction work will be managed by Major Projects and an approved contractor will execute the work. Depending on the scope, the construction contractor resourcing will be managed through a combination of existing Alliance contractors and a bid process to source out additional contractor resources where required.

1.7.4 Leave to Construct

Not applicable.

1.1 Hensall/ Goderich Transmission Reinforcement Project (AMP ID 2376)

Due to in-franchise growth on the Hensall Transmission System, inlet pressures into Northern Cross Customer Station (23N-201C) will reach minimums in 2026 on a design heating degree day (43.1 DD IOFF). Due to the undersized NPS 8 Goderich Line, low inlet pressures are expected into the Northern Cross Customer Station on a design day.

Reinforcement is required to supply adequate gas volumes to existing customers in the Forest, Hensall and Goderich regions. To meet minimum inlets into the Northern Cross Customer Station, reinforcement is required on the Hensall Transmission System along the NPS 8 Goderich Line.

If not completed, there is a risk that falling below minimum pressures at the Northern Cross Customer Station will result in this station not being able to hold its required outlet pressure in flow, resulting in Union being unable to meet established customer demands.

1.1.1 Scope

This reinforcement will install 11.4 km of NPS 10 steel 3,450 kPa MOP main to loop the existing NPS 8 Goderich Line from Hensall Road to Sanctuary Line. This looping project will run along Huron Road (Highway 8).

The benefit of this project is that it will support up to eight years of in-franchise growth on the Forest, Hensall and Goderich System based on forecasted growth, provided other areas of the system remain above minimum inlet pressures.

The project construction will start in 2026.

Alternatives are to be evaluated in 2024.

1.1.2 Expenditures

The total cost is $25 million.

2024	$67.3 thousand
2025	$2.2 million
2026	$21.7 million
2027	$1 million

1.1.3 Leave to Construct

This project will require application in 2025.

1.1 Hensall Transmission Station Rebuild Project (AMP ID 2409)

Presently, the Hensall Transmission Station is not able to supply gas at a high enough pressure. This station is not fully using the available capacity of the pipeline downstream as it supplies gas at a pressure significantly lower than the MOP. As a result, the Hensall Transmission System is not able to maximize the effectiveness of the existing pipeline infrastructure. Without a station rebuild, Hensall Transmission System will fail to maintain minimum inlet pressures into the Northern Cross Customer Station during the winter of 2023 on a design day (43.1DD IOFF). A rebuild of the Hensall Transmission Station (14N-302) is required to increase capacity and maximum sustainable outlet pressure.

The benefit of this project is that it will support in-franchise growth on the Hensall Transmission System, supporting growth in the areas of Forest, Hensall and Goderich. If not completed, there is a risk that the Hensall Transmission System will be unable to meet design day flows to existing customers.

1.1.1 Scope

A rebuild of the Hensall Transmission Station (14N-302) is required to increase capacity and maximum sustainable outlet pressure.

To meet system demands on the Hensall Transmission System and to defer pipeline reinforcement along the NPS 8 Goderich Line, this station rebuild will defer an 11.4 km pipeline project by three years.

The project construction will start in 2023.

Alternatives are to be evaluated in 2021 and 2022.

1.1.2 Expenditures

The total cost is $2 million.

1.1.3 Resources

The project will be completed by contractors with minor support from internal district resources.

1.1.4 Leave to Construct

Not Applicable.

1.1 Ingersoll Transmission Station Rebuild Project (AMP ID 2400)

Due to in-franchise growth on the Eastern Transmission System, flows through Ingersoll Transmission Station (14R-102) will exceed the station's capacity in 2024 on design day.

To meet system demands on Eastern Transmission, Ingersoll Transmission station must be rebuilt to provide adequate capacity on a design day.

If not completed, there is a risk that the station will not be able to handle the projected flows, and will not be able to meet the demands of downstream customers.

1.1.1 Scope

The Ingersoll Transmission Station will be rebuilt with construction starting in 2024.

The benefit of this project is that it will support in-franchise growth on the Eastern Transmission System serving communities like Tillsonburg and Woodstock.

Alternatives are to be evaluated in 2022.

1.1.2 Expenditures

The total cost is $16 million.

1.1.3 Leave to Construct

This project will require application in 2023.

1.2 Kingsville Transmission Reinforcement Project (KTRP) (AMP ID 1550, 1494, 1551, 1552, 857)

1.2.1 Scope

This project consists of the installation of an approximately 19 km NPS 20 pipeline from an interconnect at the existing NPS 20 Panhandle Line in the Town of Lakeshore to a new station in the Town of Kingsville. Full details of the project are available in Union's pre-filed evidence for Ontario Energy Board Application EB-2018-0013.

1.2.2 Expenditures

The total expenditure for this project is approximately $103.9 million from 2017 to 2020. The cost for this project is based on a pre-budget estimate.

1.2.3 Resources

This project will be planned and designed by resources in the Major Projects department. The construction work will be managed by the Major Projects department with a third party contractor executing the work. Construction contractor resourcing will be managed through a bid process.

1.2.4 Leave to Construct

Union has filed a Leave to Construct application with the Ontario Energy Board for this project: EB-2018-0013.

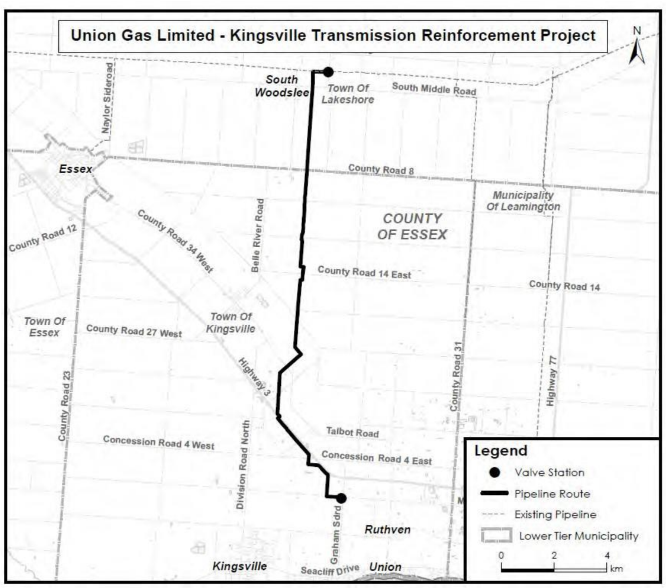


Figure 1.2.1.1: Proposed pipeline route

1.3 Owen Sound Transmission Reinforcement Project (AMP ID 2375)

Due to in-franchise growth on the Owen Sound Transmission System, pressures into Port Elgin Transmission Station (29N-101) will reach minimums in 2025 on a design heating degree day (43.1 DD). Pressures are expected to be below minimum inlet pressures of 860 kPa into Port Elgin Transmission station on a design day.

Reinforcement of the Owen Sound Transmission System is required between Teviotdale Transmission (23R-601) and Durham Gate (27R-401).

If not completed, falling below minimum pressures at Port Elgin Transmission Station will result in this station not being able to serve customers downstream in Port Elgin.

1.3.1 Scope

This reinforcement will lift the existing NPS 8 steel and lay
28,800 m NPS 16 steel pipeline at 4,670 kPa MOP. Installation will be along the easement between 43.930813, -80.761340 (approximately Highway 6 and Sideroad 3) and Durham Transmission Station.

The benefit of the project is that five years' in-franchise growth can be added to the system.

The project construction will start in 2025.

Alternatives will be evaluated in 2023.

1.3.2 Expenditures

The total cost is $51.9 million.

1.3.3 Leave to Construct

Requires application in 2024.

1.4 Owen Sound Transmission Reinforcement Project (AMP ID 863)

Due to in-franchise growth on the Owen Sound Transmission System, as well as the addition of the new EPCOR customer serving the Southern Bruce Communities, pressures into Port Elgin Transmission Station (29N-101) will reach minimums in 2019 on a design heating degree day (43.1 DD). Pressures are expected to be below minimum inlet pressures of 860 kPa into Port Elgin Transmission station on a design day. Reinforcement of the Owen Sound Transmission System is required between Durham Gate (27R-401) and Owen Sound Transmission Station (31Q-501).

If not completed, falling below minimum pressures at Port Elgin Transmission Station will result in this station not being able to serve customers downstream in Port Elgin.

1.4.1 Scope

This reinforcement will loop the existing NPS 10 steel pipeline with another 34,200 m NPS 12 steel pipeline at 4,670 kPa maximum operating pressure (MOP). Installation will be along the road allowance between Durham Gate station and Owen Sound Transmission Station.

The benefit of the project is that an EPCOR customer is added plus five years' in-franchise growth can be added to the system.

The project construction will start in 2019.

1.4.2 Alternatives Evaluated

- MOP upgrade of upstream portion of Owen Sound Transmission System
- Installing compression.

Both alternatives were rejected as they were too costly.

1.4.3 Expenditures

The total cost is $58 million (pending project funding approval). Current approved cost is $51 million in 2019 and $898 thousand in 2020.

Note: *Discussions with EPCOR are ongoing, with the timing of the project subject to finalization of contracts and confirmation of requirements.*

1.4.4 Leave to Construct

Requires application in 2018.

1.5 Oxford Transmission Reinforcement Project (AMP ID 2374)

Due to in-franchise growth on the Eastern Transmission System, inlet pressures into Delhi Transmission Station (12T-201) will reach minimums in 2023 on a design heating degree day (35 DD ION). Low inlet pressures are expected into Delhi Transmission Road Station which causes low inlet pressures into Simcoe North. As a result, this causes the system to not meet minimum inlet pressures (1,150 kPa) into Port Dover South station on a design day.

To meet minimum inlets into Delhi Transmission Station, reinforcement is required on the Eastern Transmission System between the end of Oxford Phase 1 reinforcement and Delhi Transmission Station.

If not completed, falling below minimum pressures at Delhi Transmission Station will result in this station not being able to hold its required outlet in order to maintain minimum inlets and serve customers downstream.

1.5.1 Scope

This reinforcement will involve the installation of 2.8 km of NPS 8 steel 4,960 kPa main from the end of Oxford Reinforcement Phase 1 to Delhi Transmission Station.

The benefit of the project is that it will support in-franchise growth on the Simcoe and Port Dover Distribution Systems based on forecasted growth.

The project construction will start in 2023.

Alternatives are to be evaluated in 2021.

1.5.2 Expenditures

The total cost is $7.2 million.

2021	$20 thousand
2022	$624 thousand
2023	$6.3 million
2024	$302 thousand

1.5.3 Leave to Construct

This project requires application in 2022.

1.6 Oxford Gate Station Rebuild Project (AMP ID 2408)

Due to in-franchise growth on the Eastern Transmission System, flows through Oxford Gate Station will exceed the station's capacity in 2020 on design day.

To meet System demands on Eastern Transmission, Oxford Gate station (15S-301) needs to be rebuilt to provide adequate capacity.

If not completed, there is a risk that the station will not be able to handle the projected flows, and will not be able to meet the demands of downstream customers on design day.

1.6.1 Scope

Oxford Gate Station will be rebuilt.

The benefit of this project is that it will support in-franchise growth on the Eastern Transmission System serving communities like Paris and Simcoe.

The project construction will start in 2020.

Alternatives are to be evaluated in 2018 and 2019.

1.6.2 Expenditures

The total cost is $1 million.

1.6.3 Resources

The project will be completed by contractors with minor support from internal district resources.

1.6.4 Leave to Construct

Not Applicable.

1.7 Panhandle Transmission System Reinforcement Project (AMP ID 2355)

The Panhandle Transmission System is composed of two pipelines: NPS 16/20) and NPS 20/36 extending from Dawn to the Ojibway Interconnect along with four laterals (into the Leamington/Kingsville market) and the Sandwich compression facility located near Windsor. The System can also transport volumes received at the Ojibway Interconnect back to Dawn.

In addition to serving typical residential, commercial and industrial customers, the Panhandle Transmission System also supplies four large power generation plants and a number of greenhouses in the Chatham-Kent and Leamington/Kingsville areas.

Based on the current forecast for in-franchise general service and contract growth in the Panhandle Transmission System market, Union has identified the need to reinforce the Panhandle Transmission System for the 2026 to 2027 winter operating season.

1.7.1 Scope

Union proposes to extend the NPS 36 pipeline an additional 14 km from the Dover Transmission Station towards the Comber Transmission Station paralleling the existing NPS 20 Panhandle.

The project will consist of planning and engineering to commence in 2024, with construction to begin in 2026.

1.7.2 Expenditures

The total expenditure for this project is approximately $112.6 million from 2024 to 2027. The cost for this project is based on a magnitude estimate.

1.7.3 Resources

This project will be planned and designed by resources in the Major Projects department. The construction work will be managed by the Major Projects department with a third party contractor executing the work. Construction contractor resourcing will be managed through a bid process.

1.7.4 Leave to Construct

This project will require a Leave to Construct application to be filed with the Ontario Energy Board.

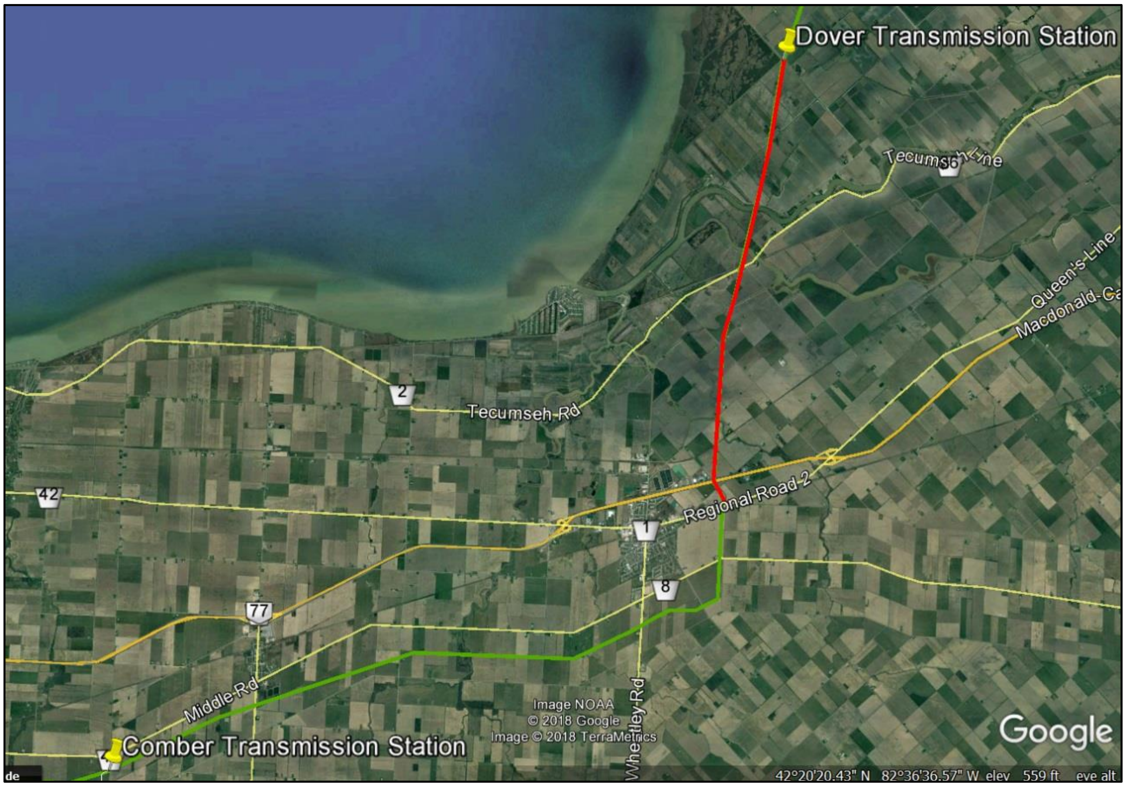


Figure 1.7.1.1: Proposed pipeline route

1.8 Parry Sound Reinforcement Phase 1 Project (AMP ID 1660)

Due to in-franchise growth on the Parry Sound Distribution System (420 kPa MOP), it is expected that system pressures at the inlet of Parry Sound Town Border Station (TBS) (44801002) will go below the required minimum in winter 2023 on a design heating degree day (49.3 DD). Pressures are expected to be below 1,900 kPa which is the minimum inlet required at Parry Sound TBS (44801002) in winter 2023 on a design day.

Reinforcement of the Parry Sound Distribution System (4,965 kPa MOP) downstream of Elmsdale CMS (44801001) is required. This will increase pressures observed at the inlet of Parry Sound TBS (44801002) and will provide approximately four years of in-franchise growth before Reinforcement Phase II.

If not completed, there is a risk that failing to meet minimum inlet at Parry Sound TBS in winter 2023 could result in customer loss on design day. No alternate feeds are available in the region to accommodate the load.

1.8.1 Scope

This reinforcement will loop the existing NPS 4 steel pipeline with another 12,500 m NPS 6 steel pipeline at 6,895/4,965 kPa MOP. Installation will occur along Hwy 518/Seguin Trail in Sprucedale region from the end of the existing NPS 6 pipeline to the intersection of Seguin Trail and John St.

The benefit of this project is that it will support four years of in-franchise growth on the Parry Sound Distribution System based on forecasted growth.

The project construction will start in 2023.

Alternatives are to be evaluated in 2021.

1.8.2 Expenditures

The total cost is $15 million.

1.8.3 Leave to Construct

Requires application in 2022.

1.9 Parry Sound Reinforcement Phase 2 Project (AMP ID1765)

Due to in-franchise growth on the Parry Sound Distribution System (420 kPa MOP). It is expected that System pressures at the inlet of Parry Sound TBS (44801002) will go below the required minimum in winter 2027 on a design heating degree day (49.3DD). Pressures are expected to be below 1,900 kPa which is the minimum inlet required at Parry Sound TBS (44801002) in winter 2027 on a design day.

Reinforcement of the Parry Sound Distribution System (4,965 kPa MOP) downstream of Elmsdale CMS (44801001) is required. This will increase pressures observed at the inlet of Parry Sound TBS (44801002) and will provide approximately five years of in-franchise growth.

If not completed, there is a risk that failing to meet minimum inlet at Parry Sound TBS (44801002) in winter 2027 could result in customer loss on design day. No alternate feeds are available in the region to accommodate the load.

1.9.1 Scope

This reinforcement will loop the existing NPS 4 steel pipeline with another 19,000 m NPS 6 steel pipeline at 6,895/4,965 kPa MOP. Installation will occur along Highway 518/Seguin Trail in Sprucedale region from the end of Phase I NPS 6 loop to Highway 518 close to Orville PRS.

The benefit of this project is that it will support five years of in-franchise growth on the Parry Sound Distribution System based on forecasted growth.

The project construction will start in 2027.

Alternatives are to be evaluated in 2026.

1.9.2 Expenditures

The total cost is $20 million.

1.9.3 Leave to Construct

This project will require application in 2026.

1.10 Sarnia Industrial Line System Expansion Project (AMP ID 884, 1560, 1561, 1562, 1563, 1199)

The Sarnia Industrial Line system is comprised of a series of parallel pipelines: NPS 10 NPS 12, NPS 16 and NPS 20. The system starts at the Vector Courtright and Great Lakes Courtright stations in St. Clair Township and extends to the Churchill Road Station in Sarnia. The system is also connected to the Dawn Compressor Station.

The NPS 12 runs the entire distance between the Courtright stations and the Sarnia Industrial Station. The NPS 20 runs the majority of the way from the Courtright stations to the Dow Valve Site. The NPS 16 runs between the Novacor Corunna station and the Dow Valve Site. The NPS 10 runs between the Dow Valve Site and the Churchill Road Station.

The Sarnia Industrial Line system is also connected to Dawn from the NPS 20 Payne to Sarnia pipeline between Payne Pool station and the Novacor Corunna station, and through the NPS 8 Dawn Kimball and NPS 10 Payne Kimball pipelines.

The Sarnia Industrial Line system was last expanded in 2015 under filing EB-2014-0333, the Sarnia Expansion Pipeline Project.

1.10.1 Scope

Union has identified the need for system reinforcement to serve forecasted industrial contract rate growth in the Sarnia market. This proposed project consists of system reinforcement from the Dow Valve Site to the Churchill Road Station.

Pipeline routes are being evaluated to identify a preferred running line. The length of the pipeline routes being considered vary from approximately 4.5 to 7.0 kilometers.

The project will consist of planning and engineering to commence in 2018, with construction to begin in 2020.

1.10.2 Expenditures

The total expenditure for this project is approximately $64.8 million from 2018 to 2021. The cost for this project is based on a magnitude estimate.

1.10.3 Resources

This project will be planned and designed by resources in the Major Projects department. The construction work will be managed by the Major Projects department with a third party contractor executing the work. Construction contractor resourcing will be managed through a bid process.

1.10.4 Leave to Construct

This project will require a Leave to Construct application to be filed with the Ontario Energy Board.

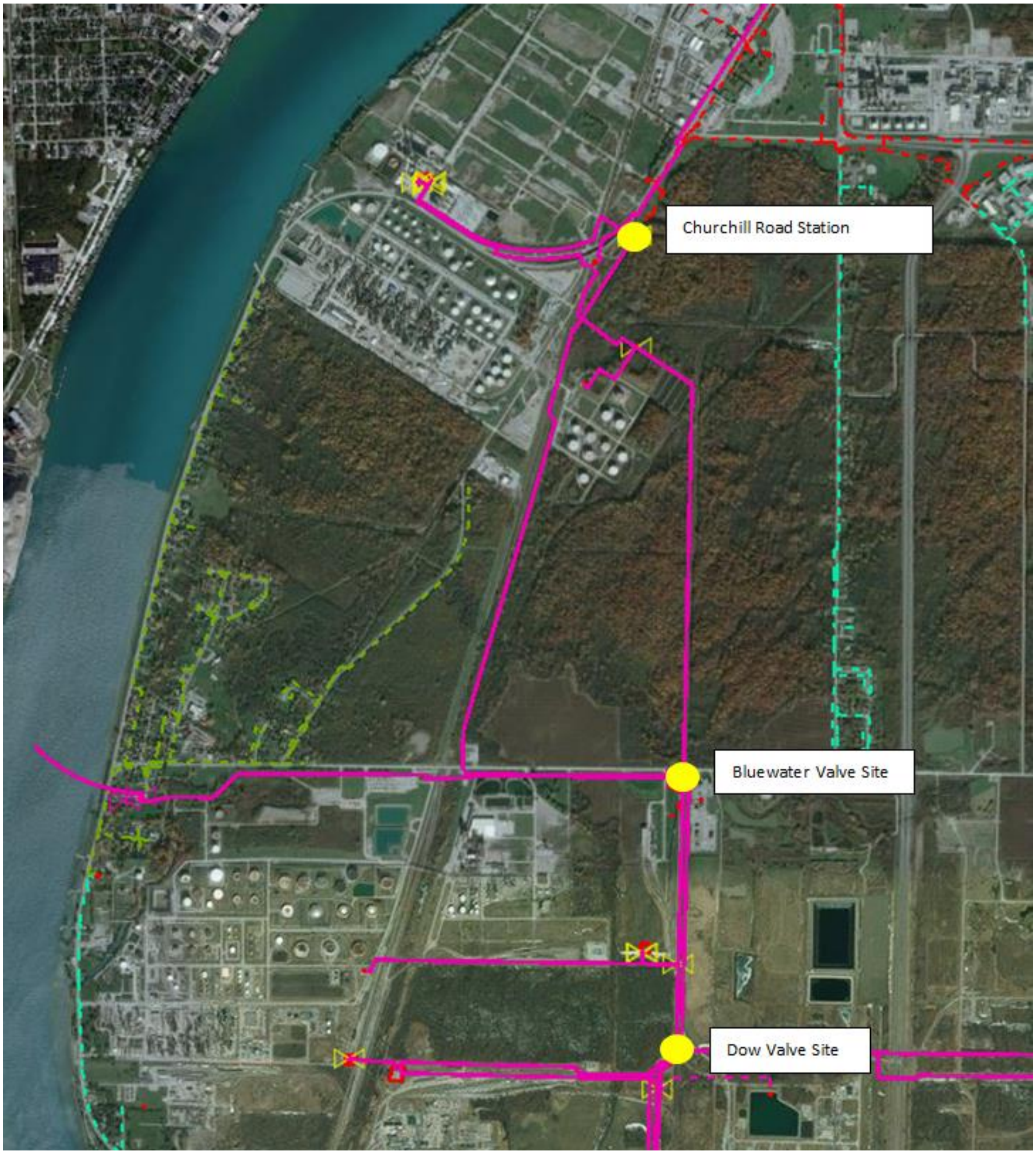


Figure 1.10.1.1: Overview of the Sarnia Industrial Line system Expansion Project area

1.11 Stratford Reinforcement Project (AMP ID 1558)

Due to in-franchise growth on the Hensall Transmission System, inlet pressures into Northern Cross Customer Station (23N-201C) will reach minimums in 2018 on a design heating degree day (43.1 DD IOFF). Due to the undersized NPS 8 Stratford Line, low inlet pressures are expected into Stratford Gate Station, which in turn causes low inlet pressures into the Northern Cross Customer Station (23N-201C) on a design day. This issue is being mitigated by temporarily relying on increased pressures available along the Dawn to Parkway System to get through winter 2018/2019.

To meet minimum inlets into the Northern Cross Customer Station (23N-201C), reinforcement is required on the Hensall Transmission System along the NPS 8 Stratford Line.

If not completed, there is a risk that falling below minimum pressures at the Northern Cross Customer Station (23N-201C) will result in this station not being able to hold its required outlet pressure in flow, resulting in Union being unable to meet established customer demands.

1.11.1 Scope

This reinforcement will install 10.8 km of NPS 12 steel 6,160 kPa MOP steel main to loop the existing NPS 8 Stratford Transmission Line from Beachville Transmission Station toward the City of Stratford, through Oxford County in Zorra Township. This looping project will run along 41st Line to Perth-Oxford Rd.

The benefit of the project is that it will support up to eight years of in-franchise growth on the Forest, Hensall and Goderich System based on forecasted growth.

The project construction will start in 2019.

1.11.2 Alternatives Evaluated

- Install 7.6 km of NPS 12 steel main (6,160 kPa) from the Beachville Takeoff to Road 96 in Zorra Township. This option was rejected as it does not provide five years of organic growth on the Hensall Transmission System.
- Install compression on the Stratford Line. This option was rejected due to high initial and operating costs.
- Looping the NPS 8 Goderich Line. This option was rejected as a significantly longer reinforcement was required in order to compensate for the undersized Stratford Line.
- Carrying out an MOP upgrade on the main running out of Hensall Transmission Station. This option was rejected as it would only provide approximately three years of growth and would not likely be able to be implemented by winter 2019/2020.

1.11.3 Expenditures

The total cost is $24.8 million pending project funding approval (PFA). Current approved cost is $23 million in 2019 and $506 thousand in 2020.

1.11.4 Leave to Construct

This project will require application in 2018.

1.12 Sudbury Transmission Compressors Project (AMP ID 2397)

The Sudbury Transmission System feeds customers up to and including Espanola. With current TransCanada PipeLines (TCPL) contract pressures, the System does not have enough liquefied natural gas (LNG) storage to meet System demands in the event of a design winter. The Transmission System is currently relying on higher-than-contracted TCPL pressures at Marten River.

Installing two 2,100 horse power (HP) Compressors upstream of Coniston at Marten River takeoff is proposed to remove the dependency on higher-than-contracted pressures. This will also help accommodate in-franchise regular-rate growth.

If not completed, there is a risk that exhausting LNG storage will result in system pressures below minimum design and will affect regular rate customers and major contract customers.

1.12.1 Scope

The project involves the installation of two 2,100 HP Compressors upstream of Coniston at Marten River takeoff.

The benefit of this project is system reliability and avoided physical/reputation costs associated with an outage.

The project construction will start in 2023.

1.12.2 Alternatives Evaluated

- Higher contracted pressures from TCPL
- Lift and lay NPS 10 from North Bay with NPS 16.

1.12.3 Expenditures

The total cost is $31.2 million.

1.12.4 Leave to Construct

This project will require an application in 2022.

1.13 Sudbury Transmission Installation Project (AMP ID 2407)

The Sudbury Transmission System downstream of Coniston splits at Azilda and feeds towards Espanola and Chelmsford. System growth predicts pressures into Chelmsford to be below minimum design in 2027. The Transmission System downstream of Coniston is expected to reach capacity in 2027.

Installing a section of pipe will eliminate an NPS 6 pipe bottleneck in the system. Several sections of NPS 6 were looped in 2015 with NPS 10.

If this project is not completed, there is a risk of an inability to attach new customers.

The benefit of this project is that it will increase system capacity and support in-franchise regular rate growth.

1.13.1 Scope

The project involves installation of 1 km of NPS 10 6,895 kPa MOP pipe.

The project construction will start in 2027.

Alternate pipe sizes and locations are to be evaluated.

1.13.2 Expenditures

The total cost is $2.9 million.

1.13.3 Leave to Construct

This project will require an application in 2026.

1.1 Sudbury Transmission Twinning Project (AMP ID 2406)

The Sudbury Transmission System is twinned from Coniston to Espanola except for a 2.55 km section that was previously abandoned. The transmission System downstream of Coniston is expected to reach capacity in 2027.

Completing twinning of the system will eliminate the bottleneck (single pipe) between Coniston and Azilda. The project is proposed to increase system capacity and support in-franchise regular rate growth.

If not completed, there is a risk of an inability to attach new customers on the systems downstream.

The benefit of this project is that it will support growth and system integrity.

1.1.1 Scope

The twinning will involve 2.55 km of NPS 12 6,895 kPa MOP pipe installed in an existing easement.

The project construction will start in 2027.

Alternate pipe sizes and alternate locations are to be evaluated.

1.1.2 Expenditures

The total cost is $6.8 million

1.1.3 Leave to Construct

This project will require an application in 2026.

1.2 Tillsonburg Transmission Reinforcement Project (AMP ID 2405)

Due to in-franchise growth on the Eastern Transmission System, inlet pressures into Simcoe North Station (12U-261) will reach minimums in 2025 on a design heating degree day (35 DD ION). Low inlet pressures are expected into Simcoe North Station (12U-261), which causes the system to not meet minimum inlet pressures (1,150 kPa) into Port Dover South station on a design day.

To meet minimum inlets into Simcoe North Station, reinforcement is required on the Eastern Transmission System just upstream of Huygies Transmission Station (12T-501).

If not completed, falling below minimum pressures at Simcoe North Station (12U-261) will result in this station not being able to hold its required outlet in order to maintain minimum inlets and serve customers downstream.

1.2.1 Scope

This reinforcement will involve the installation of 10 km of NPS 8 steel 3,450 kPa main just upstream of Huygies Transmission Station (12T-501), heading east and ending at Queensway and Hillcrest.

The benefit of the project is that it will support in-franchise growth on the Tillsonburg, Simcoe and Port Dover Distribution Systems based on forecasted growth.

The project construction will start in 2026.

Alternatives are to be evaluated in 2024.

1.2.2 Expenditures

The total cost is $15.5 million.

1.2.3 Leave to Construct

This project will require application in 2025.

1.3 Windsor Mega Hospital Reinforcement Project (AMP ID 1599)

The new Windsor Mega Hospital is looking to attach a new large-contract load near County Rd. 42 and Concession Rd. 8 in Windsor. This new site will require significant reinforcement to attach the hospital and the associated residential and commercial growth forecasted for the area. Presently, there are no mains nearby large enough to support this load. The new Windsor Mega Hospital will drive pressures below the minimum design of 140 kPa on the 420 kPa Windsor Distribution System when they attach their load.

This main extension will be constructed at the customers' expense.

Reinforcement of the Windsor Distribution System (420 kPa MOP) south of the Windsor Airport is required in order to attach new regular rate and contract rate customers. This reinforcement will provide capacity for the new Mega Hospital and for approximately 17 years of forecasted growth in the local area.

If not completed, Union will not be able to attach the new contract customer and will lose growth associated with the new hospital.

1.3.1 Scope

This reinforcement will loop the existing NPS 2 plastic and NPS 4 plastic pipeline with 4,100 m of NPS 6 plastic pipeline operating at 420 kPa MOP. Installation will be along Concession Rd. 8 from a new distribution station at Provincial Rd. to Baseline Rd., then East down Baseline Rd. to Concession Rd. 9, and then North to the customer site.

The benefit of this project is that it can support a new contract and 17 years of in-franchise growth on the Windsor Distribution System based on forecasted growth in the area.

The project construction is estimated to start in 2020.

An alternative of feeding from Rhodes Dr. via Marentette station was evaluated, but it was determined that easement would not be obtainable to run through the edge of the Windsor Airport property. Feeding from Lauzon Rd., south of the EC Row was also evaluated; however, this option was rejected due to its increased length.

1.3.2 Expenditures

The total cost is $2.4 million.

1.3.3 Leave to Construct

An application will be filed when the customer formally applies for service.

2 Pipelines

2.1 Bare and Unprotected Replacement Program (AMP ID 1996)

The purpose of this program is to identify, assess, prioritize and replace all remaining bare and unprotected steel main and associated services. These assets do not have anti-corrosion coating nor do they have any external corrosion protection installed by way of sacrificial anodes or impressed current rectifiers. These assets continue to corrode year over year contributing to leakage that increases risk to the public, drives capital expenditure to remediate, and reduces the reliability of the distribution systems for which they are a part of.

The replacement of these assets will reduce risk and increase reliability in a variety of ways:

- Minimize likelihood of further leakage – reduces risk to the public and required capital to remediate leaks.
- Removal of basement meters – improved safety and removal of below grade leak paths into homes, and improved access for meter readers.
- Upgrading of services including installation of service valves providing emergency responders with easily accessible gas shutoffs.
- Installation of Excess Flow Valves to automatically terminate the flow of gas to homes in the event of service damage.
- Increase in measurement accuracy through upgrading low pressure systems to standard distribution pressure.
- Installation of system valves on new mains to facilitate isolation of smaller sized areas of customers in the event of line hits or other emergencies.

2.1.1 Scope

The Bare and Unprotected Replacement Program includes the replacement of approximately 120 kilometres (km) of pipe and associated services. These assets are spread out across a number of Districts but are primarily located within the London, Hamilton, Waterloo and Windsor districts. A significant portion of these assets are operating at low pressure and are located in built-up locations like downtown cores with wall-to-wall concrete. This can create execution challenges and project scope changes, which are managed as needed.

Bare and Unprotected Replacement Projects are individually prioritized based on a number of factors. Some of these factors are as follows:

- Leakage history.
- Pipe vintage.
- Asset condition.

- Maximum Operating Pressure.
- Pipe size.
- Proximity to areas of high consequence.

2.1.2 Expenditures

Projects are planned on a yearly basis, and Union is targeting the full replacement of all remaining bare and unprotected assets by the end of 2024. The total expenditure for this program is $60 million from the years 2019 to 2024.

2.1.3 Resources

Bare and Unprotected Replacement Projects are typically planned and executed by the Construction and Growth departments within each District. These projects are typically executed by internal company construction crews. Larger more complex projects may be executed by third party contractor resources as necessary.

2.1.4 Leave to Construct

Not applicable.

2.2 Cathodic Protection Program (AMP ID 890)

The Cathodic Protection Program consists of the annual Priority 1 and Priority 2 anode installation program, as well as the rectifier replacement program. The program is based upon the Corrosion Control Standard Operating Practice (SOP) which provides the monitoring schedule for all steel facilities and defines the criteria for Priority 1 and Priority 2 anodes based on pipe-to-soil surveys. When the applicable corrosion prevention system reaches end of life, it is required to be replaced to maintain adequate cathodic protection.

2.2.1 Scope

Within the scope of this program are steel transmission mains, steel distribution mains, and steel isolated service lines.

2.2.2 Expenditures

The costs for the program are based on current average spends per unit. Based on this methodology, the current annual cost for the anode replacement program is $6.4 million, and the rectifier replacement cost is $0.47 million. The total program cost for 2019 to 2028 is $75.4 million. Included in this total are other cathodic protection related projects such as sectionalisation work and in some cases projects to remediate shorted casings.

2.2.3 Resources

Currently the anode installation program is completed primarily with internal resources. Approximately 10 per cent of the annual installations are completed with contractor resources. The rectifier replacements are completed with local contractor resources under the direction of the local corrosion personnel.

2.2.4 Leave to Construct

Not applicable.

2.3 Class Location Program (AMP ID 173, 897)

2.3.1 Scope

Changes in class location on pipeline systems as defined in CSA Z662 – Oil and Gas Pipeline Systems, are required to be assessed and remediated as necessary as mandated by O. Reg. 210/01: Oil and Gas Pipeline Systems under the *Technical Standards and Safety Act*, 2000, S.O. 2000, C.16. At Union, class location surveys are completed, and resulting class changes are evaluated and assessed for remediation by engineering staff on an annual basis. Pipeline segments that are deemed to have undergone a legitimate class change are evaluated based on the prescribed requirements in CSA Z662; and where deficiencies are identified, one of three forms of remediation are typically undertaken to maintain compliance to regulation.

- **Pressure Test Records** – Where pressure test records are inadequate for the new class location and the execution of a new pressure test is practical, affected pipeline segments are sometimes taken out of service to undergo an updated pressure test in order to meet the new class location requirements.
- **Valve Spacing** – Where the existing valve spacing may be inadequate based on the new class location requirements, an Engineering Assessment is completed to determine valve spacing adequacy. The result of the Engineering Assessment can be either that the valve spacing is determined to be adequate and no further remediation is required, or that the spacing is in fact inadequate and the addition of valves or pipe replacement is required.
- **Design/Location Factor** – Where the existing pipeline segment design is deemed to be inadequate for the new class location, the segment is scheduled for capital replacement and a new pipeline design is completed based on the new class location designation.

Other less common forms of remediation not identified above can also be required based on the class change assessments such as depth of cover remediation and/or repairs of pipeline defects deemed no longer acceptable for the new class location.

Given that development is occurring in close proximity to Union’s pipelines annually triggering class location changes, an annual budget is required in order to meet regulatory requirements. This work ensures we are compliant with the applicable codes and standards and contributes to our efforts to maintain public safety and operational safety of Union’s pipeline system.

2.3.2 Expenditures

The total capital expenditure of the Class Location Program is $165.4 million from 2019 to 2028.

The year 2019 will mark the end of the first six years of the program which have been at an increased spend in order to remediate the significant number of class changes that were identified at the outset of this program.

Starting in 2020, Union foresees the level of spend to be at a sustainment level, reflecting remediation efforts of only the segments being identified year over year. As Union moves further into sustainment for this program, historical spends for sustainment years will be used to further refine the yearly capital budget for this program.

2.3.3 Resources

This program is managed with internal Engineering resources at Union and is typically executed by external contractor resources.

2.3.4 Leave to Construct

Typically, the majority of the pipeline segments requiring capital replacement do not meet the thresholds requiring an application for a Leave to Construct. However, as projects are scoped for individual segment remediation, the requirement for a Leave to Construct is evaluated on a case-by-case basis.

2.4 Distribution Operations Pipeline Blankets Program (AMP ID 907, 910, Portfolios: General Mains, Leakage)

Within Distribution Operations at Union, each District must annually budget for work that is expected to occur, but for which specific projects/assets are not yet identified. These capital expenditures are grouped into maintenance blankets. The four primary blankets for pipeline assets are for **Service Replacement**, **Municipal Replacement**, **General Mains** and **Leakage**.

2.4.1 Scope

All four of these maintenance blankets are budgeted and planned by the Construction & Growth departments within the districts. These capital expenditures can be driven by a variety of reasons such as emergencies, integrity and safety, and municipal infrastructure conflicts.

- **Service Replacement:** The purpose of the service replacement blanket is to fund the replacement of services to customers as required and identified by Distribution Operations. These replacements could be as a result of integrity and safety concerns of vintage assets, or as requested by third parties when services are in conflict with contractor or municipal projects.
- **Leakage:** The purpose of the leakage blanket is to fund the capital work required to remediate leaks as they arise throughout the year. Depending on the severity of the leak, this work could be treated as an emergency expenditure for leaks of a severe nature or planned work for leaks of a less severe nature. This work could result in replacement of leaking vintage assets or in the use of repair fittings where appropriate.
- **Municipal Replacement/Relocations:** Municipal replacement or relocations of Union's assets are required when a municipality approaches Union in order to coordinate a municipal infrastructure project where Union's plant is in conflict. These projects are typically for roadwork (e.g., construction of a roundabout) but could be as a result of bridge replacement, sewer maintenance or building construction for example. The purpose of the municipal blanket for relocations is to fund the solutions needed to address pipeline assets that are in conflict with the municipal projects. Union endeavors to avoid conflicts with all its assets but when they cannot be avoided, Union will work with each municipality within established agreements to come to a mutually agreed upon resolution. In many cases, this results in the relocation of Union's plant that is in conflict, and more specifically, the removal of existing plant and the installation of new plant to maintain service to any customers reliant on the existing plant that was in conflict. This includes size-for-size replacement of main and services.
- **General Mains**: The purpose of the general mains blanket is to fund unplanned replacements and other capital maintenance work on distribution mains where unforeseen or previously unidentified integrity issues arise throughout the year and require immediate attention. Often these issues are discovered through other

planned work where mains are excavated and exposed where anomalies are discovered requiring repairs or cut outs.

2.4.2 Expenditures

These blankets are ongoing, annual programs and the baseline estimates for the annual expenditure was calculated using historical trends for each blanket. The capital expenditures for each are as follows:

- **Service Replacements** – the total expenditure for this blanket is $47 million for years 2019 to 2028.
- **Leakage** – the total expenditure for this blanket is $40.6 million for years 2019 to 2028.
- **Municipal Replacements** – the total expenditure for this blanket is $237.8 million for years 2019 to 2028.
- **General Mains –** the total expenditure for this blanket is $35.7 million for years 2019 to 2028

2.4.3 Resources

Projects associated with the blankets are typically planned and executed by the Construction and Growth departments within each district. They are typically executed by internal company construction crews but larger projects may be resourced by third party construction crews as necessary.

2.4.4 Leave to Construct

Not applicable.

2.5 London Lines Replacement Project (AMP ID 220, 2095, 2096, 2097, 2098)

The London Lines span approximately 80 km and extend from Dawn to Byron Transmission Station (13N-501) located in the London District. The London Lines consist of two high pressure pipelines running in parallel and were once considered a major feed supplying gas to the City of London and small communities between Dawn and London. The line that is located further north is known as the London South Line and is comprised mainly of NPS10 steel coated in Barrett Enamel that was installed in 1935. The line that is located further south is known as the London Dominion Line and is comprised mainly of NPS 8 steel coated in Durnite that was installed in 1936, which was subsequently replaced in 1952.

Although the majority of the London Dominion Line was replaced in 1952, the materials used were reclaimed and refurbished steel pipe from the Windsor district with an average vintage of 1920 to 1930. The London Lines have a MOP of 1,900 kPa from Dawn to Komoka Transmission Station (13N-401). Further east, the MOP from Komoka Station to Byron Transmission Station is 1,380 kPa. Due to the vintage, the quality of steel pipe installed, and the general deteriorating conditions, the London Lines has not operated near MOP in nearly four years.

The condition of the London Lines is generally poor and indicative of a pipeline reaching end of life. Depth of cover surveys have also been completed in the past that have highlighted areas of exposed piping. There have been multiple repairs completed on the lines due to leakage, corrosion, and third party damage. In addition, there are currently multiple outstanding leaks located along these lines. Below is a summary of the pipeline risks that currently exist on the line:

- Lines largely joined using unrestrained dresser couplings.
- Depth of cover issues.
- Locations with inoperable valves.
- Several corroded aerial crossings.
- Several repaired and outstanding leaks.
- Sections of the line have been abandoned due to condition.
- Currently operating pipelines between Dawn and Komoka below MOP to mitigate leak potential.

Due to the condition and existing risks associated with the London Lines, the current proposal is to complete a full replacement of the London Lines in one phase. A single-phase approach was based on the condition, number of repaired and outstanding leaks and depth of cover issues. Project scope, costing and timing may change as additional pre-engineering is completed.

2.5.1 Scope

This project involves the replacement of the entire London Lines in one phase. The remaining 75km dual-main London Lines NPS 10 and NPS 8 main operating at 1,380kPa) will be replaced with a single NPS 8 main operating at a MOP of 3,450kPa. The replacement project will begin at Dawn and completed just south of Komoka Transmission Station. The new pipeline will use the same running line as the existing London Lines, following road allowances as much as possible. The project timeline is as follows:

- 2019 – detailed pre-engineering design.
- 2020 – completed designs, environmental assessments and OEB application filing.
- 2021 – project execution.
- 2022 – clean-up.

2.5.2 Expenditures

Project development is in the preliminary phase with a magnitude estimate of $114 million. $4 million will be allocated in 2020 for pre-engineering design, environmental assessments and file an OEB application, $107 million in 2021 for project execution, and $3 million in 2022 for cleanup. Further work is being completed to develop the expenditures and to better define the budget toward the end of 2019.

2.5.3 Resources

Project management and construction management will be completed by either Union's Engineering Construction group or Major Projects group. Engineering, environmental, lands, regulatory and procurement assessments will be completed in-house at Union. Construction will be completed by a contractor selected using the approved Union procurement models.

2.5.4 Leave to Construct

The London Lines replacement project will require an Ontario Energy Board (OEB) Filing. Union will file a Leave to Construct application with the Board in 2020 to seek approval to construct.

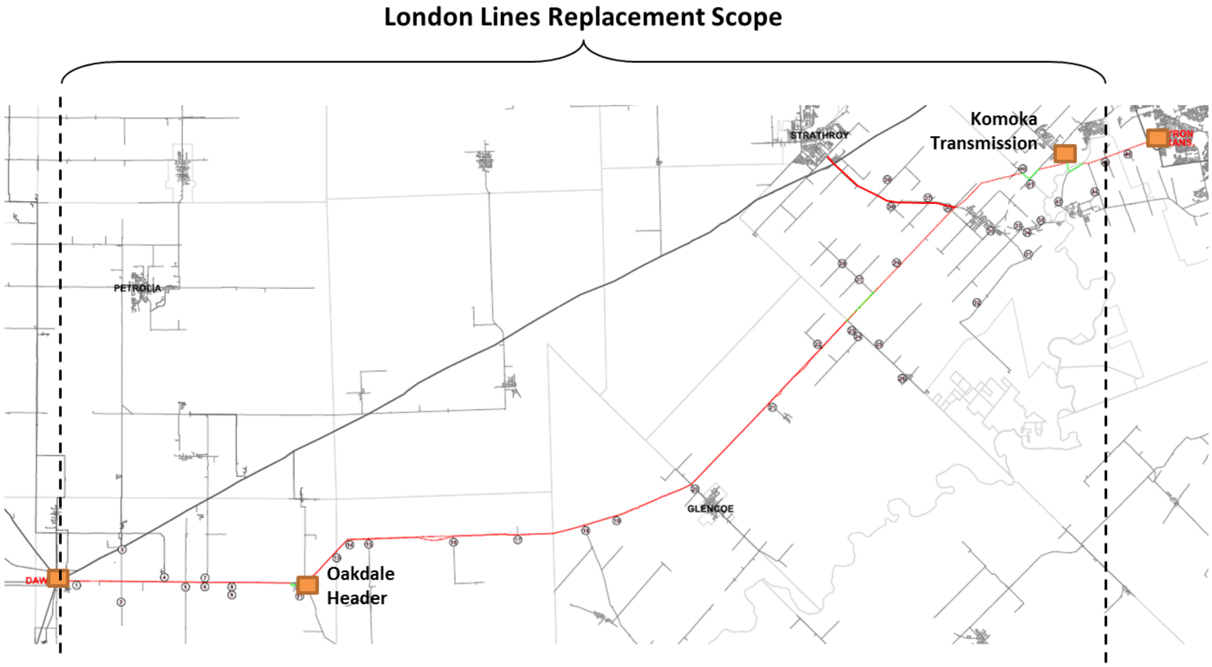


Figure 2.5.1.1: London Lines Replacement proposed project phasing

2.6 MOP Verification Program (AMP ID 906)

Maximum operating pressure (MOP) verification is the process of reviewing all existing records for a pipeline system and confirming the MOP of existing greater than 30 per cent specified minimum yield strength (SMYS) pipeline systems based upon these records. While this is not currently mandated by regulations in Canada, it is required in the United States and is expected to become a requirement in Canada in the future.

Given Union has approximately 2,980 km of pipelines greater than 30 per cent SMYS, the MOP Verification Program will be a multi-year project requiring a dedicated team. This team will be tasked with completing the verifications and determining if any pipeline remediation is required due to lack of records and/or the presence of pipe/fittings that are not properly pressure rated for the prescribed MOP of the pipeline.

The intent of the MOP Verification Program is to spread the verification work over several years to keep costs down and mitigate the need for higher expenditures in a shorter timeframe to meet these expected future mandated requirements.

2.6.1 Scope

This program will involve records review and Engineering Assessment work to verify the current MOPs of Union's greater than 30 per cent SMYS pipelines. This work is a natural progression of the existing Technical Records and Information Management efforts that have been completed at Union over the last number of years. The existing and discovered technical records will be used by engineering staff to verify that all pipelines, pipeline components and their associated material properties, including pressure test history and other relevant design and operation information, are appropriate for the current pipeline MOP. Where inconsistencies and issues arise, the need for Capital replacements in order to maintain required pipeline MOPs will be determined and executed as necessary.

2.6.2 Expenditures

The total Capital expenditure for this program is $30 million from 2023 to 2028.

Beginning in 2020, Engineering Assessments will be performed on Union's greater than 30 per cent pipeline assets to begin the MOP Verification process with respect to these assets. As this work is completed, capital dollars have been allocated beginning in 2023 to remediate issues as they arise in order to maintain the MOPs of our critical assets. As we begin to ascertain the scope of remediation required as a result of this program, the forecast of capital expenditure is expected to change.

2.6.3 Resources

Beginning in 2021, additional resources will be on boarded and are intended to be fully dedicated to this program. These resources will begin the engineering assessment work required to verify the MOPs of Union's pipelines and to scope any capital remediation requirements. Any capital remediation resulting from this work will be executed by a mix of internal resources and external contractor resources.

2.6.4 Leave to Construct

Not applicable.

2.7 Pipeline Integrity Management Programs (AMP ID 902, 175)

The Pipeline Integrity Management Program includes a systematic approach to assessing the condition, and completing the associated mitigation, on pipelines for which the stress level is at or above 30 per cent of the Specified Minimum Yield Strength (SMYS) of the pipe at its MOP, and all National Energy Board (NEB) regulated pipelines regardless of the stress level, to ensure that they are suitable for continued service. The formal program was initiated in 2002, and the baseline condition monitoring of the pipelines within the scope of the program that were installed prior to 2002 was completed by 2013, primarily through inline inspection (ILI) or External Corrosion Direct Assessment (ECDA). Work has been continuing to inspect the newer lines and to re-inspect the previously inspected lines.

The Pipeline Integrity Management Program includes approximately 2,980 km of pipe that meet the specified criteria, and includes the pipe up to and including the station inlet valve. The piping between the station inlet and outlet valve is included within the Station Integrity Management Program. The rest of the pipeline system is included within the Distribution Pipeline Integrity Management Program.

The activities associated with this work include the following three components:

- **Launchers / receivers in stations:** Install permanent ILI launcher and receiver facilities at selected Station sites where ILI runs have been identified. These programs are intended to carry on a prescribed inspection cycle and will require facilities to be available for future ILI activity.
- **Retrofitting pipeline to accommodate smart tools:** Modify pipelines to accommodate ILI tools, such as replacing reduced port valves, or bottom-out connections that prohibit the travel of ILI tools.
- **Integrity digs/mitigation:** ILI-identified defects are categorized as Immediate, Scheduled or Monitored based on Union's policy, which follows code, regulations and industry best practices.

The Distribution Pipeline Integrity Management Program includes a systematic approach to assessing the condition, and completing the associated mitigation, on pipelines for which the stress level is below 30 per cent of the SMYS of the pipe at MOP, to ensure that they are suitable for continued service. Much of this work is completed and budgeted through Distribution Operations. To supplement this work, a few targeted areas were identified within the centralized Distribution Pipeline Integrity Management Program to advance knowledge and manage risk associated with these assets.

The Distribution Pipeline Integrity Management Program includes approximately 67,440 km of mains and services within Union's pipeline system up to and including the station inlet valve that is not covered by the Pipeline Integrity Management Program. The piping between the station inlet and outlet valve is included within the Station Integrity Management Program.

2.7.1 Scope

The scope of the key activities for the greater than 30 per cent SMYS pipelines includes those activities noted earlier in this section. For the Distribution Pipelines, activities to date within scope have included advancing the assessment of legacy down plant, cased piping, and vintage plastic pipe. In 2015, Union started to complete ECDA inspections and digs on the more critical distribution lines. More focused water crossing inspections were started in 2016 and the program was further developed in 2018 and will continue for a number of years to advance the completeness of the inspection of pipelines that cross water bodies either under ground or attached to bridges.

2.7.2 Expenditures

The total capital expenditure of the Integrity Management Program is $129.6 million from 2019 to 2028.

The costs of the program were estimated using a combination of individual project estimates and historical unit costs and trends.

2.7.3 Resources

This program is managed with internal Engineering resources at Union and is typically executed by external contractor resources.

2.7.4 Leave to Construct

Typically, the majority of the pipeline segments requiring capital replacement do not meet the thresholds requiring an application for a Leave to Construct. However, as projects are scoped for individual segment remediation, the requirement for a Leave to Construct is evaluated on a case-by-case basis.

2.8 Vintage Pipe Replacement Program (AMP ID 908)

The purpose of this program is to identify, prioritize and replace critical transmission and distribution pipelines that have reached end of life and require significant capital dollars to replace.

2.8.1 Scope

There are a number of pipelines that are candidates for this program; but at this time, they have not been fully assessed and scoped for the purposes of this Asset Management Plan. As projects are further detailed, this program will be adjusted from a cost and timing perspective.

2.8.2 Expenditures

The total expenditure for this program is $75 million from the years 2019 to 2024.

2.8.3 Resources

The projects intended to be funded by this program will typically be project and construction managed by the Engineering Construction or Major Projects groups at Union. The construction execution would typically be completed by external contractor resources.

2.8.4 Leave to Construct

Most projects within this program will require Ontario Energy Board (OEB) approval/Leave to Construct applications. As projects are identified and scoped, the required applications will be filed as necessary.

2.9 Windsor Line Replacement Project (AMP ID 212, 913)

The existing 65 km Windsor Line is a distribution line operating at 1,380 kPa that runs from Windsor to Port Alma. This line, the majority of which is NPS 10, primarily serves the residential, commercial and greenhouse markets of Tilbury, Essex, Lakeshore, Comber, Leamington and Windsor. The Windsor Line can also be operated as a back feed for the Sarnia South Line and the Ridgetown Line during emergencies.

A significant portion of this line was installed in the 1930s, 1940s and 1950s and all joints prior to the 2000s were made with unrestrained mechanical couplings; portions of the older vintage pipe cannot be welded. In addition, some sections of the line cannot be isolated because of inoperable mainline valves. The Windsor Line also has sections that have poor depth of cover. Based on these integrity concerns and the significant effort and resources spent on repairing leaks on the line, the Windsor Line has been deemed a high risk and has therefore been identified as requiring replacement.

The Windsor Line will be replaced and the replacement pipeline will primarily be within road allowance with a shorter section possibly in easement. Both the services and stations will have to be upgraded for the new maximum operating pressure.

This replacement will address the integrity and operational risks with the Windsor Line and will thereby mitigate future large customer outages in the event of emergencies and necessary leak repairs, ultimately improving the overall reliability of this pipeline. The replacement will also create incremental capacity for future growth in the area.

2.9.1 Scope

The project includes the replacement of the entire Windsor Line. The existing line is a combination of NPS 10 and NPS 8 and will be replaced by an NPS 6 pipeline. The existing line operates at a pressure of 1,380 kPa and the replacement will be designed to operate at a maximum operating pressure of 3,450 kPa. The intent is to replace the existing line using the road allowance as much as possible for the new NPS 6. Approximately 650 services and 20 stations are served by the existing line which will be upgraded to the new maximum operating pressure and served by the replacement NPS 6.

Project development has started with frontend engineering design beginning in the summer of 2018 with the environmental assessment planned for 2019 and construction in 2020.

2.9.2 Expenditures

Project development is in the preliminary phase with a magnitude estimate of $88 million. Further work is being completed to develop the 2019 and 2020 expenditures and to better define the budget toward the end of 2018.

2.9.3 Resources

Project management and construction management will be completed by Union's Major Projects Group. Engineering, environment, land, regulatory and procurement will be completed in-house at Union. Construction will be completed by a contractor selected using the approved Union procurement models.

2.9.4 Leave to Construct

The scope and approval of this project is regulated by the Ontario Energy Board. Union will file a Leave to Construct application with the Board in 2019 to seek approval to construct.

The existing 65 km Windsor Line is identified in red on the map shown below.

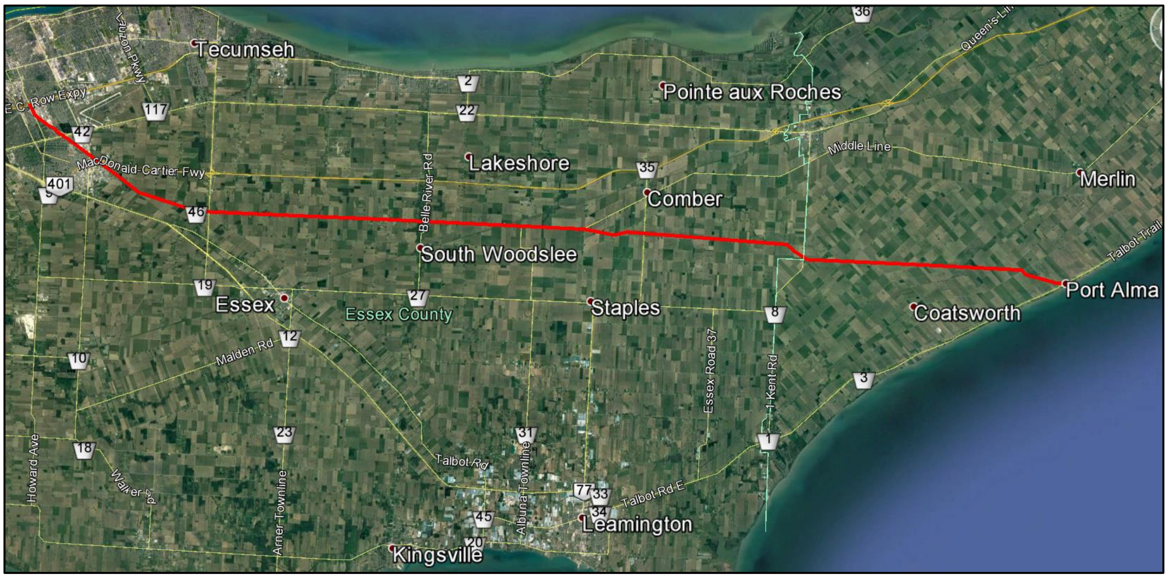


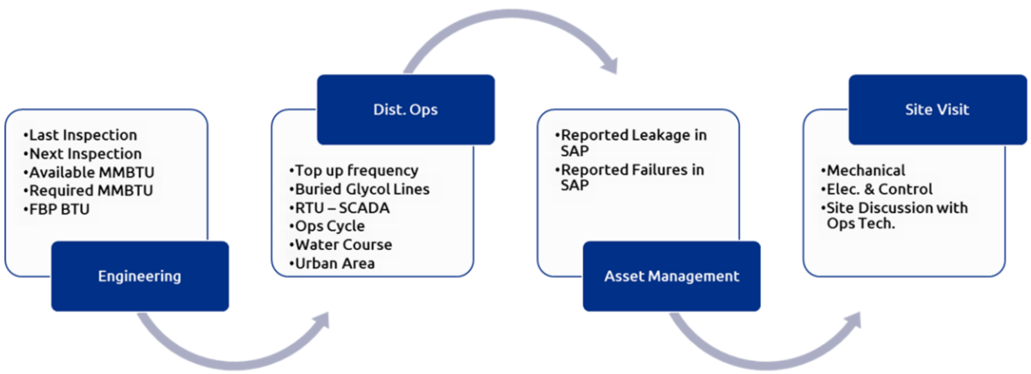
Figure 2.9.1.1: Existing Windsor Line

3 Stations

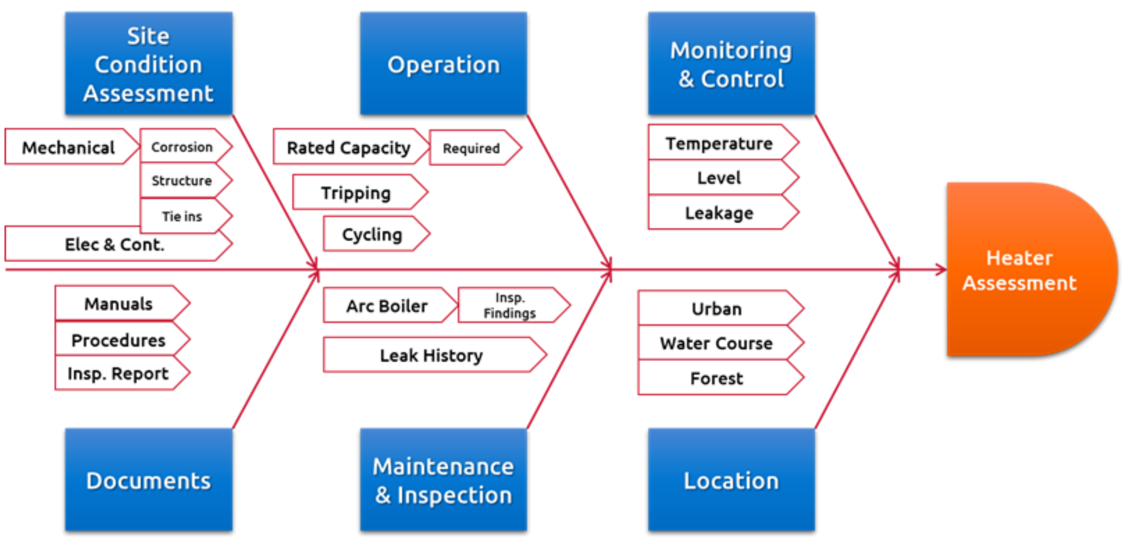
3.1 Heating Equipment Project (AMP ID 1174)

The holistic assessment of in direct-fired heaters across the franchise has been driven by: several glycol leakages, obsolete equipment, proximity to urban areas and water, inadequate heating capacity, and low efficiency. The identified objectives behind the assessment effort is to achieve safe, efficient and reliable heating systems; less hazardous to environment with low glycol contents; and suitable for future growth.

Heater Assessment Methodology

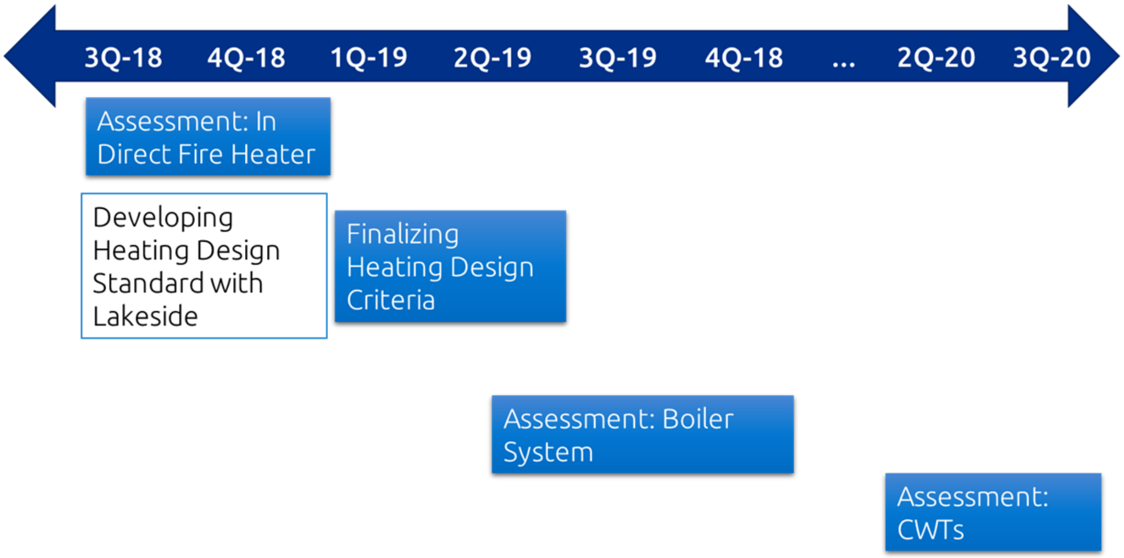


Risk Assessment Method



3.1.1 Scope

Natural gas flowing through buried pipelines loses thermal energy then when gas passes through pressure regulators. It is more subjected to the Joule Thompson effect which results in more thermal energy losses resulting in free-off around regulators and equipment malfunction. Therefore, heating equipment is used in different systems and customers' stations across the Union franchise to help mitigate this failure mechanism. Aging heating assets will need to be replaced or resized to match the required heat demand.



3.1.2 Expenditures

The forecasted expenditure of around $2 million per year is meant for the replacement or resizing of aging heating assets. This forecast will improve efficiency in operating costs of aging systems and will mitigate the risk of equipment failures that could result in loss of customers and/or loss of glycol containment.

3.1.3 Resources

This is an ongoing maintenance effort to replace equipment that has reached end of life or has been deemed obsolete. This work will maintain system reliability, ensure operating costs for heating systems are minimized and reduce the potential for glycol spills.

3.1.4 Leave to Construct

Not applicable.

3.2 Regulators/Reliefs Project (Portfolio: Regulators/ Reliefs)

3.2.1 Scope

Regulators and relief valves fail or require replacement due to age or obsolescence, whether it is at the time of meter exchange or in conjunction with other maintenance projects.

3.2.2 Expenditures

The capital expenditure on regulators and reliefs is estimated based on the historical consumption, purchasing and stocking to support ongoing maintenance work, which is equivalent to $9 to $10 million per year.

3.2.3 Resources

Regulators are purchased and stocked for field reps and technicians so that they can maintain the high reliability of our system and customer stations. This forecast will mitigate shortages of equipment so that services to customers are maintained.

3.2.4 Leave to Construct

Not applicable.

3.3 Stations Painting Program (AMP ID 1175, 206)

This is a centrally managed program 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 our Corrosion Control Standard Operating Practice (SOP) and is our documented and committed practice with respect to how we comply with the applicable codes for corrosion control on above grade station assets. This work will improve compliance and ensure the safety and reliability of Union's assets by reducing the risk of leaks and piping and/or equipment failure due to significant corrosion.

3.3.1 Scope

A proactive survey has been completed for all in scope stations to capture current coating conditions (classified to NACE criteria). A number of site and environmental conditions which would impact the lifespan of the coating (proximity to road, ground and atmospheric conditions etc.) and other components which need to be factored into the coating plan (riser wrap condition, piping insulation, lead testing etc.) have been captured. Civil components which will also need to be addressed (supports, cabinets, buildings etc.) has been captured. This data has been used to systematically prioritize all stations.

The goal of the program is to ensure all target locations are completed within a 15 year timeframe and that a sustainment program is established to ensure subsequent proactive recoating orders are established based on the individual site and atmospheric conditions. There will be a yearly project execution window of May to October beginning in 2019.

3.3.2 Resources

All high-performance coating application work will be completed by qualified contractor resources. Station assessments and all required pipe maintenance (riser coatings etc.) will be completed by company resources. All documentation components (SAP) will be completed by company resources.

3.3.3 Expenditures

The total expenditure for this program is $19.5 million. $1.5 million will be allocated in 2019 and $2 million annually for the years following.

3.3.4 Leave to Construct

Not Applicable.

4 Compression & Dehydration

4.1 Obsolete RB211-24A Dawn C Plant Project (AMP ID 1055)

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, which is 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 over which they support 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 is an indicator that the RB211-24A engine in Plant C is reaching end of life. By continuing to comply with OEM recommended Preventative 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 which will justify replacement.

4.1.1 Scope

Aside from engine obsolescence, other core plant components within Dawn Plant C are reaching end of reasonable life: for example the compressor employs an oil seal system which is now an environmentally unfriendly technology, the noise generated from the building envelope is greatest in the Dawn fleet, and the electronic control systems are a generation behind in terms of monitoring and controls. As the entire plant is out of specification in terms of the new standard compressor station designs, it is recommended that Plant C be replaced in its entirety.

4.1.2 Expenditures

The cost of a new RB211 DLE plant is estimated at $155.9 million. Design is proposed to begin in 2022 with an in-service date of 2024 and abandonment of the obsolete Plant C structures in 2025.

4.1.3 Resources

Major 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.

4.1.4 Leave to Construct

Leave to Construct is required. Timing will need to coincide with the 2022 start of the project.

4.2 Transmission Compression - Engine Overhaul Program (AMP ID 979, 1196, 1197, 949, 956, 226, 952)

Four critical compressor stations are strategically located along the Dawn to Parkway Transmission System: Dawn, Lobo, Bright and Parkway. Discrete blocks of centrifugal compression are located at each of the stations and used in various combinations to manage the seasonal and weather-dependent system flow demand. There are nine centrifugal compressors at Dawn, five at Lobo, four at Bright and four at Parkway ranging in horsepower outputs, vintages and models.

Transmission compressors can pose a very large consequence of failure as they 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 risk associated with failure of a single compressor is heavily influenced by the time of year, weather severity and time to mitigate the failure.

The 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 25,000 hour recommended interval between overhauls and then drops suddenly after an overhaul. Based on average annual use, overhauls for each engine are between 12 to 18 years and are staggered, nominally one per year.

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.

4.2.1 Scope

The 50,000 hour interval overhauls are more in-depth costing more than the 25,000 hour interval overhauls. The engines are typically removed and shipped to the OEM-approved shop in the April/May timeframe and are returned and reinstalled in the July/August timeframe.

NOTE: *The work timeframe is driven by available outage availability in accordance with the requirements of Gas Control and Business Development.*

Based on current trending, it is expected that the Bright A2 engine will reach 25,000 operational hours in 2022. An overhaul is required at 25,000 hours in accordance with Siemens specifications.

Year	Station	Plant	Engine	Operational Hours	Budget
2020	Dawn	J	Taurus T70S	40,000	$1,500,000
2023	Bright	A2	RB211 G DLE	25,000	$2,809,080
2023	Bright	B	RB211 24C	50,000	$2,288,880
2023	Bright	A1	RB211 G DLE	25,000	$3,265,871
2024	Dawn	J	Taurus T70S	40,000	$1,500,000
2025	Lobo	A1	Avon 1534 – 101G	50,000	$2,080,000
2026	Parkway	C	RB211 GT DLE	25,000	$3,100,000
2026	Parkway	D	RB211 GT DLE	25,000	$3,100,000
2027	Dawn	F2	Taurus 70S	40,000	$1,040,400
2028	Dawn	D	RB211 24C	50,000	$2,252,325

4.2.2 Expenditures

Engine overhauls range in cost from $1.0 million to $4.0 million depending on the engine model, condition and the overhaul interval.

The expected expenditure for this program is $25.5 million over the next ten years (2019-2028). This total expenditure includes costs associated with a number of smaller centrifugal compressor units listed in Section 5 Table 5.4.6.1.1

4.2.3 Resources

On-site work involving engine removal, reinstallation and commissioning, is carried out by the respective station mechanics and technicians. Time to complete the on-site work varies depending on compressor model and vintage. The removal and preparation for the shipping phase typically takes a week and the reinstallation and commissioning typically takes a week. On-site direction by an OEM field service representative may be requested in some of the more complicated installations.

Engine overhaul work is completed off site at the OEM approved shop.

4.2.4 Leave to Construct

Not applicable.

4.3 Waubuno Compressor Replacement Project (AMP ID 1152)

The Waubuno Compressor elevates available pipeline pressure to the Waubuno Pool MOP. Compression increases the working inventory value of the pool by approximately $2.2 million (at $0.75 per GJ) based on top of what the pipeline alone can achieve. The compressor is operated approximately 45 days per year in late summer to early fall to top off the pool.

The consequence of compressor failure is dominated by customer impact. Risk associated with failure of the Waubuno Compressor is heavily influenced by the level of the pool at which the failure occurs and time to mitigate the failure.

The Joy Compressor (manufactured in 1985) was a used compressor package purchased by Union 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 is catastrophic damage to the 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. In the event of a future failure if useable parts or custom machining are not available, the two options would be custom-designed aftermarket castings (if possible) or replacement of the entire compressor. However, both options would render the compression out of service for at least one operational season.

4.3.1 Scope

This project involves replacement of the Waubuno Compressor to mitigate the risk of a critical part failure that would render the compressor out of service for an extended period of time. The proposed timing to complete the on-site work is during the first and second quarters of 2021. Design and ordering of long-lead items will need to occur a year in advance.

4.3.2 Expenditures

Total capital expenditure for the replacement of the Waubuno Compressor is estimated at $18.3 million.

4.3.3 Resources

Major 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.

4.3.4 Leave to Construct

A Leave to Construct is required. Timing will need to coincide with the 2020 start of the project.

5 Liquefied Natural Gas

5.1 Boil Off Gas (BOG) Compressor Replacement Project (AMP ID 951)

The Hagar Liquefied Natural Gas (LNG) Plant was installed in 1968 to provide security of supply to the Sudbury industrial and distribution markets. 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 vapors) from the 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.

In addition to from the security of supply provided by the LNG plant, the plant has also been placed in service on occasion over the years to manage system demand. It supplemented the Marten River and Sudbury lateral capacities to manage required peak day deliverability. It was used as a virtual storage on the Dawn to Parkway Transmission System, minimizing take-off capacity at the Marten River and Sudbury Lateral TransCanada PipeLines (TCPL) take-offs to allow increased flows to arrive at the Parkway Custody Transfer Point.

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.

5.1.1 Scope

This project involves replacement of the BOG Compressor to mitigate the risk of a critical part failure that is non-repairable.

5.1.2 Expenditures

Replacement cost of the BOG is estimated at $2.1 million. The proposed timing to complete the on-site work is during the second and third quarters of 2022. Design and ordering of long-lead items will need to occur a year in advance.

5.1.3 Resources

Major Projects will work with a third party engineering firm to complete the design and a contractor to complete the fieldwork. Operations will support Major Projects as required.

5.1.4 Leave to Construct

Not applicable.

5.2 Hagar Cold Box Replacement Project (AMP ID 1052)

The Hagar Liquefied Natural Gas (LNG) Plant was installed in 1968 to provide security of supply to the Sudbury industrial and distribution markets. 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.

In addition to from the security of supply provided by the LNG plant, the plant has also been placed in service on occasion over the years to manage system demand. It supplemented the Marten River and Sudbury lateral capacities to manage required peak day deliverability. It was used as a virtual storage on the Dawn to Parkway Transmission System, minimizing take-off capacity at the Marten River and Sudbury lateral TransCanada PipeLines (TCPL) take-offs to allow increased flows to arrive at the Parkway Custody Transfer point.

The Cold Box is the core of the 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. In 2017, an exercise was undertaken to isolate and leak test the various natural gas and refrigerant paths within the Cold Box in order to determine baseline leakage. Although some cross circuit leakage was found, the rate of leakage was deemed to be well within reason by the Subject Matter Expert Consultant. Future leak test data will be gathered and compared against the baseline data to predict leakage rate of change and consequential Cold Box end of life.

5.2.1 Scope

This project involves replacement of the Cold Box in advance of leakage that would impair the plant's ability to produce LNG. Considering the complex nature of internal repair or replacement of the Cold Box, reactively responding to internal leakage would render the liquefaction process out of production and unable to meet its regulated requirements for at least an operational season.

5.2.2 Expenditures

Replacement cost of the Cold Box is estimated at $6.2 million. The proposed timing to complete the on-site work is during the second and third quarters of 2025. Design and ordering of long-lead items will need to occur a year in advance.

5.2.3 Resources

Major Projects will work with a third party engineering firm to complete the design and a contractor to complete the fieldwork. Operations will support Major Projects as required.

5.2.4 Leave to Construct

Not applicable.

5.3 Hagar KVGR and Cycle Mix Cooler Replacement Project (AMP ID 1035)

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.

In addition to from the security of supply provided by the LNG plant, the plant has also been placed in service on occasion over the years to manage system demand. It supplemented the Marten River and Sudbury lateral capacities to manage required peak day deliverability. It was used as a virtual storage on the Dawn to Parkway Transmission System, minimizing take-off capacity at the Marten River and Sudbury lateral TransCanada PipeLines (TCPL) take-offs to allow increased flows to arrive at the Parkway Custody Transfer point.

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 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.

5.3.1 Scope

This project involves replacement of the KVGR Compressor to mitigate the risk of a critical part failure that is non-repairable.

5.3.2 Expenditures

Replacement cost of the KVGR is estimated at $6.2 million. The proposed timing to complete the on-site work is during the second and third quarters of 2022. Design and ordering of long-lead items will need to occur a year in advance.

5.3.3 Resources

Major 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.

5.3.4 Leave to Construct

Not applicable.

6 Measurement

6.1 Obsolete RTU Equipment / SCADA RTU Life Cycle Project (AMP ID 934, 935, 42)

The natural gas monitoring and control system is comprised of field equipment for the Supervisory Control and Data Acquisition System (SCADA) for monitoring and control of natural gas flow and odourizing natural gas at large stations, custody measurement, and control of critical valves. This system is crucial to provide live, natural gas, measurement and operational information through the SCADA to various stakeholders.

The natural gas monitoring and control system is made up of Remote Terminal Units (RTUs) - Bristol 3330/3310, which were installed from 1989 to 2006 with the majority installed between 1995 and 1999 in locations across Union's entire franchise. Communication devices are also included (satellite/cellular/radio modems), which were upgraded between 2008 and 2010 and upgraded again from 2015 to 2019 in locations across Union's entire franchise.

6.1.1 Scope

Many RTUs are 3330/3310 which were obsolete since 2009 and are no longer supported by the manufacturer. The forecast in this category includes projects to replace all the existing RTUs and replace with current technology ControlWave Micro introduced in 2003. 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 life-cycle project will take over as the current technology will be 21 years old.

The benefit of these projects will be a smooth migration of in-service RTU fleet to current technology using a standardized approach. Currently, these legacy RTUs are at the end of their useful life and deferring this work may increase failure rate exponentially due to the wear-out effect.

6.1.2 Expenditures

The total project cost is $22.4 million for 2019 to 2028 with an average of $2.2 million per year.

6.1.3 Resources

All material and equipment are procured externally. Both internal and external resources will be used to complete different tasks under this project.

6.1.4 Leave to Construct

Not applicable.

6.2 Odourant Upgrades Project (AMP ID 30, 933)

Natural gas in its basic state is generally odourless and can be difficult to detect if accidently released to the atmosphere. Natural gas is therefore odourized at major stations as required per code Canadian Standards Association Z662 - Oil and Gas Pipeline Systems to make the presence of natural gas easier to detect, to protect the public and to operate our assets safely.

Measurement Asset Subclass	Device Type and Inventory
Odourization Systems (Bypass and Injection)	• Micro Odourant Injection System (MOIS) injection cabinets • Odourant injection tanks (approximately 71 sites) • Odourant bypass tanks (approximately 148 sites) • Environmental deodourizer units(at each injection site) • Level instrumentation(one at each odourant site)

6.2.1 Scope

This project includes upgrades to odourant systems to ensure compliance to current codes such as replacing old tanks and painting rusted containment pans and tank stands. Additionally, there is further performance capability added by installing heat traces 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.

6.2.2 Expenditures

The total project cost is $10.6M million for 2019 to 2028 with an average of $1.1 million per year.

6.2.3 Resources

All material and equipment are procured externally. Both internal and external resources are used to complete different tasks under this project.

6.2.4 Leave to Construct

Not applicable.

6.3 Meter Exchange Program (AMP ID 927, 930, Portfolio: Labour Cost for Exchange)

This category is a program to remove meters and replace them with new meters. This work is as required to comply with the legal requirements of Measurement Canada. Batches of diaphragm type meters are removed each year and tested to ensure the population of meters in the field meet regulatory requirements. Smaller meters are compliance tested to meet regulatory requirements. Larger meters (rotary and turbine type meters) and electronic volume correctors (EVCs) are condition tested in service to confirm adequate performance levels. If performance levels are inadequate, the tested meters and EVCs are then removed, re-verified and returned to service.

6.3.1 Scope

The number of meter exchanges required beginning in 2019 is shown below. These exchange requirements are expected to continually grow as the overall in service population continues to grow.

- 200 series diaphragm meters – 54,402 exchanges.
- 400 series diaphragm meters – 4,851 exchanges.

6.3.2 Expenditures

The Meter Exchange Program budget forecast includes the procurement of all types of replacement meters, EVCs, Automated Meter Reading (AMR) devices, regulators for 200/400 series replacement meters and labour cost of 200/400 series replacement meters.

The total program cost is $324 million for 2019 to 2028 with an average of $32.4 million per year. Generally, there are two components of this cost as described below:

- Material and equipment cost is $172.8 million with an average of $17.28 million per year.
- The labour cost for 200/400 series replacement meters is $151.2 million with an average of $15.1 million per year.

6.3.3 Resources

All material and equipment are procured externally. The labour cost for 200/400 series replacement meters is based on 47 per cent replacements by company crew and 53 per cent replacements using external service providers.

6.3.4 Leave to Construct

Not applicable.

7 Underground Storage

7.1 Emergency Shutdown Valve Installation Project (AMP ID 1155)

Union has upgraded wellheads and installed emergency shutdown valves (ESVs) on 128 injection withdrawal (I/W) wells for Delta Pressuring projects since 2013. These upgrades reduce the risk associated with the well by having an automated shut-off at the wellhead. The ESVs can be controlled locally, remotely, through pressure loss or through thermal activation. There are pools in Union's storage system that have not been Delta Pressured due to economic or operational reasons. These are the Payne, Waubuno, Terminus, Sombra, Edys Mills, Heritage and Tipperary pools.

7.1.1 Scope

This project will upgrade the wellhead and install an ESV on the remaining 45 I/W wells over a 5-year period. The project reduces the risk on Union's storage wells by upgrading the wellhead to the current requirements of CSA Z341-18 and by installing ESV on each of these wells. This multi-year project will target 8 to 10 wellhead upgrades annually. The first year of the project is 2020 with upgrades to be performed in the Terminus pool.

7.1.2 Expenditures

The total cost of the project is $4.4 million.

7.1.3 Resources

The project will require outside contractors to install the new wellheads, ESVs and crossover modification. Design and project management will be performed by Union personnel.

7.1.4 Leave to Construct

Not applicable.

8 Service Facilities

8.1 50 Keil Drive Category 1 Facility Project (AMP ID 1161)

8.1.1 Condition Findings

The 50 Keil Drive office is a 178,000-square-foot facility located at 50 Keil Drive North in Chatham, Ontario. The facility serves as the corporate office for Union, and supports several critical corporate functions such as Gas Control, Engineering, Corporate Security, Human Resources and Finance. The original 70,000-square-foot building was constructed in 1964 in a commercial area with close proximity to major transportation routes. A 108,000 5-storey addition was put on in 1977. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.

In 2015, a facility condition assessment was conducted by WalterFedy (WF) which followed the general protocols for the Building Condition Assessment standard published by the Institute for Research in Construction division of the National Research Council of Canada (NRCC). Union provided the WF team with access to building drawings on file, historical inspection reports, equipment inventories and testing program results. Representatives from WF met with Union facility staff and trade contractors to conduct a series of on-site investigations and interviews regarding standard facility operations, maintenance procedures, equipment replacements etc. The WF team completed a building code analysis of the facility based upon the 2012 OBC, a site topographic survey of the property, and underground sanitary and storm sewer inspections by video camera. Finally, the condition of exterior surface works including pavement, sidewalks and landscaping was inspected and field notes, sketches, checklists, photographs etc. were completed as part of the on-site investigations.

The review found the building to be deficient in several building code and life safety requirements such as the absence of a sprinkler system, fire-rated assemblies, fire-rated structure, fire stopping, fire-rated and emergency exiting requirements.

Although adequately maintained, the building envelope was found to be only in fair condition, with signs of deterioration. Many building components such as the single pane windows are original, and there is evidence of moisture damage in many areas where the inadequate glazing and insulation has caused condensation on the interior wall and sill surfaces.

Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. An FCI score is not available for this facility. However, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. An Adequacy Index (AI) score is not available for this facility. Based on the investigation findings, the building does not meet the functional requirements of the business. However, the conditions are considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Site: The site provides adequate parking and green space, and is located within adequate proximity to major transportation routes.

Meets Standards		Correctable at Current Location	
POSITIVE	Negative	POSITIVE	Negative

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 45 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

Although the building and site deficiencies are considered correctable on the existing property without the need to acquire additional land, the facility requires extensive refurbishment and improvements.

8.1.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at 50 Keil are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality, resulting in productivity challenges for staff and visitors.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.1.3 Strategy

The following options to address these deficiencies have been assessed:

1. Correct physical and functional deficiencies by refurbishing the existing facility on the current site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

The preferred strategy is option 1, to refurbish the existing facility on site. The current asset management plan has allocated funds in 2020, 2021, 2022, 2023 and 2024 for a staged implementation of the strategy. This approach will increase operational efficiencies and eliminate legacy risks associated with life safety deficiencies.

8.2 Belleville Category 3 Facility Project (AMP ID 1493, 1985)

8.2.1 Condition Findings

The Belleville Operations Centre is a 13,750-square-foot facility located at 127 Enterprise Drive in Belleville, Ontario in a location that adequately services the Belleville market. The age of the building is not known as it is a leased facility. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.

In 2016, an operational performance assessment was conducted by Union personnel which identified several deficiencies in the existing facility including but not limited to the inappropriate amount of space, inadequate storage, meeting space and site security, and legacy environmental concerns regarding water quality. The review also found the building to be deficient in several building code and life safety requirements.

Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. An FCI score is not available for this facility. However, the physical condition of the facility does not meet Union standards and is not considered correctable at this location as it is leased space.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. An AI score is not available for this facility. Based on the review, the building does not meet the functional requirements of the business and the conditions are not considered correctable at the current location as it is leased space.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Functional Obsolescence - Site: The site size is unknown. However, the site does not provide adequate traffic control, storage or security. These conditions are not considered correctable at the current location as it is leased space.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 53 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

The building and site deficiencies are numerous, and considered not correctable at this location due to the fact that this is a leased property.

8.2.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at Belleville are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality resulting in productivity challenges for staff and visitors.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life-safety deficiencies.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.2.3 Strategy

The following options to address these deficiencies have been assessed:

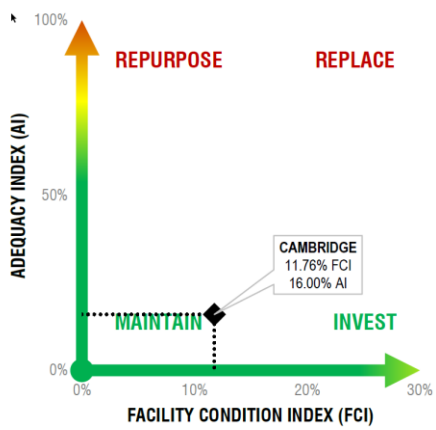
1. Correct physical and functional deficiencies by refurbishing the existing facility on the current site.
2. Terminate the lease agreement for this property and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

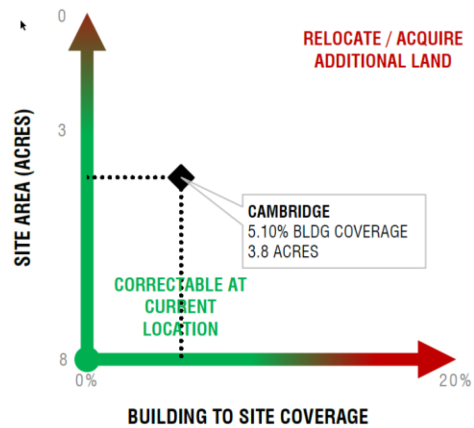
The preferred strategy is option two, to purchase land in a location with proximity to major transportation routes and construct a new fit-for-purpose facility. The current asset management plan has allocated funds in 2020 and 2021 to implement the strategy. This approach will increase operational efficiencies and eliminate legacy environmental risks associated with water quality.

8.3 Cambridge Category 3 Facility Project (AMP ID 1986)

8.3.1 Condition Findings

The Cambridge Operations Centre is an 8,800-square-foot Category 3 facility located at 221 Avenue Road in Cambridge, Ontario. The facility is considered an operations depot for the natural gas distribution business, and supports some administration support functions for the natural gas storage and transmission business. The original building was constructed in 1962 in a location with adequate access to major transportation routes. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the Cambridge facility is 11.76 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The Cambridge facility Adequacy Index (AI) is 16 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility is considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The

Cambridge site does not meet operational requirements. The yard is 0.9 acres with a single access. However, the site has adequate space to accommodate a bigger yard.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 20 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

The configuration and circulation of the yard does not meet Union standards and the current building requires refurbishment and an addition. However, the building and site deficiencies can be corrected on the existing property without the need to acquire additional land or relocate to another property.

8.3.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at Cambridge are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards
- Inadequate functionality resulting in productivity challenges for staff and visitors
- Yard constraints hindering vehicular circulation and increasing the probability of motor vehicle accidents

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies and vehicle circulation
- Financial risk due to operating costs related to inefficient equipment
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards

8.3.3 Strategy

The following options to address these deficiencies have been assessed:

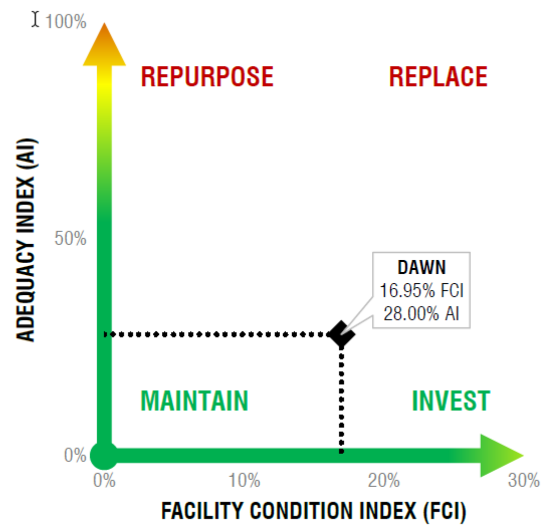
1. Correct physical and functional deficiencies by expanding and refurbishing the facility and yard on the existing site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

The preferred strategy is option one to correct deficiencies by expanding and refurbishing the existing facility and service yard. The current asset management plan has allocated funds in 2020 to fulfill the strategy. This is a more cost-effective approach and mitigates safety and financial risks.

8.4 Dawn North Admin Category 1 Facility Project (AMP ID 1167)

8.4.1 Condition Findings

The Dawn North Administration Centre is a 17,420-square-foot Category 1 facility located at 3332 Bentpath Line in Dawn-Euphemia Township, Ontario. This facility is the main administration centre for the natural gas storage and transmission business. A Master Control Room (MCR) for the natural gas storage and transportation system operates from this location and Dawn is the designated backup location for the Gas Control Centre at 50 Keil, as detailed in the corporate business continuity plan. The building was constructed in the 1970's on the Union Dawn Hub campus.



Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the Dawn facility is 16.95 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The Dawn facility Adequacy Index (AI) is 28 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility is considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Site: The Dawn North Administrative office is one of many buildings on the Dawn campus. It does not meet Union safety standards due to its proximity to the operations yard.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, some of the furnishings are considered legacy and therefore not compliant with current standards.

Although FCI and AI scores suggest the Dawn North deficiencies are correctable at the current location, relocation to another property is recommended due to proximity to the storage and transmission operations yard. The Dawn Campus includes several other parcels of land which would be suitable for a new facility to be constructed on.

8.4.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at the Dawn North facility are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Potential of injury, illness or fatality as the building is located in close proximity to the natural gas operations yard.
- Inadequate functionality resulting in productivity challenges for staff and visitors.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies and building location.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.4.3 Strategy

The following options to address these deficiencies have been assessed:

1. Correct physical and functional deficiencies by expanding and refurbishing the facility on the existing site.
2. Dispose of the existing facility and construct a new fit-for-purpose facility elsewhere on the Dawn campus.

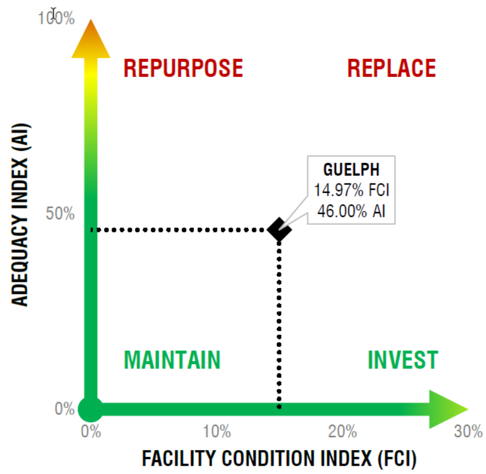
3. Do nothing.

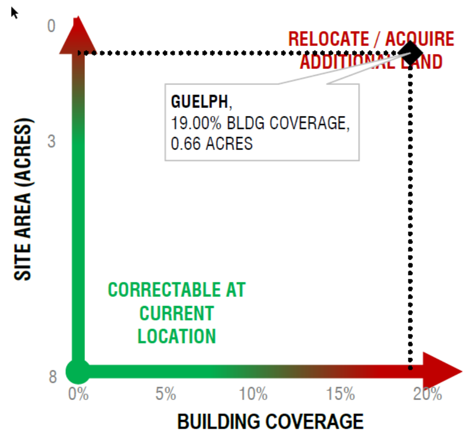
The preferred strategy is option two, to construct a new facility elsewhere on the Dawn campus. The current asset management plan has allocated funds in 2021 and 2022 to fulfill the strategy. This presents the safest, most cost-effective solution for maintaining a Category 1 facility.

8.5 Guelph Category 3 Facility Project (AMP ID 1987)

8.5.1 Condition Findings

The Guelph Category 3 Facility is a 6,659-square-foot building located at 10 Surrey Street in Guelph, Ontario. The facility is considered an operations depot and does not include any operational support functions. The original building was constructed in 1957 in a central location within proximity to major transportation routes. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements. There are legacy environmental concerns at this location as a result of prior owner's activities.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the Guelph facility is 14.97 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The Guelph facility Adequacy Index is 46 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility would be considered correctable at the current location. However, this is not recommended.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Site: The Guelph site does not meet operational requirements. The yard is 0.38 acres with a single access and considerable vehicle circulation constraints.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 100 per cent (all) of the furnishings are considered legacy and therefore not compliant with current standards.

The configuration and circulation of the yard does not meet Union standards, and the current building requires refurbishment. Building expansion and yard configuration at this location are not feasible, and consideration to do so would require an environmental control strategy.

8.5.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at Guelph are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality resulting in productivity challenges for staff and visitors.
- Yard constraints hindering vehicular circulation and increasing the probability of motor vehicle accidents.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies and vehicle circulation.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.5.3 Strategy

The following options to address these deficiencies have been assessed:

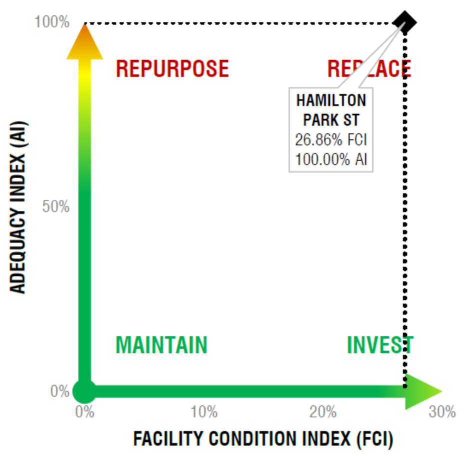
1. Correct physical and functional deficiencies by expanding and refurbishing the facility and yard on the existing site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

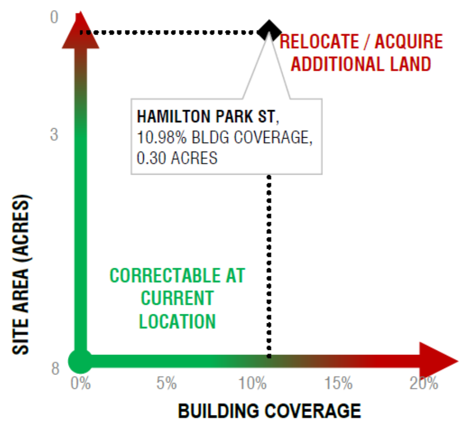
The preferred strategy is option two, to dispose of this facility and construct a new fit-for-purpose facility within proximity to major transportation routes. The current asset management plan has allocated funds in 2023 and 2024 to fulfill the strategy. This is a more cost-effective approach and mitigates safety, environmental and financial risks to the Company.

8.6 Hamilton Park Street Category 3 Facility Project (AMP ID)

8.6.1 Condition Findings

The Hamilton Park Street Operations Centre is a 1,438-square-foot Category 3 facility located at 133 Park Street North in Hamilton, Ontario. The original building was constructed in 1960 as a convenience depot for servicing the downtown area of Hamilton. The building purpose remains unchanged and no renovations have been completed since inception.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the Cambridge facility is 26.86 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The Hamilton Park Street facility Adequacy Index is 100 per cent and does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The Hamilton Park Street yard is 0.19 acres and does not meet the requirement for access, security and vehicle circulation.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, all 100 per cent (all) of the furnishings are considered legacy and therefore not compliant with current standards.

The existing building requires significant improvements. However, the property is too small to consider an investment at this time.

8.6.2 Risk and Opportunity

There are a number of consequences that Union can experience under continued operations at the Hamilton Park Street Operations Centre:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current Ontario Building Code (OBC) life safety, barrier-free and universal design standards.
- Inadequate functionality resulting in productivity challenges for staff and visitors.
- Yard constraints hindering vehicular circulation and increasing the probability of motor vehicle accidents.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies and vehicle circulation.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.6.3 Strategy

The following options to address these deficiencies have been assessed:

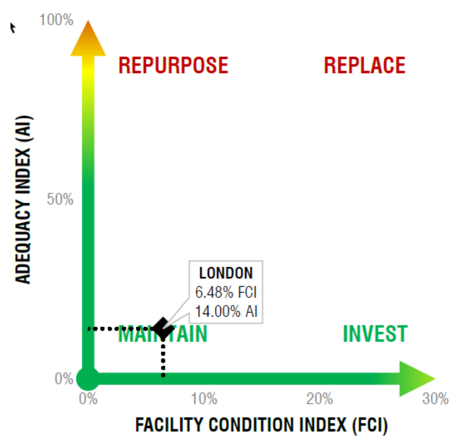
1. Purchase adjacent land and execute an expansion of the current facility. Correct physical and functional deficiencies within the building and the yard.
2. Sell existing property/facility and purchase property in the downtown core suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.
4. Close the existing facility and leverage operations depots at nearby Stoney Creek and Pritchard Road Hamilton.

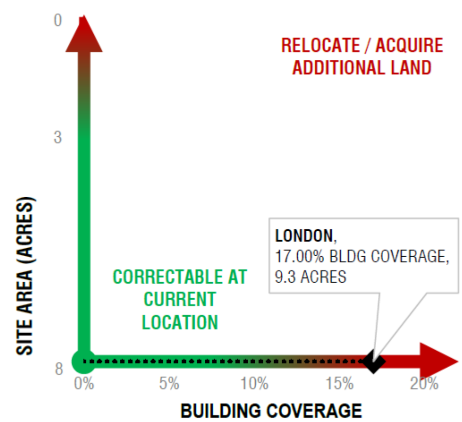
The preferred strategy is option four to close the existing facility and leverage neighbouring facilities. The current asset management plan has allocated funds in 2020 to fulfill the strategy. This is the most cost-effective approach and mitigates safety and financial risks to the Company.

8.7 London Category 1 Facility Project (AMP ID 1170)

8.7.1 Condition Findings

The London Operations Centre is a 66,840-square-foot facility located at 109 Commissioners Road West in London, Ontario. The facility serves as the main district office and provides operational support functions such as an emergency dispatch call centre, central warehousing and a fabrication (welding) shop. The London facility also serves as a main alternate location for critical corporate functions as outlined in the Corporate Business Continuity Plan. The original building was constructed in 1968 in a location that lacks direct access routes to the broader service area or major transportation routes. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Index Code (FCI) score of 0 per cent to 5 per cent. The FCI score of the London facility is 6.48 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The London facility Adequacy Index is 14 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility would be considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The London site does meet operational requirements as the yard is 3.3 acres. However, the facility location is not ideal as it is not in proximity to major transportation routes.

Meets Standards		Correctable at Current Location	
POSITIVE	Negative	Positive	NEGATIVE

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 17 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

Although the building and site deficiencies can be corrected on the existing property without the need to acquire additional land, the facility location does present operational logistics challenges.

8.7.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at London are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality resulting in productivity challenges for staff and visitors.
- Logistics challenges resulting in productivity constraints.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.7.3 Strategy

The following options to address these deficiencies have been assessed:

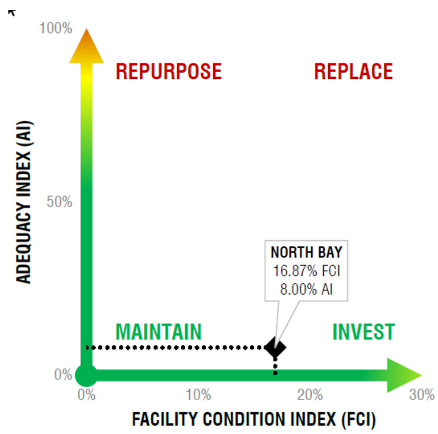
1. Correct physical and functional deficiencies by reconfiguring the yard and refurbishing the existing facility on the current site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

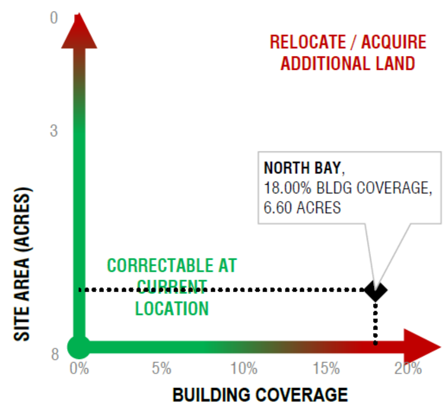
The preferred strategy is option one, to refurbish the existing facility at the current location. The current asset management plan has allocated funds in 2025, 2026, 2027 and 2028 to fulfill a staged refurbishment strategy. This approach presents the most cost-effective solution that will mitigate safety and operational risks to the Company.

8.8 North Bay Category 1 Facility Project (AMP ID 1988)

8.8.1 Condition Findings

The North Bay Operations Centre is a 39,280-square-foot facility located at 36 Charles Street in North Bay, Ontario. The facility serves as the district office and includes support functions including a commercial meter shop, a customer attachment call centre and central warehousing. The original building was constructed in 1964 in an area that has since been repurposed for residential housing. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the North Bay facility is 16.87 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The North Bay facility Adequacy Index (AI) is 8 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility would be considered correctable at the current location.

Meets Standards		Correctable at Current Location	
POSITIVE	Negative	POSITIVE	Negative

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The North Bay site does meet operational requirements. The yard is 3.5 acres with multiple access drives.

Meets Standards		Correctable at Current Location	
POSITIVE	Negative	POSITIVE	Negative

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 34 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

The configuration and circulation of the yard does not meet Union standards and the current building requires a renovation. The building and site deficiencies are correctable on the existing property without the need to acquire additional land. However, the facility is located in a residential neighbourhood without easy access to major transportation routes.

8.8.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at North Bay are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality resulting in productivity challenges for staff and visitors.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies and vehicle circulation.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.8.3 Strategy

The following options to address these deficiencies have been assessed:

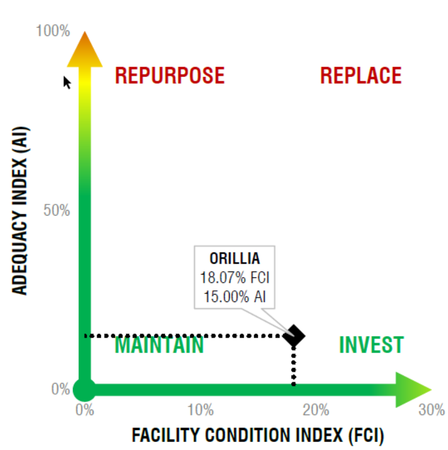
1. Correct physical and functional deficiencies by reconfiguring the yard and refurbishing the facility on the existing site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

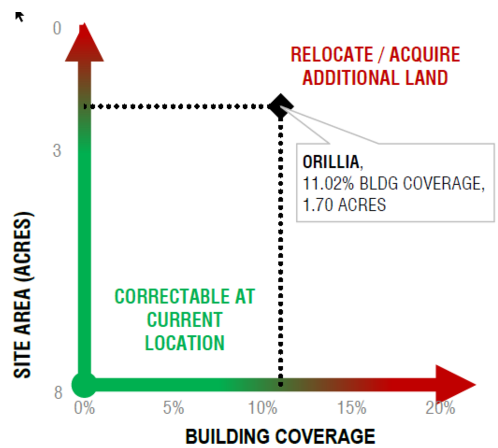
The preferred strategy is option two, to dispose of this facility and construct a fit-for-use facility in a commercial location with access to transportation routes. The current asset management plan has allocated funds in 2024 and 2025 to fulfill the strategy. This approach addresses operational logistics challenges, addresses the concerns of the residential neighbourhood and mitigates safety and financial risks to the Company.

8.9 Orillia Category 3 Facility Project (AMP ID 1171)

8.9.1 Condition Findings

The Orillia Operations Centre is a 12,254-square-foot facility located at 425 Memorial Avenue in Orillia, Ontario. The original building was constructed in 1974 in a commercial location that continues to service the surrounding area well. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the Orillia facility is 18.07 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The Orillia facility Adequacy Index (AI) is 15 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility would be considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The site does meet operational requirements. The yard is 0.7 acres.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 58 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

The configuration and circulation of the yard does not meet Union standards and the current building requires a renovation. However, the building and site deficiencies are considered correctable on the existing property.

8.9.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at Orillia are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality resulting in productivity challenges for staff and visitors.
- Yard constraints hindering vehicular circulation and increasing the probability of motor vehicle accidents.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies and vehicle circulation.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.9.3 Strategy

The following options to address these deficiencies have been assessed:

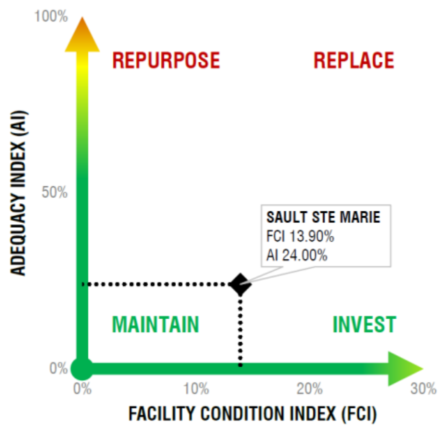
1. Correct physical and functional deficiencies by reconfiguring the yard and refurbishing the facility on the existing site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

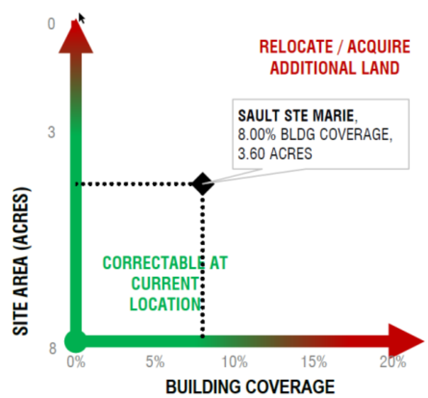
The preferred strategy is option one, to refurbish the existing facility and reconfigure the existing yard. The current asset management plan has allocated funds in 2022 and 2023 to fulfill the plan. This is the most cost-effective approach to mitigate safety and financial risks to the Company.

8.10 Sault Ste Marie Category 3 Facility Project (AMP ID 1990)

8.10.1 Condition Findings

The Sault Ste Marie (SSM) Operations Centre is a 9,500-square-foot facility located at 10 Industrial Court A in Sault Ste Marie, Ontario. The facility serves as an operations depot, and provides operational support with a fabrication (welding) shop. The original building was constructed in 1979 in an industrial area with close proximity to major transportation routes. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the SSM facility is 13.90 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	**NEGATIVE**	**POSITIVE**	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The SSM facility Adequacy Index (AI) is 24 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility would be considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	**NEGATIVE**	**POSITIVE**	Negative

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The SSM site does meet operational requirements as the yard is 2.6 acres.

Meets Standards		Correctable at Current Location	
POSITIVE	Negative	POSITIVE	Negative

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 100 per cent (all) of the furnishings are considered legacy and therefore not compliant with current standards.

Although the building and site deficiencies can be corrected on the existing property without the need to acquire additional land, the facility itself requires refurbishment and an addition.

8.10.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at SSM are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality, resulting in productivity challenges for staff and visitors.
- Logistics challenges resulting in productivity constraints.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.10.3 Strategy

The following options to address these deficiencies have been assessed:

1. Correct physical and functional deficiencies by adding an addition and refurbishing the existing facility on the current site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

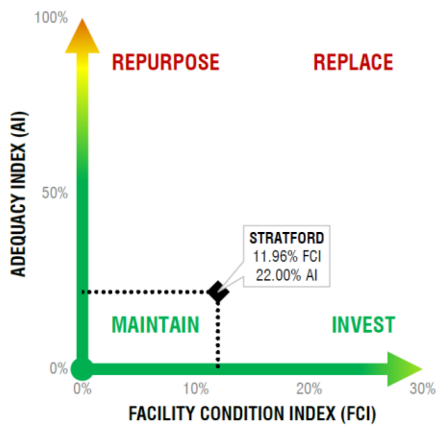
The preferred strategy is option one, to put an addition on the existing building and refurbish the existing spaces. The current asset management plan has allocated funds in

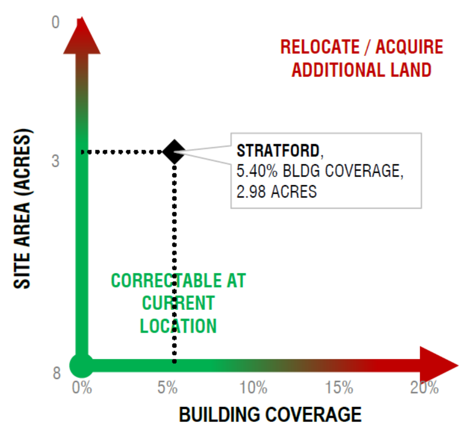
2025 and 2026 to fulfill the strategy. This approach presents the most cost-effective solution that will mitigate safety and operational risks to the Company.

8.11 Stratford Category 3 Facility Project (AMP ID 1173)

8.11.1 Condition Findings

The Stratford Operations Centre is a 7,000-square-foot facility located at 827 Erie Street in Stratford, Ontario. The facility serves as an operations depot. The original building was constructed in 1968 in a commercial area with close proximity to major transportation routes. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the Stratford facility is 11.96 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The Stratford facility Adequacy Index (AI) is 22 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility would be considered correctable at the current location.

Meets Standards		Correctable at Current Location	
POSITIVE	Negative	POSITIVE	Negative

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The Stratford site does not meet operational requirements as the yard is 1.07 acres with a single access.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 66 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

Although the building and site deficiencies are considered correctable on the existing property without the need to acquire additional land, the facility itself requires refurbishment. There are also legacy environmental issues related to water quality at this site.

8.11.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at Stratford are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality resulting in productivity challenges for staff and visitors
- Logistics challenges resulting in productivity constraints.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.11.3 Strategy

The following options to address these deficiencies have been assessed:

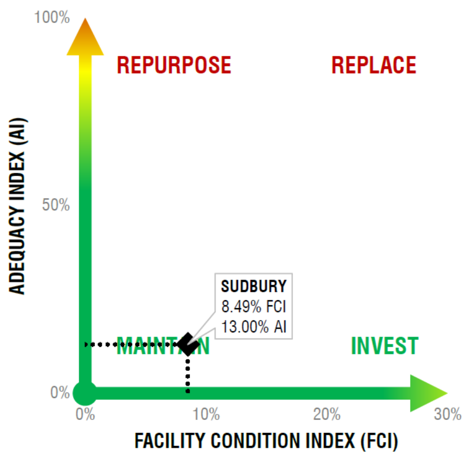
1. Correct physical and functional deficiencies by refurbishing the existing facility on the current site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

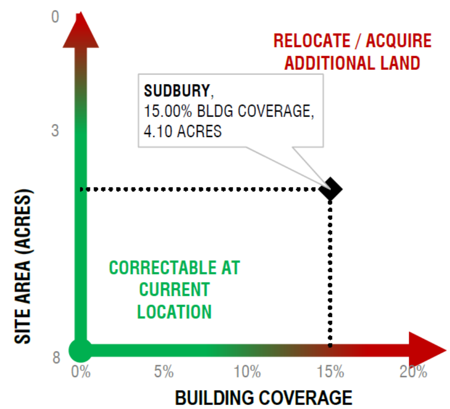
The preferred strategy is option two, to dispose of this facility and construct a new fit-for-purpose facility with access to major transportation routes. The current asset management plan has allocated funds in 2026 and 2027 to fulfill the strategy. This approach will increase operational efficiencies and eliminate legacy environmental risks associated with water quality.

8.12 Sudbury Category 3 Facility Project (AMP ID 1989)

8.12.1 Condition Findings

The Sudbury Operations Centre is a 41,686-square-foot facility located at 828 Falconbridge Road in Sudbury, Ontario. The facility serves as an operations depot and includes a distribution warehouse, a call centre and a fabrication (welding) facility. The original building was constructed in 1984 in a commercial area with close proximity to major transportation routes. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the Sudbury facility is 8.49 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The Sudbury facility Adequacy Index (AI) is 13 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility would be considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The Sudbury site does not meet operational requirements as the yard is 1.9 acres. However, this has not significantly impacted operations.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 36 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

Although the building and site deficiencies are considered correctable on the existing property without the need to acquire additional land, the facility itself is significantly oversized and requires extensive refurbishment. There are also legacy issues related to settlement of the building.

8.12.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at Sudbury are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality, resulting in productivity challenges for staff and visitors.
- Logistics challenges resulting in productivity constraints.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.12.3 Strategy

The following options to address these deficiencies have been assessed:

1. Correct physical and functional deficiencies by refurbishing the existing facility on the current site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

The preferred strategy is option two, to dispose of this facility and construct a new fit-for-purpose facility with access to major transportation routes. The current asset management plan has allocated funds in 2028 and 2029 to fulfill the strategy. This approach will increase operational efficiencies and eliminate legacy risks associated with structural settlement.

9 Technology and Information Services (TIS)

9.1 Banner Application Project (AMP ID 2274, 1997)

Banner Enlogix customer information system (CIS) is a Vertex software as a service (SAAS) offering for 1.4 million non-contract general use customers that was implemented across Union in 2000. Banner's main purpose is billing; the system annually transacts revenue over $1.5 billion. Banner is the system of record for customer, premise, account, service and meter information and all related processes.

In addition to the core CIS functions within the Banner application, there are several other associated applications Vertex provides such as Union's MyAccount application. This is a customer self-serve web portal for transacting and viewing bill images, consumption history, and registration/cancellation of EBP Equal Billing Plans (EBP) and Auto Payment Plans (APP). A copy of the code is maintained in escrow.

9.1.1 Scope

The enhancement investments for this project will ensure accurate billing services are provided to customers in Banner and meet regulatory and legislative requirements.

9.1.2 Expenditures

The total capital expenditure for the project is $122.6 million.

In 2019 and 2020, a $2.5 million enhancement to the online component (MyAccount) is required for compliance with the Accessibilities for Ontarians with Disabilities Act (AODA).

From 2019 to 2023, $9 million is required to remain compliant and implement enhancements to the system to ensure it continues to meet the business needs. Some of this work includes expected changes to the Customer Service Standards from the Ontario Energy Board (OEB) and changes to support the Energy Water Reporting and Benchmark (EWRB) regulation.

From 2024 through to 2027, the application will undergo a major life cycle replacement as the current version and underlying technologies will be over 20 years old.

9.1.3 Resources

The resourcing plans for this project are consistent with the historical expenditures. As the project plans are developed, the appropriate resources will be identified and implemented as required.

9.1.4 Leave to Construct

Not applicable.

9.2 CARE Application Project (AMP ID 2275)

The Classify Allocation Report and Exchange (CARE) application is Union's management system. It handles both incoming and outgoing nominations and validates the nominations against the related contracts for pipeline capacity. It is an in-house developed application that was originally developed in 1994 and sits on outdated architecture. As a result, this application has become difficult to support which coupled with the amount of break/fix change required to keep the system functioning is putting reliability and performance at risk. In addition, the programming language is nearing end of life making it difficult to find this skillset in developers.

CARE is one of three custom-built applications that serves Union's in-franchise and ex-franchise wholesale business (e.g., large contract rate distribution, direct purchase and storage and transportation customers) and is deemed the system of record for all gas inventories owned by Union and third parties. Every molecule of gas that enters or leaves Union's system, whether owned by Union or others, is accounted for in CARE on a volumetric basis. There are high expectations for reliability, availability and performance of the CARE application (7 days/24 hours/365 days) as it is the sole transaction system for our storage and transmission customers and internal business users.

The investment in enhancements and ultimately the life cycle of CARE is to ensure a stable, reliable, nomination and schedule system is in place that meets all regulatory requirements.

9.2.1 Scope

This project includes both annual enhancements and a life cycle project. Both are in place to ensure CARE remains stable and reliable.

9.2.2 Expenditures

The total capital expenditure for the project is $37.6 million. During 2020 to 2023, CARE will have a major life cycle replacement to ensure it continues to operate effectively.

9.2.3 Resources

For the annual enhancements, resource planning will occur when the requirements for the year are identified as per previous years.

For the life cycle project, professional resources for design and engineering will be contracted from the marketplace for this project. Union may be able to leverage the architecture and resources that are being used for ConTrax Modernization.

9.2.4 Leave to Construct

Not applicable.

9.3 CARS Application Project (AMP ID 2276)

The Construction Administration Records Systems (CARS) application is a Union application used to manage construction work orders used for new customer service lateral attachments. This application consists of an internally based application, an Internet facing application (GetConnected) as well as the business to business (B2B) component. It was developed in-house in 2009. The underlying technologies are aging and it is becoming increasingly difficult to enhance and support the application. CARS and GetConnected are custom-built applications written in C# using Visual Studio 2012, accessing an Oracle 12C database.

9.3.1 Scope

The project is intended to provide capital required to do a small amount of enhancements each year and keep the technologies used in support with the vendors. There is a major rewrite planned for both CARS and GetConnected in the next eight years.

9.3.2 Expenditures

The total capital expenditure for the project is $27.9 million. During 2021 to 2024, CARS will have a major lifecycle replacement to ensure it continues to operate effectively. In 2025, the online user interface referred to as GetConnected, will be life cycled to ensure it continues to operate securely.

Small enhancement projects are also budgeted for each year to drive efficiencies in the customer attachment workflow.

9.3.3 Resources

Union will look to implement an off-the-shelf solution rather than custom-built solutions as part of the lifecycle projects. As the project plans are developed, the appropriate resources will be identified and implemented as required.

9.3.4 Leave to Construct

Not applicable.

9.4 ConTrax Modernization Project (AMP ID 840, 2277)

ConTrax facilitates the contract to cash business processes for Distribution, Direct Purchase and Storage and Transportation (S&T) services for Union's large Commercial/Industrial customers. The application had become difficult to support due to the outdated technology and the complexity of the application as a result of having undergone several disparate and complex enhancements since it was initially implemented in 1995. The performance, reliability and flexibility of the ConTrax application is critical to Union's Business Development Storage and Transmission (BDST) growth strategy as well as the protection of base revenues. This project will modernize the ConTrax application and the ConTrax functionality in Unionline to protect Union's current business and support future growth. Wave 1 (south distribution market and core technology/architecture) of the project was successfully implemented in February 2017. Wave 2 (the rest of the distribution market) was successfully implemented in February 2018, with Wave 3 (Direct Purchase, S&T, all interfaces) scheduled to be implemented in February 2019.

9.4.1 Scope

This project will provide a modern technology stack to improve reliability, flexibility and time to market. While the underlying business processes have not changed, the manner in which they are facilitated through the application has been improved (e.g. workflow automation). The modernization of ConTrax will reduce planned and unplanned outages and will support business growth and protect existing revenue.

9.4.2 Expenditures

The total expenditure is estimated to be $17.5 million over the 10-year Asset Management Plan, not including $51.4 million spent prior to 2019.

9.4.3 Resources

This project will continue with the resourcing plan that has been in place for previous waves. In addition to Union Technology and Information Services (TIS) and business resources, there is a fixed price contract in place with the solution provider, Tata Consultancy Services for both onshore and offshore resources. Ernst and Young are providing onshore Project Management Office (PMO) services.

9.4.4 Leave to Construct

Not applicable.

9.5 Corrosion Application Replacement Program (AMP ID 2278, 2298)

The GL Essentials Corrosion Application (vendor provided software) provides asset-tracking, inspection and field data collection for routine inspection, maintenance and regulatory compliance activities on Union's pipelines. Technicians record reads, add sites, etc., on their laptops and refresh their local database when they return to the office. This is used companywide to support Union's cathodic protection system.

9.5.1 Scope

The current GL Essentials Corrosion Application will be replaced with a new solution. The software is overly complex to use and therefore inefficient. Alternative packages will be investigated as part of the lifecycle project in 2020 to 2021, including the potential of consolidating its functions into an existing application.

9.5.2 Expenditures

The total capital expenditure for the program is $4.9 million. The cost of a multi-year replacement project starting in 2020 is estimated at $3.8 million with additional costs allocated in subsequent years to allow for lifecycle/upgrades to the solution in order to maintain full vendor support. The program costs are based on Class 5 estimate.

9.5.3 Resources

The resourcing plans for this program are consistent with the historical expenditures. As the program plans are developed, the appropriate resources will be identified and implemented as required.

9.5.4 Leave to Construct

Not applicable.

9.6 Geographic Information Services (GIS) Application Program (AMP ID 2000, 2282)

Union's Geographic Information System (GIS) is used to store spatial and attribute information primarily related to underground assets (e.g., pipe, valves, fittings, district boundaries, structures, intersections, and cathodic protection, etc.). The GIS solution provides accurate data for planning, emergency response, Ontario Energy Board (OEB) mandated compliance items such as Ontario One Call, hydraulic modelling, municipal data sharing, and property tax, etc.

A module of the GIS system, G/Technology Designer, is used to design distribution services in order to release Issued for Construction (IFC) drawings to the field and also is used to update GIS based on as-built field drawings for transmission and distribution pipe projects.

G/Technology NetViewer provides a read-only interface to Union's GIS. G/Technology MobileViewer provides network disconnected read-only access to Utility Services Representatives (USRs) while working in the field. GeoMedia is the technology used for more traditional spatial analysis by select GIS technicians.

9.6.1 Scope

The annual GIS program is used to fund enhancements required to support changing business need (e.g., OEB mandated annual class location survey). The program is also used to fund larger software upgrades and life-cycle initiatives such as the GIS life cycle planned for 2022 to 2024. The current software version was originally implemented in 2007 and last updated to a more current version in 2017.

9.6.2 Expenditures

The total capital expenditure for the program is $22.2 million over 10 years. Typical annual GIS Program maintenance costs are in the range of $160 thousand to $240 thousand per year. During 2022 to 2024, the system is scheduled to go through a major life-cycle replacement. The cost of that particular upgrade is estimated between $11 million and $15 million assuming a potential change in the underlying GIS technology.

9.6.3 Resources

The resourcing plans for this program are consistent with the historical expenditures. As the program plans are developed, the appropriate resources will be identified and implemented as required.

9.6.4 Leave to Construct

Not applicable.

9.7 Meter and Measurement Application Project (AMP ID 2290, 2305)

Meter and Measurement is a set of applications that captures meter readings from residential, commercial and high volume customers, passing the data onto the appropriate billing systems.

Itron's Field Collection System (FCS) supports the residential meter reading business clients. This package interfaces with the Banner application to allow for billing of residential meters. The FCS application itself allows for route management, route status, route assignment/re-assignment and reporting.

The Gas Measurement Account System (GMAS) collects and validates all daily (or hourly) measurements at Union and sends to downstream systems such as ConTrax and Classify Allocation Report and Exchange (CARE) among others. The business clients interact with the system by accepting measurement warnings, closing meters at month-end and entering meter consumption manually when it is not available from Autosol when the meter is not communicating. The business clients also configure or group meters together for reporting purposes. There are also canned reports as part of the application.

Autosol is a polling engine application which makes calls to telemeter devices and reads measurement information which is then passed to GMAS for validation.

9.7.1 Scope

There are several upgrades to the vendor packages to ensure the applications remain supported and current over the span of 2019 to 2028 ranging from in-place upgrades to doing a market scan to ensure Union still using the technology that best meets our needs.

In addition, there are a couple of larger initiatives:

- In 2020, $2.5 million of funding is required as it is expected that there will be a significant increase in the number of Automated Meter Reading (AMR) devices (e.g., Electronic Receiver Transmitters [ERTs]) implemented across Union's franchise through an anticipated project and regular life-cycling of meters. As a result, there is a need to manage and provide a means of reporting on the increase in data (monthly to hourly) that we will receive as a result of this change.
- In 2021, $1.4 million has been set aside due to the need to life-cycle the ITRON handheld units used to capture the monthly reads. There are approximately 230 handhelds and docking stations that were purchased in 2012 and the current support agreement ends December 31, 2021.

9.7.2 Expenditures

The total capital expenditure for the project is $7.5 million. In 2020, a $2.5 million upgrade to incorporate reads from meters with AMR devices will be performed. In 2021, a $1.4 million life cycle of the Itron handhelds and docking stations is required to remain supported. The other spending is on enhancements to enable the application to continue to meet business needs and remain supported.

9.7.3 Resources

The resourcing plans for this project are consistent with the historical expenditures. As the project plans are developed, the appropriate resources will be identified and implemented as required.

9.7.4 Leave to Construct

Not applicable.

9.8 SCADA Application Replacement Project (AMP ID 2015, 2014, 2288)

The Supervisory Control and Data Acquisition (SCADA) system is used by the Union's Gas Control and Dawn Master Control Centres. It operates the company's pipeline and storage pool facilities. It is a critical 7 days/24 hours/365 days system. This set of projects continues to enhance components of the Union SCADA system in support of changing control room requirements and enhance the security of our telemetry infrastructure. Towards the end of the 10-year program, we are considering a complete replacement of the current system as there is a good chance it will be running an out-of-date operating system and end of life hardware and application software that will no longer be supported. The last major life-cycle replacement of the vendor software (i.e., Cygnet) was in 2011. The new hardware and software for this program is therefore necessary in order to use a modern architecture and includes enhancements for business, designed for both maximum security and reliability. This project will mitigate potential significant risks related to safety, finance and reputation by avoiding the continued use of outdated hardware and software.

9.8.1 Scope

The SCADA Replacement Project will start scheduling for the last few years of the 10-year Asset Management Plan. This project will involve the purchase of an entirely new SCADA system for the Union Master Control Room, including all new hardware and the new SCADA application software solution, as well as the implementation of the solution and its components. Other work included in the intervening years is allocated for telemetry upgrades, encryption rollout, and control room enhancements.

9.8.2 Expenditures

The total capital expenditure for the project is $15.4 million. The cost of the project enhancements in 2019 will be $1 million with the remainder of the funds being allocated each year through to 2023 after which the SCADA upgrade is scheduled for $10.3 million. The costs are estimated for hardware, software and professional services and are based on a Class 5 estimate.

There are no contingency or historical costs available for this project.

9.8.3 Resources

Professional resources for design and engineering will be contracted from the marketplace for this project. Historically, Union has retained architectural and engineering consulting services for the execution of similar projects.

9.8.4 Leave to Construct

Not applicable.

9.9 Service Suite Application Project (AMP ID 841, 2284)

The Service Suite application provides Work Management functionality to the majority of our Distribution Operations field workforce at Union. Planning and Dispatch Centres in London, Burlington, and North Bay manage the work for approximately 430 Utility Services Representatives (USRs) and dispatch this work through a cellular network to Panasonic Toughpads that are docked in each USR's vehicle. It is also a key technology for managing and dispatching Emergency Service orders 24 hours a day. The solution has significant interfaces with our CIS system (Banner) and Payroll system (SAP) via our time reporting and crewing application (WARP). The Service Suite application has been used at Union for the past 20 years with the last major upgrade occurring in 2007. The current version of Service Suite is 8.1.3. and is anticipated to be out of support with the vendor in 2020. This version is also dependent on aging technologies such as Windows 7 that present vendor support issues for the environment.

9.9.1 Scope

The focus of this project is to upgrade the aging Service Suite application to a newer version of the product and extend the life of the system. This is intended to be a technical upgrade with minimal new functionality added. Changes to the interfaces and reporting environment will also be minimized and only touched were needed as part of the upgrade or where objects could be retired.

9.9.2 Expenditures

The total expenditure are estimated to be $13.3 million over the 10-year Asset Management Plan. This does not include $3.2 million spent prior to 2019.

9.9.3 Resources

The resources on the project will be a mix of internal IT resources, functional area resources, and resources from the software vendor. As the project plans are developed, the appropriate resources will be identified and engaged as required.

9.9.4 Leave to Construct

Not applicable

9.10 Cloud Applications Program (AMP ID 2295)

Cloud applications are classified as cloud services that support specific, functional, business needs Applications. This Program includes funding for these applications: Contract Management System (CMS), Land Rights Management (GeoAmps) and Leak Survey (VeroTrack).

This program includes both application upgrades and a life cycle project to ensure these applications remain stable and reliable.

9.10.1 Scope

The investment in upgrades and ultimately the life cycle of these applications is to ensure stable and reliable systems are in place that meets all regulatory requirements.

9.10.2 Expenditures

The total capital expenditure for these projects is $2.3 million. In 2022, Land Rights Management (GeoAmps) will have a major life cycle replacement to ensure it continues to operate effectively.

9.10.3 Resources

For the upgrades, resource planning will occur when the requirements for the year are identified as per previous years.

For the life cycle project, professional resources for design and engineering will be contracted from the marketplace for these projects.

9.10.4 Leave to Construct

Not applicable.

9.11 Asset Management Application Program (AMP ID 2291)

This program will build an application to manage the Asset Management Program within Union and provide the tools and processes as identified in ISO 5500X. Enhanced asset analytics and decision support tools will be added to mitigate financial risks.

9.11.1 Scope

This program will contain elements of both packaged and developed applications. The implementation software will include the following:

- Capital portfolio management.
- Asset analytics and processing.
- Data capturing.
- Condition-based analysis.
- Performance management.

The program will oversee various business enhancements to existing asset management applications that will ensure the following:

- Meet the requirements for Union's asset management process.
- Implement the asset analytics and decision support tools.
- Implement software and applications to mitigate financial risks.

The program will start in 2019.

9.11.2 Expenditures

The total capital costs for the project are estimated to be $3.1 million over the 10-year period of the Asset Management Plan. In 2020, $1.2 million is required to purchase the software and $450 thousand to complete the foundation for the solution in 2021. The other spending is on enhancements to enable the application to continue to meet business needs.

The costs are based primarily on historical spend. In some cases, specific activities are identified within the Program, where high level estimates of resourcing including professional services, where identified are used. The program costs are based on a Class 5 estimate. This project is included under the Applications – Other portfolio in Section 5 Table 5.4.8.3.4.1.

9.11.3 Resources

High level requirements would be gathered from the business groups' subject matter experts (SMEs) to determine the level of effort required to complete the initiatives/projects under this Program. Existing Union resources with the required skills, knowledge, and capacity will be assigned to the appropriate initiatives/projects. If resources are not available, staff augmentation will be required and contractor staff will be on-boarded as per the needs of the initiatives/projects.

The resourcing strategy is identical to projects and programs executed in the past in the Union application development process.

9.11.4 Leave to Construct

Not applicable.

9.12 Material Traceability Application Project (AMP ID 2005, 2292)

The purpose of the Material Traceability Application Project is to provide a technical solution to ensure compliance with the Canadian Standards Association (CSA) Z662-15 code requirements.

Changes in the Z662-11 code have led to a higher level of scrutiny required in terms of records for materials and the ability to demonstrate material qualifications/specification through those records. The Technical Standards and Safety Authority (TSSA) adopted Z662-11 in November 2012 and it has since been revised to Z662-15 which was adopted by the TSSA in July 2016 (no changes to the material traceability requirements occurred between the 2011 and 2015 editions).

The Z662-11/Z662-15 codes require complete records for the material, including what specification it was made to, and the designer must ensure that it meets current requirements, which could lead to an Engineering Assessment.

9.12.1 Scope

There is a need to ensure information on the materials Union deploys in the field is accessible to the organization throughout the life of the asset. The specific types of information required are identified in the code. A technical solution will need to be deployed for field use that will allow maintenance and new-installation crews to identify the material they are deploying on specific job sites. This material information must be searchable by the business to ensure there is visibility into what materials are deployed where.

A roadmap will need to be developed to articulate how the requirements for Material Traceability will impact our current systems and potentially require new solutions as well. The roadmap will also layout the timing and scope of those changes along with the timing of the different asset types. A project plan will be built from this roadmap.

9.12.2 Expenditures

The total capital expenditure for the project is $2.5 million. The plan is to initiate the project in 2019 and, in subsequent years, incur other expenditure to complete the project and also enhance the solution to meet business needs in accordance with the defined roadmap. This project is included under the Applications – Other portfolio in Section 5 Table 5.4.8.3.4.1.

9.12.3 Resources

The resourcing plans for this project are consistent with other Technology and Information Services (TIS) projects. As the project plans are developed, the appropriate resources will be identified and implemented as required.

9.12.4 Leave to Construct

Not applicable.

9.13 Unionline Project (AMP ID 2287, 2011)

Unionline is a web-based transaction and information application that provides contract customers (i.e., large commercial and industrial, storage and transportation and energy marketers) with the ability to conduct business with Union online (i.e., nominating and reporting).

This project includes an annual program and an upgrade to the underlying technology in order to ensure reliability, performance, and to ensure Union remains compliant and competitive.

9.13.1 Scope

Annually, Union has an ongoing program for making regular investments into Unionline to enhance its function and reliability, allowing it to remain competitive with other pipeline online transactional systems. Its focus is to improve performance and reliability of the Unionline application and its internal supporting applications of CARE and ConTrax. In addition, this program is used when there are industry related changes that need to be made to the applications or new regulated changes that are not significant in nature.

In 2025, some funding has been set aside in order to review the Unionline from a lifecycle perspective. A portion of Unionline was upgraded in 2014; but with the fast changing web environment, there will likely be a need to enhance the application to support the consumer demands or changes in technology.

9.13.2 Expenditures

The average yearly program cost over the 10-year period is $25 thousand annually with an upgrade planned for 2025 to 2026 of $2.1 million.

9.13.3 Resources

A yearly program commences at the start of the year. The necessary resources are identified and perform the rollouts as per the project plan for each program year.

9.13.4 Leave to Construct

Not applicable.

9.14 Desktop Life Cycle/Sustainment Project (AMP ID 2017, 2297)

This project provides for the replacement of end user laptops and desktops using the preferred four-year refresh cycle, which mitigates financial risks. This project is in place to avoid significant operating costs due to the breakdown of aging devices along with the costs required to repair and to avoid productivity losses due to older equipment failing and being unable to keep up with operating system and software advances.

9.14.1 Scope

This project replaces the end user computing devices (laptops and desktops) as per the preferred four-year refresh cycle. It uses a cyclical approach for replacement based on warranty expiry, the logistics around operating system upgrades and hardware technology advances.

The project will start in 2019 and continue over the 10-year period until 2028.

9.14.2 Expenditures

The total capital expenditure for the project is estimated to be $28.6 million over the 10-year Asset Management Plan. The estimate is based on the expected cost of replacement devices multiplied by the number of devices to be replaced in a given year. The project costs are based on a Class 5 estimate. The expenditure amounts are consistent with the historical costs of the Project with no cost contingency.

9.14.3 Resources

As the project commences at the start of each year, the necessary resources are identified and purchased to perform the rollouts as per the project plan for that year. This resourcing plan is identical to that used in previous years for such a project.

9.14.4 Leave to Construct

Not applicable.

9.15 Server Life Cycle/Sustainment Program (AMP ID 2019, 2297)

Servers consist of devices that operate Unions' applications and data. This program provides for the replacement of servers using the preferred six-year refresh cycle and a cyclical approach for replacement based on warranty expiry and hardware technology advances. This helps the business application systems to perform as needed, and keeps technology current and at a supportable level. The program will also reduce potential outages due to aging hardware and avoid costly hardware maintenance charges as the equipment nears warranty.

9.15.1 Scope

This program will procure the replacement servers per vendor specifications and configure and implement the replacement servers into landscapes as per the preferred six-year refresh cycle.

The program is executed twice over the 10-year period starting in 2019 and again in 2025 with some procurements annually.

9.15.2 Expenditures

The total capital expenditure for the program is estimated to be $8.3 million over the 10-year Asset Management Plan.

The estimate is based on the expected cost of replacement in a given year. The program costs are based on a Class 5 estimate. The expenditure amounts are consistent with the historical costs of the program with no cost contingency.

9.15.3 Resources

This program will use vendor resources to install and configure the servers, consistent with resourcing used historically for this type of program.

9.15.4 Leave to Construct

Not applicable.

9.16 Utility Service Representative's Toughbooks Program

This program provides for the replacement of the rugged workstation hardware in the field used by the Utility Services Representatives (USRs) using the preferred four-year refresh cycle. This approach mitigates financial risk by avoiding significant increased operating costs due to failure of aging devices along with avoiding productivity losses (due to older equipment failing) and being unable to keep up with operating system and software advances. The maintained stability of the equipment ensures the USR has the required information to address the assigned work as well as emergency situations that are dispatched to the field. The current unit that is used in the trucks is the Panasonic Toughbook CF-31.

9.16.1 Scope

This program replaces the rugged workstation hardware in the field as per the prescribed four-year refresh cycle. It uses a cyclical approach for replacement based on warranty expiry, the logistics around operating system upgrades and hardware technology advances. The lifespan is deemed optimal to manage the total cost of ownership (TCO) of the units.

The program will start in 2020 and continue over the 10-year period until 2028.

9.16.2 Expenditures

The total program cost is estimated to be $9 million over the 10-year Asset Management Plan. The estimate is based on the expected cost of replacement devices multiplied by the number of units to be replaced every four years. The replacement program is anticipated to be implemented in 2020, 2024 and 2028.

9.16.3 Resources

As the project commences at the start of each year, the necessary resources are identified and purchased to perform the rollouts as per the project plan for that year. This resourcing plan is identical to that used in previous years for such a project.

9.16.4 Leave to Construct

Not applicable.

9.17 IT Technologies Program (Portfolio: IT Technologies)

The Information Technology (IT) Technologies Program contains a small portfolio of technology platforms that are used within IT and can be generally categorized as application integration systems, business intelligence systems, database systems, and application delivery support systems. Application integration systems allow the interconnection of processes and exchange of data among different business applications. Business intelligence systems allow business data to be queried, reported, and analyzed from our application systems to aid in corporate strategy planning and decision-making. Database systems provide the backend relational database technologies for storage of business data, as well as related client software to allow applications to connect to these databases. Application delivery support systems provide for software code management, web-based application operations, and software tools.

There are a number of consequences to Union if these key technologies are not maintained or renewed. These include:

- Extended outages due to failure of unsupported vendor foundational software
- Cybersecurity breaches due to the inability to apply security patches to unsupported software

9.17.1 Scope

The age range of all of the IT technologies extends to 20 years. However, plans are in place to decommission older IT technologies as more current technologies are available. The replacement/refresh strategy is driven by forecasted changes to the existing software products themselves and requirements from the business and associated applications.

The program is executed twice over the 10-year period.

9.17.2 Expenditures

The total program cost is estimated to be $12.1 million over the 10-year Asset Management Plan. The estimate is based on the expected cost of replacement of these technologies. The project costs are based on a Class 5 estimate. The expenditure amounts are consistent with the historical costs of the project with no cost contingency.

9.17.3 Resources

This program will use both internal and vendor resources to install and configure these IT technologies, consistent with resourcing used historically for this type of program.

9.17.4 Leave to Construct

Not applicable.

uniongas
An Enbridge Company

December 2017

Union Gas Asset Management Plan 2018-2027

Contents

1 Executive Summary

1.1 Purpose

The Asset Management Plan is a forecast of the growth and maintenance expenditures planned for Union Gas Ltd. (Union) assets for the years 2018 to 2027. In this plan, Union assets include Union assets and the assets of Union affiliates Market Hub Partners Canada L.P. and St. Clair Pipelines L.P. This plan demonstrates that Union will manage assets to serve our customers safely, reliably, and efficiently at the lowest cost.

1.2 About Union

Union is a major Canadian natural gas utility and has been providing natural gas services for over 100 years. Union serves about 1.4 million residential, commercial, and industrial customers in over 400 communities in northern, southwestern and eastern Ontario. Union's distribution service area is shown in Figure 1.1. Union also provides natural gas storage and transportation services for other utilities and energy market participants in Ontario, Quebec, and the United States (U.S.).

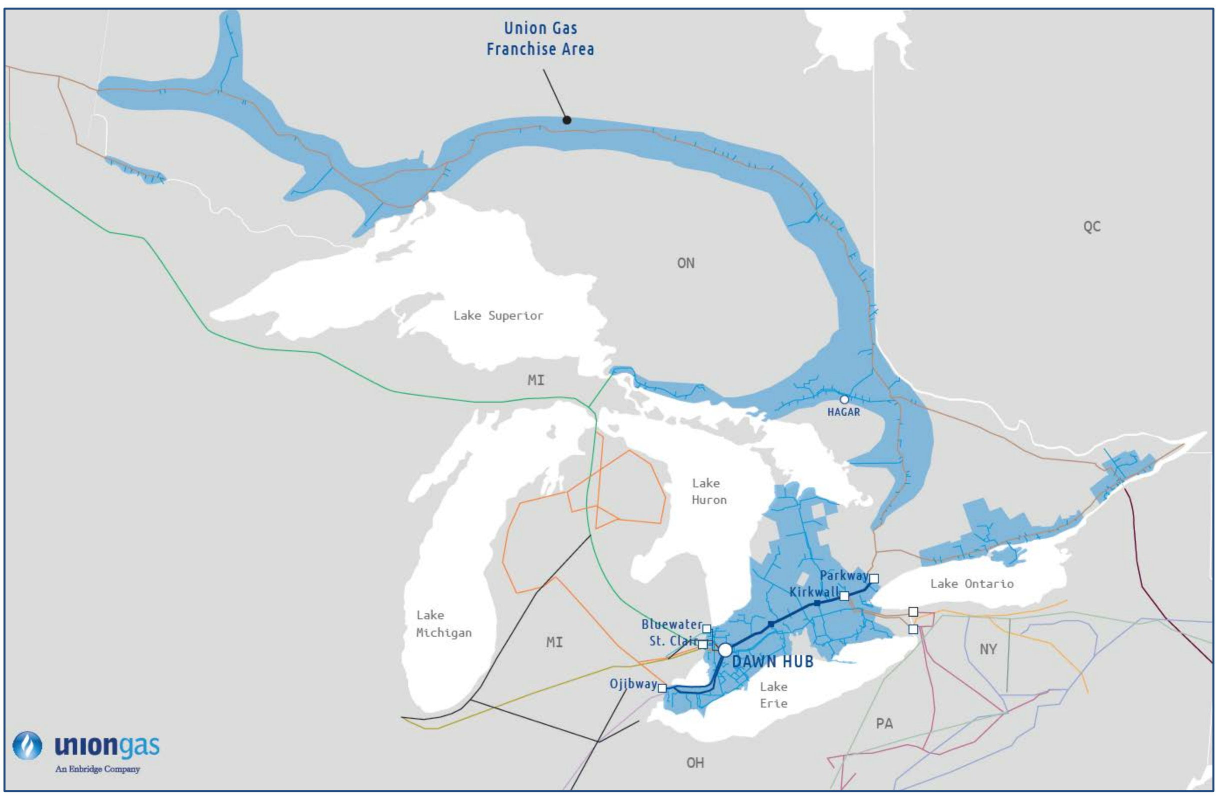


Figure 1.1: Union Franchise Area

1.3 Asset Base

Union has assets of approximately $8.2 billion and employs about 2,300 people.

Union's natural gas assets include over 70,000 km of distribution, transmission, and storage pipelines, over 2,800 system stations, about 1.4 million customer stations including meters, 4,760,000 10^3m^3 or 185 PJ of natural gas storage capacity, 760,000 International Standards Organization (ISO) horsepower of compression, and one liquefied natural gas facility.

Union's supporting assets include administration facilities, fleet vehicles, and information technology assets. The administration facilities include 82 administration buildings located across Ontario to support Union's functional business needs and activities, including the head office located in Chatham that is the workplace for over approximately 680 people. Union's fleet includes about 800 trucks and 50 cars for the field workforce plus trailers and equipment. The information technologies assets include 80 applications and technologies plus associated hardware that provide critical functionality to effectively run the business.

1.4 Current Operating Environment

New massive deposits of natural gas have been discovered in economically recoverable shale deposits near Ontario. This abundance of natural gas has resulted in natural gas prices today that are lower than they were a decade ago, with prices expected to remain economic well into the next decade. North American natural gas proven reserves are abundant and can meet forecasted demand for the next 150 years.

Communities served by natural gas use its availability and low cost as an important tool in their economic development. Many communities not served by natural gas are looking for service so that their constituents can enjoy the low cost, clean burning benefits of natural gas.

Natural gas is the cleanest burning conventional fuel producing almost no sulfur dioxide or particulate matter. Power generation by natural gas produces 45% less carbon dioxide compared to power generation by coal. Natural gas produces 25% less greenhouse gas emissions than diesel or gasoline for transportation needs. It is also the ideal low emission back up option when conditions are not optimal for solar and wind power generation.

Natural gas is also a safe energy choice. Stringent safety rules govern the production, transportation, storage, and usage of natural gas. Pipelines are the safest and most efficient mode of transporting energy.

1.5 Forecast Summary

Figure 1.2 illustrates the forecast of capital to meet growth needs and maintenance planning recommendations over the 10 year term of the Asset Management Plan. The major projects included in the maintenance plan include the Sudbury Lateral Replacement in 2018 and replacement of Dawn C compressor plant over the years 2023 and 2024. Impacts can be seen in the growth plan from major projects including

Community Expansion in 2018/2019, reinforcement of the Panhandle System in the years 2018 and 2024, and growth on the Sarnia Industrial Line System in 2023.

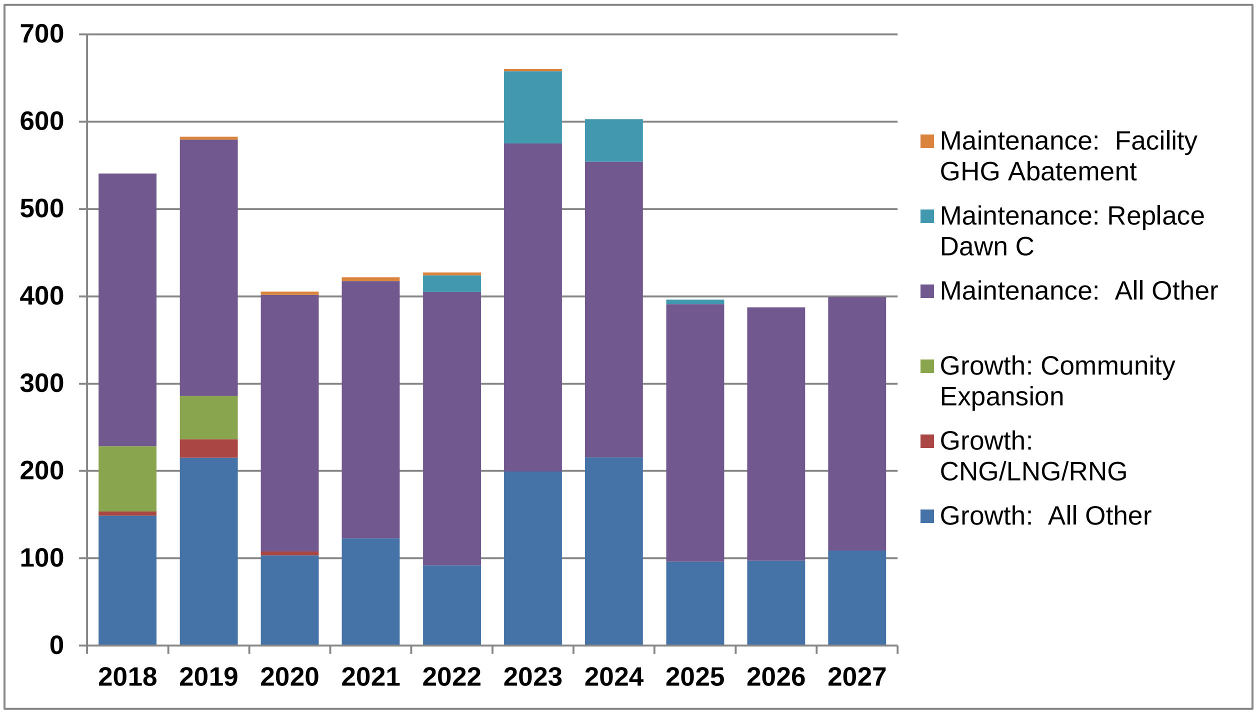


Figure 1.2: Asset Capital 10 Year Forecast (all $ in millions)

Figure 1.3 illustrates the Operations and Maintenance (O&M) forecast incremental from 2017 based on maintenance plans. These changes include new facility greenhouse gas (GHG) abatement, projects to support maintenance activities for major IT applications, increases to inspect pipelines at water crossings and bridge crossings beyond what has been done in the past, and an increased amount for inspections to support Integrity programs.

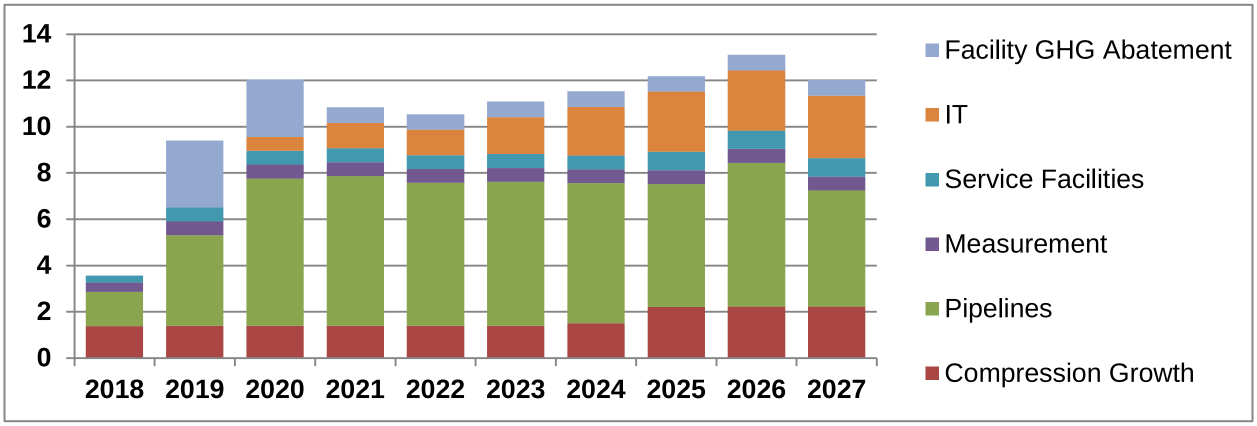


Figure 1.3: Incremental O&M 10 Year Forecast (all $ in millions, incremental to 2017)

2 Background and Objectives

2.1 Overview

Union is using comprehensive asset planning to identify and prioritize expenditures over a long term horizon to ensure funds are allocated appropriately to maintain the delivery of natural gas safely and reliably to our customers. This resulting Asset Management Plan documents the work and resources required to maintain and grow the natural gas and supporting assets to meet Union's corporate goals, specifically delivering operational excellence. This plan includes information about Union's asset planning processes and is a key input into Union's short and long term financial planning. In this plan, Union assets include Union assets and the assets of Union affiliates Market Hub Partners Canada L.P. and St. Clair Pipelines L.P.

Definitions of key terms used in this document can be found in Appendix A.

2.2 Company Background

Union is a major Canadian natural gas utility that provides energy delivery and related services to about 1.4 million residential, commercial, and industrial customers in over 400 communities in northern, southwestern and eastern Ontario. Its distribution service area extends throughout northern Ontario from the Manitoba border to the North Bay/Muskoka area, through southwestern Ontario from Windsor to just west of Toronto, and across eastern Ontario from Port Hope to Cornwall. Union also provides natural gas storage and transportation services for other utilities and energy market participants in Ontario, Quebec, and the U.S. Union'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. Union has assets of approximately $8.2 billion and about 2,300 employees.

Union's assets include small diameter pipe, meters, and regulators at homes in our franchise areas, transmission pipe up to nominal pipe size (NPS) 48 used to transport natural gas across Ontario, five main compressor plants including 20 storage compressors to move natural gas to and from our storage reservoirs and along the transmission pipelines, and a liquefied natural gas plant used to support peak shaving in one area of our company.

2.3 Asset Management

Union's Asset Management Program is an integrated program within the Union Gas Operations Management System (OMS). The purpose of the Asset Management Program is to ensure that Union is developing processes and procedures to optimally manage assets over their lifecycle. As indicated in Union's OMS Policy:

'Union Gas is committed to designing, constructing, operating and maintaining our assets with a focus on operational and personal safety, reliability, and in compliance with all legal and regulatory requirements. Leadership is dedicated to achieving performance that meets or exceeds the expectations of stakeholders.

Union Gas has adopted an integrated management system approach which strives to deliver on this commitment. This systematic management approach is documented in the organization's Operations Management System (OMS)'.

2.4 Asset Management Planning

The Asset Management Plan includes information about the addition of assets to meet customer needs and maintenance requirements to ensure ongoing safety and security of supply for Union customers. Growth includes adding assets to reinforce existing systems and to provide service to new customers. Growth is driven by increased in-franchise and ex-franchise demand as well as changes in the supply dynamics of natural gas. The process of determining maintenance requirements, referred to as Maintenance Planning in this Asset Management Plan, is completed for each asset based on asset health and compliance needs with a focus on delivering services reliably at the lowest lifecycle cost.

2.4.1 Growth Planning

Projects to accommodate new customers, to maintain adequate flow and pressure for all Union customers, and to meet storage and transportation needs of customers are planned by the Distribution, System, and Storage Planning groups. These projects include the installation of new main, reinforcement of existing mains as well as installation of new stations, and upgrades to existing stations that are a result of in-franchise or ex-franchise growth.

The Distribution Planning group make asset planning recommendations for distribution systems which generally are the pipeline and stations systems in regions throughout Union and include some of the transmission systems that supply these regions.

The System Planning group make asset planning recommendations for the three major transmission systems which include the Dawn Parkway System, the Panhandle System and the Sarnia Industrial Line System.

The Storage Planning group make asset planning recommendations for all underground storage facilities as well as for the Dawn Compressor Station.

2.4.2 Maintenance Planning

Work that will result in maintaining and extending the life of an asset, typically identified as maintenance, is included in the asset maintenance plan. This includes capital and O&M expenditures for projects ranging in complexity and scope, as well as a number of spend requirements to maintain tools and other support equipment.

Due to the complexity and variety of Union's assets, Union assets are broken down into asset classes as further explained in Section 3. Asset health requirements and maintenance plans are developed for each of Union's asset classes. Union has a number of programs in place to ensure continued reliability of each asset, including, but not limited to: asset integrity management programs, plant damage prevention programs, defined maintenance plans, and robust operational monitoring of our critical stations.

2.5 Continual Improvement

Union has followed a management system approach with the OMS since 2009. The OMS includes a number of components that drive continual improvement: measuring performance, driving improvement relative to peer companies in the natural gas industry, assessing key technical competencies, auditing processes and procedures, formal incident reporting and investigation, and monitoring and tracking corrective actions. Reviews of programs and the OMS framework are completed annually for effectiveness and are facilitated through the OMS governance.

Risk Management is an element of the OMS that is reviewed annually as part of the OMS framework review.

Asset related key performance indicators are monitored and reported annually. These include compressor reliability, natural gas outages, and third party line breaks.

Another way Union seeks 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 being an active member of subcommittees for the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems, being a member of Canadian Gas Association and American Gas Association technical committees, and participating in Canadian Gas Association and American Gas Association surveys and workshops.

Union uses audits to determine compliance and improve on processes and procedures through corrective and preventive actions. The audit strategy is reviewed through the OMS governance on a monthly and quarterly basis.

The following are examples of the internal audits that were conducted in 2016.

- Process audits were conducted on the Storage, Transmission & Operations maintenance job package processes and station as-built drawings process, and areas of improvement were identified.
- Audits were also conducted specific to the requirements of Union's Environmental Compliance Approval and to ensure compliance with Ontario Regulation 419 (Local Air Quality Regulation), A-5 Guideline – Atmospheric Emission from Combustion Turbines (installed after 1994) and the Noise Pollution Control Guidelines (NPC 205/206/300). Union was found to be in full compliance.
- The Measurement Accreditation Program was audited. The results were favourable and were confirmed through a successful Measurement Canada audit to maintain Accreditation.

The following are examples of external audits that were conducted in 2016.

- A high level assessment was completed to identify operational/Environment, Health & Safety (EHS) risk management improvement opportunities with a comprehensive evaluation of the areas known to contribute to organizational risk. The resulting report highlighted a consistent focus on risk-based decision making and strong operations leadership which translated to Union achieving the highest score ever given by this third party.

- An audit was conducted of Union's Pipeline Asset Integrity Management Program to the National Energy Board's Onshore Pipeline Regulations requirements. The results emphasized the effectiveness of Union's EHS and Integrity program.
- An audit of Union's Greenhouse Gas Emission Inventory was completed. Union achieved a positive verification that was well within the accuracy standard specified by the regulation.

In addition to audits like these, Union participates in American Gas Association peer reviews and will participate in the 2017 American Gas Association peer reviews with the focus on Damage Prevention and Quality Assurance.

3 Assets

3.1 Overview of Asset Classes

3.1.1 Introduction

Union has a network of natural gas assets that serve to receive, store, transport, and distribute natural gas. Assets illustrated in Figure 3.1 can be found at Union including underground storage, compression and dehydration, transmission and distribution pipelines, and the meters and regulator stations within our system and at our customer premises.

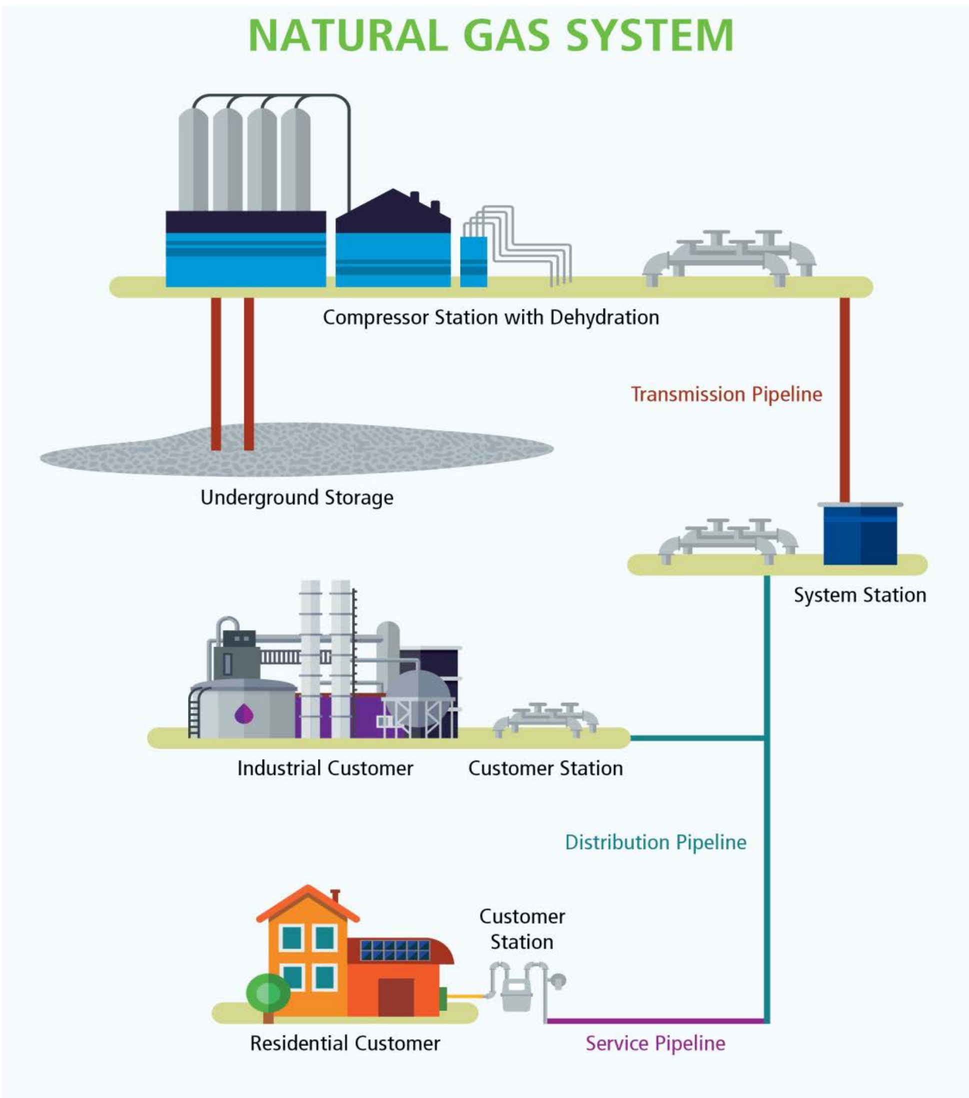


Figure 3.1: Components of a Natural Gas System

To optimize maintenance and growth strategies, natural gas carrying assets are grouped into seven asset categories and ten associated asset classes as summarized in Table 3.1. Additionally, there are three non-gas carrying asset classes that support general operations for Union: Fleet, Service Facilities, and Information Technology.

More detail about each asset class is summarized in Section 3.2.

Table 3.1: Asset Management Governance - Natural Gas Asset Classes

Asset Category	Asset Classes
Pipelines	• Pipelines Greater than or equal to (≥) 30% SMYS • Pipelines Less than (<) 30% SMYS
Stations	• System Stations • Customer Stations
Measurement	• Measurement
Utilization	• Utilization Equipment
Underground Storage	• Underground Storage
Compression and Dehydration Plant	• Compression • Dehydration Facilities
Liquefied Natural Gas	• Liquefied Natural Gas Facilities

3.1.2 Natural Gas Asset Management Governance

To ensure assets are managed consistently and in alignment with Union's OMS requirements, formal governance has been implemented. As part of the broader governance requirements, each asset class has a person who is accountable for

- the performance of the assets,
- the maintenance practices, including Standard Operating Practices, related to the asset class, and
- ensuring compliance to all applicable codes and regulations.

3.2 Asset Class Information

Each asset class contains unique properties that can be managed through similar programs and oversight. The following is a summary of the seven asset categories and ten associated asset classes identified above, as well as the three non-gas carrying asset classes considered supporting assets.

3.2.1 Natural Gas Asset Classes

3.2.1.1 Pipelines

3.2.1.1.1 **Pipelines ≥ 30% SMYS**

This asset class contains pipelines and piping components (such as valves and fittings) that operate at or above 30% of the Specified Minimum Yield Strength (SMYS) and all National Energy Board regulated lines. This class, which includes 2,970 km of pipeline systems, consists of the storage gathering system, Union's major transmission systems and the laterals connecting to the distribution networks, and the laterals feeding from the TransCanada pipeline system (Union's northern area) to the distribution systems and major customer stations. The majority of these pipelines have a Maximum Operating Pressure of 6160-6895 kPa and are ranging in diameter from NPS 4 to NPS 48.

National Energy Board regulated lines include the two NPS 12 Detroit River Crossing pipelines, the NPS 20 Bluewater pipeline, and the NPS 20 St. Clair pipeline. Although the two Detroit River Crossing pipelines operate at less than 30% SMYS, they are included in this class to ensure they have the attention and maintenance required of National Energy Board lines.

A large percentage of Union's pipelines ≥ 30% SMYS were installed over 45 years ago as evidenced by the following age profile.

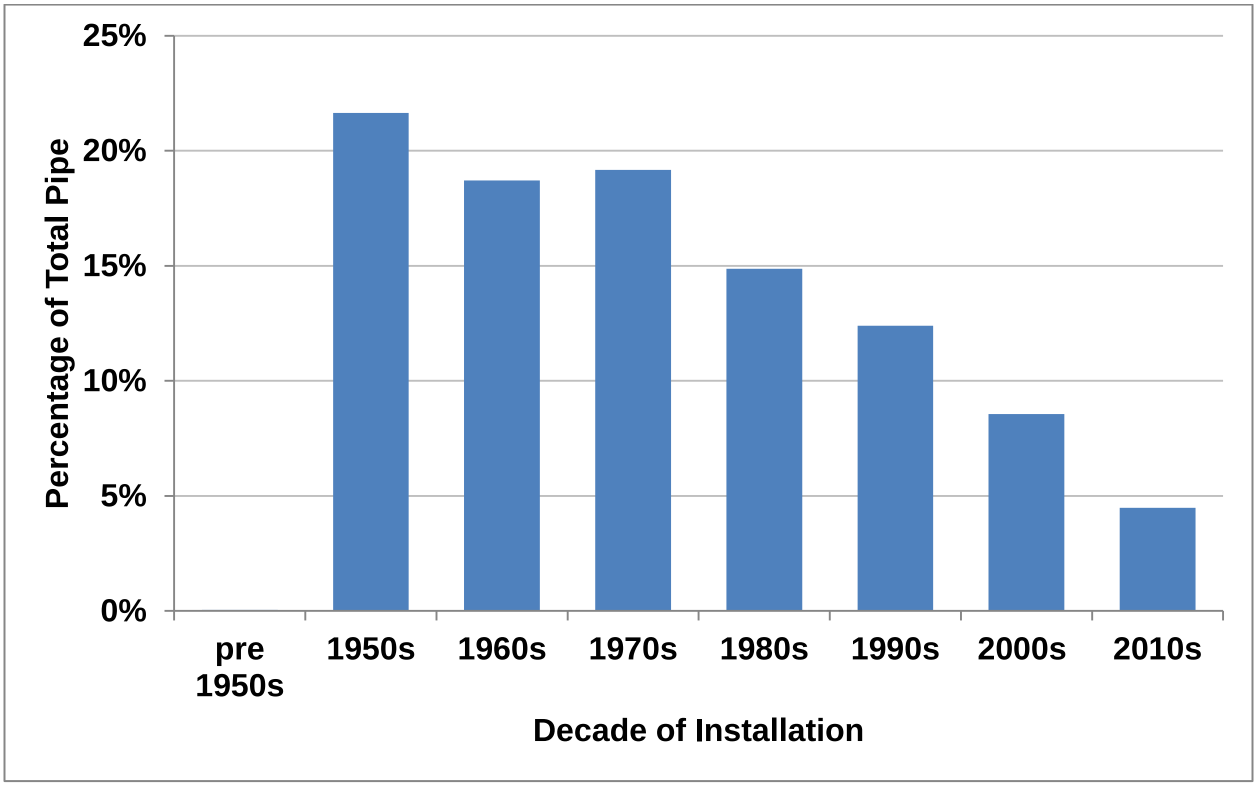


Figure 3.2: Percentage of total pipe by length versus decade of installation for pipelines ≥ 30% SMYS (Data used: December 31, 2016)

The major pipeline systems in this asset class are the Panhandle System, the Dawn Parkway System, and the Sarnia Industrial Line System.

The Panhandle System consists of 2 parallel pipelines: NPS 16 /20 and NPS 20 /36. The two NPS 12 Detroit River Crossing Pipelines connect the Panhandle Eastern Pipeline System to the Panhandle System and Dawn. This pipeline system which supplies in-franchise customer demands from Dawn to Windsor.

The Dawn Parkway System consists of 4 parallel pipelines: NPS 26, 34, 42, and 48. The NPS 26, 34 and 48 pipelines run the entire distance between Dawn and Parkway. The NPS 42 runs from Dawn to Kirkwall. A second NPS 48 was constructed between Hamilton and Milton.

The Dawn Parkway System is used to transport natural gas to in-franchise customers located east of Dawn and west of Mississauga, and for ex-franchise customers at Dawn Compressor Station, Kirkwall (Trans Canada Pipelines) and the Parkway/Parkway West Compressor Stations at the east end of Union South (Enbridge Gas Distribution, Gaz Métro Limited Partnership, utilities in the US Northeast and others).

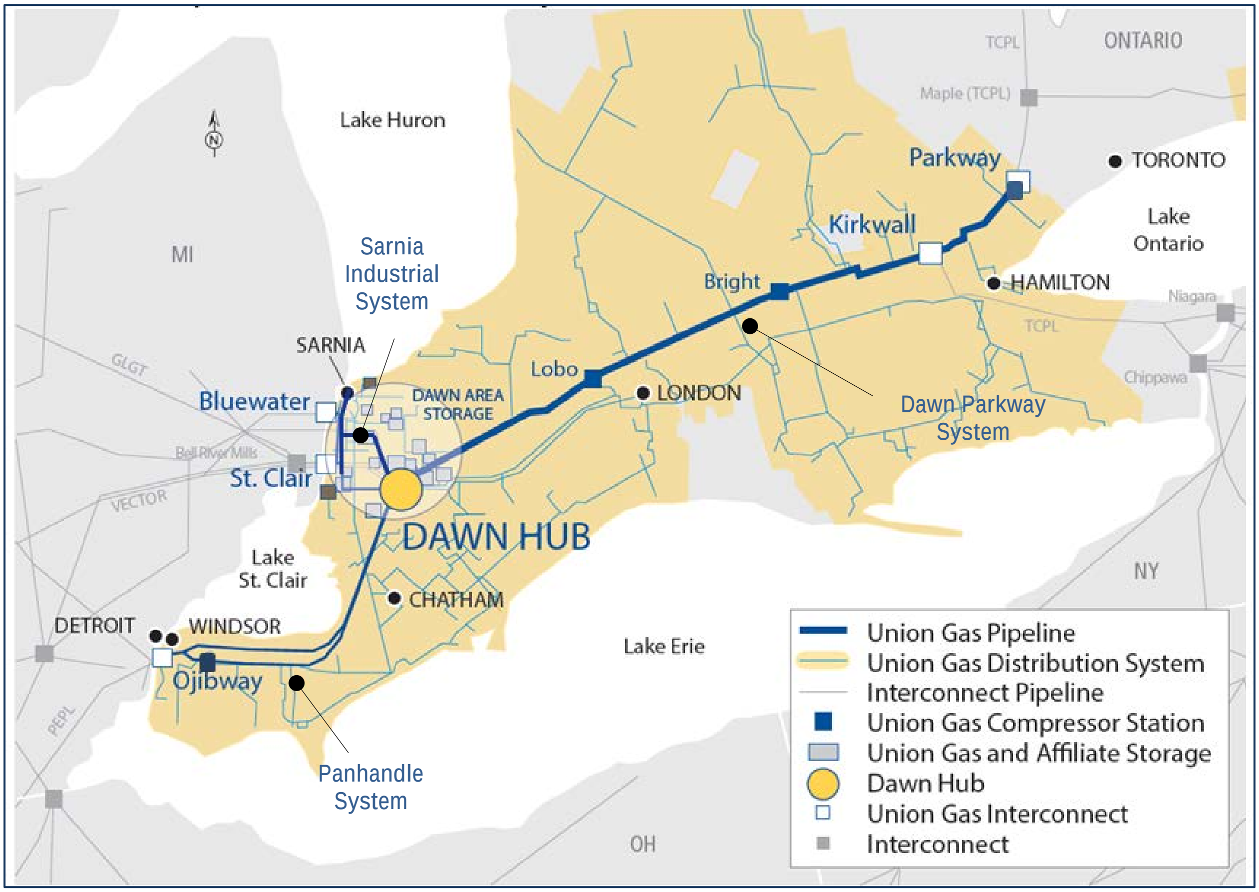


Figure 3.3: Panhandle, Dawn-Parkway and Sarnia Industrial Line Systems

Union's Sarnia Industrial Line System consists of a network of pipelines ranging from NPS 8 to NPS 20. The NPS 20 Bluewater Pipeline and the NPS 20 St. Clair Pipeline connect to the Sarnia Industrial Line System. This pipeline system services in-franchise customers in Sarnia and St. Clair Township and ex-franchise customers from St. Clair to Dawn and from Bluewater to Dawn.

Union's 2,970 km of pipelines ≥ 30% SMYS cover a large operating area, creating a variety of unique conditions, including:

- 65% of the pipelines operate at greater than 50% SMYS, none are greater than 72% SMYS
- 4% are in more densely populated areas
- 10% are in high consequence areas

NOTE: *A high consequence area is an area where a pipeline release would have greater consequence to health and safety or the environment*

3.2.1.1.2 **Pipelines < 30% SMYS**

This asset class includes pipelines, services, and piping components that operate below 30% of the Specified Minimum Yield Strength. These assets are used to transport natural gas within our distribution systems or to end use customers. This asset class includes 39,943 km of mains and associated valves and fittings. Of these mains, 52% are plastic and more than 85% operate at a pressure less than 700 kPa. This asset class also includes 1,326,000 services made up of 26,913 km of pipe and associated fittings. 70% of these services are plastic and 96% have an operating pressure less than 700 kPa. (All values are based upon December 31, 2015 data)

Although distribution networks have been in place for over 100 years, the overall system is relatively new, as evidenced by the graph below. Much of the older systems, particularly those that represented higher risk, have been replaced over time.

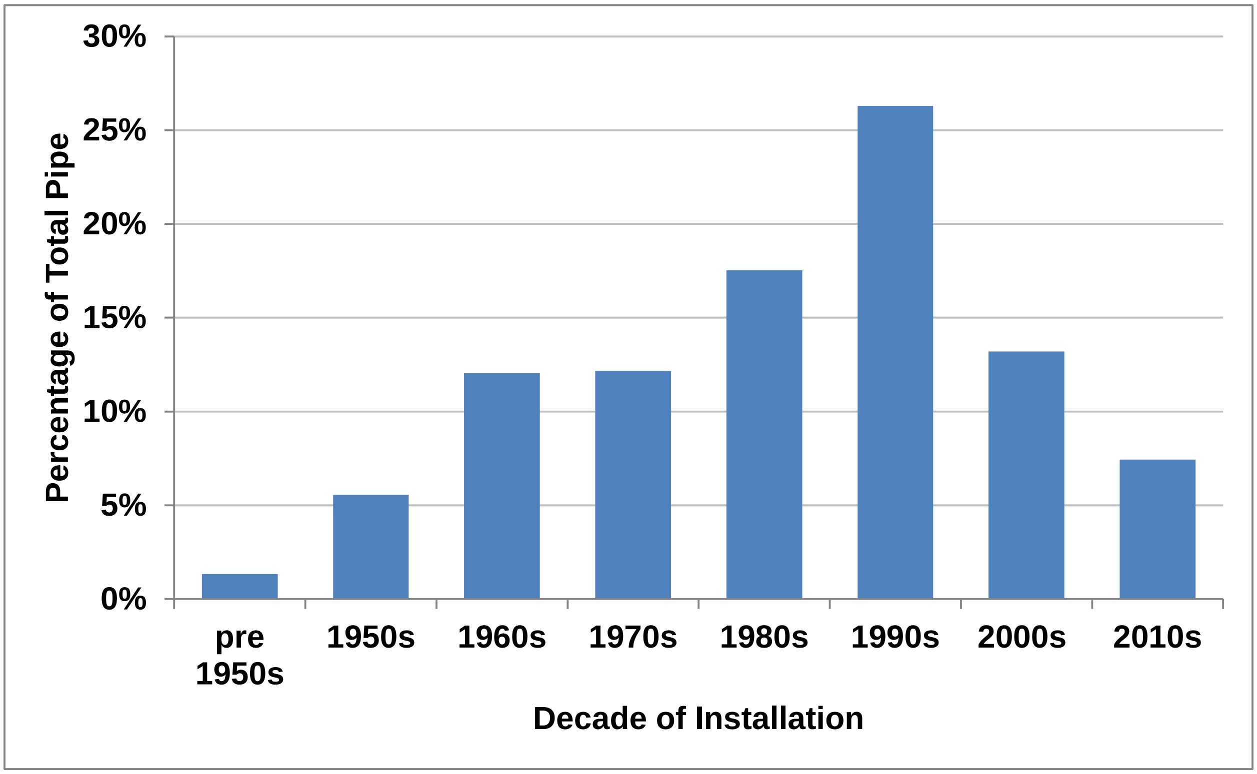


Figure 3.4: Percentage of total pipe by decade of installation for < 30% SMYS pipelines

3.2.1.2 Stations

3.2.1.2.1 System Stations

System stations are typically above grade facilities designed to reduce the operating pressure of natural gas pipeline systems through pressure control and over pressure protection. These facilities are used to transmit and/or distribute natural gas to reduced operating pressure pipeline systems which supply natural gas to cities and towns.

System station components consist of piping, meters, regulators, valves, filters, separators, heaters, odourant, controls, and in some cases, structures. System station components can vary greatly depending on the station's application and design complexity. At Union, system stations are broken down into subclasses which drive design and operating practices as well as inspection requirements. A summary of the system station subclasses can be found in Table 3.2.

3.2.1.2.2 Customer Stations

Customer Stations, similar to System Stations, are designed to deliver a specific volume of natural gas at a reduced delivery pressure from natural gas pipelines as requested and/or required by individual customers for end use consumption.

Typical delivery pressures can vary from 1.75 kPa to 1380 kPa or higher depending on individual customer needs. The pressure and volume requirements for customers are driven by the customers' natural gas fired equipment requirements.

Typical components of customer stations can vary greatly based on the size and operating requirements of a particular customer. The smallest of customer stations (meter sets) are typically composed of small diameter piping, a single regulator and meter, and a single shut off valve. Larger customer stations can be composed of filter/separators, multiple regulators and meters, large diameter piping and headers, electrical, controls and telemetry, natural gas heating, odourant injection systems, and multiple valves. Customer stations are broken down into subclasses which drive design and operating practices as well as inspection requirements. A summary of customer station subclasses can be found in Table 3.2.

Union's largest in-franchise customer station facilities typically supply natural gas to major electric power producers. The subclass A customer stations also feed natural gas to major steel mills, chemical plants, smelters, and other process based industrial plants.

Table 3.2: Inventory of System and Customer Stations

Station Subclass	Operating Parameters		Systems Station Inventory	Customer Station Inventory
	Maximum Inlet Pressure	Inlet Size		
Subclass A	Over 3,450 kPa	NPS 3 and over	280	100
	Any Pressure	NPS 8 and over		
Subclass B	Over 3,450 kPa	NPS 2	770	1,500
	3,450 kPa and Under	NPS 3 to NPS 6		
Subclass C	3,450 kPa and Under	NPS 2	1,930	11,800
	All Pressures	Less than NPS 2		
Residential	All	All		1,382,500
Total Number of Stations			2,980	1,395,900

3.2.1.3 Measurement

Measurement assets include a fully integrated family of devices that allow safe operation of the natural gas network, provide accurate and timely measurement, and monitor and control the flow of natural gas in real time. Measurement assets include the following subclasses:

- Natural Gas Meters
- Electronic Volume Correctors
- Odourization Systems
- Gas Monitoring and Control Systems

3.2.1.3.1 **Natural Gas Meters**

Natural gas meters are devices used in measuring the quantity of natural gas delivered. Meters can be further classified as custody transfer or non-custody transfer. The former are billing meters for gas purchased from suppliers or sold to customers and as such must meet the legal requirements of the Electricity and Gas Inspection Act. The latter are used for internal accounting of gas inventories.

Union uses a variety of gas meter types to fit different applications and requirements as outlined below.

Diaphragm Meters

Diaphragm meters use positive displacement technology and internal mechanical temperature compensation to calculate delivered natural gas volumes at base temperature and pressure.

The 200 class meter is the most common meter type in use.

The 400 class meters are used for commercial and large residential loads and have incrementally more capacity than a 200 class.

The 800/1000 class meters are used for large commercial, small industrial and estate residential loads.

Commercial Ultrasonic Meters

Commercial ultrasonic meters are used as a direct substitution for 800/1000 class diaphragm meters. They use inferential ultrasonic flow measurement and electronic temperature correction and consumption recording.

Rotary Meters

Rotary meters are positive displacement devices comprised of a meter body coupled with an electronic volume corrector. The two styles of rotary meters are temperature compensated and instrument drive. Rotary meters are used in commercial and industrial applications.

Turbine Meters

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 Union and other pipeline companies.

Large Ultrasonic Meters

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.

3.2.1.3.2 Electronic Volume Correctors

Rotary Temperature Compensated Modules

Rotary temperature compensation modules are directly attached to temperature compensated rotary meters. They correct meter volume to standard conditions based on temperature recorded at the meter.

Electronic Volume Integrators

Electronic volume integrators are directly attached to instrument drive rotary meters and turbine meters. They correct volume to standard conditions based on temperature and pressure recorded at the meter.

Automated Meter Reading (AMR)

AMR devices are installed on diaphragm, commercial ultrasonic, and temperature compensated rotary meters. These devices record and store meter consumption data after being corrected to standard units. They then transmit this information wirelessly to meter reading devices that upload the consumption to Union's billing system.

3.2.1.3.3 Odourization Systems

Natural gas in its basic state is generally odourless and can be difficult to detect if accidently released to the atmosphere. Natural gas is therefore odourized at major stations as required per code Canadian Standards Association Z662 – Oil and Gas Pipeline Systems to make the presence of natural gas easier to detect, to protect the public and to operate our assets safely.

3.2.1.3.4 Gas Monitoring and Control Systems

The natural gas monitoring and control system is comprised of field equipment for the Supervisory Control and Data Acquisition System for monitoring and control of natural gas flow and odourizing natural gas at large stations, custody measurement, and control of critical valves. This system is crucial to provide live natural gas measurement and operational information through the Supervisory Control and Data Acquisition System to various stakeholders.

The natural gas monitoring and control system is made up of RTUs (Bristol 3330/3310), which were installed from 1989 to 2006 with the majority installed between 1995 and 1999 in locations across our entire franchise. Communication devices are also included (satellite/cellular/radio modems), which were last upgraded between 2008 and 2010 in locations across our entire franchise.

3.2.1.4 Asset Inventory Statistics and Geographic Locations

The following table summarizes information about asset classes, major components, and their inventory.

Table 3.3: Measurement Assets and Inventories

Measurement Asset Subclass	Device Type & Inventory
Natural Gas Meters	• Diaphragm meters (1.4 million) • Rotary meters (17,500) • Turbine meters (600) • Ultrasonic meters - commercial (5,000) and interconnects (80)
Electronic Volume Correctors	• Electronic rotary modules (16,000) • Electronic Volume Integrators (2,000) • AMR Devices (73,000)
Odourization Systems (Bypass & Injection)	• MOIS injection cabinets • Odourant injection tanks (approximately 71 sites) • Odourant bypass tanks (approximately 148 sites) • Environmental deodourizer units(at each injection site) • Level instrumentation(one at each odourant site)
Natural Gas Monitoring & Control Systems	• RTU (400) • Communication equipment(cellular, satellite, radio) – (300) • Transmitters (1,500) • Power supplies etc.

3.2.1.5 Utilization

This asset class consists of the pipes, fittings, and equipment located downstream of the meter. As the components of this asset class are not owned by Union, the decisions about additions, maintenance and renewal are not made by Union and are not a part of this report. As the supplier of natural gas, Union plays a part in ensuring these systems are safe through inspections during customer visits. Union has a statutory obligation to inspect customer owned equipment at the time of initial activation and when natural gas supply is interrupted for any reason as per the Ontario Regulation 212/01 “Gaseous Fuels”.

3.2.1.6 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. The facilities are usually natural geological reservoirs such as depleted oil or natural gas fields sealed on the top by an impermeable cap rock.

Natural gas demand for Union’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 Union's customers.

Union (including Union Affiliates) stores natural gas in 23 company owned storage reservoirs and four third party storage reservoirs. The storage capability of each reservoir is determined by the reservoir's maximum operating pressure, the cushion pressure, and the size of the pool. Capacities in the 23 storage reservoirs range from 31,000 10^3m^3 (1.2 PJ) to 746,700 10^3m^3 (29.0 PJ). Through Union's reservoirs, Union has a storage capacity of 4,760,000, 10^3m^3 (185 PJ) with cushion natural gas totaling 1,640,000 10^3m^3 (62 PJ).

Each pool is protected by a Designated Storage Area as determined by the Ontario Energy Board (Board) to protect the pool from exploratory drilling. The land above each pool is leased from the landowners with storage leases. There are currently over 10,000 acres leased by Union for storage.

There are a total of 227 wells operated by Union to support the movement of natural gas into and out of the underground reservoirs. The 227 wells include 162 injection withdrawal wells, 64 observation wells, and one maintenance well.

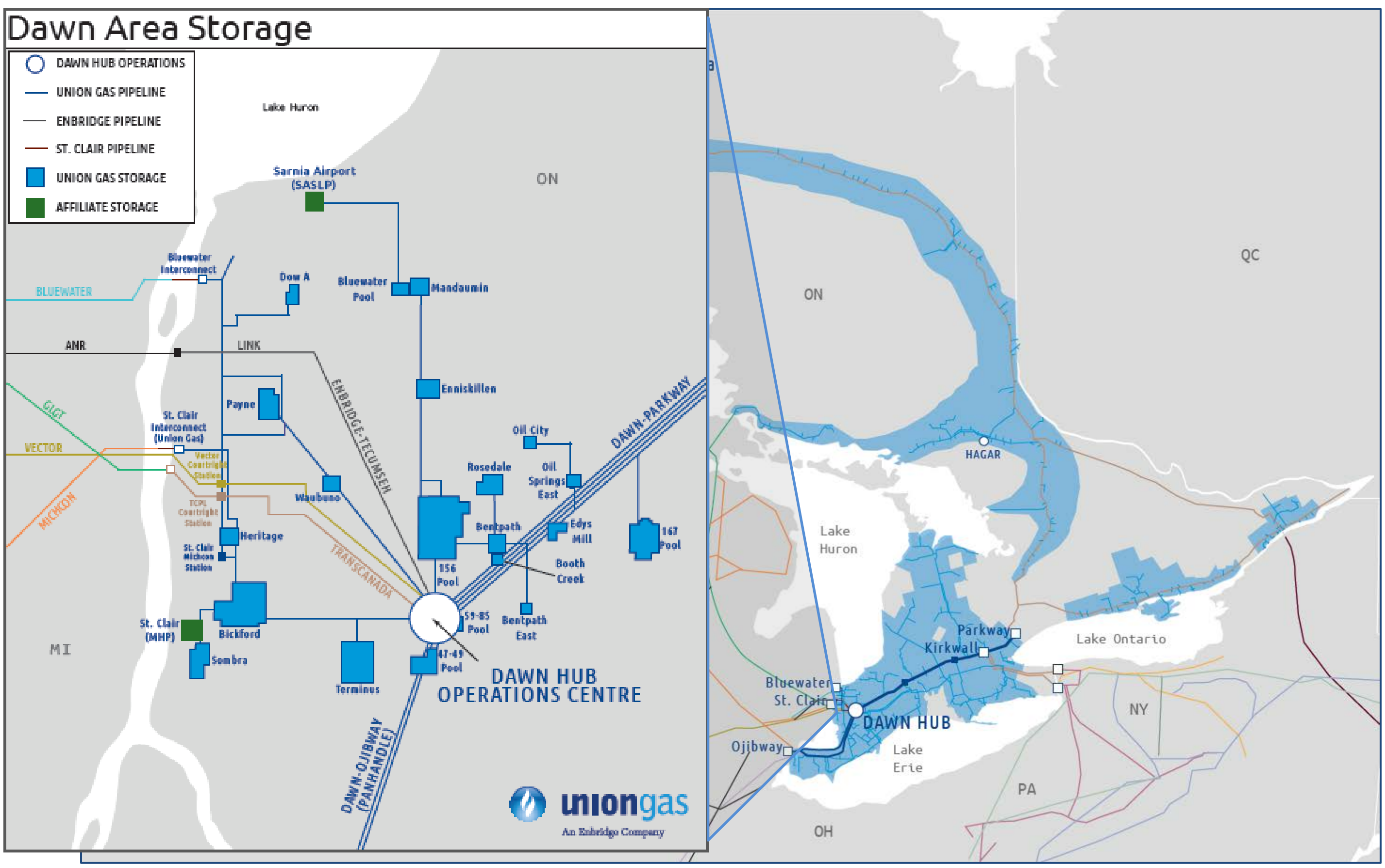


Figure 3.5: Natural Gas storage pools (Lambton County)

3.2.1.7 Compression

Union uses compressors to move natural gas throughout the natural gas system. Compressors used to compress natural gas into a transmission pipeline are designed for high flow as opposed to a large pressure increase. Compressors used to move gas into and out of underground storage are designed to provide a significant pressure increase at the expense of flow.

Dehydration facilities are also included in the compression asset category. Dehydration facilities are used to remove moisture from the natural gas to ensure the natural gas entering the transmission system meets the contractual standard of moisture content and to avoid operational problems related to high moisture content. The dehydration process involves contact between the natural gas stream and liquid glycol stream to remove excessive moisture from the natural gas stream. The resultant output is dry pipeline and customer quality natural gas.

Union's main compressors are located at the Dawn Compressor Station. Dawn is the site of the largest underground storage facility in Canada and is a key natural gas trading hub with interconnections to 10 major transmission pipeline systems including Vector, TransCanada Pipelines, Tecumseh Gas Storage, and Panhandle Eastern through the Union Panhandle transmission system. The Dawn Compressor Station consists of nine compressors with a combined total of 253,150 ISO horsepower, a major natural gas dehydration plant and associated piping, large diameter valves, electrical components and other equipment required to support the operation of this station.

There are four major compressor stations located along the Dawn Parkway System located at Lobo, Bright, Parkway West, and Parkway and can be seen if Figure 3.3. These stations consist of a total of 13 compressors with a combined total of 432,400 ISO horsepower.

Union maintains loss of critical unit coverage at Dawn and at the compressor stations located along the Dawn Parkway System. Loss of critical unit coverage is required to provide compression to continue to provide services to customers if an unplanned compressor outage of a compressor that would create the greatest loss of system capacity if it failed on a Design Day.

Union has many other compressor stations located around the franchise including compressors located at underground storage facilities and in remote geographic areas.

Table 3.4: Compression Inventory

Location	Inventory	General Notes
Dawn Compressor Station	9 Compressors 1 Dehydration plant	Interconnects with pipelines from a number of other companies and Union's storage system. Provides supply to the Union transmission systems and loss of critical unit coverage for the Dawn Parkway System.
Lobo Compressor Station	5 compressors	Supports gas transmission from London towards Woodstock on the Dawn-Parkway system. It includes the current loss of critical unit coverage for the Dawn Parkway System.
Bright Compressor Station	4 compressors	Supports gas transmission from Woodstock towards Toronto (Parkway) on the Dawn-Parkway system
Parkway Compressor Station	2 compressors	Acts as a custody transfer station to Enbridge and TransCanada Pipelines and provides required delivery pressure to TCPL
Parkway West Compressor Station	2 compressors	Acts as custody transfer station to Enbridge and TransCanada Pipelines and provides required delivery pressure to TCPL as well as loss of critical unit compressor for Parkway.
Sandwich Compressor Station	1 compressor	Supports movement of gas from the Panhandle Eastern Pipeline system towards Dawn
Hagar Liquefied Natural Gas Station	2 compressors	Supports the Sudbury System during peak periods, provides additional compression as required to maintain pressure.
Iroquois Falls Compressor Station	1 compressor	Supports required delivery pressure for industrial plant in Iroquois Falls
Remote Storage Pool Compressor Stations	14 compressors	Supports storage facilities

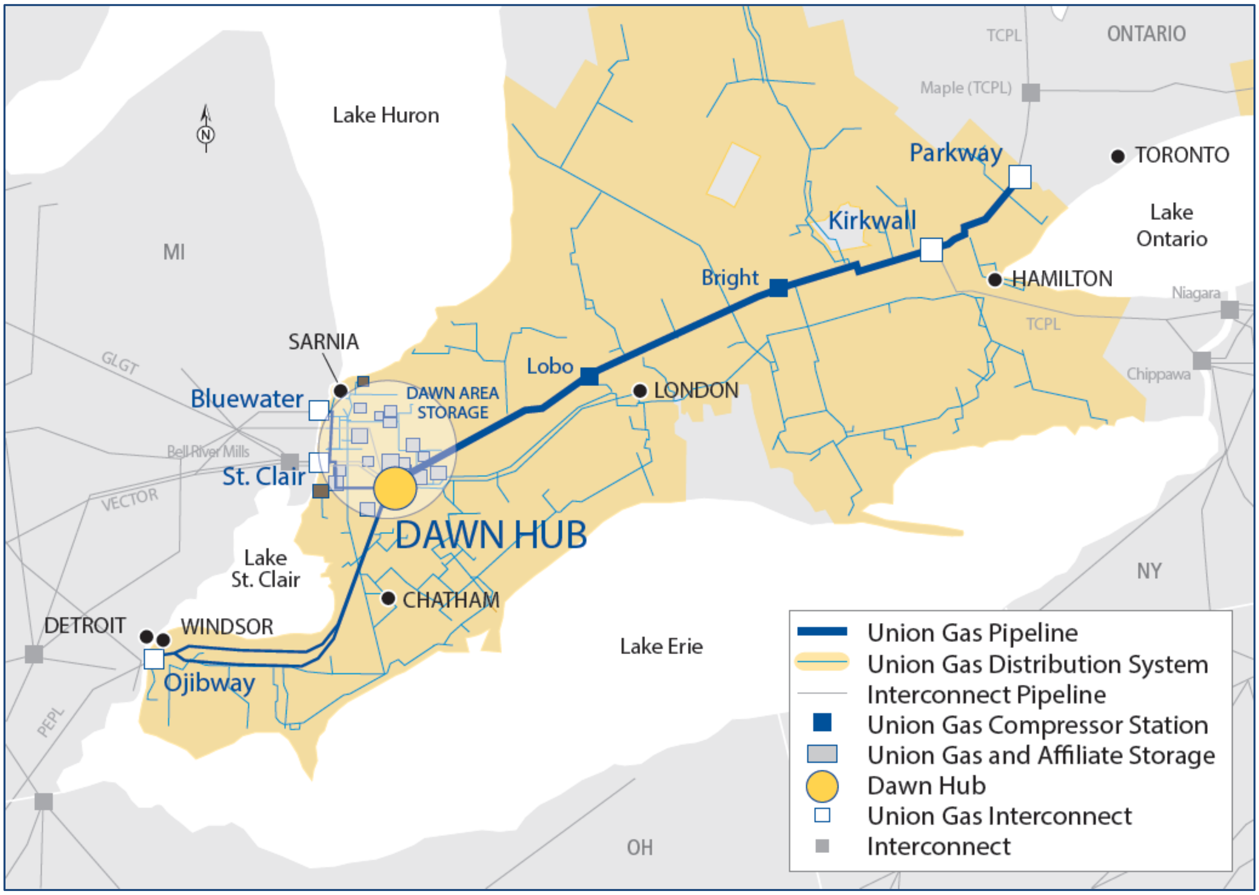


Figure 3.6: Overview of storage and transmission system showing major compressor plants

3.2.1.8 Liquefied Natural Gas (LNG)

Union operates one LNG facility, Hagar, located near Sudbury Ontario, which has been in operation since 1968. Union's Sudbury system is within the TransCanada Pipeline delivery area known as Union Northern Delivery Area. The Hagar facility is interconnected with Union's Sudbury Lateral pipeline system.

As an integrated storage and transmission system operator Union requires the capacity to support the integrity of the system as a whole and the provision of service to all customers. This facility with stored liquefied natural gas provides reserve capacity and allows for the operational balance necessary to manage all of the services Union offers. It ensures reliable supply through Union's storage, transmission, and distribution systems during peak periods.

The Hagar LNG plant is used to support the Sudbury area during peak periods, supply shortfalls, and unplanned pressure drops or outages. As an example, Hagar's LNG was used for this purpose on February 19, 2011, when TransCanada Pipeline experienced a pipeline rupture, fire, and explosion near Beardmore, Ontario.

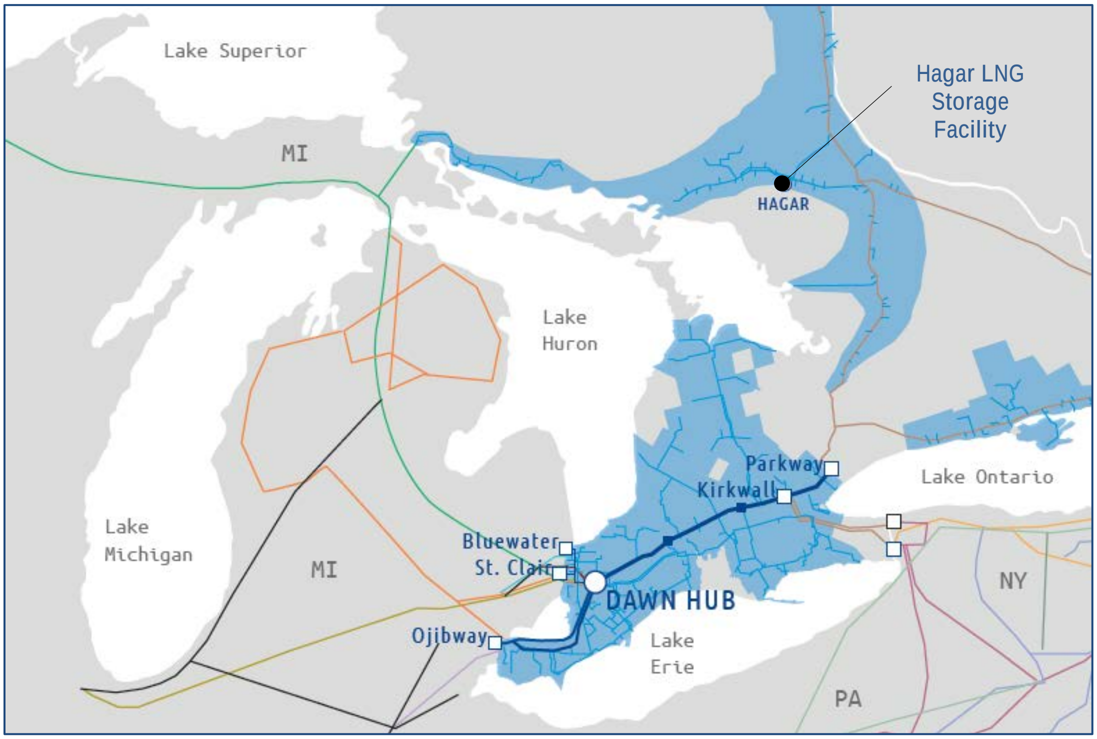


Figure 3.7: Hagar LNG Plant Location

3.2.2 Supporting Asset Classes

3.2.2.1 Service Facilities

Union manages 82 service facilities that include 63 owned and 19 leased facilities. The service facilities are located across Ontario from Windsor to Kingston to Keewatin and support Union's functional business needs and activities. Service facilities range in size from small, 100 square feet, to large, greater than 100,000 square feet, and equal 1,245,291 square feet in total of building space managed.

The service facilities' usages vary within the portfolio dependent on functional needs of the business, and can include meeting and offices spaces, operations services spaces, training spaces, and centralized operations distribution warehouses. The assets within these facilities will also vary depending on their usage.

The office spaces include conference and meeting rooms, enclosed individual offices and open offices with workstations, control rooms, business centres, reception areas, supporting common areas, and building service spaces. The operations service spaces include welding shops, service material storage, meter shops, fabrication shops, and laboratories. The training spaces range from training rooms to training facilities consisting of classrooms and training labs and fields.

3.2.2.1.1 Service Facilities Function

Union Head Office and supporting Chatham locations

Union's Head Office facility is located at 50 Keil Drive North, Chatham, Ontario. The facility includes three buildings totaling 193,533 sq. ft. on a 15.3 acre river side property. The three buildings include the powerhouse, the print shop, and the main building. The main building is made up of a three level 'old' section at the front and a 'link' in the middle that were constructed in 1966, as well as a six level 'tower' at the back that was added in 1976. The main building houses company leadership and support/service offices, employee and building services, cafeteria, meeting room and common space. Also occupied in the main building is the critical Natural Gas Control room. Approximately 680 employees work in Head Office.

Figure 3.8: Union Head Office, 50 Keil Drive North, Main Building Front

Other service facilities in Chatham area include four leased spaces to support overflow from Head Office, a space used for a technical lab, the Chatham Airport hangar that is used to support corporate Head Office travel requirements, and an Information Technology Centre that is used to accommodate approximately 200 employees.

District Offices

Union has 12 main administrative offices to service geographic areas called Districts, as well as a number of smaller regional offices and service centres that typically consist of a small office, service shop, and storage area. A listing of these service facilities can be found in Appendix E.

Compressor and Storage Support

Union has administration offices, service, and warehouse buildings, unoccupied Heritage buildings, Dawn sewage lagoon, and speciality property only sites with garden or animal habitats to support the compressor and storage operating groups. A listing of these service facilities can be found in Appendix E.

Regulatory Offices

Union leases three office locations to support regulatory/government business needs. A listing of these service facilities can be found in Appendix E.

Property Only

Union has four properties that do not have buildings. A listing of these service facilities can be found in Appendix E.

3.2.2.2 Fleet

Union owns approximately 1,275 vehicles, trailers, and equipment across Ontario from Windsor to Cornwall to Kenora to support Union's operational business needs. These assets include the vehicles listed in Table 3.5 plus 300 pieces of equipment and 175 trailers.

The vehicles, equipment, and trailers can vary dependent on the operational needs. Vehicles are sub-divided further into heavy, medium, and light vehicles.

Table 3.5: Union Fleet Vehicles

Vehicle	Example	Inventory
Cars	Ford Focus/Escape	50
Light Trucks	Vans, Pick-ups, USR1 Truck	500
Medium Trucks	USR2 & USR3 Trucks, Cube vans etc.	207
Heavy Trucks	Dump Trucks	43

3.2.2.3 Information Technology

3.2.2.3.1 **Information Technology Applications**

Information Technology (IT) applications include 16 key IT applications that provide critical functionality to Union employees and customers by contributing to the support and growth of our natural gas storage, transmission, and distribution business. Key IT applications also rely on ancillary systems that have been added over time to provide additional functionality as the business needs change and grow. There are an additional 64 smaller IT applications that support specific functional business needs. The IT applications can be classified as Commercial-off-the-Shelf (COTS), internally developed solutions, or cloud services. The age range of the internally developed solutions can extend out as far as 20 years before a lifecycle replacement/significant upgrade occurs. Technology upgrades and enhancements may occur regularly to internally developed solutions. The age range of the COTS applications extends out as far as 15 years;

however, the majority are within a 10 year range and rely on the vendor to maintain support. Lifecycle activities are based on risk factors identified for each application.

3.2.2.3.2 IT Technologies

The IT technologies asset class contains nine key technologies that are used within IT and are categorized as application integration systems, business intelligence systems, and database systems. Application integration systems allow the interconnection of processes and exchange of data among different business applications. Business intelligence systems allow business data to be queried, reported, and analyzed from our application systems to aid in corporate strategy planning and decision-making. Database systems provide the back end relational database technologies for storage of business data, as well as related client software to allow applications to connect to these databases.

The age range of the all of the IT technologies extends to 20 years. However, plans are in place to decommission older IT technologies as more current technologies are available.

3.2.2.3.3 Hardware

Hardware includes general hardware used to support the entire business as well as specialized hardware specific to an application or area of the business. General hardware includes workstations, networks, servers, and security. Workstations include laptops, desktops, monitors and accessories, printers, and plotters. Networks consist of routers, switches, hubs, firewalls, devices required to maintain voice communication and video conferencing networks, as well as patch panels cabling systems that link internal local area networks to high-speed data circuits. Servers consist of the devices that operate Union's applications and store data. Security involves the protection of control systems, business applications, computer infrastructure, and data networks.

Specialized hardware products are required to support specific business needs and include meter reading equipment, call centre network devices, and other communication devices that allow work to be completed in remote areas of the franchise as well as maintain the safety of field employees and equipment. The lifespan of hardware assets typically ranges between 4 to 7 years depending on the device. The devices within each group vary in age. A portion of all the hardware assets are upgraded each year to ensure ongoing operational reliability.

4 Growth Planning

4.1 Growth – Overview

In-franchise growth at Union is defined as increased natural gas peak demand in the franchise areas of Union.

Ex-franchise growth is the increased storage and transportation needs of customers primarily outside the franchise who provide or require natural gas services in Ontario, Quebec, and major U.S. natural gas consuming areas like the U.S. Northeast.

4.2 Asset Growth – In-Franchise

In-franchise growth is driven by a combination of adding new general service or contract rate customers and changes in the peak demand of general service and contract rate customers. The primary driver for growth is the value that natural gas provides to residential, commercial, agricultural, and industrial customers.

Union records indicate that the total annual average use per customer has been declining since the early 1990s. This trend is expected to continue due to energy efficiency related activities, Demand Side Management (DSM) programs, and the potential impact of Cap-and-Trade initiatives.

While annual average use per customer is decreasing over time, the Design Day Demand, which is the total average daily demand and peak hourly demand at the design weather condition, is increasing over time. The Design Day is the coldest potential winter day in our franchise.

General service growth is comprised of new residential housing, commercial customer additions, small industrial customer additions as well as customers converting to natural gas usage. Customer growth in the general service market mimics the population growth in the franchise. Commercial and industrial customer growth is typically a proportion of residential growth averaging one commercial/industrial attachment for every nine residential attachments.

Growth in the contract rate markets tend to be driven by a combination of population growth in the franchise as well as broad economic drivers. Typically, growth in institutional markets is driven by community growth that spurs the need for new and expanding social services such as hospitals and universities. Natural gas demand is also increasing in these segments with the adoption of combined heat and power applications as a way to economize on their electricity costs.

The industrial contract rate market growth is driven by economic and investment factors such as exchange rates, tax rates, alternate fuel costs, cost of electricity, and proximity to markets.

The greenhouse contract rate market continues to grow. Natural gas is the fuel of choice for these enterprises and growth in the greenhouse market shows no signs of slowing down.

Future growth in the industrial rate contract market may come from chemical and mining segments. Any future contract rate projects are subject to the economic tests identified in EBO 188.

Conversely, the power generation contract market has seen a decline from customers not renewing contracts. This has been partially offset by the TransCanada Energy's Napanee plant to be in commercial operations in early 2018. As the province's nuclear refurbishment plan is executed, additional generation may be required as various nuclear plants are taken out of service for major maintenance. However, it is not certain at this time whether this need would be met with natural gas fired generation since the Independent Electricity System Operator has indicated they are agnostic with respect to generation fuel type.

Growth in design day consumption has been modest in Union's franchise area. Increases in general service demand follows the population growth. A forecast of annual consumption and the number of customers can be found in Table 4.1. These projected growth figures, plus a forecast of contract growth based on historical contract growth, were used to create the forecasts in this plan.

Table 4.1: Forecast of Consumption and Customers

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Consumption ($10^6 m^3$)	13,064	13,199	13,142	13,167	14,124	14,050	13,873	13,850	14,631	14,524
Customers (in 1,000's)	1,497	1,517	1,536	1,554	1,572	1,590	1,608	1,625	1,644	1,661

4.3 Asset Growth – Ex-Franchise

Growth in the ex-franchise storage and transmission business is driven by economic factors such as exchange rates, interest rates and gross domestic product, but the primary driver relates to changing North American natural gas market fundamentals such as demand and supply, natural gas prices, natural gas basis differentials (price differential between location), and North American wide infrastructure projects.

The major contributing factor to Union's recent infrastructure growth relates to the growth in natural gas production from the Marcellus and Utica shale basins which are within 300 km of Ontario and the Dawn Hub. As a result, the flow of natural gas on the Canadian and U.S. pipeline grid is changing and evolving at rapid pace.

Market participants in Ontario, Québec, and the U.S. Northeast have been restructuring their natural gas supply portfolios since the mid 2000s, purchasing less Western Canadian Sedimentary Basin natural gas supply and more supply from production basins and liquid market centres like the Dawn Hub which is located closer to their end-use markets. As a result, Union's customers have increased short haul transportation capacity easterly from the Dawn Hub on the Dawn Parkway System and decreased long haul transportation from the Western Canadian Sedimentary Basin.

Although difficult to forecast, going forward Union expects further growth along the Dawn Parkway System driven by further long haul to short haul transportation restructuring, natural gas fired generation due to Ontario's nuclear refurbishment plan when executed, and further growth in the U.S. Northeast.

4.4 Asset Planning

Asset Planning for the natural gas assets is conducted by three groups aligned with the asset classes defined in Section 3.

4.4.1 Distribution Growth

Union's Distribution Planning group is accountable for making asset planning recommendations with regard to the sizing of mains, services, and station capacities in the Union franchise distribution systems. The distribution systems are designed to ensure the appropriate infrastructure is in place to supply natural gas to customers within the many towns and cities across the franchise. This is accomplished through the use of hydraulic modelling techniques.

Distribution Planning designs systems to meet peak hourly consumption to ensure there are no outages on the Design Day. Metered data is gathered and analyzed each year to calculate demand assumptions used for system design. Although annual consumption has been decreasing year over year, Union has not seen a decrease in peak hourly consumption.

The Facilities Business Plan (FBP) is an internal planning process used by Union for the identification of reinforcement facilities required to support forecasted growth over a specific geographic area. The FBP is developed for a geographic study area which provides an overall business case for the long range system expansion for the area. Union's franchise area has been divided into a number of specific FBP study areas based on operational areas, pipeline system configuration, and geographical features. FBPs provide a complete analysis of the study area based on a 10 year customer forecast, called the FBP forecast. Based on the FBP forecast, future facilities, both new and reinforcement, can be identified, economically evaluated, optimized, and scheduled to meet the future growth demands on the system.

The advantages of this FBP long range planning approach can be summarized as follows:

- Through the identification of future growth areas, Union can be more responsive to customer needs.
- Optimum, least cost facilities can be identified to service the growth.
- Long-term security of supply to the overall system can be achieved.

The timing of the facilities is based on current customer attachments and demand forecasts which determine the need for additional facilities. Union updates each FBP as required to monitor the development of the system and to determine if the plan should be modified in any way.

It is Union's objective to provide adequate capacity to serve both current customers and new customers being added to the system. The system will be continuously monitored to better determine when and what reinforcement will be needed to keep the system above the required minimum pressure to serve our customers.

Figure 4.1 shows an example of an FBP map depicting areas of growth within an FBP study area.

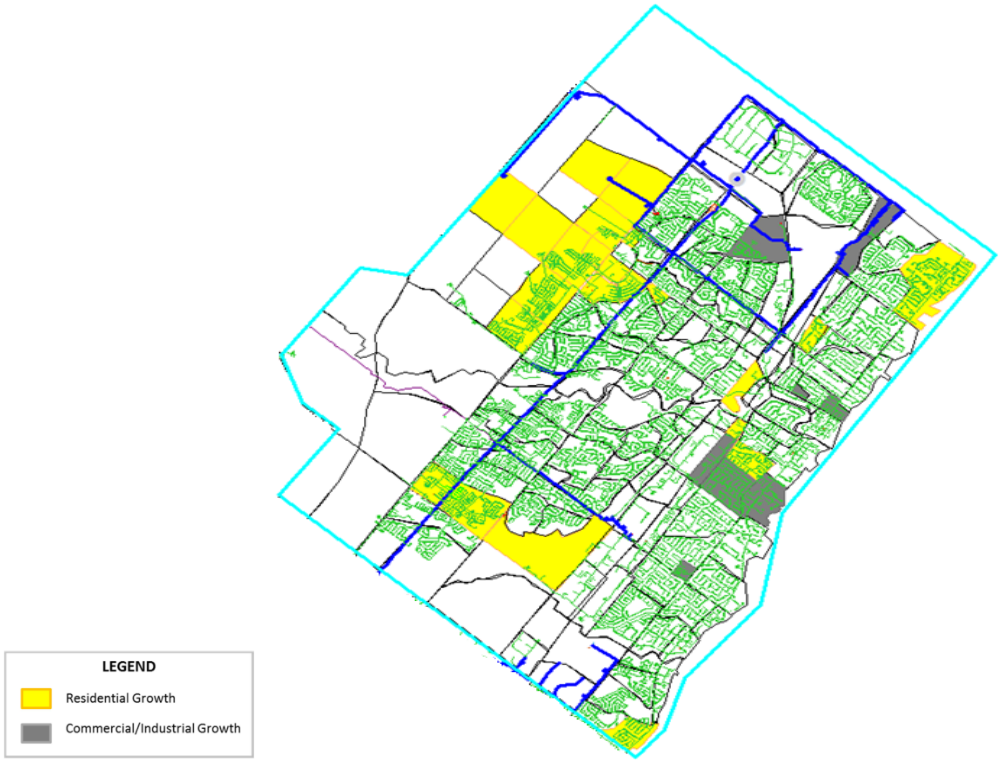


Figure 4.1: Example of an FBP Map Showing Residential and Commercial/Industrial Growth

4.4.1.1 Distribution Growth Forecasts

Table 4.2: Distribution Planning 10 Year Growth Summary (all $ in millions)

Project/Program/ Portfolio	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
General Customer Growth	75.4	87.2	76.8	78.1	79.6	83.3	85.1	84.0	87.8	87.0	**824.3**
Distribution Reinforcement	8.6	18.4	10.2	3.9	4.1	10.1	1.7	7.2	3.8	5.9	**73.9**
Transmission Reinforcement	11.9	15.5	12.5	6.2	0.1		32.1		5.7	16.2	**100.2**
Community Expansion	74.6	49.4									**124.0**
Distribution Planning Total	**170.5**	**170.4**	**99.5**	**88.2**	**83.7**	**93.4**	**118.9**	**91.2**	**97.4**	**109.0**	**1122.4**

4.4.1.2 Summary of Distribution Growth

General Customer Growth

General Growth is the forecast to attach new general service customers and new contract rate customers in the distribution systems and is based on the forecasts provided in Table 4.1.

Reinforcement Projects

Reinforcement includes the reinforcement projects identified through the FBP processes. These projects are important to meet the forecasted growth and will ensure Union is able to serve and satisfy those customers.

Table 4.3 summarizes the distribution and transmission reinforcement projects greater than $5 million forecasted by Distribution Planning. The distribution projects will reinforce systems used to distribute natural gas to current and new customers. The transmission projects will reinforce major transmission lines, such as pipelines, compressor equipment, measurement, and regulation.

Table 4.3: Distribution Planning Reinforcement Projects Greater than $5 Million. (all $ in millions)

Project/Program/ Portfolio	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
Distribution Reinforcement											
Parry Sound Reinforcement	0.3	12.8					12.0				**25.0**
Sudbury Area Reinforcement									5.7		**5.7**
Transmission Reinforcement											
Brantford - Eastern Transmission Reinforcement (Oxford Reinforcement)	6.7										**6.7**
Owen Sound Reinforcement Phase 4	4.0	15.0									**19.0**
Stratford Reinforcement			12.5				6.0			16.2	**34.7**
Guelph Reinforcement				6.2							**6.2**
Dunnville Line Reinforcement							11.0				**11.0**

4.4.1.2.1 Summary of Distribution Reinforcement Projects Greater than $5 Million

Parry Sound Reinforcement

Reinforcement in this area is required in 2019 and again in 2024 to maintain adequate capacity in this system. Commercial growth has been higher than historical and this set of projects will accommodate identified residential growth as well as the newly established industrial park in the area.

Sudbury Area Reinforcement

This project is Phase 2 of the original project completed in 2017 to reinforce between the towns of Frood and Azilda. This proposed 2026 project accounts for the remainder of what will be required to support system growth in Sudbury beyond year 2026. The project was broken up into two sections to accommodate ease of construction and defer spend as long as possible. It was determined that Phase 1 provided eight years of in-franchise growth which is a long enough time horizon to defer Phase 2 until it is required in 2026. This project is required to ensure the systems in the area of Chelmsford and Espanola will have adequate capacity to meet demand on a peak winter day.

4.4.1.2.2 Summary of Transmission Reinforcement Projects Greater than $5 Million

Oxford Reinforcement

The Oxford Reinforcement Project reinforces the Eastern Transmission System. This project is located upstream of a past reinforcement of the Oxford area and is being driven by in-franchise growth. Over the last few years the industrial base, both new and existing, has been growing at a steady rate. This project is required to maintain capacity in the Port Dover area and benefits the entire Eastern Transmission System serving the Districts of Hamilton/Halton, Waterloo, and London.

Owen Sound Reinforcement Phase 4

This NPS 12 pipeline reinforcement project is a continuation from the end of the major reinforcement project completed in 2006, and will allow Union to meet the in-franchise general service demands of the fast growing Waterloo District. This project benefits the entire Owen Sound Transmission System, and has been advanced for completion in 2019 subject to the approval of the Community Expansion projects.

Stratford Reinforcement

The Stratford Reinforcement Project is a part of the Forest/Hensall/Goderich Transmission System. This project is a new reinforcement project starting at a takeoff from the Dawn Parkway System to allow for continued in-franchise growth of the London District.

Guelph Reinforcement

This project is required to allow for continued in-franchise growth to the city of Guelph. This project is needed to support continued growth in this busy area.

Dunnville Line Reinforcement

The Dunnville Line is part of the Eastern Transmission System. This project reinforces the existing system from the Caledonia takeoff into the Dunnville area and is required to maintain adequate capacity in this system.

Community Expansion

In response to the Board's initiative to address the Ontario government's desire to expand natural gas distribution systems to communities that currently do not have access to natural gas[1], Union has filed proposals with the Board designed to facilitate

[1]Minister of Energy correspondence dated February 17, 2015 and Board invitation for parties to submit a community expansion proposal dated February 18, 2015

enhanced access to natural gas for non-served rural, remote and First Nation communities, and businesses in the province.

Union's initial Community Expansion proposal[2] focused on four projects:

- Kettle and Stony Point First Nation and Lambton Shores
- Milverton, Rostock and Wartburg
- Prince Township
- Moraviantown First Nation

These four expansion projects have been approved by the Board for both rate and facility (leave to construct).

Construction Schedule

In Service in 2017

- Kettle and Stony Point First Nation and Lambton Shores
- Milverton

Construction in 2018

- Rostock and Wartburg
- Prince Township
- Moraviantown First Nation (subject to NGGP funding)

The availability of natural gas in these four project areas will create a number of benefits, both from a customer and community perspective. Not only will natural gas provide annual energy savings for customers, it will also result in reduced costs and increased efficiencies for existing businesses. The expansion of natural gas to these areas will help remove economic barriers.

Although Union's current expansion proposal focuses only on these projects, this does not preclude Union from expanding to other areas not served by natural gas. However, to enable the economic expansion of natural gas infrastructure to communities that would otherwise not receive natural gas service, a system expansion surcharge and Board approval will be required.

Union Gas is currently working with the government to finalize NGGP grants for additional community expansion projects that would be installed in the 2019 through 2020 period. Union would require facility (leave to construct) and/or rate approval from the Board to construct these projects.

Lastly, the Board has put forth a Procedural Order for Union and EPCOR to submit a Common Infrastructure Plan (CIP) to serve the South Bruce expansion area. The CIP proposals were filed with the Board on October 16, 2017.

[2] EB-2015-0179 updated application and evidence dated March 31, 2017

4.4.2 System Growth

Union's System Planning group is accountable to make asset planning recommendations for the three major transmission systems: The Dawn Parkway System, the Panhandle System, and the Sarnia Industrial Line System. These systems move natural gas from receipt points to delivery locations along the pipeline to meet the volumetric demands and pressure requirements of Union's in-franchise and ex-franchise customers. The pipeline system forms the foundation for future development as customers' needs grow, and represents the supply into the Union South Distribution Planning models as detailed in the Distribution Growth section.

System Planning designs systems to meet peak daily consumption to ensure there are no outages on the Design Day. Metered data is gathered and analyzed each year to calculate demand assumptions used for system design. Although annual consumption has been decreasing year over year, Union has not seen a decrease in peak daily consumption.

Demand for additional long term capacity on Union's major transmission systems is typically met through installation of new pipeline, station, and/or compression. Non-facility options are also considered using gas supply on third party contracts for peaking service to optimize the resources used to provide service. Consideration of options will include evaluating the effect on system reliability, service quality, security of supply, and rates for service. Options are considered based on the "lowest cost per throughput" or highest economic benefit.

The Asset Management Plan provides a magnitude level estimate of future pipeline or compression facilities and does not include any non-facility alternatives or detailed economics for alternative comparisons. In the event that the projects identified in the asset plan proceed, Union will complete a Leave to Construct Application where a detailed and rigorous examination of both the facility and non-facility alternatives, including detailed costs and economics will be completed when required.

4.4.2.1 System Growth Forecast

Table 4.4: System Planning 10 Year Growth Summary (all $ in millions)

Project/Program/ Portfolio	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
Dawn Parkway System	25.7	5.0									**30.7**
Panhandle System	14.8				0.3	12.8	94.7	4.9			**127.5**
Kingsville Transmission Reinforcement Project	12.5	89.2	2.5								**104.2**
Sarnia Industrial Line System		0.1	1.6	34.8	8.2	93.4	1.8				**139.9**
System Planning Total	**53.0**	**94.3**	**4.1**	**34.8**	**8.5**	**106.2**	**96.5**	**4.9**			**398.0**

4.4.2.2 Summary of System Growth Projects

Dawn Parkway System

Years 2018 and 2019 of the Dawn Parkway System forecast include the remaining commissioning and clean-up costs from the installation of the 2017 Dawn H, Lobo D and Bright C compressors. Future Dawn Parkway System expansion is not currently forecast as the expansion is primarily driven by changes to North American natural gas market fundamentals where shippers look to access economic natural gas supplies. Should demand increase along the Dawn Parkway System, it is anticipated the next facilities required will be Parkway E compressor, NPS 48 Kirkwall to Hamilton, and NPS 48 Dawn to Enniskillen. The costs or timing of these facilities has not been determined. These facilities will provide ex-franchise customers additional access to the liquidity, storage, and transportation services available at the Dawn Hub and meet their market needs.

Panhandle System and Kingville Transmission Reinforcement Project

Panhandle System expansion is driven by in-franchise growth in Chatham-Kent, Windsor-Essex and surrounding area, including the fast growing greenhouse market in the Leamington/Kingsville area. The forecast includes the Kingsville Transmission Reinforcement Project consisting of 17 km of up to NPS 20 pipeline and is driven by an increased growth forecast along the Panhandle System. This project also reinforces the distribution system, and without very limited growth can occur. The Panhandle system costs include clean-up costs in 2018 associated with the EB-2016-0186 Panhandle Reinforcement Project. Additional Panhandle System facilities are planned for construction in 2024 and include construction of approximately 14 km of NPS 36 pipe looping the existing NPS 20 from Dover Transmission station towards Comber Transmission Station. These facilities will provide in-franchise customers in the Chatham-Kent, Windsor-Essex and Leamington/Kingsville areas increased access to low-cost natural gas for use in their homes and businesses.

Sarnia Industrial Line System

Sarnia Industrial Line System expansion is driven primarily by in-franchise industrial contract rate growth. The project consists of pipeline to directly serve new customers as well as additional reinforcement of the Sarnia Industrial Line System directly to Dawn.

4.4.3 Storage Growth

Union's Storage Planning group is accountable to make asset planning recommendations for all Underground Storage facilities, as well as the Dawn Compressor Station. The modelled deliverability required from Dawn is a direct output from the System Planning models previously defined and the Union system supply arriving at Dawn from the Gas Supply Plan.

The natural gas storage assets are expanded through either improving existing storage pools or developing new storage pools. Improvements are generally made by increasing the maximum operating pressure of the pool. New storage pools are typically developed by converting a depleted natural gas production field. A Board application and approval is required for developing or improving a storage pool.

In EB-2015-0551 the Board determined that Union is required to reserve 100 PJ of storage space to serve the needs of its in-franchise customers. On an annual basis the in-franchise storage space requirements are determined through a natural gas supply plan, using the aggregate excess methodology. The current 10 year forecast indicates that the in-franchise customer requirements are less than the 100 PJs of reserved storage space. This is primarily due to DSM which has reduced the annual consumption of natural gas. Additional requirement for storage space for ex-franchise customers is determined by market demand, market prices, and the availability of economic projects.

Any deliverability shortfalls on Design Day indicate additional storage assets are required. Adding storage wells, compression and piping are typical methods to improve deliverability. Storage deliverability projects also require Board approval for construction.

No storage growth is forecast at this time.

4.4.4 Growth – Other

A new area of growth for Union is Compressed Natural Gas (CNG), Liquefied Natural Gas for vehicles (LNG), and renewable natural gas (RNG). Projects forecast in these areas will support Ontario's Climate Change Action Plan.

4.4.4.1 CNG/LNG/RNG Growth Forecast

Table 4.5: CNG/LNG/RNG 10 Year Asset Management Forecast (all $ in millions)

Project	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	10 Year Total
CNG/LNG/RNG Growth Projects	4.9	21.0	4.1								30.0

4.4.4.1 Summary of CNG/LNG/RNG Growth Projects

Compressed Natural Gas (CNG)

Union's CNG project will establish key heavy-duty truck CNG refuelling infrastructure on Canada's busiest trucking corridor. It will be accomplished as a partnership of leading, Canadian industry providers of CNG solutions. The project scope will encompass all aspects of engineering, approvals, procurement, construction, commissioning, and ongoing operation and maintenance of three refueling stations at strategic locations along the Highway 401 corridor including Windsor, London/Woodstock and Eastern Ontario (Napanee/Kingston).

The objective of this project is to provide the reliability and attractive pricing that is critical for the many fleets that regularly use the Highway 401 corridor to make long-term CNG adoption decisions for their operations. Growing CNG penetration in Ontario is strategically significant as it allows Union to grow natural gas consumption while simultaneously reducing Ontario's GHG emissions.

Moving forward with this project will allow Union to leverage federal government incentive funding and our early mover advantage. It will also allow us to reduce GHG emissions in accordance with Ontario's Climate Change Action Plan.

Liquefied Natural Gas for Vehicles (LNG)

Union will pursue opportunities to use the liquefaction capacity that is available from the Hagar LNG facility. The project involves installing a truck loading facility on site so that trucks can be safely loaded with LNG while on a weigh scale. This project is contingent on customer interest and receipt of funding from the NGGP.

Renewable Natural Gas (RNG)

Renewable Natural Gas (RNG) is a renewable and carbon neutral fuel produced by the decay of organic materials in an oxygen free environment. RNG is fully interchangeable with conventional natural gas meaning that no major infrastructure changes are required and RNG can be used with existing downstream appliances. Communities, governments, and businesses can produce and make use of RNG while reducing their GHG emissions, and increase their sustainability by turning waste into a resource and supporting the local economy.

These projects will make use of biogas that is currently being flared by upgrading the biogas gas into pipeline quality RNG and injecting that gas into our system. The projects include the procurement, installation, and commissioning of cleaning, conditioning, and injection equipment.

4.5 Asset Growth Recommendations

Table 4.6 and Figure 4.2 summarize the Asset Growth Financial Forecast to meet customer growth needs for the period of the Asset Management Plan. Larger projects have an impact on certain years. Impacts can be seen from major Distribution and System Growth projects including growth from Community Expansion in 2018/2019, growth on the Panhandle System in 2019 and 2024, and growth on the Sarnia Industrial Line System in 2023.

Distribution Growth is based on a forecast that incorporates historical growth with econometric factors. System and Storage Growth are based on a combination of an econometric forecast and ex-franchise growth. There is no ex-franchise growth forecast in this plan.

Table 4.6: Asset Growth 10 Year Capital Forecast (all $ in millions)

Project/Program	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
Distribution	170.5	170.4	99.5	88.2	83.7	93.4	118.9	91.2	97.4	109.0	**1122.4**
System	53.0	94.3	4.1	34.8	8.5	106.2	96.5	4.9			**402.2**
Other – CNG/LNG/RNG	4.9	21.0	4.1								**30.0**
Growth Total	**241.5**	**330.8**	**113.2**	**146.8**	**115.4**	**200.6**	**216.0**	**96.1**	**97.4**	**109.0**	**1666.6**

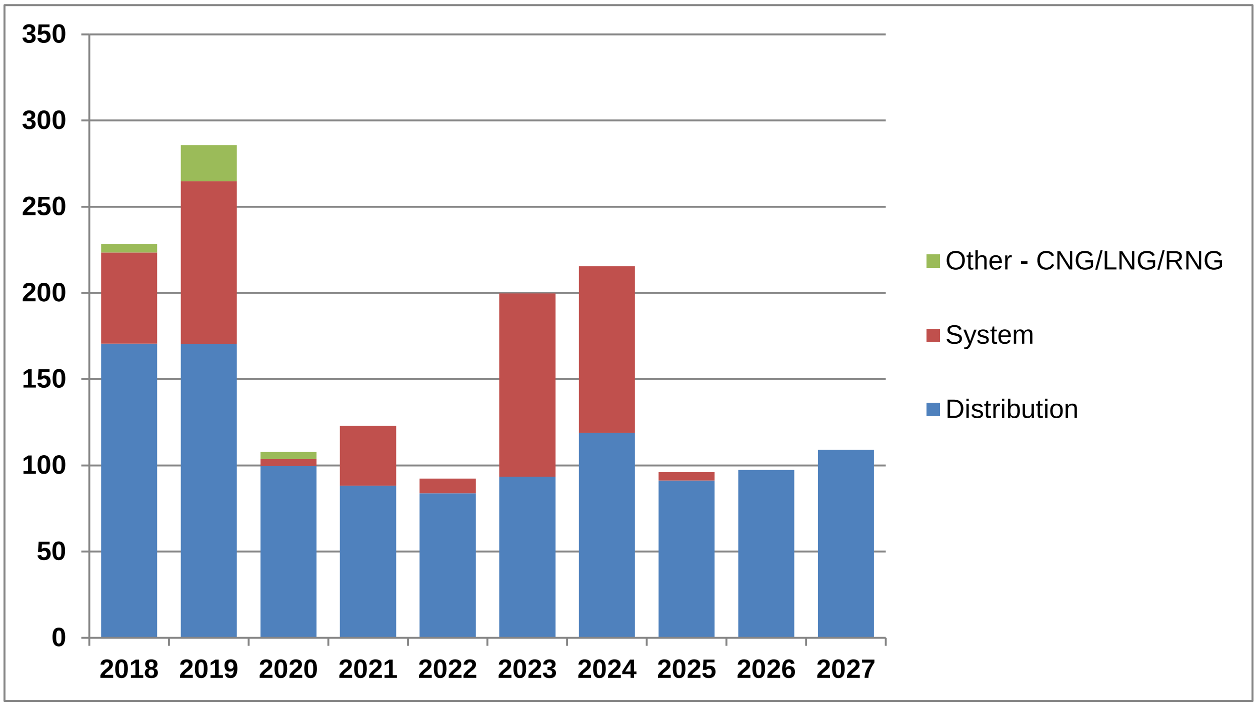


Figure 4.2: Asset Growth 10 Year Capital Forecast (all $ in millions)

5 Maintenance Planning

5.1 Maintenance Planning – Overview

Maintenance Planning at Union is the planning of maintenance capital and operating and maintenance expenditures to ensure the safe, reliable, and compliant delivery of services over the life of the assets.

The asset lifecycle planning process ensures that optimal decisions related to maintenance expenditures are made through proper prioritization of all identified issues and projects. The creation of a 10 year Asset Management Plan ensures that issues are identified early allowing for proper risk assessment, project planning, and execution.

Maintenance is determined based on the unique requirements of the asset class to ensure optimal maintenance is being performed and compliance requirements are met. Basic maintenance strategies generally fall into several common categories ranging from run-to-failure to condition-based maintenance.

All assets pass through a number of phases throughout their lifecycle, described in the following cycle. The primary focus of this section is to outline how projects to renew or replace assets are identified, selected for execution, and approved. The creation of the 10 year Asset Management Plan is an important tool to ensure that capital resources are allocated to the highest priority items to reduce risk through improving reliability and safety.

5.2 Asset Lifecycle Model

The Asset Lifecycle Model, as it applies to assets in operation, has five phases:

i. Project Identification
ii. Project Prioritization and Selection
iii. Project Design and Execution
iv. Asset Operation and Maintenance
v. Asset Retirement, Renewal or Replacement

5.2.1 Project Identification

Projects are identified in a number of different ways. Union's risk management processes involve a number of formal steps to identify, mitigate, and monitor risks. Section 6 of this plan provides a detailed outline of Union's Risk Management process. Mitigation for the risks identified through this process are often projects to improve reliability or safety. Projects may also be identified or required as a result of regulation or code changes. Projects can also be identified when municipal projects result in conflicts with our infrastructure requiring relocations.

All potential projects are reviewed, evaluated, tracked, and monitored over time to determine if the risk level associated with a given item is increasing or stable. These potential projects, with a variety of priority levels, are used as a starting point for the annual budget cycle.

5.2.1.1 Risk Management Process

Section 6 of the Asset Management Plan provides more information about the manner in which items are raised and assessed using consistent risk management processes. The OMS Risk Matrix is applied to determine the overall risk level, and risk mitigation plans are then developed. Items are raised through field input, input from subject matter experts, or evidence as derived from Union's asset data systems (e.g., Geographic Information System).

5.2.1.2 Asset Condition or Health

Asset condition is monitored and will impact the need for a project to either replace an asset or to restore its performance to the required level. As asset condition and performance degrade, risks are raised through the risk management process. There are a number of factors that affect asset health and these generally apply to all asset categories.

The following are examples of some of these factors.

- Third Party Damage
- Construction and Installation quality/practices
- Corrosion
- Age (IT application, corrosion, number of cycles)
- Operating conditions
- Operating practices
- Maintenance Program Effectiveness
- Environmental conditions

Third Party Damage - When third parties perform work near our facilities, there is a risk that they may damage our pipeline facilities. This is called third party damage and Union has a number of strategies to mitigate this risk. Mitigations include Union being a founding and contributing member of Ontario One Call, being a lead proponent to the Ontario Underground Information Notification Systems Act, and actively participating on the Ontario Regional Common Ground Alliance. Other mitigations for higher pressure pipelines include:

- Providing Union personnel to observe when others are working near our facilities (third party observation)
- Installing markers or signs along the pipeline which provide information about the presence of the high pressure pipeline
- Establishing easements over certain pipeline and then monitoring (ground and aerial surveys) and maintaining these easements to keep them clear of excess vegetation and of third party structures

All incidents of third party damage are tracked and assessed to determine improvement solutions.

Construction/Installation Practices - Union has developed and maintains manuals and specifications which outline proper installation and maintenance methods and stringent quality control to ensure these requirements are met. All pipeline systems are designed by Professional Engineers and use Union approved materials which meet or exceed Code requirements. Union has high quality and safety standards that construction contractors must meet. Maintenance and major construction projects performed by contractors have an assigned inspector to ensure the quality of the installation, that it is constructed as per the design, and that proper construction procedures are followed.

Corrosion – In addition to pipeline coatings, anodes and rectifiers are used to provide cathodic protection and reduce the chance of corrosion of pipelines. The level of cathodic protection is regularly checked to ensure adequate levels of protection. Pipelines that are identified to have inadequate cathodic protection will be assessed to determine the root cause of the inadequate protection and a solution will be implemented. Pipeline corrosion is also measured and assessed by either inline inspection runs or External Corrosion Direct Assessments and digs for pipelines ≥ 30% SMYS.

Age - While age can be a factor in determining asset health or condition, on its own it is generally insufficient to make decisions related to replacement projects. There are some key areas in which age is used to drive maintenance requirements and this is primarily with respect to large rotating equipment such as gas turbines, power turbines and compressors. The Original Equipment Manufacturers (OEM) prescribe maintenance intervals that are based on machine run hours. Although the age of the asset may not have a direct impact on its condition, there comes a point where obsolescence becomes the primary risk. Whether it is an IT application or an aging compressor, as the asset ages beyond a certain point, vendor support for it declines to a point that the risk becomes intolerable.

Operating Conditions - Operating conditions such as the flow profile of a station, magnitude of pressure differential, and equipment settings, can all impact the health of station assets. Equipment that is stressed due to “on/off” type operation or consistently operating at its maximum capacity can accelerate the degradation in performance of the asset and the frequency of maintenance interventions and/or failures. Natural gas quality can also have an impact on the health of the asset. Debris, pipeline corrosion, and pipeline contaminants including moisture can cause damage to the equipment.

Operating Practices - The conditions under which the equipment is operated is a significant determinant of asset health. Operating procedures, training and ongoing monitoring of key operational parameters are all used as a means to ensure the longevity of the equipment by ensuring that the asset is operated in a manner that is consistent with its capabilities and design.

Maintenance Program Effectiveness - An effective maintenance program ensures that the essential care items such as lubrication, alignment, and filtration are completed as required to ensure the asset continues to perform its required performance. An effective inspection program will ensure that asset performance degradation is identified early to allow for proper planning and scheduling of not only maintenance interventions but also longer-term capital replacements.

Environmental elements - Environmental elements include factors such as ambient temperature, moisture, oxidation, lightning strikes, power surges, sunlight, and ultraviolet radiation.

Security: Industry Best Practices - As cyber security and perpetrators become more prevalent and more sophisticated in how they attempt to exploit application and IT technology vulnerabilities, changes must be made and costs incurred to maintain an appropriate level of IT Security. This is assessed in relation to IT industry best practices. Various reviews including application penetration testing are performed regularly to evaluate current security levels.

Asset Health: Pipelines ≥ 30% SMYS - In 2002, Union developed a software algorithm with the assistance of a third party consultant to aid in risk assessments for the pipelines ≥ 30% SMYS. This software algorithm, processed through an application called the Risk Analyst Tool, uses a number of probability and consequence factors to calculate a Total Risk Score for all pipelines ≥ 30% SMYS within Union's system. This tool was originally used to prioritize pipeline integrity inspections as part of the integrity management program at Union. As Union completed the inline inspections of its pipelines it began to focus more on managing the risks of the anomalies identified and used a risk based approach to prioritize the work. Going forward, Union will further leverage the Risk Assessment tool to focus on assessing asset health.

Union is now using the Risk Analyst Tool to assess the health of pipelines ≥ 30% SMYS. The Risk Analyst Tool analyzes a pipeline by segments of identical pipeline attributes. For each segment, a variety of factors are used to calculate both relative scores for probability of poor asset health and consequence of failures. This calculation is based on a number of different asset-related attributes for each segment that is assessed.

Examples of these attributes include pipe grade, wall thickness, coating type, % SMYS, Maximum Operating Pressure, depth of cover, and results from in-line inspection and External Corrosion Direct Assessment. The Risk Analyst Tool can provide results for both individual pipeline segments as well as an entire pipeline. In addition to the scores for both probability and consequence, the tool also generates an overall risk score for both pipeline segments and entire pipelines.

Moving forward, the Risk Analyst Tool will be used on an annual basis to generate updated asset health data for review and assessment. The highest probability and consequence factor scores as well as the highest total risk scores will be reviewed to identify if there are any potential asset health concerns which require further engineering review. The associated factors will be verified, and if deemed appropriate, an engineering review will be initiated for the specific pipeline. The engineering review will determine if any additional measures are required to assess the integrity of the pipeline, or if the inspection frequency of the pipeline needs to be adjusted. Once the engineering review is completed, if any remediation is required, the project will be risk-ranked in accordance with Union's Risk Management processes and will follow Union's budget process.

Asset Health: Underground Storage - Storage Wells - In 2009, Union developed a semi-quantitative risk tool that evaluates the condition of Union's storage wells. This algorithm uses risk and consequence factors to determine a total risk score for each well that can be compared to other wells. Union has used a third party consultant to help in the various weightings and risk calculation of the algorithm. The risk tool helps prioritize remediation activities by indicating the greatest risk reduction for individual well workovers.

The risk tool analyzes each well's attributes to calculate a risk and consequence score. Examples of these attributes include pool location, casing wall thickness, presence of corrosion, wellhead construction, cement quality, maximum operating pressure, well deliverability, distance to nearest residence, and pool size. The risk tool is updated on an annual basis to generate an updated well risk score.

Asset Health: All Other Assets - While there is no specific tool to assess asset health for assets excluding pipelines ≥ 30% SMYS and pipes in storage wells, the health of these assets is managed through Union's Risk Management processes and procedures as described in Section 6.

As Union identifies individual asset risks or systemic issues with particular asset classes across the franchise, these risks are brought to the risk workshops where Union's subject matter experts discuss the issues and risk rank them. The responsible Asset Class Managers will then begin to plan and prioritize the necessary work required to mitigate these issues.

As needed, additional data is used from corporate systems such as Union's geographic information system to assess failure rates and failure modes, when available, to further quantify asset health to help support asset management related decisions and capital and O&M spend. Union also leverages industry knowledge and experience to gain external perspectives on issues that may be prevalent with other utilities across North America. As additional data and subject matter expertise is gathered and assessed, programs are created as needed to address specific asset health related risks over defined time periods determined by the associated risk severity of these issues. Many of these programs are highlighted in section 5 Maintenance Planning.

5.2.1.3 Regulatory Requirements or Changes

Potential projects are identified when regulations change or our understanding of the regulations changes. This driver is not necessarily related to the actual condition of an asset yet it is part of the maintenance capital budget as it is driven by a need to upgrade the asset to new standards set by changing regulations. Key standards that drive maintenance requirements are:

- Canadian Standards Association Z662–15 Oil and Gas Pipeline Systems and the Technical Standards and Safety Authority (TSSA) Code Adoption Document
- Canadian Standards Association Z341Storage of Hydrocarbons in Underground Formations, and the Oil, Gas and Salt Resources of Ontario Operating Standards
- Ontario Building Code for Service Facilities
- O.Reg.419/05 (Environmental Protection Act, R.S.O. 1990)

The standards related to pipeline assets have resulted in the creation of a number of key Standard Operating Practices (or SOPs) that address code requirements and outline how Union ensures compliance with Standards and Codes.

5.2.1.4 Contractual Obligations

Due to contractual agreements with municipalities, Union is required to relocate existing plant in cases where it conflicts with municipal infrastructure renewal projects. Union will strive to resolve conflicts by proposing alternative designs to avoid the need to relocate facilities where practical. In cases where no resolution can be achieved, Union will use this opportunity to renew facilities to ensure that an infrastructure renewal project in the near future does not result in additional disturbance to the municipality.

5.2.2 Project Prioritization and Selection

The 10 year Asset Management Plan is used as the starting point for the annual capital budget process. The annual capital budget process is used to determine the budget for the following year. Through the budget preparation process, the risks that each project is mitigating are re-evaluated and endorsed. It is at this point that new projects may also be identified to mitigate risk. The following graphic outlines the budget cycle process with the Asset Management Plan as the starting point:

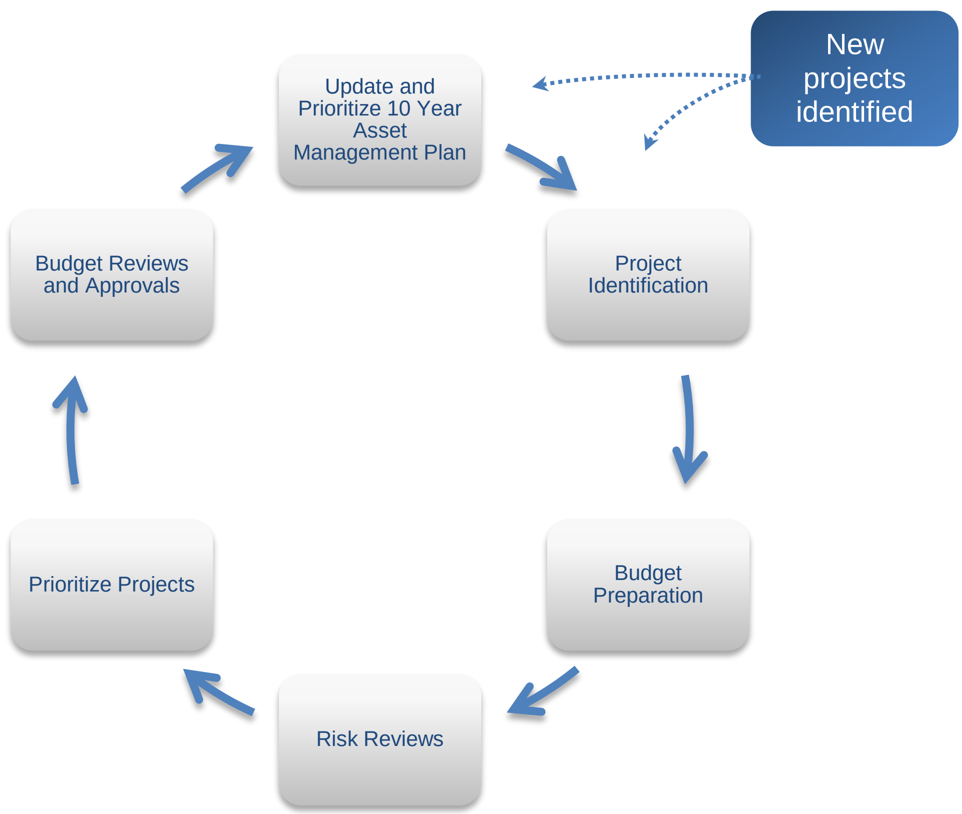


Figure 5.1: Annual Budget-Asset Management Plan Cycle

As there are finite resources to complete maintenance capital projects, projects are selected for the Asset Management Plan on the basis of their relative priority. All projects are evaluated and prioritized using a common methodology to ensure that maintenance capital resources are employed to address the highest priority items across all asset categories.

Union has developed a consistent methodology for prioritization of all projects, as depicted in the figure below. The figure shows that there are projects of a higher priority nature at the top of the graphic to lower-priority projects at the bottom. It is also important to note that the projects toward the high priority end of the spectrum have inherently less flexibility on the level of expenditure and timing. As we move down the priority spectrum, there is an increasing level of flexibility in expenditures and timing.

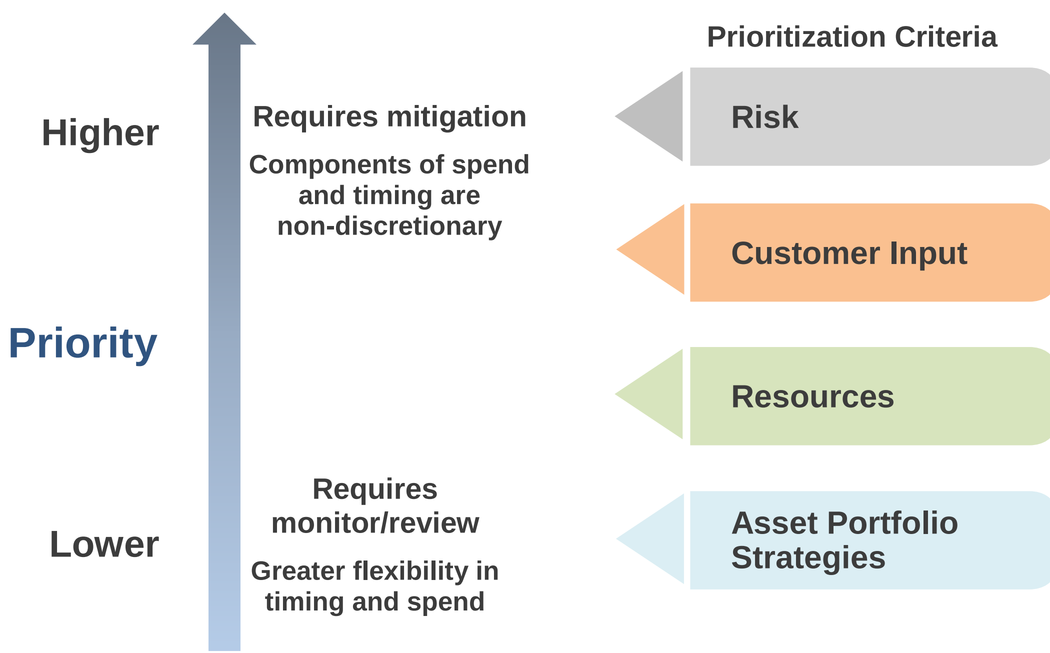


Figure 5.2: Asset Management Plan Prioritization Criteria

It is important to have a mix of higher priority and lower priority projects to allow for adjustments to be made as circumstances change. If for whatever reason a high priority project is identified in a given budget cycle, a lower-priority project will need to be displaced to provide needed capital resources.

Several criteria are used to consistently prioritize all projects and portfolio strategies within in the overall maintenance capital portfolio. These criteria are depicted in Figure 5.2.

- Risk is one of the most important criteria, and is assessed using Union's Risk Management process. Risk is a combination of likelihood of the event and consequence of that particular event.
- Customer input and preferences, as obtained through various customer engagement activities, are carefully considered when making strategic asset maintenance decisions. Union's 2017 customer engagement survey showed that customers have an overwhelming preference to maintain a steady pace of spend to keep the system healthy in the long run. Evidence of Union's commitment to a steady pace of spend on assets can be seen in the overall 10 year maintenance capital outlook in Section 5.6. The project descriptions found in Section 5.3 share more detail on how specific results of the customer engagement survey were considered[1].
- Resource availability is also used to assist in project selection. Given a number of projects of equal priority (or risk), workload distribution is used to make final decisions of which projects will proceed in a given year.
- Asset Portfolio Strategies are important decision criteria that are used to select certain projects over others. These strategies are given higher priority to ensure continuity in addressing a broader issue holistically.

Projects that are rejected must be reprioritized to a subsequent year in the asset plan using the above criteria. The following figure outlines the decision process for prioritizing the budget and the subsequent years within the Asset Management Plan. The figure exhibits the manner in which projects that are rejected from the current budget are loaded into the following year of the plan, reprioritized and ultimately accepted or rejected for that year of the plan. Those projects that are rejected are subsequently loaded into the following year and the process is repeated for each year of the plan. This process ensures that the highest priority work is planned in each year based on the best information at the time the plan is created. In the case of a lower risk project, the system will continue to push the project to future years. This approach also allows us to track and monitor issues that have been raised so they are not forgotten. These can be revisited each to determine if the risk associated with the issue has changed.

[1] Unless otherwise stated, the results presented relate to residential customer feedback.

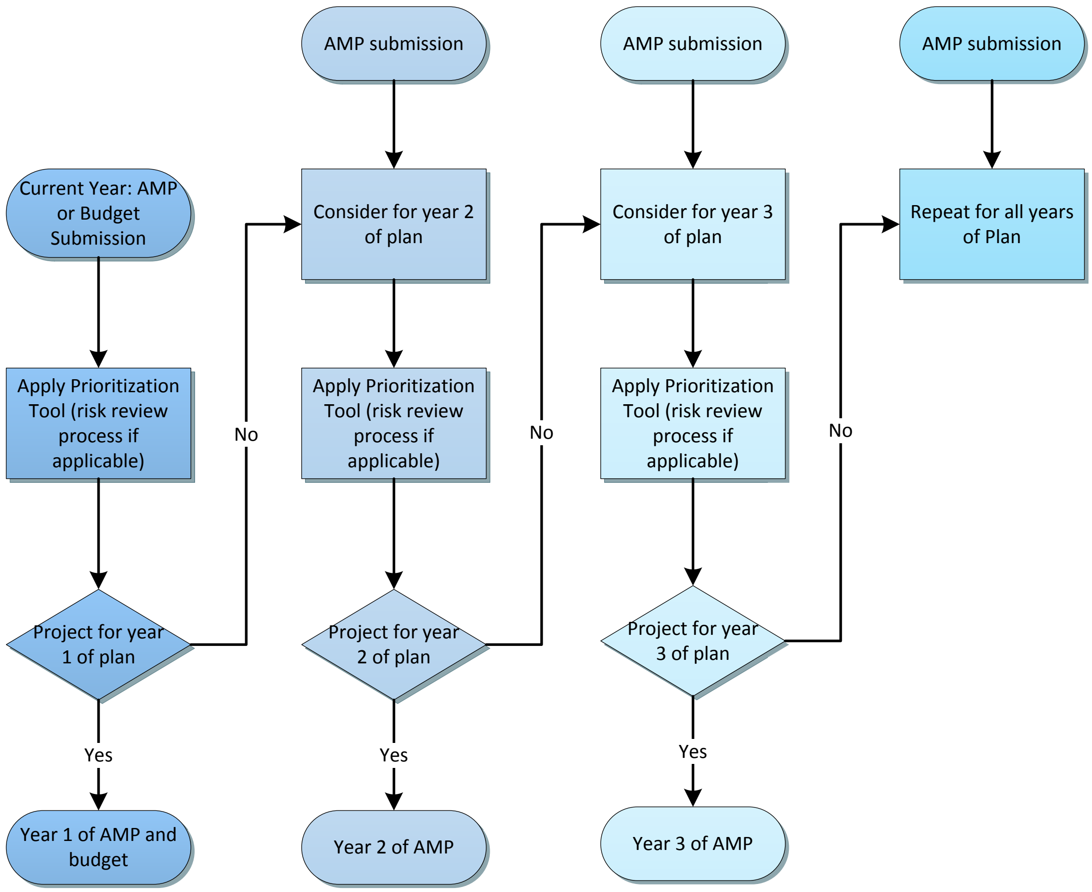


Figure 5.3: Annual Prioritization Flow of Asset Management Plan Projects

5.2.3 Project Design and Execution

Whether it is a project that is designed by internal engineering resources or by external design firms, a strict set of design and construction specifications are followed. It is understood that the proper design, installation/construction and commissioning will affect the performance of the asset throughout the asset lifecycle. Decisions made in this phase will have a profound impact on the health and performance of the asset through the operation and maintenance phases.

5.2.4 Asset Operation and Maintenance

This phase of asset's life is the longest phase. The success of this phase of the lifecycle is to a significant degree determined by decisions made in the previous two phases. The manner in which the asset is operated and maintained will have a direct impact on its performance and longevity. Through this phase, incremental operation and maintenance expenditures are typically identified to support changes in maintenance plans (e.g., new technology, new regulations).

5.2.4.1 Asset Operation

It is important that the operator of the asset understands the capabilities of the asset. Operating an asset in a manner that demands more of the asset than it was designed for will have a negative impact on its health and performance resulting in premature degradation. In the case of physical assets, operating procedures are developed to convey to the operator of the asset the acceptable range of operation and the limits of the asset performance. For many assets, there are controls in place to raise alarms when certain detrimental operating conditions are experienced.

5.2.4.2 Asset Maintenance

The mission of maintenance is to preserve the required level of performance of the asset. This is accomplished through a variety of maintenance strategies that range from a simple run-to-failure type of strategy to continuous condition monitoring and condition-based maintenance. The type of maintenance strategy employed is selected to adequately address the consequence of failure of the asset within the limits of technical feasibility of proactive tasks to identify potential failures.

Although maintenance strategies and tactics do vary somewhat amongst the various asset categories, in general, the same types of strategies are employed in each. All asset categories have two major groupings of maintenance activities: preventive and corrective. Generally, preventive maintenance means all activities that are done in order to prevent a functional failure of the asset; whereas, corrective maintenance describes all activities that are performed to restore the performance of the asset to its desired standard. Corrective maintenance can be either proactive, in the case where the corrective action is completed prior to point at which the asset can no longer perform its required function; or, reactive which is typically referred to as break/fix.

Pipelines ≥ 30% SMYS are monitored using inline inspection (ILI) or External Corrosion Direct Assessment at a prescribed frequency as part of the Pipeline Asset Integrity Management Program, Class Location surveys and Depth of Cover surveys. Any anomalies that are identified using an ILI run will be assessed using Union's Pipeline Integrity Engineering Reference Manual practices which may drive pipeline maintenance. This program is an example of condition monitoring techniques to identify potential failures early allowing for good planning and scheduling of intervention at the right time.

Across the physical asset classes, there is generally a heavy reliance on inspections and condition monitoring to identify potential failures. There are a number of key SOPs that are generally based on code requirements for inspection and maintenance of natural gas assets. These SOPs typically prescribe a required minimum inspection frequency, the scope of the inspection as well as the requirements to complete remedial actions to correct identified deficiencies.

In general, inspections are a form of condition monitoring with tasks and inspection points designed to identify certain expected failure modes that may be present. A repair or restoration task is only undertaken in the event that an impending failure is identified.

Time-based maintenance activities are those that occur at a pre-determined interval (either calendar time or run hours). Time-based activities are often referred to scheduled restoration, discard or renewal. Examples of scheduled maintenance tasks include:

- Scheduled replacement of diaphragm meters
- Scheduled restoration of gas turbines based on OEM recommended overhaul interval
- Technologies such as workstations, servers, network devices, databases and integration tools are upgraded every 3-4 years to maintain vendor support, performance, reliability and provide higher levels of security

One approach to defining asset maintenance strategies that is seeing wider adoption at Union, particularly in the realm of rotating equipment, is Reliability Centred Maintenance (RCM). RCM is a very prescriptive approach to developing a maintenance program that begins with a clear understanding of the asset function. The maintenance tactics are derived as a means to preserve the required function of the asset. This is accomplished by identifying all functions of the asset and its functional failures and failure modes.

RCM then determines a consequence for each failure mode and applies a decision matrix that leads to the optimal solution or maintenance strategy to reduce or eliminate the consequence of each identified failure mode. This approach also requires the developer to question the economic business case of the suggested action to avoid over-maintaining the asset where the consequence does not warrant the effort to avoid it - a situation that results in the very legitimate maintenance strategy of run-to-failure.

5.2.5 Asset Retirement, Renewal or Replacement

When the asset reaches the end of its life, meaning the cost to continue to operate and maintain the asset are greater than the cost or replacing it or the risk of continuing to operate and maintain it becomes too great, a number of alternative solutions are identified. These various alternatives are evaluated and one is ultimately selected, proposed in the asset management and subsequently included in the Asset Management Plan and the maintenance capital budget at the appropriate time based on risk assessment and economic analysis.

5.3 Maintenance Projects

5.3.1 Pipelines

Table 5.1: Pipelines 10 Year Forecast of Capital (all $ in millions)

Project/Program/ Portfolio	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
Pipeline Integrity < 30%	32.4	56.4	61.8	60.9	57.7	60.0	64.4	47.4	54.3	64.8	**542.1**
Municipal Replacement	20.8	20.4	24.5	24.5	25.0	25.0	25.0	25.0	25.0	25.0	**240.2**
Pipeline Integrity ≥ 30%	19.4	20.2	14.3	14.1	13.9	13.6	13.6	13.6	13.6	13.6	**150.1**
Class Location	22.9	24.9	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	**167.8**
MOP Verification			0.5	5.0	10.0	10.0	10.0	10.0	10.0	10.0	**65.5**
Sudbury Line Sections 2&3	67.2	2.3									**69.5**
Pipelines Total	**162.6**	**124.3**	**116.2**	**119.5**	**121.6**	**123.6**	**128.1**	**111.0**	**108.9**	**119.5**	**1235.2**

5.3.1.1 Summary of Pipeline Maintenance Capital Projects

Pipeline Integrity

Projects in this category are the result of the Asset Integrity Management Program that is required to comply with codes. Assessment and maintenance of the integrity of our pipeline systems ensures safety and reliable service our customers.

The ≥ 30% SMYS pipeline integrity projects include assessments and associated remediation including Class Location annual assessments, internal and external integrity inspections, and depth of cover surveys.

The < 30% SMYS pipeline integrity major programs include:

- Anode installation
- Replacement of bare/unprotected steel pipe
- Bridge crossings replacements
- Water crossing replacements
- Schedule 10 piping replacement
- Remediation of depth of cover Issues
- Replacement of distribution pipelines which have reduced asset health

Specific to replacement of bare and unprotected steel pipe, Union's 2017 customer engagement survey found that 50% of those surveyed recommend prioritized replacements, while 41% recommend following existing practices for replacement. The positive feedback supports Union's strategy for replacing bare and unprotected steel pipe over the next ten years.

This forecast will mitigate risks associated with our pipeline systems and support compliance.

A 10 Year Forecast of Capital for Pipelines that includes more detail on the Pipeline Integrity forecast can be found in Appendix B.

Municipal Replacement

Projects in this category are pipeline projects 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 Union to avoid conflicts with municipal infrastructure early in the planning stage. If a conflict is unavoidable, the Union asset pipeline will be relocated or replaced.

Class Location

Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines ≥ 30% SMYS and any changes in class location need to be assessed to the current standard to determine if pipeline modifications are required. Given development is occurring close to Union's pipelines annually triggering class location changes, an annual budget is required for the pipeline to meet the current standard requirements which generally involves replacement of the pipe segment. Remediation includes pressure testing, installation of valves, remediating depth of cover issues, and in some cases pipeline replacement. This work ensures we are compliant and fosters safety of the public and Union's pipeline system.

Maximum Operating Pressure (MOP) Verification

MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing ≥ 30% 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 Union has approximately 2970 km of pipelines ≥30% 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% of those surveyed recommend to wait for regulation requirements to keep costs down, 40% recommend to proactively implement industry standard. Spreading the verifications over several years will both keep costs down and also 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 timeframe to meet these expected future mandated requirements.

Sudbury Pipeline Section 2 and 3

Sudbury Section 2 and 3 is a ≥ 30% SMYS pipeline which has neared its life expectancy. Recent analysis of the current condition of Sudbury Section 2 and 3, the amount already spent maintaining this pipeline, and consideration of future maintenance spend requirements have led to a plan for complete replacement.

Replacement of this pipeline reduces the maintenance spend requirements on this pipeline which is a more efficient use of funds from both company and customer perspectives.

Table 5.2: Pipelines 10 Year Forecast of Incremental O&M (all $ in millions, incremental to 2017)

Project/Program	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Integrity	1.7	4.1	4.9	4.2	3.9	3.9	3.7	2.9	3.7	3.8
MOP Verification			1.3	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Pipeline Incremental O&M Total	**1.7**	**4.1**	**6.2**	**6.3**	**6.0**	**6.0**	**5.8**	**5.0**	**5.8**	**4.6**

5.3.1.2 Summary of Pipeline Incremental Operations and Maintenance

Pipeline Integrity

This spend is the amount forecast for integrity to cover additional work to inspect pipelines at water crossings and bridge crossings beyond what has been done in the past. This also includes an increase to further the pipeline integrity management program in terms of External Corrosion Direct Assessment inspections, furthering the assessments for stress corrosion cracking, and increased ILI frequency inspection requirements.

Maximum Operating Pressure (MOP) Verification

The MOP verification project will be new work and requires new resources to complete, which is the majority of this incremental spend requirement. In instances of insufficient records, validation digs may be required to determine potential remediation requirements, which are also part of this additional spend. As above, Union's customer engagement survey results demonstrated public support for this program.

5.3.2 System & Customer Stations

Table 5.3: System and Customer Stations 10 Year Forecast of Capital (all $ in millions)

Project/Program/ Portfolio	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
Heating Equipment		1.8	3.3	2.0	2.0	2.0	2.0	2.0	2.0	4.3	**21.4**
Major Station Project – Hamilton Gates 1 and 2	3.5	5.3									**8.8**
Regulators/Reliefs	8.6	8.9	9.0	9.1	9.3	9.8	9.9	10.2	10.3	10.2	**95.2**
Replacement of Vaulted Stations	0.3	0.9	0.8		5.4					1.3	**8.7**
Station Painting Program	1.5	1.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	**19.0**
Stations Capital Maintenance	2.1	2.7	2.9	3.2	1.2	1.4	1.3	1.2	1.2	2.8	**20.2**
Stations Total	**16.1**	**21.1**	**18.1**	**16.3**	**20.0**	**15.1**	**15.2**	**15.4**	**15.5**	**20.6**	**173.2**

5.3.2.1 Summary of System and Customer Stations Maintenance Capital Projects

Heating Equipment

Natural gas heating equipment is used in many system and customer stations across the Union franchise to help mitigate failure of equipment due to the freezing of liquids in the gas stream as well as moisture that surrounds buried piping. Over Union's many years of operation a variety of heating systems have been used resulting in many variations of equipment age, and the introduction of equipment obsolescence. This project is an ongoing maintenance effort to replace equipment that has reached end of life or has been deemed obsolete. This work will maintain system reliability, ensure operating costs for heating systems are minimized and reduce the potential for glycol spills. This forecast will improve efficiency in operating costs of aging systems and will mitigate the risk of equipment failures that could result in loss of customers and/or loss of glycol containment.

Major Station Project – Hamilton Gate 1 & 2

In 2018 and 2019, Union is planning to fully rebuild two of its largest System stations – Hamilton Gate 1 and 2. This work is being done to address a number of risks, the primary being that the valve site feeding both stations has developed significant corrosion features requiring full replacement. While this is the primary risk at the station, both heating systems are past their expected age, there is mercury contamination present at these sites, the regulators are failing at an accelerated rate, and the filters are undersized based on expected volumes through these stations. The benefit of this project will be continued system reliability and the efficient delivery of natural gas to the city of City of Hamilton. The forecast will mitigate risk associated with corrosion of the valve site and deterioration of existing equipment that could result in reduced supply of natural gas to the City of Hamilton.

Regulators/Reliefs

This capital spend represents the year over year cost of purchasing and stocking of natural gas regulators and relief valves for the purposes of supporting ongoing maintenance work. As regulators and relief valves fail or require replacement due to age or obsolescence, whether it be at the time of meter exchange or in conjunction with other maintenance projects, regulators are purchased and stocked for field reps and technicians so that they can maintain the high reliability of our system and customer stations. This forecast will mitigate shortages of equipment so that services to customers are maintained.

Replacement of Vaulted Stations

Union's system station assets include a number of below grade vaulted stations that are advanced in age creating significant maintenance challenges due to their confined nature as well as a variety of risks with respect to asset deterioration and equipment failure. This project will replace all remaining vaulted stations with above grade facilities and will reduce the risk of equipment failure with respect to these assets and ensure the reliability and integrity of these sites are maintained. With the vault design, water ingress can occur that can make these stations more difficult to maintain. The water can causes frost heave, accelerated corrosion, can interfere with the proper operation of equipment, and can cause the vault to corrode. All of these factors have a negative effect on reliability and can create personal injury risks. As the solutions for each asset are developed, the customer engagement results asking for the most cost effective solutions will be leveraged to select either a typical system station design with land purchase or an above grade enclosure station where land purchase is impractical. This forecast will decrease risk of equipment failure, improve system reliability and result in the stations being more safely and efficiently maintained.

Stations Painting Program

This is a centrally managed program to apply high performance paint to stations where existing paint has begun to fade 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 our Corrosion Control SOP and is our documented and committed practice with respect to how we comply with the applicable codes for corrosion control on above grade station assets. The benefit of this work is primarily the safety and reliability of our assets and ensuring code compliance. This forecast will improve compliance and reduce the risk of leaks and piping and/or equipment failure due to significant corrosion.

Stations Capital Maintenance

This category includes a number of risk remediation programs and general maintenance activities that are part of the core system and customer station maintenance work at Union:

- **Frost Heave** - Stresses imparted on station facilities due to frost formation in below grade soil are targeted for remediation in some cases. This can include the addition of station heaters or simply the excavation and leveling of station sites where heaving is less severe. This work ensures the risk of leaks and piping failures are reduced and therefore system reliability is maintained. This also ensures Union workers are not subjected to maintenance challenges where piping can spring out of place due to the stresses imparted from frost heave.
- **Obsolete equipment** - As station facilities age, regulators and relief valves can become obsolete due to vendors no longer supporting specific types of equipment or simply that they have aged and created maintenance and reliability concerns. This project is an effort to remediate all currently identified obsolete equipment from our system. The allocated cost is for installation and fabrication time; equipment cost is covered in the regulator/relief valve line item. This program will build on system reliability and generate field efficiencies due to reduced variability of equipment found in the field and simplified maintenance.
- **Regulator Freeze offs** - As natural gas supplies into the pipeline systems change, natural gas quality can also change. Existing system stations that experience significant pressure cuts combined with elevated moisture content in the natural gas stream can cause freezing of regulators and loss of downstream customers. Sites of concern will continue to be addressed as needed.
- **Station Blankets** - Spend is also allocated to each region to ensure they have capital available for unforeseen maintenance challenges. These challenges can be leaks or failures that require short turnaround times for remediation, particularly if there has not been a specific project identified for affected assets.

This forecast will improve system reliability and help ensure continued service to our customers.

5.3.3 Measurement

5.3.3.1 Measurement Forecast

Table 5.4: Measurement 10 Year Forecast of Capital (all $ in millions)

Project/Program	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
Meter Exchange Program	21.9	22.4	25.0	25.2	26.1	26.3	26.4	27.4	27.6	27.7	**256.2**
Obsolete Equipment/ Odourant Upgrades	2.3	3.7	5.3	3.9	3.4	2.9	3.3	3.3	3.3	3.3	**34.6**
Measurement Total	**24.3**	**26.0**	**30.3**	**29.1**	**29.5**	**29.2**	**29.7**	**30.7**	**30.9**	**31.0**	**290.7**

Further detail on specific Measurement maintenance tactics can be found in Appendix C.

5.3.3.2 Summary of Measurement Maintenance Capital Projects

Meter Exchange Program

This category is a program to remove meters and replace them with new meters. This work is as required to comply with the legal requirements of Measurement Canada. Batches of diaphragm type meters are removed each year and tested to ensure the population of meters in the field meet regulatory requirements. Smaller meters are compliance tested to meet regulatory requirements. Larger meters (rotary and turbine type meters) and Electronic Valve Integrators are condition tested in service to confirm adequate performance levels and if not, they are then removed, re-verified and returned to service.

The number of meter exchanges required beginning in 2017 is shown below. These exchange requirements are expected to continually grow as the overall in service population continues to grow.

- 200 series diaphragm meters – 52,000 exchanges
- 400 series diaphragm meters – 5,200 exchanges

Obsolete Equipment/SCADA RTU Lifecycle

Many RTUs are obsolete and are no longer supported by the manufacturer. The forecast in this category includes projects to replace all the existing remote terminal units and replace with current technology. 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 2024, the SCADA RTU lifecycle project will take over.

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 the end of their useful life and deferring this work may increase failure rate exponentially.

Odourant Upgrades

The spend in this category includes projects to upgrade odourant systems to ensure compliance to current codes and add performance capability with heat traces 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.

Measurement Electronics Upgrades

The expenditures in this category include low budget small scale capital projects to sustain and enhance operational support. These projects include Auto-Oilers, Turbo Correctors (TOC), lab upgrades, technician tools, industrial billing modems upgrades, billing communication modem lifecycle, and measurement replacement at low flow odourant sites. The benefit of these projects will be smooth and reliable operation.

Table 5.5: Measurement 10 Year Forecast of Incremental O&M (all $ in millions, incremental to 2017)

Program	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Meter Exchanges	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6

5.3.3.3 Summary of Measurement Incremental O&M

Meter Exchanges

This incremental forecast is required to accommodate large ultrasonic meter recertifications as per Electricity and Gas Inspection Act and Measurement Canada regulatory requirements.

5.3.4 Utilization

With the exception of Union's service facilities, Union does not own assets within the utilization class. Maintenance planning strategies are part of the service facilities plans.

5.3.5 Underground Storage

Table 5.6: Underground Storage 10 Year Forecast of Capital (all $ in millions)

Project/Program/ Portfolio	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
Storage Improvements	0.7	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	**9.6**
Storage Integrity	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	**2.5**
Underground Storage Total	**0.9**	**1.4**	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**	**12.1**

5.3.5.1.1 Summary of Storage Maintenance Capital Projects

Storage Improvements

These projects improve the performance, condition and safety of the storage wells. The following are examples of storage improvement projects:

- Performance improvement projects include well testing to identify and remediate wells that have lost deliverability through ongoing operation.
- The installation of emergency shutdown valves on storage wells to provide the ability to remotely isolate each well.
- A wellhead pressure and flow monitoring project to identify flow restrictions, interference between flowing wells, and identify deliverability losses with the goal of maintaining and improving Union's total system deliverability.

Storage Integrity

Casing inspection logs are completed on a prescribed basis as per Canadian Standards Association Z341 Storage of Hydrocarbons in Underground Formations. The storage integrity projects include remediation requirements as a result of the casing inspection log. The remediation may include additional testing, well relining, repair or well abandonment. In some cases, additional wells may be required to replace the lost well deliverability as a result of the remediation

5.3.6 Compression and Liquefied Natural Gas

Table 5.7: Compression 10 Year Forecast of Capital (all $ in millions)

Project/Program /Portfolio	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
Compressor Overhauls	0.8	0.4	9.6	0.2	1.7	9.2	3.9	0.4	6.2		**32.4**
Compressor Upgrade - Replace Plant C					19.3	82.9	48.7	5.0			**155.9**
Compressor Upgrade - Replace Waubuno			3.2	15.2							**18.3**
Compressor and Dehy Capital Maintenance	5.0	3.3	2.2	1.4	1.0	1.0	1.1	1.1	1.1	3.7	**20.9**
Compression Total	**5.7**	**3.7**	**15.0**	**16.8**	**22.0**	**93.1**	**53.7**	**6.5**	**7.3**	**3.7**	**227.5**

Table 5.8: Liquefied Natural Gas (LNG) 10 Year Forecast of Capital (all $ in millions)

Project/Program/ Portfolio	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
LNG Capital Maintenance	0.5	2.4	1.8	1.6	8.0	1.7	1.7	8.8	1.8	1.8	**30.3**

5.3.6.1 Summary of Compression and LNG Maintenance Capital Projects

Compressor Overhauls

These projects consist of the OEM prescribed scheduled maintenance/overhauls (engines, power turbines, and compressors). The overhauls satisfy the OEM recommendations to maintain equipment reliability. The project includes full internal inspections and replacement of wear items to maintain reliability and reduce the risk of failure. These projects ensure continued asset and system reliability. If the OEM recommended maintenance intervals are exceeded, the risk of reduced reliability and performance increases.

Compressor Upgrade – Replace Plant C

This project is the replacement of Dawn C plant due to the obsolescence of this second-generation RB211-24A compressor unit that was installed in the early 1980s. The manufacturer has indicated the unit will be obsolete and no longer supported when it reaches an age of about 40 years. This means that parts and components required to support the on-going operation of the unit may no longer be available. Union has experienced the unavailability of parts with a similar unit that has reached an age of obsolescence and is being retired in 2017. Replacement of this unit in 2023 will reduce the risk of a long-term outage due to a failure and the system reliability impacts.

Compressor Upgrade – Waubuno

This project is to replace the aging storage compressor at the Waubuno Station. This unit is used to inject natural gas into the Waubuno Storage Pool. The asset is over 30 years old and of a vintage that is becoming more and more challenging to maintain in terms of sourcing replacement parts. Manufacturer support of this equipment is becoming less and less certain. In order to ensure a reliable storage and withdrawal service, this unit will need to be replaced to avoid a significant outage.

Compressor and Dehydration Capital Maintenance

These projects consist of various compressor and Dehydration asset class replacements. These projects include replacement of UPS battery banks with a finite life, LED lighting upgrades as existing lighting ballasts fail. This forecast will improve system integrity and reliability.

LNG Capital Maintenance

The projects consist of Hagar Plant improvements. These projects are mainly due to the age of the plant as it is a 1966 vintage. The upgrades will reduce risk due to the aging plant and improve reliability in preparation for potential increased production demands. This forecast will improve system integrity and reliability.

Table 5.9: Compression 10 Year Forecast of Incremental O&M for (all $ in millions, incremental to 2017)

Project/Program	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Support New Compression Assets	1.4	1.4	1.4	1.4	1.4	1.4	1.5	2.2	2.2	2.2

5.3.6.2 Summary of Compression Incremental O&M

Support New Compression Assets

The incremental O&M forecast is to provide day to day maintenance and support of new compressor assets.

5.4 Supporting Assets

This grouping of assets includes Service Facilities, Fleet and Information Technology.

5.4.1 Service Facilities

The service facilities maintenance activities, programs and best practices were established to ensure building, employee, and site safety, compliance, and reliability. Service facilities maintenance activities are driven by a combination of several different maintenance programs and best practices to ensure building safety, legislative compliance, reliability, quality, value, and the functional needs of each business unit are met in order to fulfil our core responsibilities as a natural gas distribution company.

These activities, programs and best practices include internal and third party assessments to critical infrastructure at predefined intervals, proactive and reactive maintenance and repair programs, and strategic renovation or replacement of service facilities to reduce the average age maximizing asset life while balancing costs.

Table 5.10: Service Facilities 10 Year Forecast of Capital (all $ in millions)

Project/Program/ Portfolio	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
Service Facilities Maintenance	5.3	5.3	3.1	3.0	3.0	3.0	3.0	2.0	2.0	2.0	**31.7**
New Service Facilities	6.1		1.0	8.5	12.0	12.0	4.5	5.5	5.5	5.5	**60.6**
Service Facilities Modernization	3.1	9.8	10.9	3.5			7.5	7.5	7.5	7.5	**57.3**
Service Facilities Total	**14.4**	**15.1**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**149.5**

Further detail on the proposed Service Facilities spending can be found in Appendix D.

5.4.1.1 Summary of Service Facilities Maintenance Capital Projects

Service Facilities Maintenance

These projects include mitigation to lifecycle risks including issues with grounds, pavement, roofs, walls, windows, door, interior finishes, heating, ventilation, air conditioning, plumbing, electrical, lighting, furniture, access and building automation systems. Projects in this grouping are also aimed at enhancing physical security to meet existing and new security risks in proactive approach.

Planned expenditures will aid in assuring business continuity, safe reliable natural gas service and potential significant O&M savings from HVAC replacements, LED lighting conversions and building envelope upgrades.

Existing Service Facilities Modernization

These projects will address lifecycle risks, optimize current business unit space layout and ensure compliance with current Ontario Building Code requirements including fire spread mitigation. These projects will also contribute to our efforts in conservation of energy at various locations, including Chatham District Office & 50 Keil Drive North, Dawn North Administration Building, and London District Office.

These 30-50 year old buildings have been maintained but would greatly benefit from modernization to aid in assuring business continuity, safe reliable natural gas service while reduce operating costs.

This approach with a steady pace of spend is consistent with customer engagement feedback.

New Service Facilities

This category includes projects to build new service facilities that are better sized and are in a better location to accommodate the local operations. These also have improved lighting, heating and ventilating systems that will result in lower operating costs and better security.

This approach with a steady pace of spend is consistent with customer engagement feedback.

Further detail on the New Service Facilities forecast can be found in Appendix D.

Table 5.11: Service Facilities 10 Year Forecast of Incremental O&M (all $ in millions, incremental to 2017)

Project/Program	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Additional Security Guards	0.3	0.6	0.6	0.6	0.6	0.6	0.6	0.8	0.8	0.8

5.4.1.2 Summary of Service Facilities Incremental O&M

Additional Security Guards

The incremental O&M forecast is to provide additional security for new compressor assets.

5.4.2 Fleet

Preventive maintenance activities, processes, procedures and manuals for the fleet assets have been established to ensure asset and employee safety, compliance, and reliability. Maintenance activities are driven by a combination of programs and best practices to ensure vehicle, equipment and trailer safety, legislative compliance, reliability, quality, value, and to ensure the functional needs of each business unit are met.

Asset replacement decisions are based on age, mileage, condition, risk of failure and functional need. Each asset is ranked and evaluated annually. Maintenance dollars are spent based on risk with the highest risk items being completed first.

5.4.2.1 Fleet Forecast

Table 5.12: Fleet 10 Year Forecast of Capital (all $ in millions)

Program	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
Fleet	12.0	12.0	10.0	8.2	8.3	8.5	8.7	8.8	9.0	9.2	**94.7**

Fleet Replacement

This forecast includes an increase in the years 2018 to 2020 to replace fleet vehicles that would have been replaced in the years 2015 to 2017. During the years 2015 to 2017, the fleet expenditures was reduced as the funds were allocated to higher priority projects.

This approach with a steady pace of spend is consistent with customer engagement feedback.

5.4.3 Information Technology (IT)

IT application and related technology work activities are driven by a combination of enhancement projects and lifecycle upgrades/replacements. The overarching objective is to ensure that IT applications and related technologies provide desired functionality, perform efficiently, and are usable, reliable, maintainable, and compatible with other applications/technologies, as well as secure.

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.

Work activities include reviews of best practices, internal and third party assessments, development of technology roadmaps, maintenance and replacement of applications and/or technologies.

Business cases are developed for each IT investment and are prioritized using compliance, lifecycle, financial strategic, and reputational strategic drivers.

During the IT application lifecycle there are technology and design reviews to ensure new systems are implemented in the most cost effective manner, using standard tools and proper security coding practises.

5.4.3.1 IT Forecast

Table 5.13: IT 10 Year Forecast of Capital (all $ in millions)

Project/Program/ Portfolio	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
Applications	23.6	28.4	27.7	27.9	30.5	30.7	27.7	41.7	44.1	33.5	**315.8**
Hardware	3.2	6.2	7.4	6.3	4.6	5.7	7.9	5.8	5.8	3.8	**56.7**
IT Technologies	1.5	1.5	1.0	1.3	1.2	1.3	1.6	1.3	1.3	1.4	**13.4**
IT Total	**28.3**	**36.0**	**36.1**	**35.5**	**36.3**	**37.7**	**37.2**	**48.8**	**51.2**	**38.7**	**385.8**

5.4.3.2 Summary of Information Technology Capital Projects

Applications

Changes to IT Applications are categorized into the following three types;

- **Enhancements** – Small to medium sized projects to add functionality and/or adapt the application to new business requirements.
- **Upgrades** – Primarily focused on applications that leverage vendor software. Regular version upgrades are required in order to maintain vendor support.
- **Lifecycle Projects** – Medium to large projects where the entire system is replaced with either a new in-house developed application or different vendor supplied software. COTS (Commercial-off-the Shelf) or vendor supplied applications are

typically life cycled every 10-15 years to maintain support. In-house custom develop applications tend to have a longer life span and undergo a lifecycle replacement every 20-25 years.

The majority of the proposed IT capital is for life cycling existing applications. Given there are 16 key applications and lifecycle projects typically take 3-4 years to implement, there will need to always be 2-3 active medium to large application projects in order for the systems to be properly working. This supports the desire expressed by Union's customers that costs be kept at a consistent, stable level.

Further, deferring some of the proposed IT projects could result in outages that take several days to resolve, impacting Union's ability to provide safe and reliable operations – something that Union customers also indicated a strong preference for.

A 10 Year forecast of Capital for IT that includes more detail on the IT Application forecast can be found in Appendix F.

Further detail on the IT Application forecast can be found in Appendix F.

Hardware

These projects include the purchase of new and replacement hardware such as workstations, networks, servers and security components. Also included in this category are specialized devices such as meter reading handhelds, ruggedized laptops for use within the Utility Service trucks, and security cameras for monitoring remote facilities.

IT Technologies

These are projects to install new or upgrade existing IT Technologies that include application integration systems, business intelligence systems, database systems, and web delivery systems. Application integration systems allow the interconnection of processes and exchange of data among different business applications.

Table 5.14: IT 10 Year Forecast of Incremental O&M (all $ in millions, incremental to 2017)

Project/Program	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Maintenance Activities			0.6	1.1	1.1	1.6	2.1	2.6	2.6	2.7

5.4.3.3 Summary of IT Incremental O&M

Maintenance Activities

The incremental Operations and Maintenance forecast is maintenance activities for major IT applications. A majority of the incremental Operations and Maintenance is maintenance on new software licences.

5.5 Facility GHG Abatement

Union is committed to the ongoing review of opportunities that will reduce greenhouse gas emissions from its natural gas transmission, storage and distribution operations in future years. Recent feasibility studies have identified several potential facility abatement opportunities that would lead to a reduction in methane and carbon dioxide emissions over the next ten years.

Results of Union's 2017 customer engagement study showed that given the option between the status quo and paying an additional 50 cents per year for Union to reduce its GHG emissions beyond what is regulated, 58% of residential customers would prefer to pay for the additional reduction. However, a third (33%) say Union should not go beyond the regulated emissions requirement. Nine percent either weren't sure or didn't have a strong opinion.

Results showed that commercial customers are not quite as willing as residential customers to pay for additional reductions in GHG emissions: almost half (49%) would agree to a $2 per year increase in rates for an additional 25% in emissions reductions, but 42% say Union should meet but not exceed the regulated requirement. Fewer than one-in-ten (8%) did not offer an opinion.

Union has developed criteria to further evaluate these potential facility abatement opportunities to ensure the implementation of initiatives effectively balances customer preferences, compliance obligations, anticipated future regulations, and other noteworthy benefits such as safety and operational reliability. The following table shows Union's estimated potential 10 year capital and operations and maintenance forecasts for facility abatement initiatives, subject to annual review and evaluation. Detailed results of Union's feasibility studies and potential future abatement opportunities can be found in Union's 2018 Utility Cap-and-Trade Compliance Plan, filed with the Board on November 9, 2017.

Table 5.15: Facility GHG Abatement 10 Year Capital Forecast (all $ in millions)

Project	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Facility GHG Abatement		3.5	3.8	4.5	3.3	2.5				

Table 5.16: Facility GHG Abatement 10 Year Incremental O&M Forecast (all $ in millions, incremental to 2017)

Project	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Facility GHG Abatement		2.9	2.5	0.7	0.7	0.7	0.7	0.7	0.7	0.7

5.6 Maintenance Planning Recommendations

Table 5.17 and Figure 5.4 summarize the Maintenance Capital forecast recommendations to mitigate risk, maintain integrity, improve reliability, manage integrity and meet compliance requirements. A significant portion of the forecast is for larger long term projects such as the Meter Exchange Program and Asset Integrity Programs.

Larger projects have an impact on certain years. These include Replacement of the Sudbury Lateral in 2018 and replacement of Dawn C in 2024.

Emerging trends such as meeting new Material Traceability requirements are not currently included in the forecast. More information about these programs can be found in Section 8.

Table 5.17: Maintenance Capital 10 Year Forecast (all $ in millions)

Asset Category	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
Pipelines	162.6	124.3	116.2	119.5	121.6	123.6	128.1	111.0	108.9	119.5	**1235.2**
Stations	16.1	21.1	18.1	16.3	20.0	15.1	15.2	15.4	15.5	20.6	**173.2**
Measurement	24.3	26.0	30.3	29.1	29.5	29.2	29.7	30.7	30.9	31.0	**290.7**
Underground Storage	0.9	1.4	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	**12.1**
Compression and Dehydration Plant	5.7	3.7	15.0	16.8	22.0	93.1	53.7	6.5	7.3	3.7	**227.5**
Liquefied Natural Gas	0.5	2.4	1.8	1.6	8.0	1.7	1.7	8.8	1.8	1.8	**30.3**
Service Facilities	14.4	15.1	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	**149.5**
Fleet	12.0	12.0	10.0	8.2	8.3	8.5	8.7	8.8	9.0	9.2	**94.7**
IT	28.3	36.0	36.1	35.5	36.3	37.7	37.2	48.8	51.2	38.7	**385.8**
GHG Facility Abatement		3.5	3.8	4.5	3.3	2.5					**17.5**
Overheads	47.3	48.0	46.4	46.9	47.3	47.8	48.2	48.7	49.2	49.2	**479.0**
Maintenance Total	**315.4**	**291.0**	**293.5**	**294.6**	**312.7**	**375.5**	**338.9**	**295.2**	**290.2**	**290.2**	**3096.9**

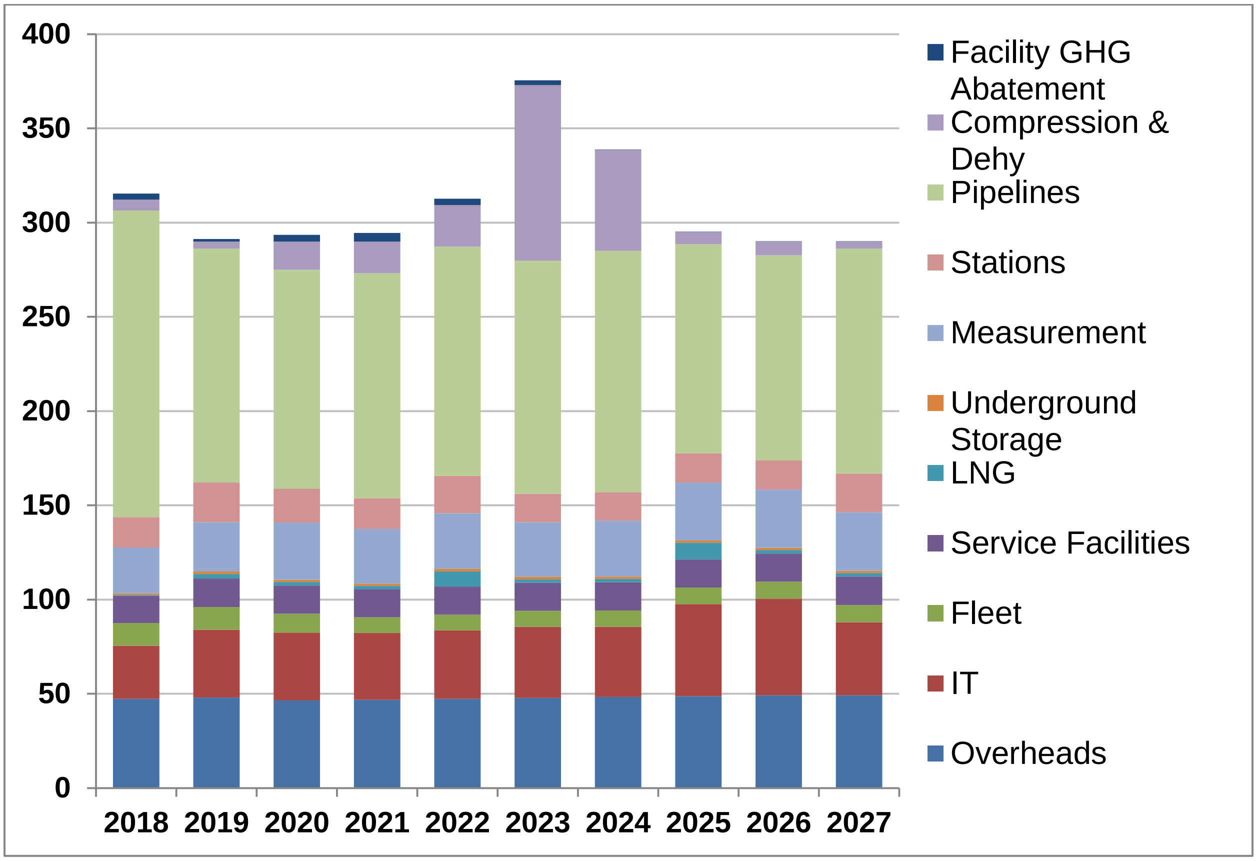


Figure 5.4: Asset Maintenance Capital Forecast (all $ in millions)

Table 5.18: Incremental O&M 10 Year Forecast (all $ in millions, incremental to 2017)

Project/Program	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Compression Growth	1.4	1.4	1.4	1.4	1.4	1.4	1.5	2.2	2.2	2.2
Service Facilities	0.3	0.6	0.6	0.6	0.6	0.6	0.6	0.8	0.8	0.8
Pipelines	1.7	4.1	6.2	6.3	6.0	6.0	5.8	5.0	5.8	4.6
Measurement	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
IT			0.6	1.1	1.1	1.6	2.1	2.6	2.6	2.7
Facility GHG Abatement		2.9	2.5	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Incremental Operations and Maintenance Total	**3.8**	**9.6**	**11.8**	**10.6**	**10.3**	**10.8**	**11.2**	**11.9**	**12.7**	**11.6**

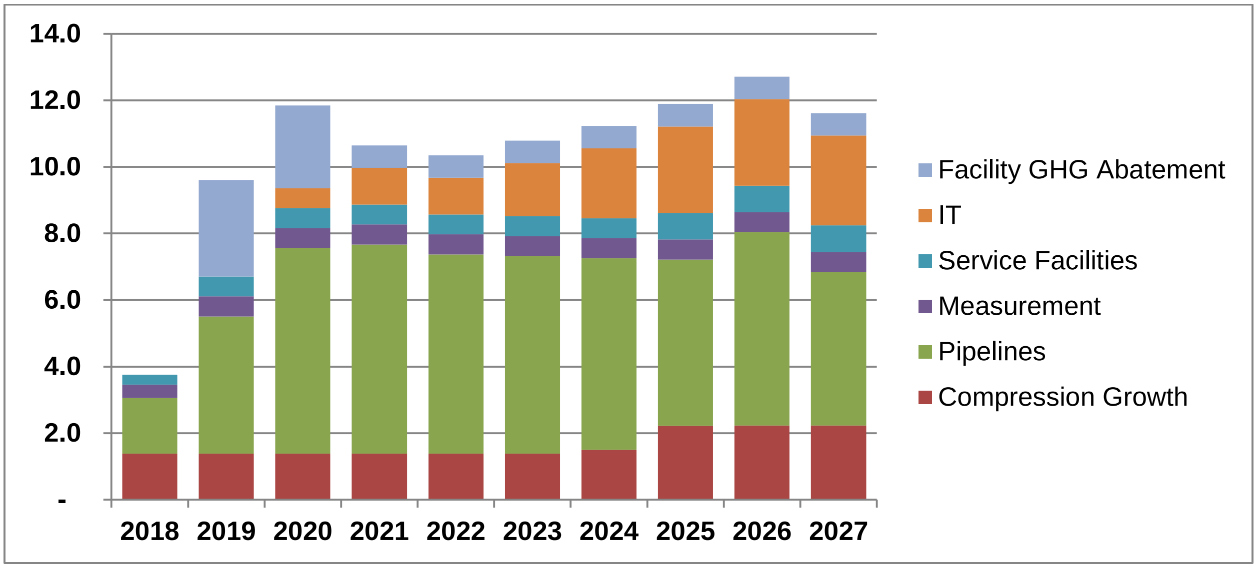


Figure 5.5: Incremental O&M 10 Year Forecast (all $ in millions, incremental to 2017)

6 Risk Management

6.1 Introduction

At Union, Risk Management is a fundamental element of the OMS. Union's Risk Management processes include formal steps to identify hazards, assess the associated risk, mitigate risks, and monitor both the risks and the overall process. The Union Gas OMS sets out the risk management expectations to identify the applicable hazards that can be controlled or influenced. Processes and procedures for operational risks are followed is to reduce or eliminate risks using a systematic approach to decision making.

The Risk Management process is a key component of the overall asset management planning and is an integral part of the Maintenance Planning which is detailed in Section 5. Risk based decision making is a fundamental requirement of sustainable Asset Management.

6.2 Risk Management Overview

Risk Management at Union is a cycle of continual review and improvement. The cycle is depicted in the following graphic and is detailed in the sections below.

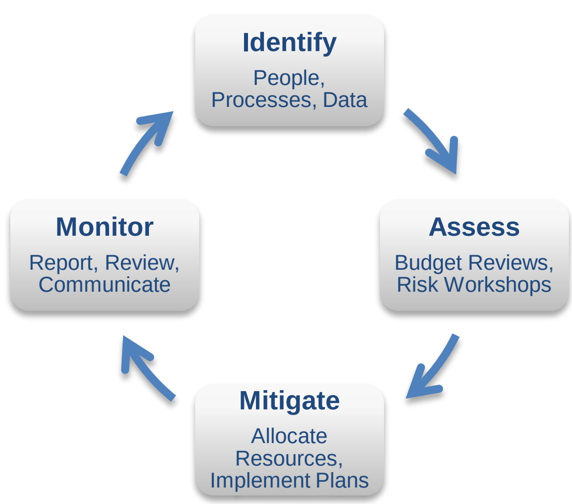


Figure 6.1: Risk Management Cycle

6.3 Hazard Identification

The Risk Management processes include steps to identify hazards in areas of operation that have resulted or may result in operational loss. These hazards are to be identified with consideration given to normal operations, abnormal operations, and potential emergency situations. Hazard identification is a key input into the Union risk assessment process and Union has a number of processes to identify hazards.

6.3.1 Hazards Identified via Database Reviews

Union has a number of different databases containing operational data which can be used by subject matter experts to help identify potential new hazards. These databases are reviewed periodically to identify potential new hazards and to help determine in any existing risks should be reassessed. These can include maintenance planning and scheduling databases, incident reporting databases, and third party damage databases.

6.3.2 Hazards Identified via Front Line

There are a number of processes used by front line employees to report on various matters that could identify potential hazards. These include feedback forms to communicate technical feedback and process improvement ideas. These processes are not specifically focused on identifying hazards; however the information tracked as part of these processes is reviewed periodically to determine if potential new operational hazards may have been identified.

6.3.3 Hazards Identified via Targeted Reviews

At Union, there are several processes used to identify hazards in specific areas of focus. These are targeted reviews focussed on specific areas of operations under Union's OMS. These include reviews of management system programs, risk registry reviews, and reviews of maintenance capital budget submissions. A portion of these specific reviews are focused on identifying any new potential hazards in that area of focus.

6.4 Risk Assessment

The hazard identification process identifies issues to move through to the next step of the risk management cycle – Risk Assessment. Identified hazards are assessed to determine the risk they pose to the organization. This would be in the form of assessing a new risk or re-evaluating a current known risk. Risk assessments are completed using Union's OMS Risk Matrix that includes scenario based risk assessments. The overall risk rank of each identified hazard is considered by taking into account the consequence and likelihood of an event. The Risk Matrix shown in Figure 6.2 is a tool used to help evaluate and rank operational risks.

			Consequence				
			C1	C2	C3	C4	C5
ALMOST CERTAIN	L5	Likelihood/Probability	III	II	II	I	I
LIKELY	L4		III	III	II	II	I
OCCASIONAL	L3		IV	III	III	II	II
RARE	L2		IV	III	III	III	II
REMOTE	L1		IV	IV	IV	III	III

Figure 6.2: Union Gas OMS Risk Matrix

Union's Risk Matrix:

- Is a 5 X 5, semi-quantitative risk matrix
  - Used to assess all operational risks consistently
- Has seven consequence categories
  - Injury, Regulatory, Loss of Containment, Environmental, Financial, Reliability / Customer Impact, Reputation
- Documents 4 different risk levels
  - Risk I, II, III or IV have different associated actions

Union uses several different forums to complete risk assessments. The majority of risk assessments are completed in a risk workshop style review. All risk workshops are completed with a consistent, systematic approach to risk assessment. Facilitation is completed by the Asset Management group to ensure consistency. Where warranted, additional specialized risk management tools are used. Hazard and Operability studies and inspection analysis are some of the more specialized risk assessment tools that are used.

6.4.1 Annual Risk Registry Workshops

There are a series of annual risk review workshops completed to review the central operational risk registry. These are held with a key group of subject matter experts and are focussed on asset classes. The goal of the review is to review identified hazards, trends, incidents, industry information, etc. to determine if new risks should be added to the risk registry or if changes need to be made to existing risks in the risk registry.

6.4.2 Maintenance Capital Budget Reviews

Union has a centralized review process to review all maintenance capital budget operations related submissions. As part of Union's risk management practice, standard processes are applied to maintenance capital budget submissions. Risk assessments are facilitated centrally for all operations maintenance capital budget submissions. For each budget submission, the risk level is reviewed and agreed to by technical subject matter experts, process owners, and a risk management subject matter expert.

6.4.3 Targeted Risk Reviews

There are several forums at Union that could trigger a separate focussed risk assessment. Risk assessments for specific risks or issues can be triggered by an incident, audit, OMS governance request, etc. These targeted risk reviews are centrally managed by the Asset Management group and follow the same process as the regularly scheduled risk reviews.

6.5 Risk Mitigation

Risk is one of the key factors used to prioritize Union programs, initiatives, and asset improvement projects. For risks deemed to be unacceptable by the appropriate level of management, controls must be developed and implemented to bring the risk to a level that is acceptable. Union processes are in place to provide direction on the level of acceptable risk. All risks are reviewed for potential improvements to the controls or asset replacement.

All reasonable efforts should be made to implement controls based on the following hierarchy while taking into account the nature of the risk and financial considerations:

- Elimination
- Substitution
- Engineering controls
- Administrative controls
- Personal protective equipment
- Contingency plans

Further detail related to how mitigation plans are reviewed and prioritized as part of the Asset Management Plan is found in Section 5.

6.6 Risk Monitoring

Union monitors operational risks and shares the status of risks with the appropriate audience in the organization, based on Union's OMS standards. Controls that mitigate risk are reviewed for effectiveness through program reviews, internal audits, subject matter experts, etc. Significant operational risks are reviewed with the Operations Steering Committee and the OMS Leadership Group on a quarterly basis until the risk is reduced to an acceptable level. The high level overview of the OMS governance is shown below in Figure 6.4.

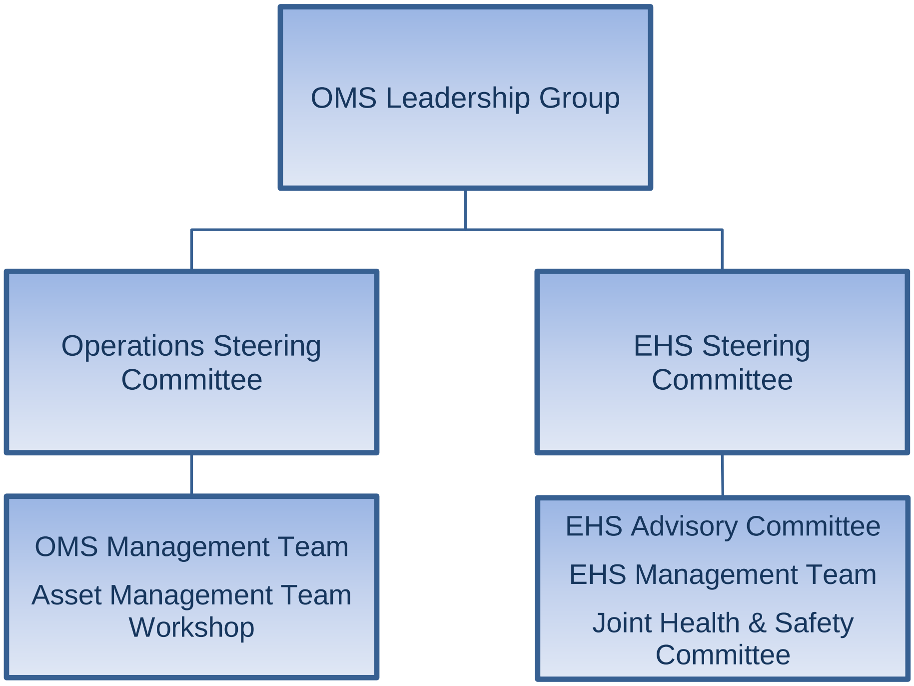


Figure 6.4: Union Gas OMS Governance

Risk Management is regularly reviewed for effectiveness. Risk Management is an element of the OMS that is reviewed annually as part of the OMS framework review. The system has been reviewed as part of broader Management system reviews and has included an external assessment, a third party audit, and participation in the American Gas Association Peer Review. The Risk Management system has also been reviewed on several occasions via an internal survey of participants. All reviews have been favourable and have confirmed the Union's Risk Management processes are effective. Improvement opportunities have been identified during these reviews and they have been included in the continual improvement process for Risk Management.

7 Forecast Summary

Figure 7.1 illustrates the forecast of capital to meet growth needs and lifecycle recommendations over the 10 year term of the Asset Management Plan.

The Maintenance Plan includes larger projects such as the replacement of the Sudbury Pipeline Sections 2 and 3 in 2018 and replacement of Dawn C compressor in 2024. Impacts can be seen in the growth plan from System growth projects such as the addition of Lobo D compressor, Bright C compressor, Kingsville Transmission Reinforcement, Panhandle Transmission, and the Sarnia Industrial Line System expansion.

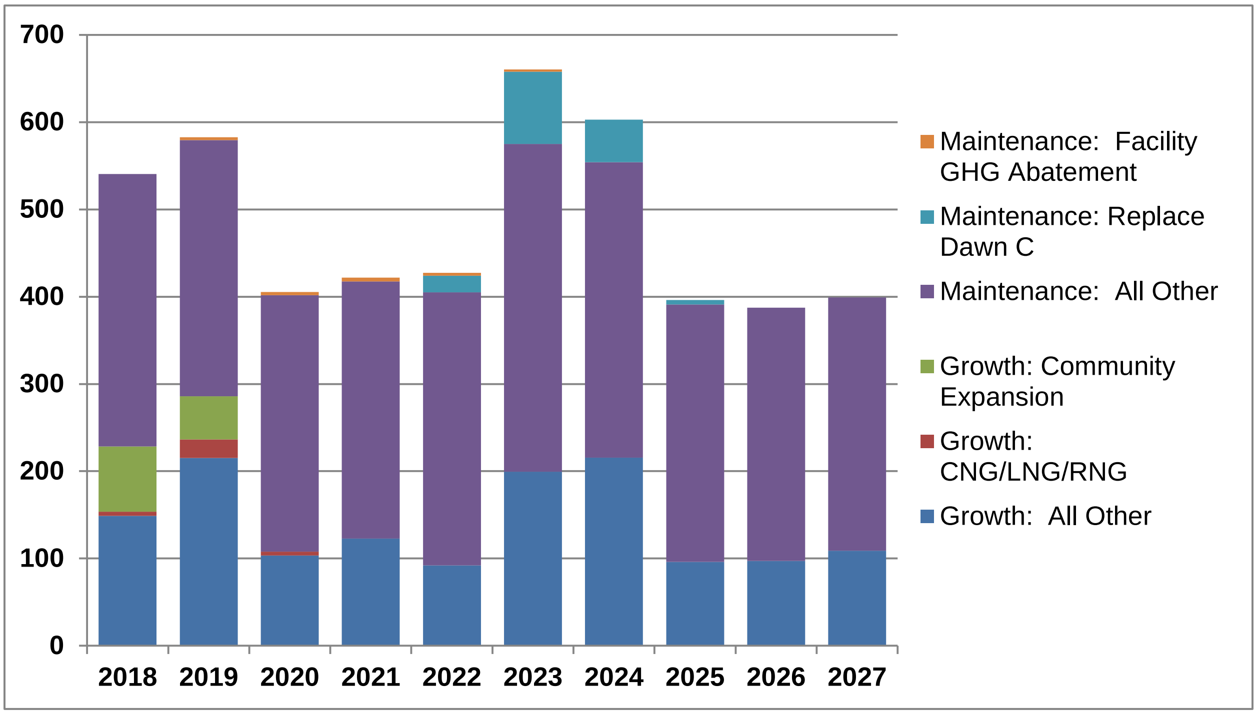


Figure 7.1: Asset Capital 10 Year Forecast (all $ in millions)

Figure 7.2 illustrates the incremental Operations and Maintenance forecast based on changes in lifecycle plans. These changes include projects to support lifecycle activities for major IT applications, to inspect pipelines at water crossings and bridge crossings beyond what has been done in the past plus an increased amount of inspections to support Integrity programs for pipelines, to support the exchange program for a larger population of meters, and for added security provided by the service facilities and day to day support for new compressor plants.

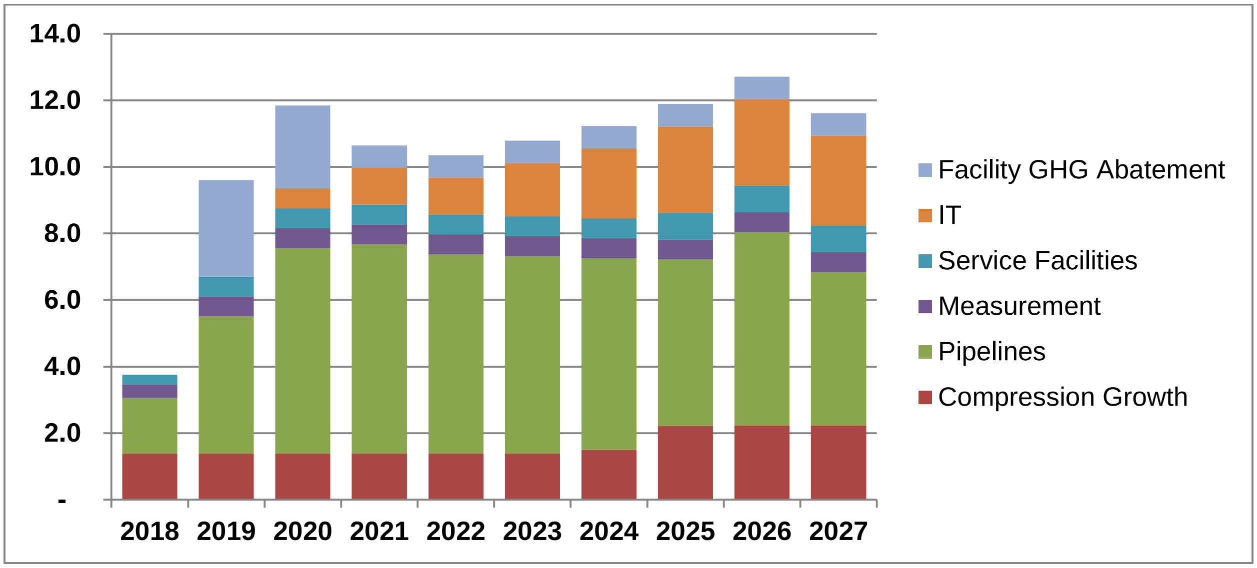


Figure 7.2: Incremental O&M 10 Year Forecast (all $ in millions, incremental to 2017)

8 Emerging Trends

8.1 All Assets

The requirement to have detailed records for all natural gas-carrying components called Material Traceability is an emerging issue in the natural gas industry. Union has initiated a project team to identify solutions for improved material traceability. The impact of these solutions will be assessed as a standalone project outside of the Asset Management Plan.

8.2 Pipelines

There may be a need to replace sections of one of the four pipelines that make up the Dawn Parkway system in the future beyond the scope of this Asset Management Plan as indications of stress corrosion cracking have been found. Active inspections have been conducted including a number of in-field assessments that show that stress corrosion cracking is on the surface only. Inspections and remediation will continue as part of the Asset Integrity Management Program.

8.3 Customer and System Stations

With increasing electricity rates, Union is seeing a significant increase in the installation of natural gas fired combined heat and power generation facilities or cogeneration facilities by our customers. In higher voltage applications, Union customer station facilities that feed these cogeneration facilities are to be designed and constructed in such a way as to isolate our equipment from the potential of electrical fault damage and to mitigate the associated risk of personal injury to anyone coming into contact with these facilities at the time of an electrical fault. There is the potential that across the Union franchise some cogeneration facilities may have been installed without the appropriate isolation built into the Union customer stations. Union will work to identify all existing customer station facilities that feed natural gas to cogeneration plants and will upgrade these stations with protection from electrical faults as required.

8.4 Measurement

Union continues to evaluate the use of automated meter reading technology in a wide variety of scenarios. Scenarios being considered include; all new attachments and all meter exchanges, high risk locations, high consecutive estimate locations due to weather or access and system-wide implementation that would include all 1.4 million measurement points.

The benefits of implementing automated meter reading technology include: improved safety by mitigating hazards on site, enhanced customer satisfaction and brand image, more accurate consumption information for planning and forecasting and avoidance of downstream costs caused by estimations.

Appendix A - Key Terms

% SMYS: Based upon Canadian Standards Association Z662 – Oil and Gas Pipeline Systems:

$$S_h = \frac{P*D}{2*t} \qquad \% \text{ SMYS} = (S_h/\text{SMYS})*10$$

Where: S_h is the design operating stress,
P is the MOP of the pipe,
D is the outside diameter of the pipe,
t is the nominal wall thickness of the pipe
SMYS is the specified minimum yield strength of the pipe

Compressor: A mechanical device for increasing the pressure of natural gas for purposes of transmission or for storage in underground storage facilities

Compressor Station: Permanent facilities which contain one or more compressors used to supply the energy needs to move natural gas through the pipeline systems at increased pressures.

Dawn: Located southeast of Sarnia, Ontario, Dawn is referred to as a Hub as it represents the point where Union's supply, underground storage and transmission systems meet. A number of other ex-franchise pipeline systems (e.g. TCPL, Vector) are interconnected to Union's system at Dawn

Dehydration Plant: A natural gas processing facility that removes water vapour by passing natural gas through a glycol contactor, which absorbs water vapour from the natural gas stream and dries the natural gas

GHG: Greenhouse Gas

LDC: Local Distribution Companies

NPS: Nominal Pipe Size – approximate exterior pipe diameter in inches

Remote Terminal Unit (RTU): a dedicated electronic controller used for data acquisition and processing.

Supervisory Control and Data Acquisition System (SCADA) – the system used to monitor and control systems from a remote location, as well as to supply important data and make it accessible for casual users.

sm^3/hr: A gas measurement of standard cubic meters per hour of gas volume passed through a meter is converted to standard units applying pressure and temperature factors.

SMYS: Specified Minimum Yield Strength - The minimum yield strength prescribed by the specification under which the material is purchased.

TC: Temperature Compensate

Appendix B – Further Detail for 10 Year Forecast of Capital for Pipelines (All $ in millions)

Project/Program/ Portfolio	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
Pipeline Integrity < 30% SMYS: Bare Unprotected	8.0	15.0	15.7	15.0	15.0	15.0	15.0				**98.7**
Pipeline Integrity < 30% SMYS: Bridge Crossings	0.4		2.9	1.6	1.7	1.1	1.1	1.2	1.2	2.5	**13.8**
Pipeline Integrity < 30% SMYS: Cathodic Protection Advancements	1.2	1.4	1.5	1.3	1.1	0.8	0.8	0.8	0.8	0.8	**10.7**
Pipeline Integrity < 30% SMYS: Other	16.6	24.2	31.7	28.9	20.9	18.0	18.2	18.4	18.6	21.0	**198.5**
Pipeline Integrity < 30% SMYS: London Lines		0.6	10.0	14.0	9.1	15.4	9.8				**58.9**
Pipeline Integrity < 30% SMYS: Schedule 10 pipe	5.7										**5.7**
Pipeline Integrity < 30% SMYS: Windsor Line	0.6	15.3			9.9	9.6	19.4	27.0	33.6	40.5	**155.8**
Municipal Replacement	20.8	20.4	24.5	24.5	25.0	25.0	25.0	25.0	25.0	25.0	**240.2**
Pipeline Integrity ≥ 30% SMYS: Integrity Management Program	14.4	14.7	13.3	13.1	12.9	12.6	12.6	12.6	12.6	12.6	**131.6**
Pipeline Integrity ≥ 30%: Bruce Lake/Ear Falls	5.0	5.5									**10.5**
Pipeline Integrity ≥ 30%: Depth of Cover			1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	**8.0**
MOP Verification			0.5	5.0	10.0	10.0	10.0	10.0	10.0	10.0	**65.5**
Class Location	22.9	24.9	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	**167.8**
Sudbury Line Section 2&3	67.2	2.3									**69.5**
Pipelines Total	**162.6**	**124.3**	**116.2**	**119.5**	**121.6**	**123.6**	**128.1**	**111.0**	**108.9**	**119.5**	**1235.2**

Pipeline Integrity < 30% SMYS: Bare and Unprotected

This program is to replace all the bare and unprotected steel mains within Union's franchise which are more susceptible to leaks given they haven't been cathodically protected since installation. About 60% of these mains are in in urban areas, approximately 5% of which are in highly developed areas. The remainder of these mains are in more rural areas. 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.

The bare and unprotected steel replacement project was part of the customer engagement survey and 50% of those surveyed recommend prioritized replacements, while 41% recommend following existing practices for replacement.

Pipeline Integrity < 30% SMYS: Bridge Crossings

Union has approximately 200 instances where pipelines of various sizes and pressures are attached to bridges. These pipelines have varied asset health, some of which are coming to end of life and need to be replaced, preferably below grade. The main driver is external corrosion, which is accelerated due to salt and water from road spray. Reducing spend in this category may lead to pipeline leaks which would be very difficult and expensive to complete immediately; it is much better to complete proactively when the work can be effectively planned and constructed.

Pipeline Integrity < 30% SMYS: Cathodic Protection advancements

This program implements solutions to reduce the amount of down plant within Union's system and ensures all pipelines are adequately protected cathodically from external corrosion. Reducing spend in this area will impact the asset health of some pipelines and may lead to a reduced life expectancy or increased chance of leaks requiring repair.

Pipeline Integrity < 30% SMYS: London Lines and Windsor Lines

Both of these pipelines are nearing end of life and significant amounts are being spent to maintain these pipeline systems. Multi-year replacement strategies have been developed for both of these pipelines based upon known risk factors. If these replacement spends are reduced or deferred, significant amounts will be required to continue to maintain these pipelines.

Pipeline Integrity < 30% SMYS: Schedule 10 Pipe

Union has approximately 14 km of Schedule 10 distribution main within two communities. This thin-wall pipe is very difficult to weld and requires special welding procedures. Removing this pipe from Union's system will also reduce the chance of leaks due to failure of older welds.

Pipeline Integrity > 30% SMYS: Bruce Lake/Ear Falls

The Bruce Lake/Ear Falls lateral is a pipeline which needs to be operated at an elevated pressure to maintain Union's system. Union has completed a detailed engineering review to ensure the condition of this system prior to increasing the pressure on this lateral, which includes making the pipeline piggeable, completing an inline inspection, and taking the line out of service to complete a pressure test on the pipeline. Deferring or reducing spend on this project will create risk of potential customer loss during high demand periods.

Pipeline Integrity > 30% SMYS: Depth of Cover

In compliance with the TSSA Code Adoption Document, Union has an annual depth of cover survey program for all 30% SMYS pipelines. These surveys may identify locations were remediation is required. Reducing spend in this area may create non-compliance issues.

Appendix C - Measurement Maintenance Tactics

Measurement Asset Sub-Class	Device Type	Maintenance Drivers	Maintenance Strategy & Tactics
Gas Meters	• Diaphragm meters (1.4 million) • Rotary meters (17,500) • Turbine meters (600) • Ultrasonic meters (commercial and interconnects) (4000 & 80)	• Compliance • Life cycle	• Diaphragm meters – Compliance sampling. Repaired or retired when removed. • Other meters - Planned maintenance as per company procedures. Condition based monitoring/time triggers. Seal expiry – out of date removal. Preventive maintenance - repair and redeploy or retire
Electronic Volume Correctors	• Electronic rotary modules (16,000) • Electronic Volume Integrators (1500)	• Compliance • Battery replacement • Life cycle	• Planned maintenance as per company procedures. Condition based/time triggers. Seal expiry – out of date removal. Preventive maintenance - repair and redeploy. Proactive battery replacement program
Odourization Systems **(Bypass & Injection)**	• MOIS injection cabinets • Odourant injection tanks (approximately 71 sites) • Odourant bypass tanks (approximately 148 sites) • Environmental deodourizer units(at each injection site) • Level instrumentation(one at each odourant site)	• Safety • Compliance • Reliability • Life cycle	• Visual inspections • Planned and unplanned maintenance • Monitoring alarms and diagnostics
Gas Monitoring & Control Systems	• RTU (400) • Communication equipment(cellular, satellite, radio) – (300) • Transmitters (1500) • Power supplies etc.	• Safety • Compliance • Operational sustainability • Reliability	• Visual inspections • Planned and unplanned maintenance • Monitoring alarms and diagnostics

Appendix D – Further Detail for 10 Year Forecast of Capital for Service Facilities (All $ in millions)

Project/Program/ Portfolio	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
Service Facilities Maintenance	5.3	5.3	3.1	3.0	3.0	3.0	3.0	2.0	2.0	2.0	**31.7**
New Service Facilities											
Belleville	6.1										**6.1**
Orillia			1.0	6.0							**7.0**
London				2.5	12.0	12.0	3.5				**30.0**
Cornwall							1.0	4.5			**5.5**
Stratford								1.0	4.5		**5.5**
Leamington									1.0	4.5	**5.5**
Simcoe										1.0	**1.0**
Service Facilities Modernization											
Head Office Power House	2.1	2.7									**4.8**
555 Riverview	1.0	6.1	3.0								**10.1**
Dawn North Admin		1.0	7.5	3.5							**12.0**
496 Riverview			0.4								**0.4**
Head Office							7.5	7.5	7.5	7.5	**30.0**
Service Facilities Total	**14.4**	**15.1**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**149.5**

Appendix E - Service Facilities Location Information

District Offices

Location	Tertiary Function	Owned /Leased	Address	Bldg (sq. ft.)	Age	Site area (acres)	No. of Bldgs
Kingston		Owned	1653 Venture Drive. Kingston	30,850	2009	3.10	1
Burlington		Owned	4475 Mainway, Burlington	23,000	2008	2.87	2
Hamilton	Technical Training	Owned	918 South Service, Stoney Creek	54,500	2013	8.42	3
London	Central Warehouse	Owned	109 Commissioners Rd, London	65,081	1968	9.23	3
Sarnia		Leased	815 Confederation St., Sarnia	23,200	1964	4.96	2
North Bay	Meter Shop	Owned	36 Charles Street, North Bay	50,600	1964	6.16	5
Thunder Bay		Owned	1211 Amber Drive, Thunder Bay	44,285	1996	5.73	1
Timmins		Owned	615 Moneta St., Timmins	13,681	1959	2.08	1
Brantford.	Call Centre	Owned	348 Elgin St., Brantford,	45,330	1995	9.68	1
Waterloo		Owned	603 Kumpf Drive, Waterloo	40,032	1984	10.00	3
Chatham	Meter Shop	Owned	555 Riverview Drive, Chatham	60,000	1972	12.91	3
Windsor		Owned	3840 Rhodes Drive, Windsor	35,725	2009	4.24	1

Regional Offices/Service Centres

Location	Owned /Leased	Address	Bldg (sq. ft.)	Age	Site/ area (acres)	No. of Bldgs
Belleville	Leased	127 Enterprise Dr., Belleville	13,750	1988	6.88	1
Cobourg	Owned	520 Thompson St, Cobourg	7,186	2006	3.09	1
Cornwall	Leased	2910 Copeland, Cornwall	6,980	1996	3.50	1
Ancaster	Owned	1474 Sandhill Dr., Ancaster	5,524	1992	1.93	1
Hamilton	Owned	581 Kenilworth Ave., Hamilton	0	N/A		0

Location	Owned /Leased	Address	Bldg (sq. ft.)	Age	Site/ area (acres)	No. of Bldgs
Hamilton	Owned	133 Park Street N., Hamilton	1,428	1960	0.30	1
Hamilton	Owned	335 Pritchard Road, Hamilton	7,186	2007	1.50	1
Milton	Owned	8015 Esquesing, Milton	7,000	1994	4.71	1
Huron Park	Leased	Centralia	5,000			1
Simcoe	Owned	RR #7 Hillcrest Rd., Simcoe	11,594	1956	3.34	3
St. Thomas	Owned	25 Sparling Road, St. Thomas	6,638	1979	2.30	2
Stratford	Owned	827 Erie St., RR #3, Stratford	7,000	1967	2.93	1
Woodstock	Owned	350 Beards Lane, Woodstock	7,509	1982	3.01	1
Bracebridge	Owned	342 Eccleston Drive, Bracebridge	732	1967	0.43	2
Elliot Lake	Leased	14 Oakland Blvd., Elliot Lake	1,961			1
Englehart	Owned	137 Third Avenue, Englehart	400			1
Haileybury	Owned	450 Meridian Ave, Haileybury	2,196	1965	0.23	1
Huntsville	Owned	184 Main Street West, Hunstville	463	1969	0.23	2
Orillia	Owned	425 Memorial Ave, Orillia	10,075	1974	1.84	1
Parry Sound	Leased	12 Seguin, Parry Sound	1,600			1
Sault Ste. Marie	Owned	10 Industrial Court, Sault Ste. Marie,	8,000	1978	2.02	2
Sudbury	Owned	828 Falconbridge Rd., Sudbury	36,717	1984	4.00	2
Atikokan	Owned	426 O'Brien St., Atikokan	1,338	1967	0.18	1
Cochrane	Owned	156 Fifth Ave., Cochrane	1,442	1966	0.20	1
Dryden	Owned	304 Kennedy Road, Dryden	1,798	1979	0.50	1
Ear Falls	Owned	5 Mills St, Ear Falls	960	2015	0.53	1
Fort Frances	Leased	851 McIrvine., Fort Frances	3500		N/A	1
Geraldton	Owned	1017 Main St., Geraldton	1,464	1964	0.36	1
Hearst	Owned	51 Eighth St., Hearst	848	1973	0.11	1

Appendix E - Service Facilities Location Information

Location	Owned /Leased	Address	Bldg (sq. ft.)	Age	Site/ area (acres)	No. of Bldgs
Iroquois Falls	Owned	522 d'Iberville Ave., Iroquois Falls	1,442	1966	0.40	1
Kapuskasing	Owned	47 Burnelle Rd., Kapuskasing	4,330	1990	1.36	2
Keewatin	Leased	4091 Hwy #17 West, Keewatin	2,500			1
Kirkland Lake	Owned	14 Kirkland St. E., Kirkland Lake	2,411	1964	0.72	2
Matheson	Owned	413 Park Lane, Matheson	484	1968	0.33	1
Nipigon	Owned	2 Wadsworth Dr., Nipigon	1,282	1963	0.86	1
Cambridge	Owned	221 Avenue Road, Cambridge	7,306	1962	4.00	2
Clarksburg	Leased	369 Clark Street, Clarksburg	880	2015		1
Dunnville	Owned	1202 Pine Street, Dunnville	6,994	1990	2.96	2
Guelph	Owned	10 Surrey Street, Guelph	6,350	1957	0.63	2
Hanover	Leased	69-14th Ave Unit 2, Hanover	1,600			1
Owen Sound	Owned	1602 23rd St. East, Owen Sound	7,300	2006	2.00	2
Palmerston	Owned	206 Whites Rd. Palmerston	720			1
Leamington	Owned	357 Oak St. Centre, Leamington	4,803	1961	2.01	1

Regulatory Offices

Location	Owned /Leased	Address	Leased (sq. ft.)
Ottawa	Leased	46 Elgin St. Ottawa	200
Toronto	Leased	2300 Yonge St, Toronto	2,650
Toronto	Leased	777 Bay Street, Toronto	10,581

Property Only Service Facilities

Location	Owned /Leased	Address	Site Area (acres.)
Brantford	Owned	315 Colborne Street, N3S 3N1	0.63
Brantford	Owned	11 East Ave, Brantford, N3S 7P4	0.62
Hamilton	Owned	360 Strathearne Ave. Hamilton	6.11
Hamilton	Leased	361 Strathearne Ave. Hamilton – Hydro Easement at access	N/A

Compressor and Storage Support

Location	Primary Function	Address	Bldg (sq. ft.)	No. of Bldgs
Bright	Admin. Office	866139 Township Rd 10 - Blandford	10,213	1
Dawn - EOC Building	Admin. Office	3332 Bentpath Line, Dresden	6,810	1
Dawn - South Support	Admin. Office	3332 Bentpath Line, Dresden	13,500	1
Dawn Operation Center - North Admin	Admin. Office	3332 Bentpath Line, Dresden	128,348	1
Hagar	Admin. Office	317 Northern Rd - Hagar	2,314	1
Lobo	Admin. Office	11025 Ivan Drive - Ilderton	13,768	1
Parkway West	Admin. Office	6626 9th Line - Mississauga	10,206	1
Parkway Heritage houses/barn	Heritage	6626 9th Line - Mississauga	N/A	3
Parkway healing garden	Property Only	6626 9th Line - Mississauga	N/A	0
Parkway Snake habitat	Property Only	6626 9th Line - Mississauga	N/A	0
Dawn - Mechanics Building	Service	3332 Bentpath Line, Dresden	10,500	1
Dawn - Sewage Lagoon Treatment	Sewage Lagoon	3332 Bentpath Line, Dresden	270	2
Dawn - Warehouse	Warehouse	3332 Bentpath Line, Dresden	16,000	1

Appendix F – Further Detail for 10 Year Forecast of Capital for IT Applications, Technologies and Hardware (All $ in millions)

Project/Program /Portfolio	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10 Year Total
Key Applications											
Banner	0.4	2.0	3.5	2.1	2.1	2.2	12.1	32.1	37.3	27.1	**120.9**
CARE	0.2	0.2	6.1	11.1	10.1	9.2	0.2	0.1	0.2	0.2	**37.6**
CARS	0.1	0.8	0.2	7.2	7.4	7.4	2.0	2.0	0.3	0.3	**27.7**
ConTrax	12.6	7.9	0.1	0.3	0.3	0.1	2.4	0.1	0.1	0.1	**24.0**
Corrosion			1.5	2.0	0.2		0.2		0.3		**4.2**
GIS	0.3	0.8	1.0	0.7	6.0	6.0	6.0	0.5	0.2	0.2	**21.7**
Meter & Measurement Applications	0.2	0.3	3.5	0.2	0.5	0.1	0.2	0.3	0.2	0.1	**5.6**
SCADA	0.8	1.0	1.0	1.0	1.0	1.1	2.1	4.2	2.0	1.0	**15.2**
Service Suite	7.8	13.0	7.4	0.1	0.3	0.1	0.1	0.1	0.3	0.1	**29.3**
Applications Other	1.2	2.4	3.4	3.2	2.6	4.5	2.4	2.3	3.2	4.4	**29.6**
Hardware	3.2	6.2	7.4	6.3	4.6	5.7	7.9	5.8	5.8	3.8	**56.7**
IT Technologies	1.5	1.5	1.0	1.3	1.2	1.3	1.6	1.3	1.3	1.4	**13.4**
IT Total	**28.3**	**36.0**	**36.1**	**35.5**	**36.3**	**37.7**	**37.2**	**48.8**	**51.2**	**38.7**	**385.8**

Key Application Projects

Banner – is used to bill Union's 1.4 million residential customers as well as the large commercial and industrial accounts. In 2019 & 2020, a $2.5M enhancement to the on-line component referred to as My Account is required for compliance with the AODA (Accessibilities for Ontarians with Disabilities Act). During 2024 through to 2027, the application will undergo a major lifecycle replacement as the current version and underlying technologies will be over 20 years old. The other spending is on enhancements to enable the application to continue to meet business needs.

CARE – is Union's gas management system which handles both incoming and outgoing nominations. It validates these requests against Union's pipeline capacity. In 2020-2023, CARE will have a major lifecycle replacement to ensure it continues to operate effectively. It is an in-house developed application that was originally developed in 1994. The underlying technologies are no longer supported by the vendor and it's becoming increasingly difficult to maintain resources trained in the older programming tools.

CARS – allows customers and contractors to submit and track their requests to get gas service at their location. In 2021-2024, CARS will have a major lifecycle replacement to ensure it continues to operate effectively. It was developed in-house in 2009. The underlying technologies are no longer supported by the vendor and it is becoming increasingly difficult to maintain resources trained in the older programming tools. In 2025, the on-line user interface referred to as Get Connected, will be enhanced to ensure it continues to operate securely.

CONTRAX – provides billing of Distribution, Storage & Transportation services for large Commercial/Industrial accounts and Direct Purchase customers. A lifecycle replacement project was started in 2013 and will finish in 2019. The application had become difficult to support due to the outdated technology and the complexity of the application as a result of having undergone several disparate and complex enhancements since it was initially implemented in 1995.

Corrosion - provides asset-tracking, inspection and field data collection system for routine inspection, maintenance and regulatory compliance activities on Union's pipeline built on vendor provided software. The software is overly complex to use and therefore inefficient. Alternative packages will be investigated as part of the lifecycle project in 2020-21, including potential of consolidating its functions into an existing application.

GIS – is Union's geographic information system (GIS) application for storing spatial and attribute information primarily related to underground assets (e.g. pipe, valves, fittings, district boundaries, structures, intersections, etc.). It provides accurate data for planning and emergency response. The application consists of a suite of purchased software products that will need to be life cycled in 2022-2024 to maintain vendor support. The current software version was implemented in 2007.

Meter and Measurement – is a set of applications that captures meter readings from residential, commercial and high volume customers, passing the data onto the appropriate billing systems. In 2020, the residential meter reading application will be upgraded to incorporate reads from meters with AMR devices. It is expected that through the regular life cycling of meters, a sufficient number them will have this feature.

SCADA - the Supervisory Control and Data Acquisition System is used to monitor and control Union's pipelines and stations from a remote location, as well as to make important data accessible for other users for system planning. The software monitors pressures, flows and gas quality. A lifecycle of the SCADA application is planned for 2024-2027 with upgrades to both the host application and the telemetry throughout. The last major lifecycle replacement of the vendor software (Cygnet) was in 2011.

Service Suite – is vendor software configured to provide electronic work orders to Union's 400 Utility Services Representatives across Ontario. It is used to dispatch workers in the event of a gas emergency. The application also accepts completion of work. The last major lifecycle occurred in 2007. A lifecycle project was initiated in 2016 to find a product that could better serve the requirements as well as a solution that was more stable. The current system has both performance issues as well as frequent outages. The new system is targeted to go live in 2020.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, Page 3

> "Enbridge Gas's Distribution Integrity Management Program ("DIMP") continually evaluates assets to identify risks and determine the condition of pipelines in the distribution network. Analysis conducted by Enbridge Gas has shown that the existing London Lines are in poor condition and have several active degradation factors, including loss of containment, shallow depth of cover, and corrosion induced wall loss."

Questions:

(a) Please file any guidelines and procedures that govern Enbridge Gas's Distribution Integrity Management Program ("DIMP").

(b) Please list and describe the kinds of reports prepared pursuant to Enbridge Gas's Distribution Integrity Management Program.

(c) Please file all materials prepared as part of Enbridge Gas's Distribution Integrity Management Program in relation to the London Lines.

(d) Please compare what was known of the London Lines pipeline condition pursuant to DIMP on (a) January 1, 2010, (b) January 1, 2015, and (c) January 1, 2020.

Response:

a) Please see Attachment 1 for the guidelines and procedures that govern Enbridge Gas's Distribution Integrity Management Program.

b) Enbridge Gas's Distribution Integrity Management Program prepares two kinds of reports:

- Asset Health Review: A yearly reliability and condition assessment is performed by the DIMP department of distribution gas carrying assets.

Currently the Asset Health Review assesses Legacy Enbridge Gas Distribution Assets and a portion of Legacy Union Gas Plastic Mains. The DIMP department is currently working to integrate Legacy Union Gas distribution gas carrying assets as part of the Asset Health Review.

- Integrity Assessments: These reports are reliability and condition assessments on specific groups of assets, components or hazards. The reports typically gather background information about the topic of study, define a population, analyze, define and review the condition and reliability of the assets or components and provide recommendations for further review or mitigation.

c) The Integrity Assessment, as filed at Exhibit B, Tab 2, Schedule 1, Attachment 1 is the material prepared as part of the Enbridge Gas's Distribution Integrity Management Program in relation to the London Lines. Also, see Exhibit.I.FRPO.5.

d) Please see Exhibit I.BOMA.5 a).

Distribution Integrity Management Program

MP-05-01

As part of Enbridge Gas Distribution's Integrated Management System
October 10, 2017

Program

—

Company: Enbridge Gas Distribution

Owned by: Integrity Department

Controlled Location: Integrated Management System Teamsite

Table of Contents

Table of Figures

Table of Tables

1 Introduction

Enbridge Gas Distribution's (EGD's) Integrated Management System (IMS) is a framework used to carry out business activities in a systematic manner. The IMS ensures that EGD meets the regulatory and corporate obligations related to safety and operational reliability. The IMS document outlines both what management system requirements are expected and how they are carried out in a common way across the organization.

The MP-05 Integrity Management Program is one of six Management Programs included in EGD's IMS. It follows the expectations outlined in the IMS document and provides more specific detail on how the MP-05 meets its requirements and manages its activities. The MP-05 Program covers the four gas carrying asset classes (Pipe, Station, Storage, and Customer) that make up the Enbridge Gas Distribution Pipeline System. Several unique Integrity disciplines are required due to the distinctive nature of the comprehensive registry of assets within the gas carrying system. In addition, there are specific codes, standards, and regulations that may only apply to certain asset types. For these reasons the integrity of these asset classes are managed by the following Integrity Management Programs (IMPs) under Integrity Management Program MP-05.

- Distribution Integrity Management Program (DIMP)
- Transmission Integrity Management Program (TIMP)
- Facilities Integrity Management Program (FIMP)
- Customer Integrity Management Program (CIMP)

These Integrity Management Programs are designed to primarily satisfy Regulatory requirements (NEB, TSSA), and CSA Z662 Annex N. They also identify, define, control, and improve processes for core and interconnected activities that affect gas carrying assets. Data is collected from Integrity Operating Programs (IOPs) and analyzed to assess the condition and risk of the pipeline system. The assessment and risk information is used to develop risk mitigation activities.

The governance of the IMPs and the IOPs ensures that these programs are effective at mitigating integrity risk and identifying opportunities for optimization by demonstrating their compliance with company and regulatory requirements.

Refer to the Gas Distribution Integrity Core Process document for a high level description of the core functions used in the Integrity Management Program (MP-05) for the EGD Pipeline System.

2 Purpose

The purpose of the Distribution Integrity Management Program (DIMP) is to ensure that the distribution pipeline system is suitable for continued, safe, reliable, and environmentally responsible service, and to comply with regulations.

More specifically, the role of DIMP within EGD is to monitor conditions of the distribution pipeline system that could lead to failures and to proactively eliminate or mitigate those conditions. This is achieved through DIMP by applying the following:

- Gathering knowledge about asset condition to determine failure probability to support key asset decisions based on risk, and proposing proactive mitigation projects to Asset Management.
- Complying with current TSSA Code Adoption Documents, Industry & Company Standards as listed in the MP-05 Integrity Management Program document
- Ensuring clear roles and responsibilities for achieving DIMP integrity objectives and performance targets
- Measuring, monitoring, and reporting integrity performance
- Ensuring effective practices for developing and maintaining job competencies
- Anticipating, recognizing, evaluating, and controlling distribution system integrity hazards and risks

3 Scope

This document provides an overview of the Distribution Integrity Management Program's processes, policies, and activities.

DIMP ensures reliability of gas carrying Pipeline Systems by calculating the Probability of Failure (PoF) based on input from the Integrity Operating Programs (IOPs) and passing it on to Asset Management for analysis that in turn eliminate or mitigate EGD's exposure to risk. DIMP also performs integrity assessments to constantly monitor and assess the condition of the Pipeline System.

DIMP complies with the most recent requirements of the TSSA Director's Public Safety Order by ensuring that the threats to all gas carrying assets listed in *Table 7 Pipeline System Threats* are identified, detected, prevented, or mitigated.

DIMP applies to the Distribution gas carrying asset classes listed in the table below:

Table 1 DIMP Asset Classes

Asset Class	Description
Pipe	Mains, headers, and service pipe, steel risers, anodeless risers, composite risers, copper risers, below- and above-ground valves
Station	District / header / sales***** stations; farm taps; customer meter sets (***** *sales stations include pressure factor stations, standard sales stations, mini sales stations, low pressure delivery stations*)
Storage	Engine/Compressor Cylinders, Crankshafts and Bearings, Foundations, Power Cylinders, Engine Frames, Camshafts, Gas Aftercoolers, Wells, Valves

DIMP does **not** apply to:

- EGD affiliates and other business units (Gazifère, Enbridge New Brunswick, St Lawrence Gas)
- Non pipeline-related assets – including buildings (e.g., EGD's Meter Shop and Engineering Materials Evaluation Centre); tools, equipment, and vehicles; IT software and hardware
- Mechanical material handling generally associated with on-site warehousing activities – including palletizing, transporting, or stacking closed portable containers of hazardous materials
- Worker safety management – including slips, trips, and falls

4 Regulatory and Corporate Requirements

The regulatory and corporate requirements that apply to DIMP are listed in the table below.

Table 2 Regulatory and Corporate Requirements

Reference	Description
EGD	Policies, safety alerts, engineering memos, and all references.
TSSA	Advisories and Director's Orders.
CSA Z662	Oil and Gas Pipeline Systems and any modifications through code adoption documents made by the authority having jurisdiction. For Ontario requirements, refer to the TSSA Director's Order FS-220-16.
O. Reg. 210/01	Oil and Gas Pipeline Systems.

Codes and standards for particular operating programs within DIMP have been presented in their respective Integrity Operating Program (IOP) document.

5 Stakeholder Engagement

5.1 Internal Stakeholders

Internal communications occur on a regular basis through various medium to encourage a top-down as well as bottom-up flow of information. DIMP uses the stakeholder engagement methods outlined in the Integrated Management System IM-01 and Integrity Management Program MP-05 documents.

Expectations and needs of DIMP's main internal stakeholders are defined in the Integrity Management Program MP-05 document and those specific to DIMP (at a high-level) are presented in the table below.

Table 3: Internal Stakeholders – Needs and Expectations

Internal Stakeholders	Needs And Expectations
Asset Intelligence	• Provides asset, failure, condition and multiplier data • Establishes data governance for data used • Provides cost data for risk portion of AHR • Establishes data requirements for asset sub-classes • Provides feedback for continuous improvement and data governance
Asset Management	• Prioritizes assets and topics to study • Receives, reviews, and approves DSI assessments • Provides information and context regarding the studied asset or topic • Provides recommendations regarding potential mitigation activities • Establishes asset management strategy • Identifies required asset sub-classes • Reviews and approves changes and results • Utilizes results to create capital plans
Asset Renewal and Improvement	• Provides Operational Subject Matter Advisor input. Can recommend assets and topics to study. Review results and provides feedback. • Provides impact of proactive and reactive work
Corrosion Prevention	• Provides Cathodic Protection Subject Matter Advisor input • Can recommend assets and topics to study • Can provide insight on cathodic protection data. • Can provide recommendations as to potential process and program changes
Customer Connections and Construction	• Provides Operational Subject Matter Advisor input • Can recommend assets and topics to study • Reviews results and provides feedback. • Provides impact of proactive and reactive work

Internal Stakeholders	Needs And Expectations
Distribution Protection	• Provides Distribution Protection Subject Matter Advisor (SMA) input • Provides Damage Prevention data • Can recommend assets and topics to study • Can provide insight on how damages affect Asset Health • Can provide recommendations as to potential process and program changes
Engineering	• Can recommend assets and topics to study • Creates the construction processes manuals affecting the behavior of assets • Provides the analysis required during the DSI assessment • Can provide recommendations as to potential construction process changes • Provides SMA input during model development • Provides predictive models that may influence changes to policy
Engineering Materials Evaluation Centre	• Provides failure investigation information and lab testing for model development • Can recommend assets and topics to study • Provides guidance and recommendations regarding lab testing processes • Provides input into material fault reports and failures investigations • Provides guidance and recommendations regarding lab testing processes
Gas Storage	• Provides Operational Subject Matter Advisor input • Can recommend assets and topics to study • Reviews results of study and provides feedback • Provides impacts of proactive and reactive work
Leak Survey	• Provides Cathodic Protection Subject Matter Advisor (SMA) input. • Provides leak survey data and schedule is incorporated into Decision Support tool • Can provide recommendations as to potential process and program changes
Network Operations	• Provides operational Subject Matter Advisor (SMA) input • Reviews study results and provides feedback • Provides impact of proactive and reactive work
Risk Management	• Provides consequence model framework for AHR • Decision Support Tool funnels projects work for QRAs

5.2 External Stakeholders

The majority of communication with EGD's external stakeholders is handled through areas listed in the Integrated Management System IM-01 and Integrity Management Program MP-05 documents. Some Operating Programs within DIMP interface with external stakeholders more regularly.

The expectations and needs of DIMP's external stakeholders are defined at a high-level in the table below:

Table 4: External Stakeholders – Needs and Expectations

External stakeholders	Needs and Expectations
TSSA	The Technical Standards and Safety Authority is Ontario's regulator under O. Reg. 210/01 for oil and gas distributing systems.
Ontario Energy Board	The Ontario Energy Board is the financial regulator for EGD that reviews the 10 year Asset Plan and the EGD rate case which is produced from the results of the AHR.

6 Leadership

6.1 Management Program Policies

DIMP is guided by the governing policies outlined in the Integrated Management System IM-01 and Integrity Management Program MP-05 documents. Adherence to the policy ensures the continued safe, reliable, and environmentally responsible service.

6.2 Organizational Roles, Responsibilities, and Authorities

The Integrated Management System IM-01and Integrity Management Program MP-05 documents outline the governance structure for the Accountable Officer and the other roles which operate beyond DIMP. For the roles and responsibilities that are specific to DIMP they have been presented in the table below. Specific roles and responsibilities for internal stakeholders are presented in each Integrity Operating Program.

Table 5: Roles and Responsibilities for Individuals

ROLE	RESPONSIBILITIES
Director of Integrity	• Provides overall leadership to DIMP • Provides High-level Contractor management • Ensure adequate resources to manage program effectively • Provides high-level cost/budget oversight
Manager, Distribution Integrity & Reliability	• Aligns DIMP with the IMS to ensure consistency and integration • Ensures DIMP follows the PDCA cycle for continual improvement • Approves DIMP related communication and updates to this document • Ensures that the Integrity Assessment and Asset Health Review Programs meet the requirements of the Integrity Operating Program documentation • Assesses resource needs required for DIMP • Provides direct leadership to the DSI Group and to the Integrity Assessments Program • Provides direct supervision of the DSI Integrity Technologists and the Supervisor Asset Health Review Program • Plans and executes the DSI Assessments Program overseen by the DSI group • Implements new procedures and monitors DSI Assessment Program • Obtain resources required to maintain the DSI Assessments Program
Supervisor, Asset Health Program	• Reviews the DIMP document annually • Maintains adequate control of the DIMP document • Fields change requests to the document and follows Management

ROLE	RESPONSIBILITIES
	of Change process for its updates • Aligns the DIMP documentation to the IMS to ensure consistency and integration • Reports on results/decisions of DIMP in the Integrity Management Program annual report • Provides adequate and effective communication about DIMP • Provide direct supervision of the DSI Project Managers ensuring the DSI Assessments program is operating as intended • Organizes training and consistently monitors DSI Project managers • Identifies process gaps within the DSI Assessments Program • Tracks to closure the recommendations provided by the DSI Assessments
DSI Project Manager	• Completes DSI Assessments • Manages and completes DSI Assessment throughout entire project cycle • Participates as a Subject Matter Advisor for the applicable assets the Project Manager has assessed • Tracks to closure the recommendations provided by the DSI Assessments
DSI Integrity Technologist	• Assists in the completion of DSI Assessments • Supports the DSI Project managers as assigned in the collection, review and analysis of data pertaining to the applicable DSI Assessment
Asset Management Asset Manager	• Provides direction as to the topics and assets to be assessed by DSI. • Reviews and approves DSI Assessments • Manages implementation of any recommended mitigation actions which are approved.

In addition, DIMP has established teams and committees who collectively have the roles and responsibilities listed in the table below.

Table 6 Committee Responsibilities

Roles	Responsibilities
P.O.L.E. Committee	• Investigates issues related to faulty materials and components that could lead to damage or failure to the pipeline operating system • Conducts root cause analysis to help prevent future issues or events • Establishes corrective actions with due dates • Tracks all reported material faults until they are closed

7 Program Records

Refer to Records Management Policy on ELink for details regarding Program Records.

8 Change Management

Refer to IM-01: Integrated Management System – Section 3.3 "Management of Change" for details regarding change management.

9 Competency and Training

9.1 Resources

9.1.1 People

DIMP is complex program and requires expert knowledge and integration of multiple technical disciplines including engineering, material science, geographic information systems (GIS), data management, probability and statistics, and risk management.

The personnel involved in the integrity management program must be aware of the Integrity Management Program MP-05 program and be qualified to execute all of the DIMP activities within the program.

Integrity Management competency requirements are evaluated on an ongoing basis. New technology requirements, workload, regulatory and stakeholder needs may require additional resources or training. These needs are monitored and acted upon by the applicable Department Manager.

The following key competencies are mandatory to perform DIMP activities:

- Excellent project management skills, ability to independently organize and manage multiple technically challenging projects simultaneously in order to meet and deliver objectives
- Strong team leading capabilities and experience with positively influencing others and working in a team environment promoting collaboration
- Effectively builds and maintains positive professional relationships within other business units and customers
- Analytical approach to problem solving, good understanding of trending analysis, root cause analysis, failure mode identification, probability of events, and the ability to apply engineering principles to analysis
- Excellent written and verbal communication skills that can successfully communicate technical content to a less technical audience
- Employs advanced time management skills in order to manage and meet project major milestones

- Solid understanding of distribution system assets, construction methodologies, common failure modes found within EGD components, engineering disciplines and material sciences, probability and statistics, and risk management
- Proficient in working with computer systems and software (such as Excel, MS Word, databases)
- Engineering degree and/or PMP

9.1.2 Infrastructure

Specific infrastructure requirements are detailed in the supporting IOPs.

9.2 Training Requirements

Refer to MP- 05 Section 4.2 Competence and Training for details regarding training requirements.

10 Threats to the Distribution Pipeline System

DIMP includes several condition monitoring programs which identify threats to the gas carrying assets to reduce risk through IOP activities and integrated processes, such as Asset Health Review for example.

DIMP monitors the health of gas carrying assets within the Pipeline System. Depending on data review and concerns identified, integrity assessments are initiated and mitigation plans are implemented if required to maintain the health of all gas carrying assets in the Distribution System.

10.1 Threat Identification

DIMP identifies threats through the analysis of the data and information collected by the IOPs. Each of the threats listed in the CGA and ASME B31.8S, *Managing System Integrity of Gas Pipelines* was assessed based on available distribution system data and supplemented with Subject Matter Advisor (SMA) information sessions to provide the table below.

Table 7 Pipeline System Threats

Type	Threat Category	Threat	Description
Time-Dependent	Corrosion	External Corrosion	Deterioration of the pipe due to an electrochemical reaction between the pipe material and the environment outside the pipe.
		Internal Corrosion	Deterioration of the pipe due to an electrochemical reaction between the pipe material and the environment inside the pipe.
		Stress Corrosion Cracking	Cracks in the pipe due to the interaction of tensile stresses in the pipe material with a corrosive environment.
	Plastic Material	Plastic Degradation	Sunlight contains a significant amount of ultraviolet radiation. The ultraviolet radiation that is absorbed by a thermoplastic material may result in actinic degradation (i.e., a radiation promoted chemical reaction) and the formation of heat. The energy may be sufficient to cause the breakdown of the unstabilized polymer and, after a period of time, changes in compounding ingredients. Thermoplastic materials that are to be exposed to ultraviolet radiation for long periods of time should be made from plastic compounds that are properly stabilized for such conditions.
		Rock Impingement	This phenomenon results of an intermittent or permanent contact of a hard object - most often not directly injurious - with the PE pipe that creates a

Type	Threat Category	Threat	Description
			localized increase of the tension in the pipe and, in turn, generates the progressive cracking from the inside towards the outside, in line with the hard point, over a few millimeters in the pipe inner surface.
Stable	Manufacturing	Long Seam Defects / Pipe Defects	Defects introduced during pipe manufacturing, such as laminations, inclusions, hard spots. Pipe manufactured using techniques now known to have weaknesses, such as low-frequency electric resistance welded pipe, lap welds, butt welds, and electric flash welds.
	Construction / Fabrication	Girth Weld Defects / Coupled / Pressure Welds Branch Connections	Defects and weaknesses introduced during pipeline construction, such as bad field welds, stripped threads, and broken pipe.
		Wrinkle Bends	Defects and weaknesses introduced during pipeline construction due to wrinkle bends.
		Other Improper Construction	Leaks caused by pre-commission construction issues (e.g. not following procedures, not having competency/training, cross bore, loose tee cap, cracked tee cap due to over tightening).
		Coupled / Pressure Welds Branch Connections	Defects and weaknesses introduced during pipeline construction, such as bad field welds, wrinkle bends, stripped threads, and broken pipe.
	Equipment	Control System Malfunction (e.g. regulators, relief valves)	Control system failed to perform requested action as designed or performed an action in error.
		Gasket / ML Valves	Pipeline facilities other than pipe and pipe components, such as pressure control and relief equipment, gaskets, O-rings, and seals.
Time-Dependent	External Interference	1st or 2nd Party	Inadvertent external interference by a person or group of people employed by or that has undertaken a contract with an operating company to provide goods or services.
		Third Party Damage	Accidental or intentional excavation damage by a third party (that is, not the pipeline operator or contractor) that causes an immediate failure or

Type	Threat Category	Threat	Description
			introduces a weakness (such as a dent or gouge) into the pipe.
	Incorrect Operations	Human Error	Decision error made by operating company during service causing a failure of the pipeline system and resulting in an incident.
		Incorrect Procedure	Post-commission: insufficient procedure provided inadequate documentation / records.
	Weather and Outside Forces	Earth Movements / Floods	Geotechnical investigations shall provide sufficient data concerning the ground and the ground-water conditions at and around the construction site for a proper description of the essential ground properties and a reliable assessment of the characteristic values of the ground parameters to be used in design calculations.
		Cold Weather / Heavy Rains	State of the atmosphere with respect to heat or cold, wetness or dryness, calm or storm, clearness or cloudiness. Also, weather is the meteorological day-to-day variations of the atmosphere and their effects on life and human activity. It includes temperature, pressure, humidity, clouds, wind, precipitation, and fog.
		Lightning	Any form of visible electrical discharges produced by thunderstorms.
		Wild fire	
		Wildlife / Animal	An animal that belongs to a species that is wild by nature, and includes game wildlife and specially protected wildlife.
	Cyber Attack	Cyber Attack	Cyber-attacks — the manifestation of either physical or logical threats against computers, communication systems or networks with the following traits: a) Originate from either inside or outside the facility; b) Involve unauthorized physical access or logical threats; c) Can be direct or non-direct in nature; d) Are conducted by threat agents having either malicious or non-malicious intent; e) Have the potential to result in direct or indirect adverse effects or consequences to CEA's (cyber essential asset).

11 Program Cycle (Plan-Do-Check-Act)

The Plan-Do-Check-Act (PDCA) model is a key component of EGD's Integrated Management System used for continual improvement.

The Distribution Integrity Management Program follows the PDCA cycle that is described *Figure 1 PDCA Cycle Activities* below. Refer to the IM-01 Integrated Management System document for more information related to PDCA.

Plan

1. Identify threats and barriers to pipe, storage, and station assets and their components
2. Assess and calculate integrity risks to pipe and station assets and their components
3. Calculate probability of failure
4. Develop strategies / corrective actions to reduce operating risks related to customer assets components to As Low As Reasonably Practical (ALARP)
5. Plan corrective actions
6. Define data requirements for models

Do

1. Perform Integrity Assessments
2. Gather knowledge about asset condition and failure probability for the Asset Health Review Program
3. Implement and monitor corrective actions
4. Manage, control and retain DIMP Records
5. Implement changes through the Management of Change process
6. Continue to develop and assess competencies
7. Gather knowledge on current asset condition through IOP outputs
8. Generate Failure Curve
9. Develop and configure new model
10. Develop AHI Formulation
11. Determine asset health for customer asset

Act

1. Adjust corrective actions
2. Develop strategies to mitigate asset health risk level
3. Provide Asset Health results to asset managers for capital planning and project scoping
4. Use Asset Health results for decision support

Check

1. Monitor and measure the results of the corrective actions to reduce operating related risks customer assets components to As Low As Reasonably Practical (ALARP)
2. Assess if asset health risk is acceptable
3. Identify IOPs' data, process, and reporting gaps
4. Look for opportunities for optimization
5. Compare projections vs. new data
6. Validate AHR models against filed conditions

Figure 1 PDCA Cycle Activities

11.1 Program Planning (Plan)

Plan | Do | Check | Act

Once the threats have been identified as per *Section 10 Threats to the Distribution Pipeline System* the probability of failure is calculated for each component within the gas carrying distribution system, and the probability of failure is calculated.

Strategies are then developed to reduce operating risk related to the distribution system components to As Low as Reasonably Practical (ALARP). The program manager and operations personnel develop the mitigation project plan. Depending on the above factors, implementation will occur and targets established. The project is tracked through completion by Asset Management.

The risk to the asset is re-calculated annually to determine effectiveness of the mitigation plan. Data changes made through this mitigation plan are fed into the Asset Health Model to adjust failure probability curves.

IOPs are planned and executed by Program Owners and Operations personnel to mitigate and repair DIMP assets. The plan establishes target values for inspection and survey that are tracked to manage performance.

11.2 Mitigation and Condition Monitoring (Do)

Plan | **Do** | Check | Act

11.2.1 Integrity Operating Programs

DIMP is responsible for integrity related concerns from IOPs listed in *Figure 2 Integrity Management and Operating Programs Structure*. All integrity related concerns are communicated to the managers of Distribution Integration & Reliability (DI&R) and Risk Management.

The IOP plans are executed by the Operations group. The completion of these activities is documented in system records. The record entries are then reviewed and evaluated by DIMP and adjustments made to the Asset Health Failure Model.

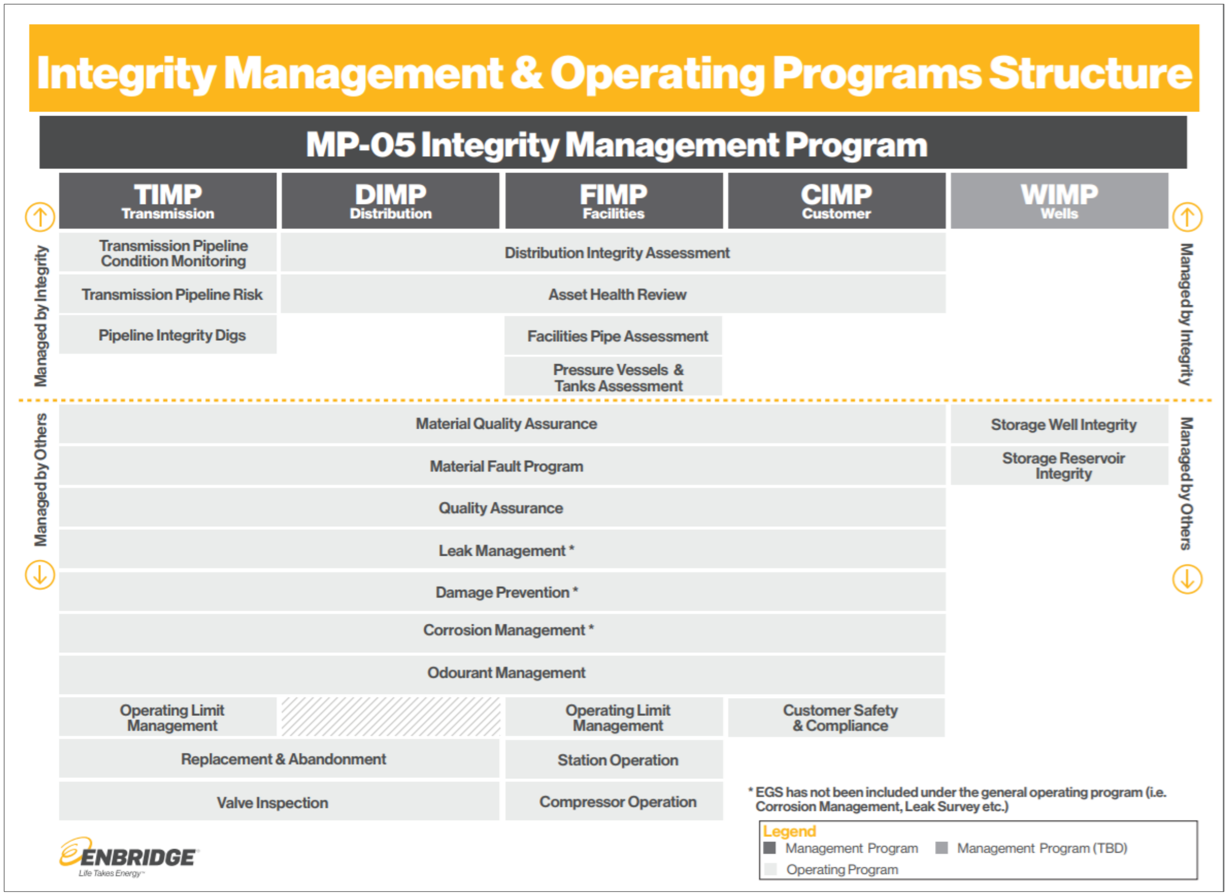


Figure 2 Integrity Management and Operating Programs Structure

11.2.2 Mitigation Projects

The output from IOP activities are collected and analyzed through Integrity Assessments which feed into several programs and models, such as the Asset Health Review (AHR) that contribute to the mitigation strategies required to prevent failures and reduce the risks to our system.

New technologies, material testing and failure analysis are implemented to mitigate integrity threats and enhance asset integrity understanding or risk mitigation.

The integrity assessment report is issued to the respective asset manager for review and project ranking. The following criteria are used by asset management process to determine the ranking: resources, capital budget, and synergy between other asset projects, training, special procedures, selective targeting, timing, safety requirements, and approvals.

The mitigation project plans are executed by the operations group. The completion of these activities is documented in system records. The record entries are then reviewed and evaluated by DIMP and adjustments made to the Asset Health failure model. The mitigation project is monitored by Asset Management to ensure efficient capital expenditure.

11.3 DIMP Performance Measures and Evaluation (CHECK)

Plan | Do | Check | Act

DIMP assesses the results measured and collected through the IOPs and compares them against the targeted or expected inspection results to ascertain the deviation between the actual and expected outcomes. This phase verifies the suitability and completeness of the plan.

The asset health review process is integrated into DIMP and plays an important role in distribution asset management. It provides a baseline for the health of our distribution assets and the process enables DIMP to balance performance, risks, and costs to make the most informed decisions about the asset integrity.

11.4 Continuous Improvement (ACT)

Plan | Do | Check | Act

DIMP is committed to continual improvement of the program through: ongoing assessments, management reviews and audits of Integrity Management Operating Programs. The results of these assessments can identify potential gaps in processes industry leadership by benchmarking performance against industry peers.

Ongoing assessments and reviews provide opportunities to continually improve programs so that regulatory requirements are met and customer asset risks are maintained at As Low As Reasonably Practical (ALARP) levels.

Continuous improvement opportunities are identified through several methods such as root cause identification, assessing the effectiveness of current or past mitigation programs, improvements to condition models, and through worker feedback.

12 Risk Assessment

The condition and Probability of Failure (PoF) of distribution gas carrying assets are collected through Integrity Assessments and Asset Health Review (AHR) tool. In order to help facilitate the risk assessment the Integrity Assessment should collect and provide the following:

- Description of the asset and how it is utilized within the EGD system
- List of applicable failure modes and root causes
- Failure data and MFR data for the determination of past and current failure rates and frequencies as well as understanding of root causes
- Failure projections for the failure modes
- Current mitigation activity and / or asset condition monitoring programs if present and the effectiveness of the programs
- Possible recommendations for risk reduction

DIMP is responsible for providing Risk Management and Asset Analytics details for the Asset Management team referenced in the figure below.

Figure 3 Asset Management Strategy

12.1 Integrity Assessments

The Integrity Assessment performed within DIMP is developed to uncover and determine missing data or information necessary to complete a risk assessment. DIMP provides a framework for deliverables, reviews, and content expected within an Integrity Assessment and is incorporated to fit the complexity and scope of the individual asset being assessed and should follow the guidelines established through CSA Z662 Annex B in order to support an accurate risk assessment.

In addition, the integrity assessment should also:

- Identify the current state of the asset population through the data gathering processes.
- Include a strategy for the data analysis, which will identify the failure modes, extent of failure in the population, trending analysis, failure rate predictions, locations of assets, determination of confidence levels, and determination of probability for failure and consequence of failure.
- Include proposed SMA resources and schedule for the Assessment.
- Develop a budget if required.

12.1.1 Data Gathering

In order to determine the current condition of the distribution system, the assessment reviews and investigates:

- Internal records and databases
- Material fault reports
- External information sources such as industry information and fault sources
- Tacit knowledge from SMAs

This information is used to develop the failure history, population size, asset locations, asset vintages, and relevant data to allow for the data analysis.

If existing sources are insufficient to accurately and completely develop a conclusion regarding the current state of the asset, field work may need to be specified in order to evaluate current conditions through investigative daylighting exercises, asset surveys, or perhaps obtaining samples for analysis.

The integrity assessment ensues that the surveys, field sampling, and data collection conforms to industry requirements and meet required confidence levels to allow for modelling to occur.

12.1.2 Data Analysis

DIMP assessments include a data analysis strategy. Once the required data has been acquired, the data then goes through a rigorous analysis to identify: failure modes, extent of failure in the population, trending analysis, failure rate predictions, determination of confidence levels, and determination of probability for failure and consequence of failure.

If data gathering results in only a sampling, statistical methods will be adopted in order to project the findings of the sampling onto the full population. The development of predictive modelling may be required through the assessment in order to enable the forecasting of the asset population condition and potential time to failure.

The data analysis forecasting and conclusions are reviewed by the Subject Matter Advisors (SMAs) to determine if the models align to internal experience and knowledge.

The data analysis delivers all of the essential ingredients required by the Asset Management team to perform an accurate risk assessment for a give asset. Regardless of the degree of probability and consequence of failure, all asset information is provided to the Asset Management Program for risk assessment and risk prioritization.

12.2 Risk Evaluation and Risk Significance

Asset Management receives the data analysis information provided through the integrity assessment and then performs a risk analysis and risk evaluation. The results of the assessment assist the decision-maker in determining the appropriate action.

The risk assessment is conducted in compliance with the principles outlined in the Operational Risk Management (ORM) framework as well as the process set forth by CSA Z662 Annex B section B.5. The estimated risk is compared and prioritized against all other known EGD risks.

The risk assessment is completed as per the EGD Risk Register Guide**.** The guide outlines the methodology, information requirements, and knowledge requirements for a risk assessment and provides detail on how to complete a risk assessment.

The risk assessment determines EGD’s total risk exposure (in dollars) for a given asset. Risk is the product of the probability of an event occurring multiplied by the consequences (dollar value) of having that event occur.

RISK = (Probability of Failure x $Cost of Consequences)

The probability of an event occurring can be determined through several means including:

- Using past failure data
- Projections of future failures
- Statistical modelling

The Risk Register Guide provides details on how to determine probabilities of failure. The consequence values are obtained from reviewed and approved lists which can be found in the Risk Register Guide. The risk assessment is completed by a competent risk assessor in conjunction with the Subject Matter Advisor (SMA) using the Risk Assessment template.

Risk reduction options are developed in order to reduce risk to a practical and acceptable level by reducing the frequency of occurrence and / or the consequence of an event. These options will form the foundation for the Mitigation Plan if required.

The risk assessment allows for a given asset to be compared against other assets in terms of company exposure. The portfolios of risk assessments are reviewed by the Risk Directors and are used to help facilitate capital spend decisions.

12.3 Continuous Risk Assessment and Risk Reduction

Risk assessments are repeated as new information becomes available.

12.4 Final Assessment Report

Upon completion of the Integrity Assessment, the DSI Project Manager creates a Final Assessment Report which draws conclusions and recommendations for risk reduction based on the findings of the Integrity Assessment.

The Final Assessment Report also includes the placement of the asset relative to the Risk & Solution Register. The recommended mitigation activities (if required) will be outlined along with expected risk reduction implications for the proposed activity. The recommended actions may include further condition monitoring of the asset, targeted field inspection programs, and / or field repair or replacement activity.

The Assessment Report is distributed to the appropriate stakeholders for review and approval. These stakeholders are typically the Directors of those Business Units that are involved as asset owners, such as: SMA sponsors, Asset Management, or owners of asset condition monitoring programs. The Final Assessment Report is used to evaluate Asset Management decisions going forward to ensure that they promote safety, reliability with no adverse effects on the environment.

13 Control and Maintenance

The table below provides information related to control and maintenance.

Table 8 Document Control and Maintenance

Owned by	Review	Distribution
Integrity and Quality Management	Annually	Enbridge Gas Distribution and Affiliates

Appendix A: Terms and Acronyms

Click the following link to view a list of terms and definitions.

Terminology and Definitions

Click the following link to view a list of acronyms.

Acronym Dictionary on ELink.

Appendix B - History of Changes

Changes made to this document are tracked in the table below.

Table 9 History of Changes

Revision Date	Version	Administrator	Approver
2017-09-01	V 1.0	Waleed Abdulaal, Integrity Project Manager	Brad Patzer, Manager Distribution Integrity & Reliability Peter Jurgeneit, Director Integrity & Quality Management

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1

Question:

(a) When was Enbridge first aware that “there could be in excess of 6,000 unrestrained compression couplings”? (see p. 3)

(b) When was Enbridge first aware that it did “not have sufficient records identifying the existence and location of” the compression fittings on the London Lines? (see p. 4)

(c) When was Enbridge first aware that “[r]ecords indicate that the pipe used for reclamation had multiple instances of laminations along with surface corrosion resulting in flaking of the pipe”? (see p. 4) Please file those records.

(d) Please provide a table for the London Lines indicating (a) each leak, (b) the class, (c) when discovered, and (d) when repaired. (see p. 8)

(e) Enbridge states on page 9 that “[f]urther analysis of the data shows that the areas where the pipe is within Agricultural land use (approximately 63% of the measurements), 85% of the measurements did not meet the minimum internal standard for depth of cover to protect against heavy cultivation damage.” When was Enbridge first aware of this? When was Enbridge first in possession of the underlying data?

(f) When was Enbridge first aware that “over 36% of the London Lines has a depth of cover less than 0.75 m3”? (see p. 9)

(g) Enbridge states on page 13 that “[f]eedback gathered by the Company shows consistently high amounts of corrosion across many lengths of pipe.” When was this information obtained?

(h) Enbridge states on page 19 that “[a] new Pipeline is also proposed to start at Strathroy Gate Station (Calvert Drive, Municipality of Strathroy-Caradoc). It will be NPS 6 and run for 8.4 km along Sutherland Road.” When did Enbridge first consider this option?

Response:

a) Prior engineering assessment reports (Katie Hooper Report – 2002) identified that the London South Line and portions of the original Dominion Line utilized dresser (compression coupling) construction. Please see Exhibit I.BOMA.5 for the report.

b) The prior engineering reports identified that the records showed the style of construction consisted of dressers, however the number and locations of these dressers were not included in the records. Please see Exhibit I.BOMA.5 for the prior engineering reports.

c) The Jack Chen engineering report from 2016 first mentions concerns with the integrity of the reclaimed pipe – refer to section 4.4.4 - Pipe Condition Records and Imperfection Repairs. Please see Exhibit I.BOMA.5 for the report.

d) Please see the Leak Repair Summary filed at Exhibit I.ApprO.3 a), Attachment 1, that details the repairs which occurred, the year of repair and the classification of the leak at the time that the repair work order was created.

e) As part of the comprehensive scoping work and the development of this project, a comprehensive depth of cover survey was conducted and subsequently completed in June, 2020. However, earlier engineering reports provided insight into the depth of cover, for example the Katie Hooper 2002 report states a depth of cover survey was performed in 2000, showing significant sections of pipe with a depth of cover less than 24 inches. However, the more recent survey of 2020 shows increased concern for the lack of cover over the majority of pipe.

f) See response to part e).

g) During the course of scoping and project development, Enbridge Gas gathered details about condition to assist in the risk assessment from subject matter experts, records, surveys, prior assessments and reports. The compilation of this material took place early in 2020.

h) This option was first considered in 2018 when high level analyses were being reviewed for pipeline replacement, then refined and finalized in 2020.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

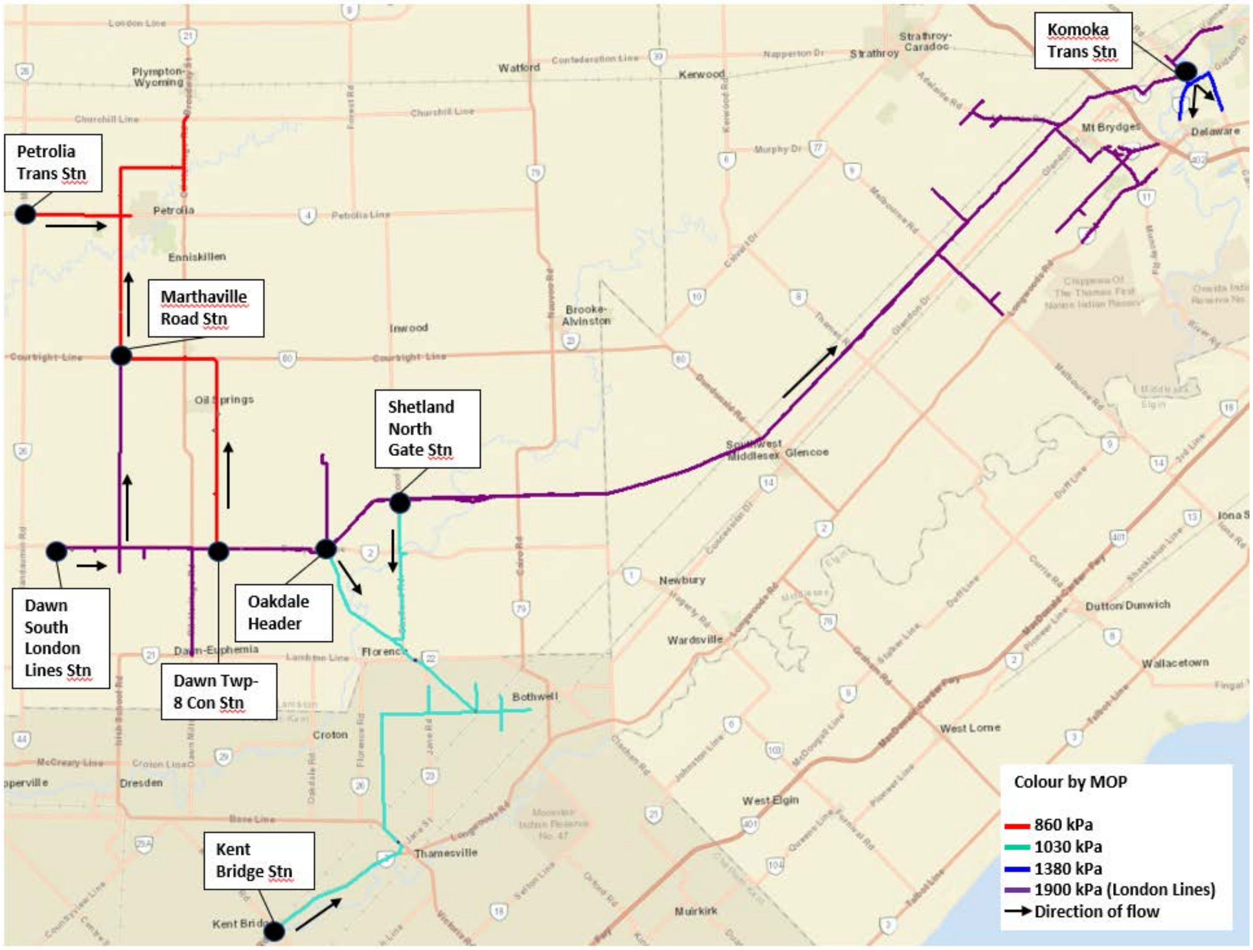
Exhibit B, Tab 1, Schedule 1, Page 2

Question:

(a) Please provide a map showing how London Lines connects into the wider gas transmission system. Please include arrows to show the direction of flow at peak. Please at least label the London Lines and the pipelines feeding the London Lines.

Response:

a) The existing London Lines are only fed from the Dawn South London Lines Station, they are not fed from any other pipeline. See below for the map of connections to other systems of lower MOPs.


Petrolia Trans Stn
Marthaville Road Stn
Shetland North Gate Stn
Oakdale Header
Dawn South London Lines Stn
Dawn Twp-8 Con Stn
Kent Bridge Stn
Komoka Trans Stn
Colour by MOP
860 kPa
1030 kPa
1380 kPa
1900 kPa (London Lines)
Direction of flow

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Page 13; Exhibit B, Tab 2, Schedule 4, Page 1; Exhibit B, Tab 2, Schedule 5, Page 1

> "Enbridge Gas compared the proposed replacement project to the cost of investment in supplemental DSM programming sufficient to reduce hourly peak system demands to the point that sections of the existing pipeline could be replaced with a smaller diameter NPS 4 pipeline. Enbridge Gas found that the cost of investment in sufficient supplemental DSM programming to reduce system demands by 359 m3/h was approximately $4.3 million over two years. This solution would only provide peak hourly system demand reductions sufficient to defer the need for the proposed project or a further pipeline expansion project by two years based on Enbridge Gas's current demand forecasts. The cost to execute a supplemental DSM program that satisfies the forecast demand would exceed the $2.9 million in cost savings of the downsized project design."

Questions:

(a) Enbridge states that it "compared the proposed replacement project to the cost of investment in supplemental DSM programming sufficient to reduce hourly peak system demands …" Please explain why Enbridge conducted its analysis based on hourly peak system demands versus design day demands.

(b) Please file all analysis and spreadsheets underlying the information provided in Exhibit B, Tab 2, Schedule 4.

(c) How did Enbridge determine that "the cost of investment in sufficient supplemental DSM programming to reduce system demands by 359 m3/h was approximately $4.3 million over two years"? Please provide all details and calculations.

(d) When did Enbridge first conduct the analysis to determine that "the cost of investment in sufficient supplemental DSM programming to reduce system demands by 359 m3/h was approximately $4.3 million." Please provide the month and year.

(e) Do the above two references examine the same DSM alternative? If they are different, please explain why.

(f) Enbridge says that "the need for replacement of the London Lines cannot be deferred."[1] Elsewhere, Enbridge says DSM could "defer the need for the proposed project or a further pipeline expansion project by two years based on Enbridge Gas's current demand forecasts."[2] Please explain.

(g) Putting aside cost issues, is there enough time for Enbridge to implement a DSM program to defer the need for an NPS 6 pipe versus an NPS 4 pipe for the 10.3 km in question? If not, why not?

(h) Is there enough lead time to implement alternative 5 (replace with NPS 6/4 3450 kPa line, reducing proportion of NPS 6 through supplemental DSM).

(i) Please list all large use customers on the London Lines and indicate when, or if, Enbridge most recently reached out to them to determine if they might be interested in an interruptible contract.

(j) What is the peak hourly demand for all large use customers on the London Lines (aggregate)? Please use the peak demand figures used for planning purposes and explain the assumptions around whether this assumes a coincident system peak demand.

(k) Please explain why the DSM alternative explores replacing only 10.3 km of the NPS 6 pipe with an NPS 4, not a larger portion of the 39 km of planned NPS 6 pipe?

(l) How much could be saved by replacing (i) all 39 km of the NPS 6 pipe with NPS 4 pipe and (ii) half of the NPS 6 pipe with NPS 4 pipe. Please provide the underlying details and calculations.

(m) How did Enbridge determine that downsizing from NPS 6 to NPS 4 for 10.3 km would save $2.9 million? Please provide the underlying details and calculations.

<u>Response:</u>

(a) Enbridge Gas conducted the analysis based on peak hour because all distribution pipeline systems are designed to meet customer requirements on a peak hourly basis, not on the basis of design day.

(b) The high level DSM analysis that was conducted for the proposed project was provided in order to be responsive to OEB direction in the 2015 – 2020 DSM Framework that states as part of any utility application for a leave to construct of future infrastructure projects, “the gas utilities must provide evidence of how DSM has been considered as an alternative at the preliminary stage of project development”. However, DSM is not relevant as it cannot address the integrity and safety drivers that underpin the need for this project. The analysis and spreadsheets will not provide any additional insights to aid the Board in its decision and accordingly are not being provided. See Exhibit I.STAFF.13 for more information.

(c) See response to part b).

(d) August 2020.

(e) Yes.

(f) See response to part b).

(g) The IRP framework proceeding in progress seeks to answer questions of IRP planning process and sequencing among other items. The 2018 IRP Study suggested a utility would require a 5-year timeline to properly implement DSM as an alternative to infrastructure investments[3]. The updated ICF Jurisdictional Review supports maintaining this lead time rule.[4] On this basis there is inadequate time to implement incremental DSM programming to defer the need for a slightly smaller pipe for a short amount of time.

(h) Please see response to part g).

(i) The names of large customers cannot be provided due to confidentiality. There is only one customer served from the London Lines who signed a long-term firm contract in early 2019.

(j) As noted in part i) there is only one large volume (contract customer) served from the London Lines. Their contracted hourly peak load cannot be provided due to confidentiality.

(k) Alternative 5 is the comparison between minimum viable to sustain connected firm demand in 2021 and a replacement of existing capacity (the Proposed Project). The balance of the NPS 6 is required to sustain 2021 system demands.

---

[3] EB-2020-0091, Integrated Resource Planning Proposal – IRP Study, July 22, 2020, pp. ES-7, ES-17, & 40-41.
[4] EB-2020-0091, Additional Evidence, October 15, 2020, Exhibit B, Appendix A, pp. 2 & 81.

(l) Replacing all or half of the NPS 6 with NPS 4 would be unable to sustain 2021 firm system demands. The minimum viable design is alternative 5, any additional pipe size reduction is infeasible.

(m) To determine cost difference of the 10.3 km of NPS 6 for NPS 4, the per-meter costs for the NPS 6 and for the NPS 4 pipelines were calculated based on the project cost estimate. The per-meter costs were applied to the 10.3 km length, and the difference in costs between NPS 6 and NPS 4 were calculated to be $2.9 M.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Page 13; Exhibit B, Tab 2, Schedule 4, Page 1; Exhibit B, Tab 2, Schedule 5, Page 1

> “The cost to execute a supplemental DSM program that satisfies the forecast demand would exceed the $2.9 million in cost savings of the downsized project design. The cost to execute a supplemental DSM program that satisfies the forecast demand would exceed the $2.9 million in cost savings of the downsized project design.”

Questions:

(a) Please provide the demand forecast underlying the above quote.

(b) Please indicate the demand thresholds at which:

   a. 10.3 km of NPS 6 can be replaced with NPS 4;

   b. Half of the NPS 6 can be replaced with NPS 4; and

   c. All 39 km of NPS 6 can be replaced with NPS 4.

(c) Please provide a demand forecast for the London Lines of the (i) annual demand, (ii) average daily demand, and (iii) design day demand. Please provide the forecast for each year for as long a period as is reasonably feasible.

(d) Please indicate the thresholds for (i) annual demand, (ii) average daily demand, and (iii) design day demand at which:

   a. 10.3 km of NPS 6 can be replaced with NPS 4;

   b. Half of the NPS 6 can be replaced with NPS 4; and

   c. All 39 km of NPS 6 can be replaced with NPS 4

Response:

(a) The forecast demand referenced is the total connected demand of current and anticipated connected firm general service customers for all years up to and including 2021.

Peak Flow	(m3/hr)
Total	18,900
Residential	62%
Commercial	28%
Industrial Equivalent	10%
DD	43.1

(b)

a. The demand threshold for alternative 5 is a peak flow of approximately 23,100 m3/hr.
b. This theoretical design cannot sustain predicted demand for 2021. Due to the interconnectivity of the system, this analysis cannot be completed without determining where the load reduction would occur.
c. Please see part (b) b.

(c) As per Exhibit I.ED.5 a), the pipeline sizing is completed on peak hourly requirements only. A demand forecast for daily and annual has not been completed.

(d) As per Exhibit I.ED.6 c) sizing is not associated to annual or daily.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

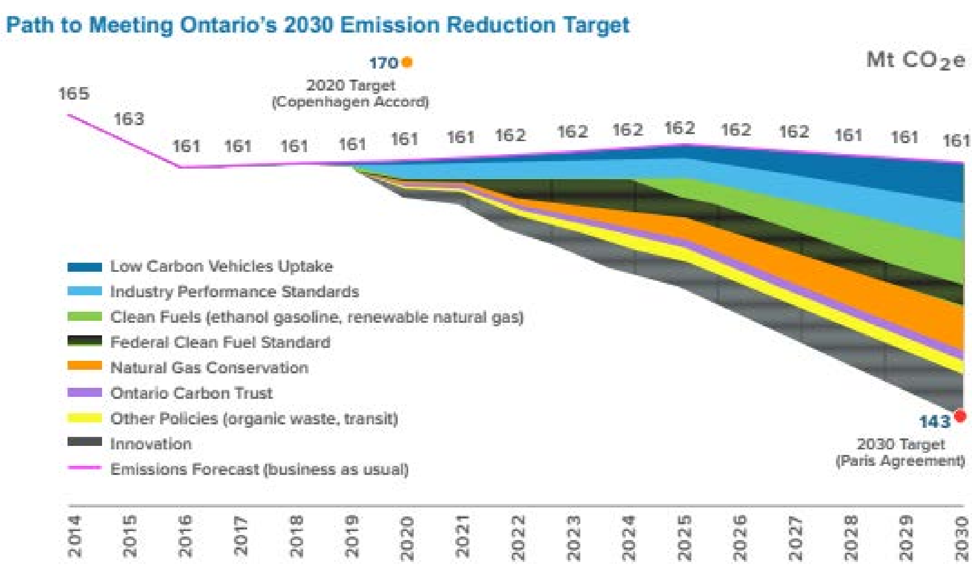
Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Page 13; Exhibit B, Tab 2, Schedule 4, Page 1; Exhibit B, Tab 2, Schedule 5, Page 1

Preamble:

Ontario's Environment Plan includes targets for carbon emissions to decline from natural gas use over the coming decade and by 3.2 MT by 2030. The decline is illustrated in orange in the below excerpt from the Environment Plan:



[1]

[1] Government of Ontario, *A Made-in-Ontario Environment Plan*, November, 2018, p. 23.

Questions:

(a) Please recreate the demand forecasts referenced in Environmental Defence Interrogatory # 6(a) and (c) on the hypothetical assumption that Ontario's meets its Environment Plan targets with respect to DSM for 2021 and going forward. Please answer the question on a best-efforts basis and with any caveats as necessary. Please make assumptions as necessary and state all assumptions.

(b) The Environment Plan targets require declining carbon emissions from gas and thus declining gas use:

   (i) If this comes to pass, could part or all of the NPS 6 pipe be replaced by an NPS 4 pipe? Please explain.

   (ii) If gas usage declines in accordance with the Environment Plan, at what point in time will the proposed NPS 6 be unnecessary to meet customers' needs? Please explain.

(c) Please file a copy of the Environment Plan.

Response:

a) to c)

ED has put forward a number of questions that seek to have Enbridge Gas create new evidence such as new potential forecast demand scenarios based on a number of hypothetical assumptions. The information requested is not available to Enbridge Gas or cannot be produced within a reasonable timeframe. These potential alternate hypothetical scenarios are not relevant to the Application evidence given that this is a project driven by integrity issues and is sized based on existing capacity replacement. It is Enbridge Gas's view that the scenarios would not be useful, even to the extent they could be created.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Page 13; Exhibit B, Tab 2, Schedule 4, Page 1; Exhibit B, Tab 2, Schedule 5, Page 1

> "The cost to execute a supplemental DSM program that satisfies the forecast demand would exceed the $2.9 million in cost savings of the downsized project design. The cost to execute a supplemental DSM program that satisfies the forecast demand would exceed the $2.9 million in cost savings of the downsized project design."

Questions:

(a) Please recreate the demand forecasts referenced in Environmental Defence Interrogatory # 6(a) and (c) on the hypothetical assumption that all achievable cost-effective DSM had been implemented in the area served by the London Lines from 2017 onward. Please base your answer on the 2016 Achievable Potential Study commissioned by the OEB and the IESO. Please answer the question on a best-efforts basis and with any caveats as necessary. Please make assumptions as necessary and state all assumptions. For example, please make and state assumptions as necessary to address the fact that the potential study figures begin in 2019, which is now in the past.

(b) Please recreate the demand forecasts referenced in Environmental Defence Interrogatory # 6(a) and (c) on the hypothetical assumption that all achievable cost-effective DSM is implemented in 2021 and going forward. Please base your answer on the 2019 Achievable Potential Study commissioned by the OEB and the IESO. Please answer the question on a best-efforts basis and with any caveats as necessary. Please make assumptions as necessary and state all assumptions. For example, please make and state assumptions as necessary to address the fact that the potential study figures begin in 2019, which is now in the past.

(c) Please file the (i) 2016 DSM Potential Study and (ii) 2019 DSM Potential Study.

Response:

a) and b) Please see Exhibit I.ED.7.

c) Enbridge Gas assumes that ED is referring to the OEB's: (i) Natural Gas Conservation Potential Study, submitted by ICF International to the OEB on June 30, 2016 and updated on July 7, 2016; and (ii) 2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study, submitted by Navigant Consulting Ltd. to the OEB and IESO on September 13, 2019 and updated on December 10, 2019.

   The OEB has made both of these studies as well as associated OEB directives and supporting data available to the public via its website at: https://www.oeb.ca/industry/policy-initiatives-and-consultations/natural-gas-conservation-potential-study. Neither of these studies was authored or commissioned by Enbridge Gas.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Page 13; Exhibit B, Tab 2, Schedule 4, Page 1; Exhibit B, Tab 2, Schedule 5, Page 1

Questions:

(a) How has Enbridge been ensuring the ongoing safe and reliable operation of the London Lines despite their problematic conditions?

(b) How long would it be sufficiently safe and reliable for Enbridge to continue to ensure the safe and reliable operation of the London Lines as described in (a).

(c) How long could Enbridge provide for sufficiently safe and reliable operation of the London Lines through repairs?

Response:

a) The London Lines are monitored and managed through leak management surveys, preventive corrosion control programs, valve inspections, and plant damage prevention strategies. Plant damage prevention strategies include third party observation of external contractors when excavating in the vicinity of the pipeline system, aerial patrol of the pipeline system to observe excavation activities in the vicinity of the pipeline system, and pipeline marker placement to identify the existence of a pipeline.

   Further risk mitigation measures have been implemented to minimize leak intensity, minimize small leaks from forming, minimize pull-out forces on unrestrained compressor couplings, and to increase walking of the pipeline to observe any changes to areas of concern. These measures include reducing the system operating pressure of the London Lines by approximately 25% and increasing the leak survey frequency from two (2) times per year to three (3) times per year.

b) As described in part a) most of these measures are reactive in nature (i.e. monitoring of the lines) and will only improve our response times once a leak has occurred. These measures do not stop or slow the degradation processes. It is difficult for Enbridge Gas to make statements on future safety and reliability of the lines, other than the company expects leaks and interruptions to increase with time due to continued degradation.

c) Please see response to part b).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Page 13; Exhibit B, Tab 2, Schedule 4, Page 1; Exhibit B, Tab 2, Schedule 5, Page 1

Questions:

(a) Please estimate the probability (%) that an NPS 6 pipe will be required for the full 39 km proposed by Enbridge in: (i) 2030, (ii) 2040, and (iii) 2050? Please provide a specific percentage with any caveats as necessary.

(b) Please estimate the probability (%) that an NPS 4 would be sufficient for the at least 10 km of the 39 km planned by Enbridge in: (i) 2030, (ii) 2040, and (iii) 2050. Please provide a specific percentage with any caveats as necessary.

(c) Is Enbridge willing to bear any of the risk that the proposed infrastructure will be underutilized or stranded in: (i) 2030, (ii) 2040, or (iii) 2050?

Response:

a) and b) Please see Exhibit I.ED 7 a).

c) No. Enbridge Gas expects the Proposed Project to be utilized for the foreseeable future.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Page 13; Exhibit B, Tab 2, Schedule 4, Page 1; Exhibit B, Tab 2, Schedule 5, Page 1

Questions:

(a) Please confirm the percentage of Ontario's annual greenhouse gas emissions that are attributable to natural gas combustion.

(b) What is the value of Enbridge's physical regulated assets in Ontario minus depreciation? What percentage change will this project make to that value?

(c) What is the current rate base for all of Enbridge's regulated assets in Ontario? What percentage change will this project make to the total rate base?

Response:

(a) The percentage of Ontario's annual greenhouse gas emissions that are attributable to natural gas combustion is 31% as of 2018, the most recent year for which data was available.[1]

(b) The net book value of Enbridge Gas's regulated property, plant and equipment, as at December 31st, 2019, was approximately $13.010 billion (gross plant of $20.403 billion less accumulated depreciation of $7.393 billion, as presented in Exhibit B, Tab 1, Schedule 4, in EB-2020-0134). Therefore, the London Line Replacement Project cost of $164.1 million, represents approximately 1.26% of the net book value of the Company's regulated property, plant and equipment, as at December 31st, 2019 (without consideration for the average of monthly averages impact of the project's in-service date).

[1] Based on natural gas consumption data from Statistics Canada (Canadian Monthly Natural Gas Distribution, Table 25-10-0059-01) and GHG emissions data from Environment Canada (2020 National Inventory Report, Table A11-12). Emissions from natural gas combustion in Ontario were 50,376 ktCO_2e in 2018. Total GHG emissions in Ontario were 165,000 ktCO_2e in 2018.

(c) Enbridge Gas's regulated rate base for the year ended December 31st, 2019, was approximately $13.139 billion (as presented in Exhibit B, Tab 1, Schedule 4, in EB-2020-0134). Therefore, the London Line Replacement Project cost of $164.1 million, represents approximately 1.25% of the Company's regulated rate base for 2019 (without consideration for the average of monthly averages impact of the project's in-service date).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit F, Tab 2, Schedule 1

> Enbridge estimates $27 million in abandonment costs.

Questions:

(a) How much of the pipeline will be abandoned in place versus removed?

(b) Please compare the proposed $27 million in abandonment costs with abandonment costs in a number of comparable projects. Please include comparative information such as cost per km.

(c) Is the $27 million in abandonment costs more or less than the amount collected through the depreciation expense for future abandonment costs thus far in relation to the London Lines? Please explain.

(d) Enbridge has previously stated "[f]uture abandonment costs charged to earnings through the depreciation expense are recorded as a liability on the Enbridge Gas financial statements and are collected from all ratepayers."[1] How much money has Enbridge collected from ratepayers for abandonment costs in relation to the London Lines? If these funds are collected on a broader basis or over a wider geographical area, please provide the broader financial figures and attribute a portion to the London Lines on a best-efforts basis. Please explain the answer.

(e) What amount has Enbridge collected from ratepayers through the depreciation expense for all future abandonment costs in Ontario? How many km of pipeline does Enbridge have in service in Ontario that are NPS 4 or larger? What is the size of this current project as an approximate percentage of Enbridge's pipeline system in Ontario?

[1] EB-2019-0188, Exhibit I.ED.4.

Response:

a) The estimates for abandonment are at a high-level of detail at this time. For the estimate in the pre-filed evidence, the lengths used for the calculations were:

   a. Abandon in Place: 83 km
   b. Removal: 51 km

   These lengths are projections based on pipeline vintage and location. As the detailed design progresses, these lengths will be adjusted and the estimate will be revised.

b) The abandonment cost for the London Lines is approximately $200 per meter. As there is a substantial length of the Existing Lines that is in easement, the amount of pipe that is abandoned in place vs. removed will be dictated by existing easement language. Negotiations will be required as described in the pre-filed evidence, at Exhibit B, Tab 1, Schedule 1, paragraph 4. The abandonment cost cannot be compared to other projects as each abandonment is unique given the circumstances of the abandonment, and therefore the cost will be different in each circumstance. In any event, Enbridge Gas is not seeking approval for the abandonment cost in this application. See Exhibit F, Tab 1, Schedule 1, paragraph 2.

c) Enbridge Gas is not able to provide the specific amount of abandonment costs (or net salvage or cost of retirements) recovered in relation to the existing London Lines pipelines. The costs collected through the asset depreciation rates over the life of the pipelines are calculated at the group (or pool) level, and not the individual asset level. Please see Exhibit I.STAFF.11 b).

d) As indicated in part c) to this response, Enbridge Gas is not able to quantify the specific amount of abandonment costs (or net salvage or cost of retirements) recovered in relation to the existing London Lines pipelines. Part e) to this response provides the total outstanding liability for future abandonment costs (or net salvage or cost of retirements) recognized by the Company.

e) Enbridge Gas is not able to quantify the total amount of abandonment costs (or net salvage or cost of retirements) it has recovered through depreciation to date, as the actual abandonment costs (or net salvage or cost of retirements) have been netted against amounts collected over time. However, the outstanding liability for future abandonment costs (or net salvage or cost of retirements) recognized by the Company as at December 31, 2019 was approximately $1.4 billion.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 5, Page 1

Question:

(a) Please provide the underlying calculations used to arrive at the cost figures for the proposed project and alternative 5 in the Summary of Alternatives, including the DCF tables.

Response:

a) Please see Exhibit I.STAFF.12 b) and the table below for a breakdown of the project costs.

London Lines Replacement	Mainline: Dawn-Komoka	Mainline: Strathroy Feed	Stations	Services	Abandonment	Total
Materials	$4,959,000 This costs consists of: - the pipe mill quote for new NPS 4 and NPS 6 pipe. - mainline fittings, estimate based on recent pricing.	$657,000 This costs consists of: - the pipe mill quote for new NPS 6 pipe. - mainline fittings, estimate based on recent purchases.	$1,823,000 This includes the aggregated cost of all fittings in each station based on typical drawings and materials. Unit pricing is based on recent purchases.	$125,000 Based on standard material costs and sourced vendor.	$0 Minimal material costs anticipated.	$7,564,000
Construction and Labour	$73,885,000 Prime contractor costs are based on courtesy quotes. Other third-party services, direct internal project expenses and wages, permanent easement and temporary land use are based on a combination of courtesy quotes and subject matter expert experience / historic pricing.	$3,437,000 Prime contractor costs are based on courtesy quotes. Other third-party services, direct internal project expenses and wages, permanent easement and temporary land use are based on a combination of courtesy quotes and subject matter expert experience / historic pricing.	$8,221,000 Prime contractor costs are based on courtesy quotes. Other third-party services, direct internal project expenses and wages, and purchase and temporary land use are based on a combination of courtesy quotes and subject matter expert experience / historic pricing.	$4,005,000 Average cost per meter for labour is based on recent average for District work. Assumes the local alliance partner will complete this work. This is an all in cost.	$19,776,000 Prime contractor costs are based on courtesy quotes. Other third-party services, direct internal project expenses and wages, temporary land use are based on a combination of courtesy quotes and subject matter expert experience / historic pricing. (Note: this part of the project is still in development. Assumptions made for lengths of abandon in place, abandon and remove, contamination, land costs, etc.)	$109,324,000
Contingencies	$10,824,000 Contingency is 15% per Class 4 estimate. Has been Legacy-Union Gas standard to file with 15% contingency.	$578,000 Contingency is 15% per Class 4 estimate. Has been Legacy-Union Gas standard to file with 15% contingency.	$1,310,000 Contingency is 15% per Class 4 estimate. Has been Legacy-Union Gas standard to file with 15% contingency.	$619,000 Contingency is 15% per Class 4 estimate. Has been Legacy-Union Gas standard to file with 15% contingency.	$2,633,000 Contingency is 20% per preliminary Class 4 estimate. Has been Legacy-Union Gas standard to use 20% contingency when work is complex/not well defined yet.	$15,964,000
Interest During Construction	$823,000 Calculated using estimated cashflow with interest rate of 2.48% the OEB prescribed interest rate in effect as the time the estimate was completed.	$43,000 Calculated using estimated cashflow with interest rate of 2.48% the OEB prescribed interest rate in effect as the time the estimate was completed.	$142,000 Calculated using estimated cashflow with interest rate of 2.48% the OEB prescribed interest rate in effect as the time the estimate was completed.	$49,000 Calculated using estimated cashflow with interest rate of 2.48% the OEB prescribed interest rate in effect as the time the estimate was completed.	$0 No IDC as assumed abandonment work will occur after project is in service.	$1,057,000
Estimated Incremental Project Capital Costs	$90,491,000	$4,715,000	$11,496,000	$4,798,000	$22,409,000	$133,909,000
Indirect Overhead	$20,798,000 Calculated on project costs including materials, construction & labour and contingency estimates using EGI overhead capitalization rate of 22.7%.	$1,083,000 Calculated on project costs including materials, construction & labour and contingency estimates using EGI overhead capitalization rate of 22.7%.	$2,640,000 Calculated on project costs including materials, construction & labour and contingency estimates using EGI overhead capitalization rate of 22.7%.	$991,000 Calculated on project costs including materials, construction & labour and contingency estimates using EGI overhead capitalization rate of 22.7%.	$4,677,000 Calculated on project costs including materials, construction & labour and contingency estimates using EGI overhead capitalization rate of 22.7%.	$30,189,000
Total Estimated Project Capital Costs	$111,289,000	$5,798,000	$14,136,000	$5,789,000	$27,086,000	$164,098,000

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit A, Tab 1, Schedule 1, Page 1

Preamble:

“The Existing Lines comprise the London South Line and London Dominion Line which are two pipelines that are parallel to each other, approximately 60 km and 75 km in length, respectively.”

Question:

a) Is the London Dominion Line was one of the assets acquired by the legacy Union Gas Company when it purchased the assets of Dominion Natural Gas Company Limited from Cities Service Company in 1958.

b) Are the London South Line and the London Dominion Line located on the same side of the roads that they follow?

c) What is the approximate physical separation of the two lines?

d) How many direct service connections are there on each line?

e) Are there any tie-over connections between the two lines? If the answer is yes, please provide the number. If the answer is no, please explain why not.

Response:

a) No.

b) The location of the London Lines along the roadway varies, sometimes the Lines are on opposite sides of the road, sometimes they are on the same side. At some points the lines cross over one another.

c) The physical separation between the two lines varies, as noted in part b), the lines cross at some points and would by physically very close at those points. The physical separation ranges from 0 m horizontally (and approximately 0.25 m vertically) to 264 m horizontally. On average, the lines are likely around 5-10 m apart.

d) London South Line – 52 Services
London Dominion Line – 76 Services

There are 7 services for which the company does not have record of which Line the service is tied into or the year of the service installation.

In Exhibit B, Tab 1, Schedule 1, paragraph 45, the number of services was incorrectly shown as 148. The correct number should be 135. Enbridge Gas will file a correction to this exhibit with the interrogatory responses.

e) There are eight tie-overs. There are also six additional interconnects where the Lines are connected at a station.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit A, Tab 1, Schedule 1, Page 2

Preamble:

Energy Probe would like to understand how and why Enbridge management reached the decision to replace these two lines.

Question:

a) On which date did Enbridge Gas management decide to replace the two lines?

b) Please provide the positions/titles of management staff who made the decision.

c) Please file the information that was presented to management staff in support of the decision including all presentations and reports.

Response:

a) A Vice President Steering Committee review was held on June 23, 2020 where a decision was made to proceed with the replacement project.

b) Please see slide 4 in Attachment 1.

c) Please see Attachment 1. Please note on slide number 9, of the 29 leaks repaired 23 are Class A or B with 4 Class C leaks and 2 unclassified.

London Lines Replacement

Steering Committee Review
June 23, 2020

ENBRIDGE®

Project Lead: Brad Patzer
Functional Director: Hilary Thompson

Meeting Purpose

Goal: To review the current status of the proposed London Lines Replacement Project and next steps to an LTC filing for August 20

Safety Moment – Bike Helmet Replacement

ENBRIDGE
Life Takes Energy™

- When should you replace your bike helmet?
  - Did you crash it? Replace immediately.
  - Did you drop it hard enough to crack the foam? Replace.
  - Is it from the 1970's? Replace.
  - Is the outside just foam or cloth instead of plastic? Replace.
  - Does it lack a CPSC, ASTM or Snell sticker inside? Replace.
  - Can you adjust to fit it correctly? No - Replace!!
  - Every 8 years

http://www.helmets.org/replace.htm
https://www.helmets.org/inspection.htm

Governance

London Lines

ENBRIDGE
Life Takes Energy

Sponsor: Hilary Thompson

Functional Manager: Erik Naczynski

Asset Management Steering Committee

Michelle George, Jim Sanders, Malini Giridhar

Operating Committee

Shawn Khoshaien, Hilary Thompson, Neil MacNeil, Steven Jelich, Mike Wagle, Mark Kitchen

Core Team

Dale Fisher, Erin Wishart, Erik Naczynski, Brad Patzer, Byron Madrid, Aron Murdoch, Allison Chong, Zachary Willemsen, Lija Ward, Darryl Arnold, James Whittaker, Brandon Ott, Angela Scott, Fred Butrico, Rob Sterling, Todd Piercey, Hooman Zahedi, Ahmed Nossair

Key Stakeholders

Dist Ops, Engineering, Asset Management (Asset Managers , Risk Strategy & Planning), Integrity Management, Capital Development, Network Analysis, Regulatory

RAPID on Key Decisions

London Lines

Key Decisions	Recommend	Perform	Input	Agree	Decide
Approve Risk Results **(Is Risk Analysis Acceptable?)**	Catherine M.	Dale F.	Zachary W. / Lija W. (NA) Azhar A. (Pipeline Eng) Ann-Marie H. (Stations Eng) Darryl A. / James W. (Operations) Angela S. / Fred B. / Rob S. (DIMP / FIMP) Brad P. / Erik N. (AM) Allison C. / Aron M. / Byron M. (Capital Development) Brandon O. / Vanessa I. (Regulatory)	Erik N. Shawn K.	* Steven J. (Risk Owner)
Accept or Treat Risk	Catherine M.	Dale F.	Zachary W. / Lija W. (NA) Azhar A. (Pipeline Eng) Ann-Marie H. (Stations Eng) Darryl A . / James W. (Operations) Angela S. / Fred B. / Rob S. (DIMP / FIMP) Brad P. / Erik N. (AM) Allison C. / Aron M. / Byron M. (Capital Development) Brandon O. / Vanessa I. (Regulatory)	Erik N.	* Steven J.
Decide on Risk Treatment	Erik N.	Brad P.	Zachary W. / Lija W. (NA) Azhar A. (Pipeline Eng) Ann-Marie H. (Stations Eng) Allison C. / Aron M. / Byron M. (Capital Development) Catherine M. / Dale F. (Value) Darryl A. / James W. (Operations) Angela S. / Fred B. / Rob S. (DIMP / FIMP) Brandon O. / Vanessa I. (Regulatory)	Steven J. Shawn K. Neil M. Mark K. Michael W.	Hilary T.

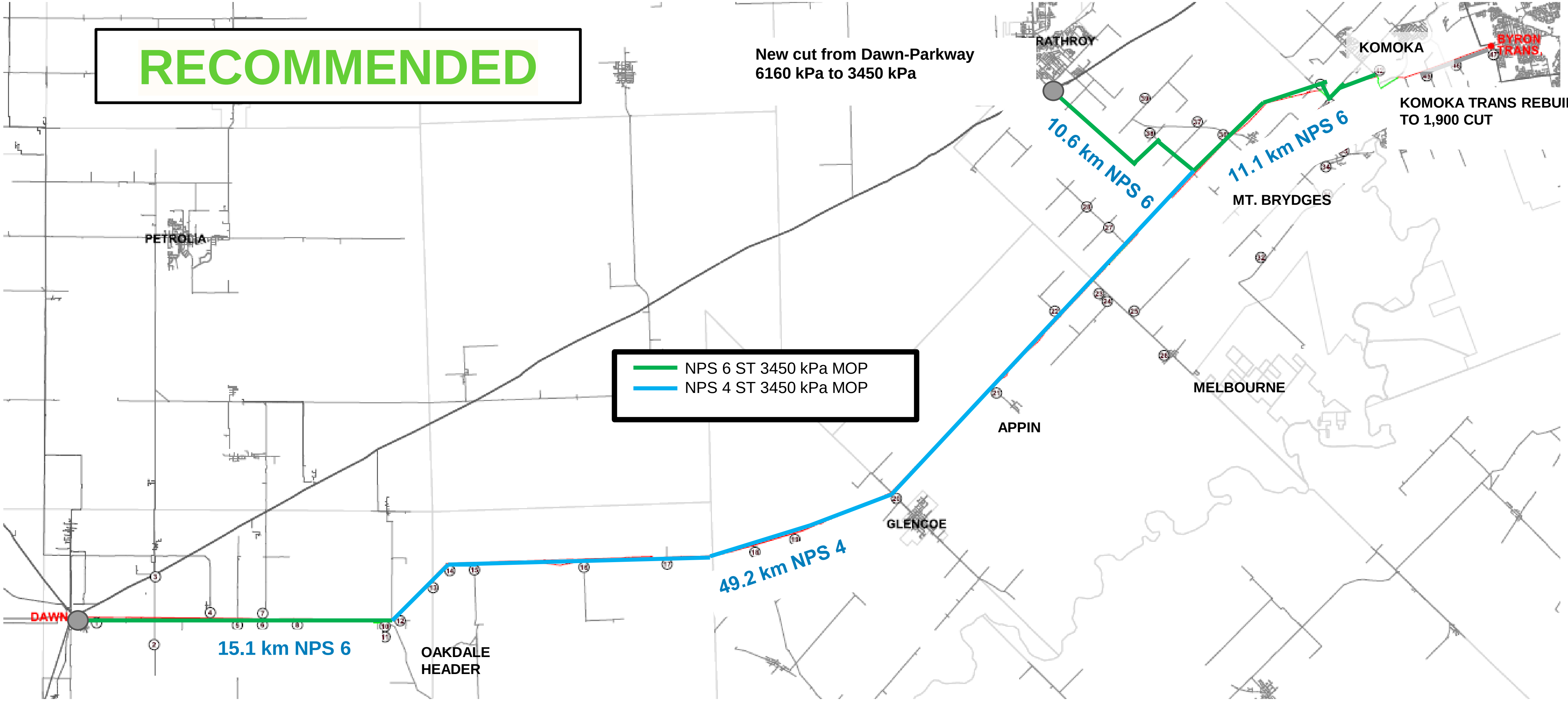
* Further discussions ongoing

Executive Summary

- **The London Lines has been initially assessed as a medium risk, with some segments as high risk**
  - There are a number of different risk scenarios
  - Several of the outcomes are medium risks
- **The risk is trending up due to age and condition**
- **Recommendation is to:**
  - Pursue replacement of the existing London South and London Dominion Lines with a single 3450kPa NPS 6 / 4 main that is back fed from Strathroy Gate, submitting an LTC application for August 20, 2020 with an in-service date of late December 2021

Mitigation Proposals
3450 kPa Option – with Strathroy Backfeed

ENBRIDGE
Life Takes Energy



Background

ENBRIDGE
Life Takes Energy™

- Twin steel pipelines, majority NPS 8 and NPS 10, commonly known as the London Lines. The majority of existing London Lines was installed in1935 and 1936. The London Dominion Line was replaced in 1952 but with 1920/30's vintage reclaimed pipe. Some sections have since been abandoned and other sections have been replaced.
- Operates at pressure significantly less than the MOP of 1,900 kPa (275 psi) in order to reduce number of leaks (set pressure is approximately 1415 kPa, (205 psi))
- Integrity
  - Associated risks from outstanding C-leaks
  - Constructed with unrestrained dresser coupling fittings (approximately 5,000)
  - 53 Aerial crossings which in some instances are bare and/or have unrestrained dresser couplings
  - Inoperable valves including valves installed at grade/in the ground
  - Depth of cover issues where 15.5% of measurements taken were below 0.6m (CSA Z662 standards per Sec 12.7)
  - Homemade bridge crossings across deep ditches to allow access for leak survey
  - Increased difficultly of repairs including finding pipe suitable for welding
- O&M resources
  - Reduction in the amount of O&M resources needed to address, monitor, and fix new and outstanding leaks is substantial. Repair costs have historically been $15-$60K, however future repair costs are expected to be significantly higher due to changes in repair methods and weldability concerns.

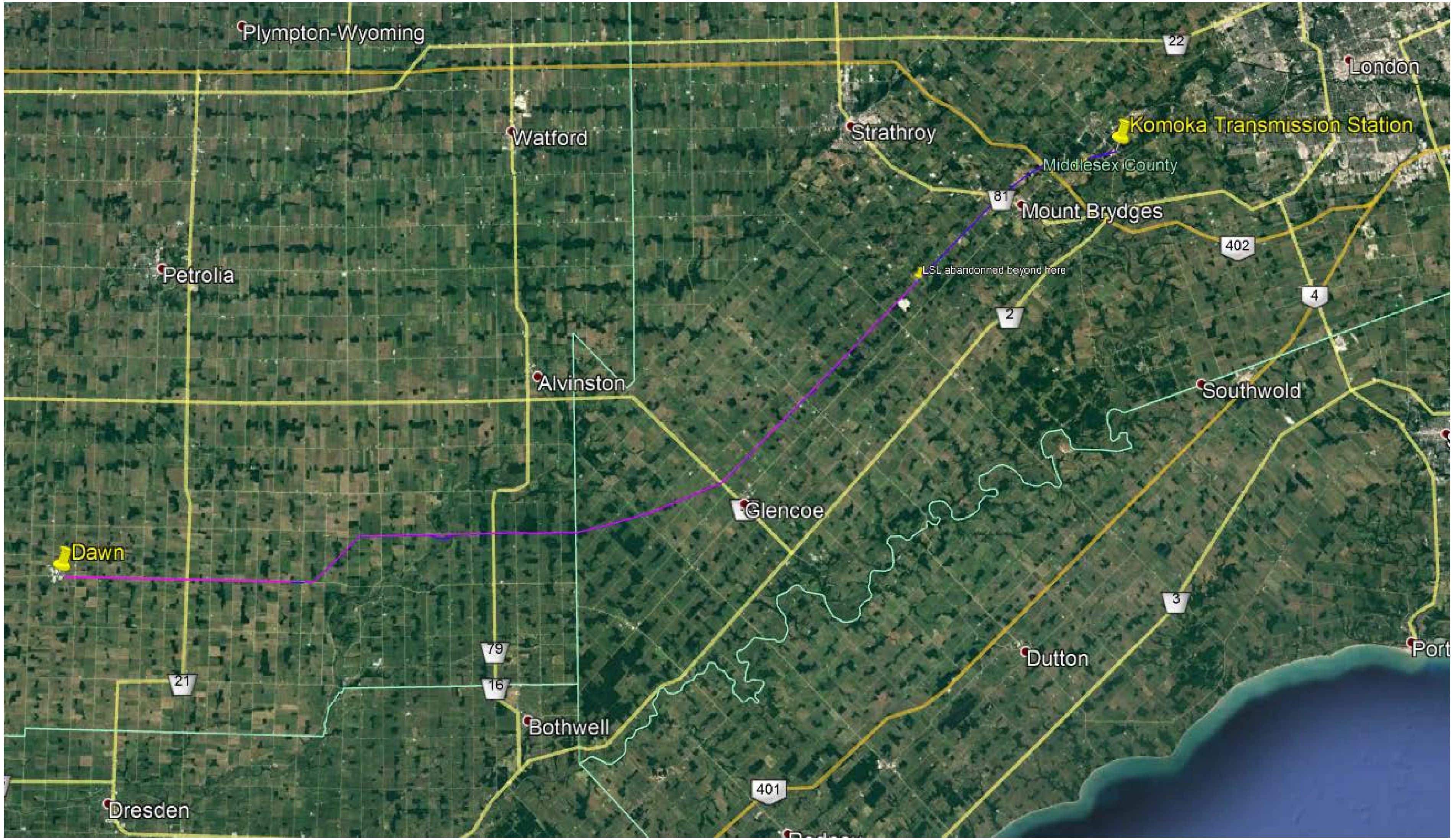
Leak Rate Comparison

The table below shows the leak causes for recently repaired A & B leaks

Year of Repair	Compression Coupling	Corrosion	Repair Clamp	Unknown	Valve	Weld	Grand Total
2011				1			1
2012	1		1	3			5
2013	1	1	3	1	1		7
2014	1	1	2		2		6
2015		1		1			2
2016		1					1
2017		1	1		2	1	5
2018				1			1
2019	1						1
Grand Total	4	5	7	7	5	1	29

Map of Existing London Lines

ENBRIDGE
Life Takes Energy



Risk Assessment Background

- Initial ranking completed at Legacy UG
  - Ranked as a Risk III, i.e. medium. High level assessment.
- A qualitative exercise is underway to further assess the risk
  - Risk will be completed to similar level of detail to Windsor lines assessment
  - Initial review completed
  - Based on that input, the risk scenarios and rankings have started to be built out
  - Further data validation and data collection and assessment is occurring

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

Draft Heat Map

ENBRIDGE
Life Takes Energy™

London Lines Initial Risk Rankings – Subject to data refinement, risk review and endorsement

L7	Medium	Medium	High	Very High	Very High	Very High	Very High
L6	Medium	Medium	Medium	High	[illegible]	High	Very High
L5	Low	Medium	Medium	[illegible]	High	Very High	Very High
L4	[illegible]	[illegible]	Medium	Medium	Medium	High	Very High
L3	Low	Low	Low	Medium	Medium	Medium	High
L2	Low	Low	Low	[illegible]	[illegible]	Medium	Medium
L1	Low	Low	Low	Low	Low	Medium	Medium
	C1	C2	C3	C4	C5	C6	C7

Customer Loss [2]

Financial [1]

Reputational [1]

Health and Safety [1]

1 – Fairly consistent and systemic throughout majority of pipeline.
2 – Confined to certain sections with higher customer loss. Medium risk for portions of pipeline.

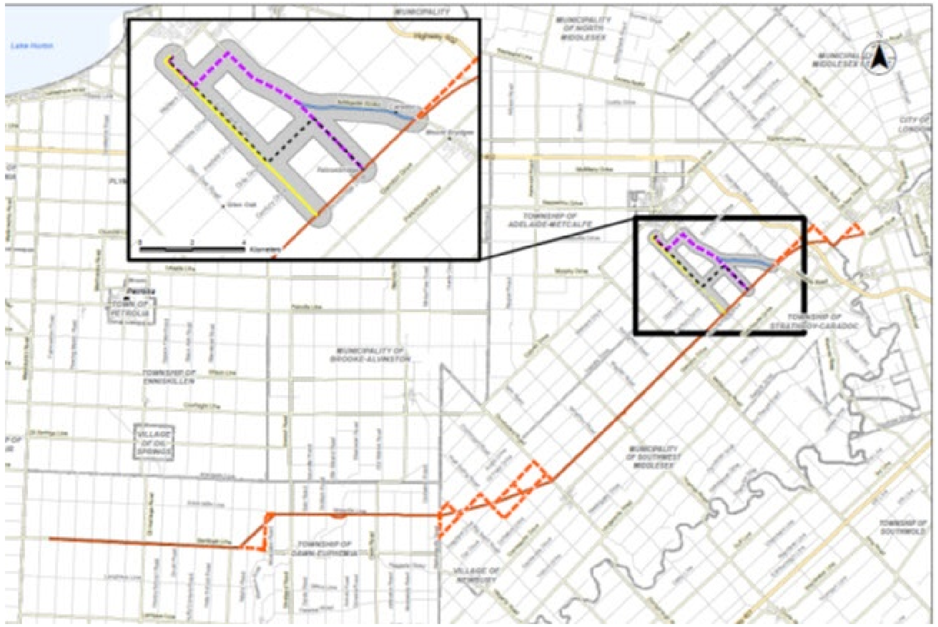
DRAFT

DRAFT

Mitigation Proposals

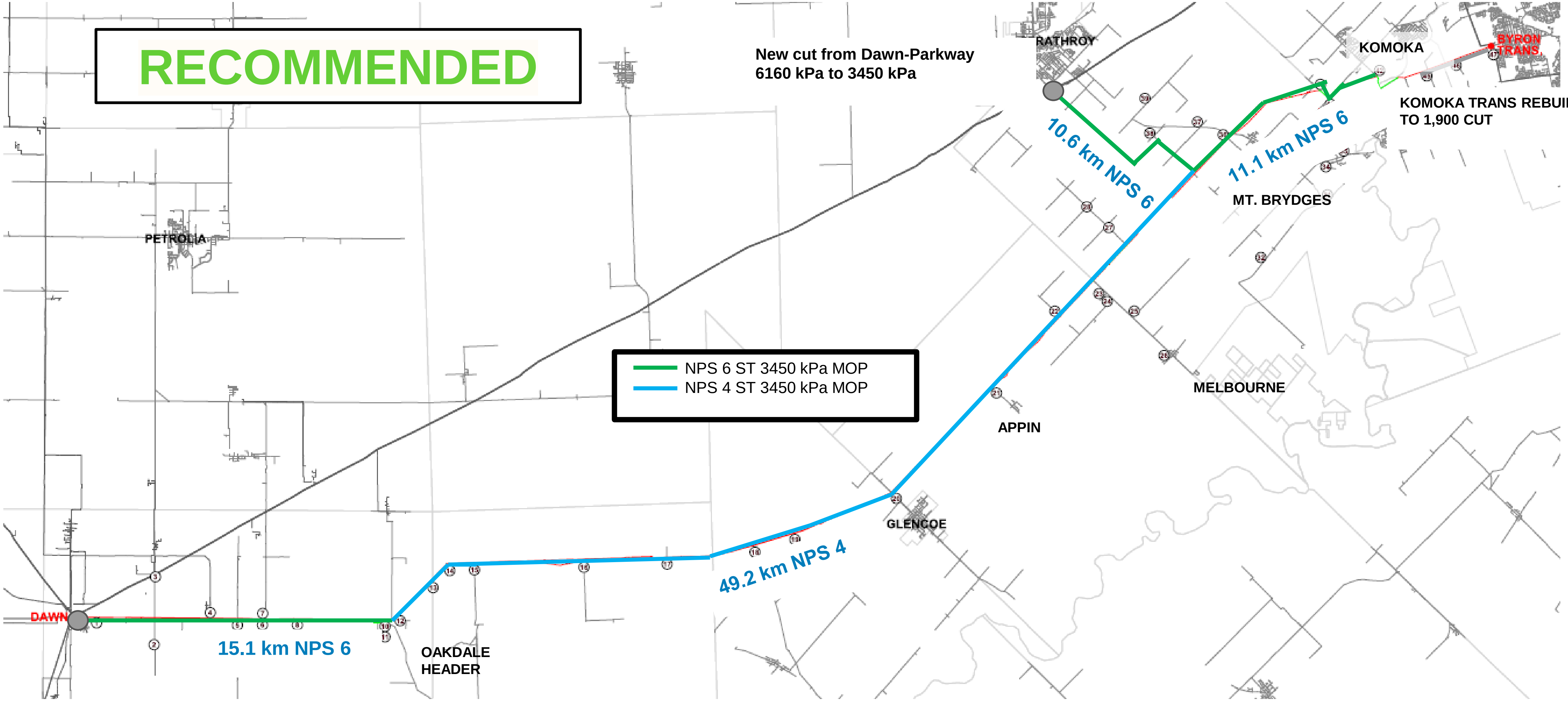
Growth Assumptions:

- 20 years Regular Rate growth added as per historical attachment rates
  - Average attachments were recalculated for 2016-2018 data
- All designs reviewed for two peak conditions:
  - 43.1 DD IOFF (Design Day with interruptible customers off)
    - No contract growth identified
  - 24.3 DD ION (Fall Peak with interruptible customers on)
    - Future fall growth assumed at 60% of winter – standard for heat sensitive loads
    - No commercial fall peaking growth or contract growth identified



Following maps show current pipe path, however NA has run scenarios against the newly recommended path

Mitigation Proposals
3450 kPa Option – with Strathroy Backfeed



Class 5 Cost Estimate Comparison

	3450 kPa Option – Single Fed from Dawn	3450 kPa Option – with Strathroy Backfeed	1900 kPa Option - with Strathroy Backfeed	1900 kPa Option – Single Fed from Dawn	1900 kPa Option – two feeds with central IP system
Direct Capital Subtotal	$ 101,300,000	$ 90,200,000	$ 102,400,000	$ 116,200,000	$ 99,000,000
General Contingency @ 20%	$20,300,000	$ 18,000,000	$ 20,500,000	$ 23,200,000	$ 19,800,000
C55 DIRECT CAPITAL TOTAL	**$ 121,600,000**	**$ 108,200,000**	**$ 122,900,000**	**$ 139,400,000**	**$ 118,800,000**
C55 Dismantlement Subtotal	$ 21,084,360	$ 21,084,360	$ 21,084,360	$ 21,084,360	$ 21,084,360
C55 Dismantlement Contingency @ 20%	$ 4,215,640	$ 4,215,640	$ 4,215,640	$ 4,215,640	$ 4,215,640
C55 DISMANTLEMENT TOTAL	**$ 25,300,000**	**$ 25,300,000**	**$ 25,300,000**	**$ 25,300,000**	**$ 25,300,000**
C55 Project Total*	**$ 146,900,000**	**$ 133,500,000**	**$ 148,200,000**	**$ 164,700,000**	**$ 144,100,000**
IDC/Loadings	TBD	TBD	TBD	TBD	TBD
OVERHEADS	TBD	TBD	TBD	TBD	TBD
PROJECT TOTAL					

Notes:
1) C55 Project Total does not include IDC/Loadings/Overheads

Timing

ENBRIDGE
Life Takes Energy

TASK	START	END
Scope Revision and Risk Assessment		
Develop Risk Assessment	5/30/20	6/30/20
Network Analysis Sizing and Pressure Analysis	5/30/20	6/15/20
Operating Committee Endorsement	6/19/20	6/19/20
Steering Committee Endorsement	6/23/20	6/23/20
Final Risk Assessment Review	7/13/20	7/13/20
LTC Application		
Environmental Assessment (EA) Report	12/11/19	6/30/20
Review Final EA report	7/1/20	7/8/20
Filing Environmental Report with OPCC	7/9/20	7/9/20
OPCC Term of Engagement (42 days)	7/9/20	8/19/20
Draft LTC Application	6/25/20	7/20/20
Internal Review of all sections	7/20/20	8/25/20
Update LTC based on OPCC comments	8/20/20	8/25/20
File LTC Application	8/25/20	8/25/20
OEB Hearing	8/25/20	3/31/21
OEB Approval of LTC Application	3/31/21	3/31/21
Design and Procurement	4/27/20	4/16/21
Capital Allocation Committee		
Stage Gate 1 to 2 Presentation	8/20/20	8/20/20
Stage Gate 2 to 3 Presentation	10/23/20	10/23/20
Board Approval	11/20/20	11/20/20
OTC Package Complete	3/31/21	4/16/21
Locates	4/16/21	5/17/21
Construction	5/17/21	10/29/21
Final Testing	11/1/21	11/12/21
Dewatering & Drying	11/15/21	11/26/21
Tie-Ins & Energization	12/1/21	12/14/21
Abandonment & Restoration	1/3/22	TBD

Lessons Learned from Windsor Filing

ENBRIDGE
Life Takes Energy™

Windsor Line Replacement Project – OEB findings on Key issues:

1. Integrity Issues

- Intervenors' Concerns:
  - Energy Probe submitted that there was inadequate evidence provided by EGI that the OEB could rely upon regarding the various integrity concerns that necessitated the replacement of the pipeline.
  - Energy Probe also argued that EGI evidence on the integrity issues is a summary in nature and should have included more evidence on the nature of the identified integrity issues (leaks, depth of cover issues, inoperable valves, and vintage pipe that is not weldable) which would help to draw a reasonable conclusion regarding the urgency of the replacement of the pipeline
- OEB Findings:
  - To provide more comprehensive supporting evidence on the integrity issues and why these integrity issues cannot be rectified without necessitating the replacement of the pipeline
  - OEB expects a more thorough presentation of the project need given the funding requested
  - Evidence should be clear, well-supported and objective

Lessons Learned from Windsor Filing

ENBRIDGE
Life Takes Energy™

Windsor Line Replacement Project – OEB findings on Key issues:

2. Proposed facilities and alternatives

- Intervenors' Concerns:
  - FRPO questioned whether Enbridge Gas had considered the option of using a NPS 4 for some section of the proposed pipeline and stated that EGI should have provided more compelling evidence (including cost) on all alternatives, (selected alternative vs alternatives not selected).
- OEB Findings:
  - To provide more compelling evidence on future demand (forecasted and un-forecasted) to justify the need of the proposed pipe size in pre-filed evidence. The OEB found the evidence provided regarding future demand somewhat speculative.
  - The Board found that it would have also been helpful for Enbridge Gas to have addressed in its original application the need for the Project to ensure back feed capacity and avoid pressure reductions – needs that were raised by Enbridge Gas later in the proceeding.
  - In weighing the merits of the arguments of Enbridge Gas, OEB staff and intervening parties, the OEB found a lack of sufficient evidentiary support for the Project using the Enbridge Gas pipeline size option instead of the less expensive hybrid.

Lessons Learned from Windsor Filing

Windsor Line Replacement Project – OEB findings on Key issues:

3. Agreement with Municipality

- OEB Findings:
    - If there is any indication that it will be difficult to obtain agreement with the municipalities involved in an LTC application, we should strongly suggest that the municipalities intervene in the OEB process so that the Board is aware of their concerns, and that these concerns could be addressed as part of the LTC proceeding.

Next Steps

Next Steps:

1) Complete risk assessment and risk owner endorsement for end July
2) Complete Integrity review of condition
3) Direction from Engineering on integrated policies for:
    1) Treatment of C-Leaks
    2) Treatment of Compression Couplings
    3) Treatment of Aerial Crossings
4) Complete filing for LTC August 20

ENBRIDGE

Questions?

—

Thank You

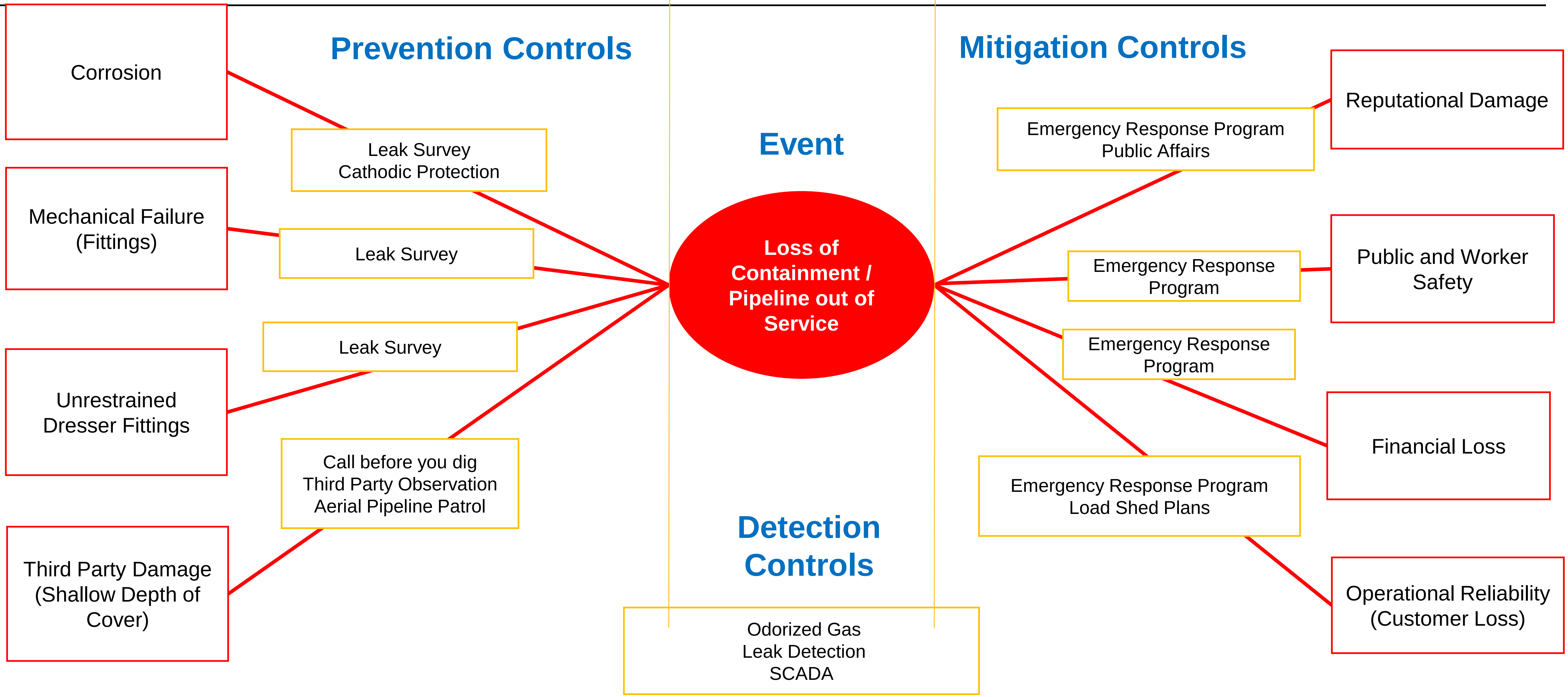
Appendix

DRAFT

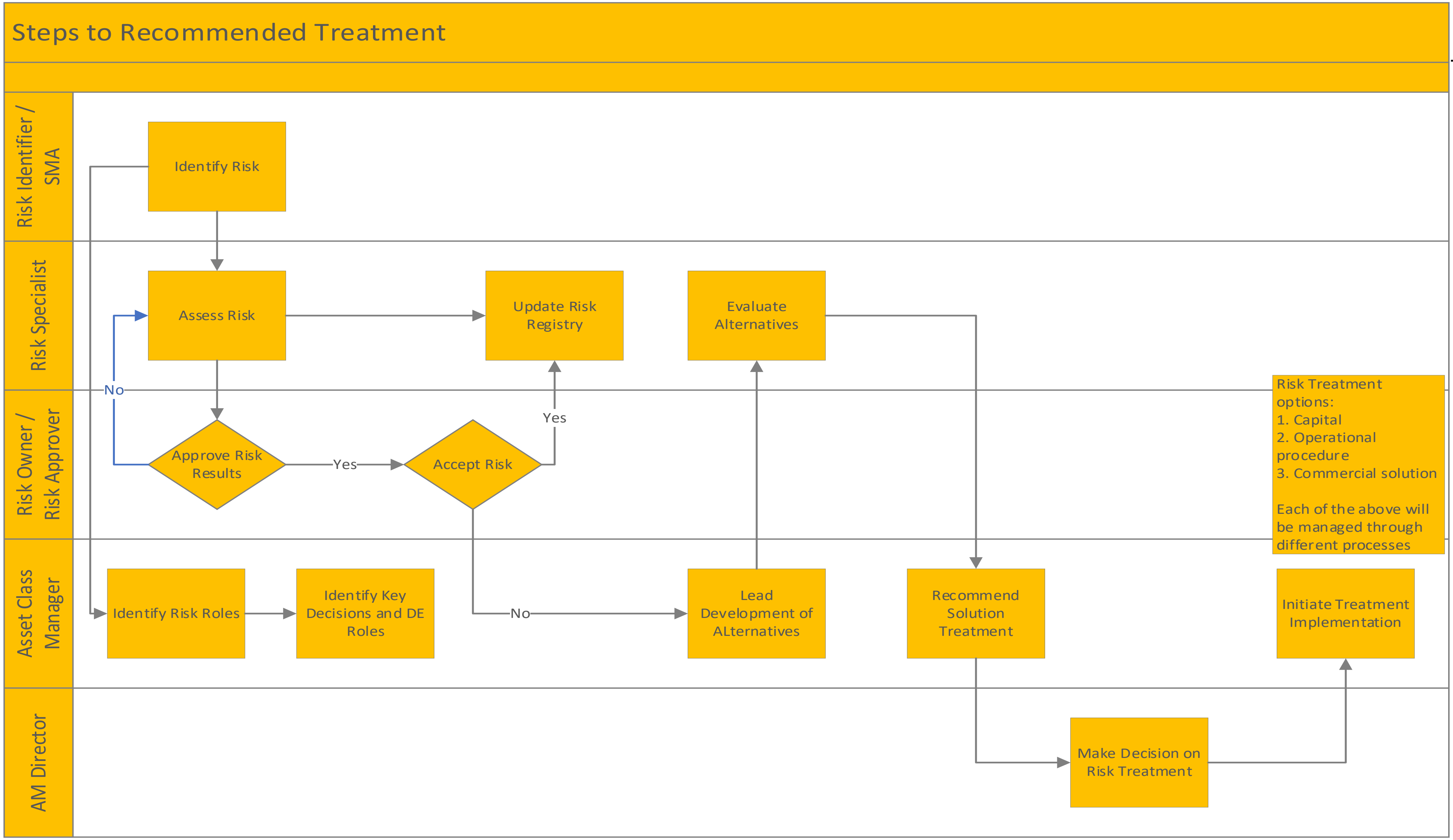
Condition Concerns With London Lines
Bow-Tie for Illustrative Purposes

Sources

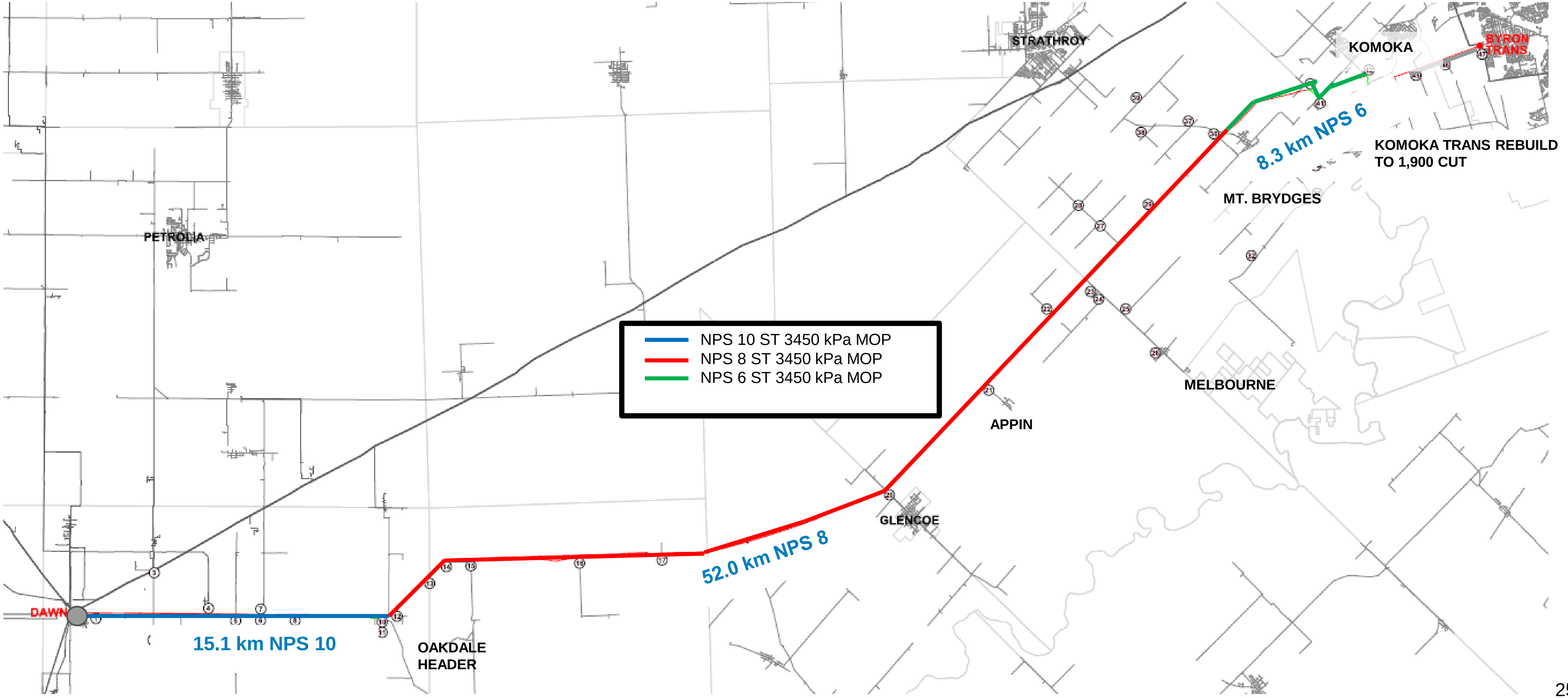
Consequences



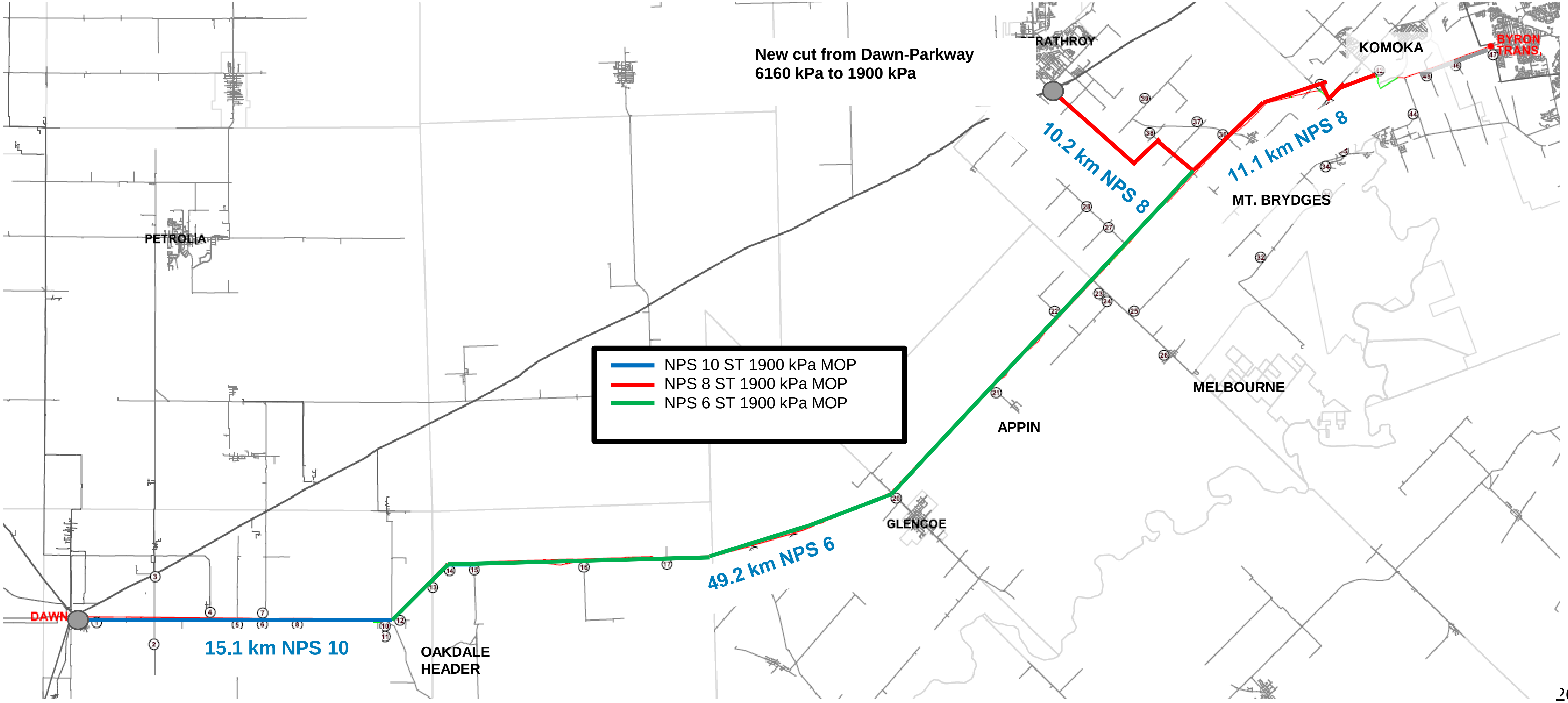
Proposed Decision Path



Mitigation Proposals
3450 kPa Option – Single Fed from Dawn

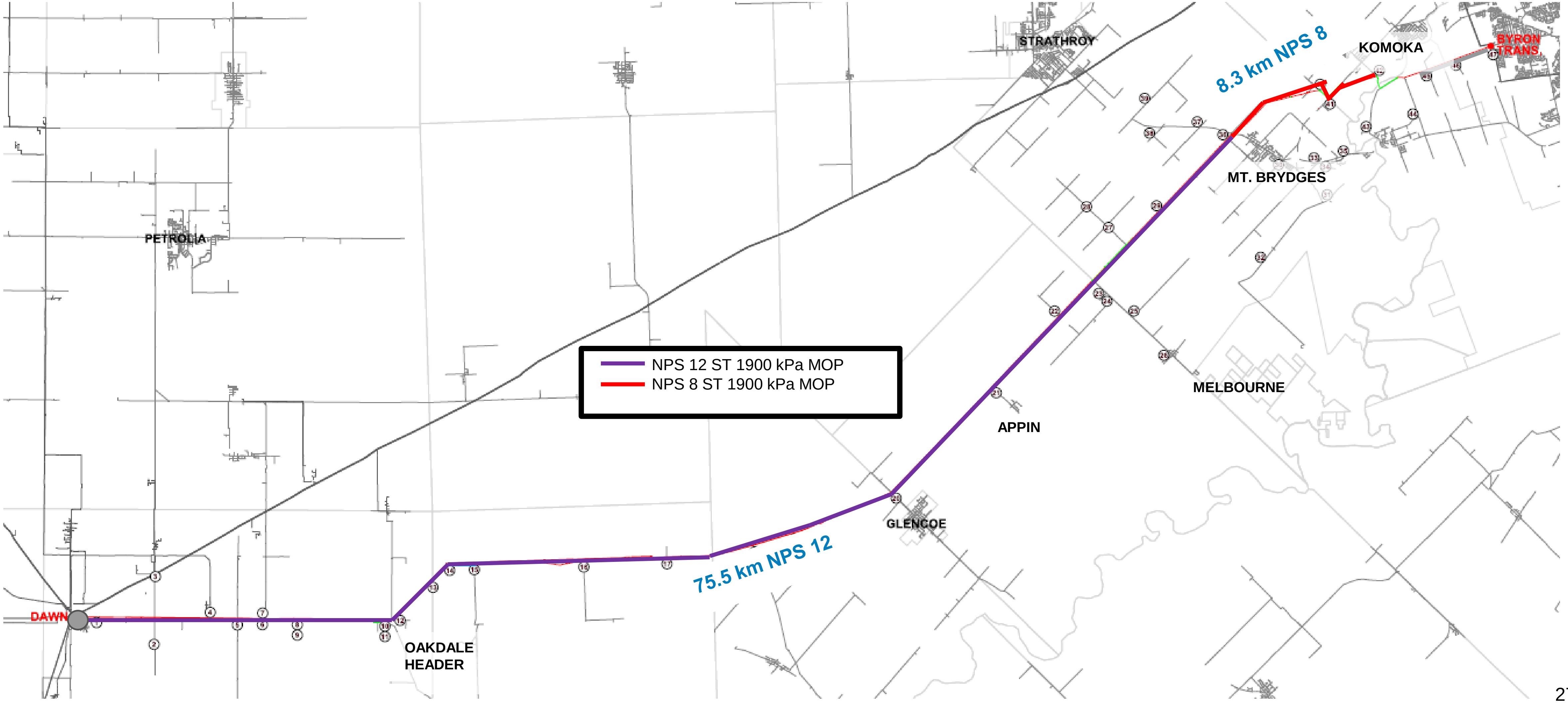


Mitigation Proposals
1900 kPa Option - with Strathroy Backfeed

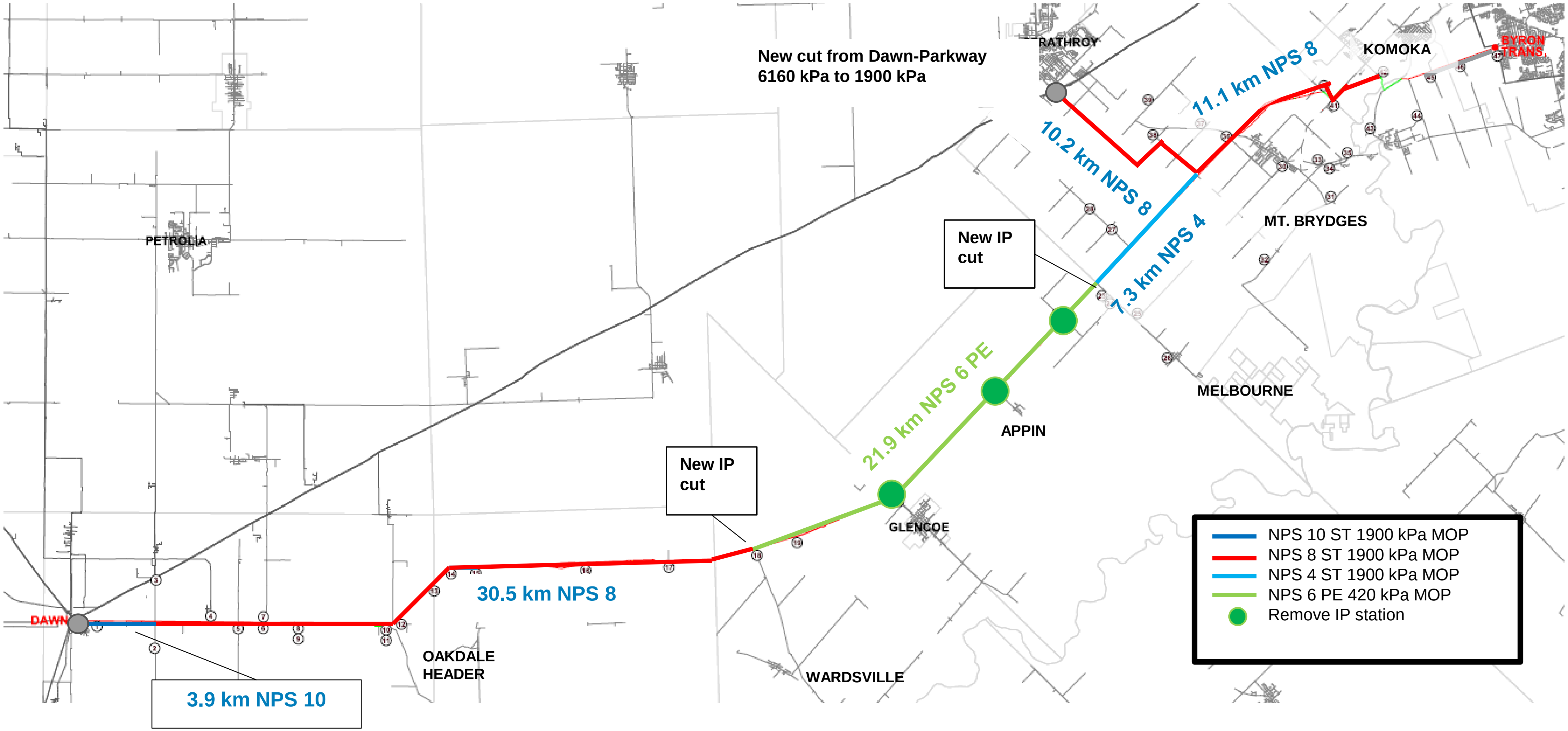


Mitigation Proposals
1900 kPa Option – Single Fed from Dawn

ENBRIDGE
Life Takes Energy



Mitigation Proposals
1900 kPa Option – two feeds with central IP system



Pictures

Exposed Ditch Crossing/ Valve Access

23367 Old Airport Rd, Glencoe

ENBRIDGE
Life Takes Energy

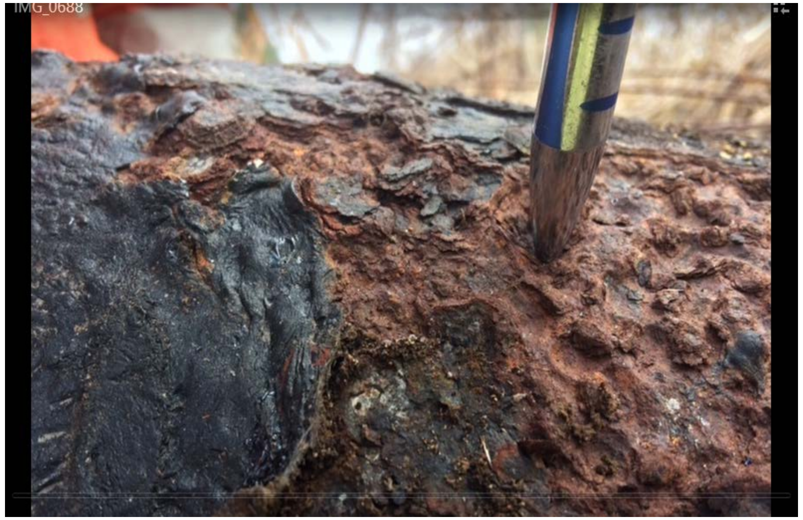
Aerial Crossing

Bentpath Line & Hale School Rd

Sydenham River Crossing

Installation likely on creek bed – Mosside Line & Aughrim Line

Corrosion on Exposed Pipe



ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, pages 3 and 6

Preamble:

"Compression couplings are known to provide minimal pull-out resistance, and depending on design, could cathodically isolate pipe. They are also a source of leaks especially if there is ground movement or large temperature fluctuations such as freeze/thaw cycles."

Question:

a) Have there been any instances of pull-out on the London South Line? If the answer is yes, please provide number and year of occurrence.

b) Please describe the method of repair if there is a pull-out.

c) Can leaks occur even if there is no pull-out?

d) When was the last time that Enbridge Gas or Legacy Union Gas conducted a pipe-to-soil survey of cathodic protection on the London South Line?

e) Please file the report of the most recent pipe-to-soil survey of the London South Line.

f) When was the last time Enbridge Gas or Legacy Union Gas conducted a leak survey of the London South Line?

g) Please file the report of the most recent leak survey of the London South Line.

h) Have there been any through wall corrosion leaks on the London South Line? If the answer is yes, please provide number and year of occurrence.

Response:

a) There is no known record of pull-out on the London South Line.

b) If there is a pull-out, the section of pipeline where the pull-out occurs would need to be isolated and repaired. The method of repair could vary.

c) Yes, leaks can occur even if a pull-out does not occur. Pipe stab depth, and angle can contribute to leaks around mechanical couplings due to the pipe sealing mechanism not providing full containment. Temperature fluctuations and ground settlement can also contribute to mechanical couplings leaking without requiring pull-out as there can be loss of gas containment around the coupling seals.

d) The last pipe-to-soil survey of cathodic protection was conducted in Q3 2020.

e) Please see Attachment 1 for the report.

f) The last Leak Survey that was completed was in April 2020.

g) The results from the Leak Survey are shown in the pre-filed evidence, at Exhibit B, Tab 1, Schedule 1, Figure 2.

h) Please see the Leak Repair Summary filed at Exhibit I.ApprO.3 a), Attachment 1.

2020 Pipe-to-Soil Survey
London South Pipeline

Run Date: 11/12/2020 10:22:15 AM

ENBRIDGE

Begin Date:	1/1/2020	**District:**	London
End Date:	11/12/2020	**Work Area:**	Lon.South Ln Wht Vlv (450)
System:	Pipeline	**Line#/Section#/ServiceID:**	450-Lon.South Ln Wht Vlv

Report Version: 1.1

Line Reading History

Reading Location		Read Type	Read Limit	Year(s) 2020
1-00	TB-1 (N) WIRES	Pipe to Soil	-0.85	-1.15
1.1-00	TB-1.1 N	Pipe to Soil	-0.85	-1.12
2-00	TB-2 (N)	Pipe to Soil	-0.85	-1.23
3-00	TB-3 (N)	Pipe to Soil	-0.85	-1.09
4-00	TB-4 (N)	Pipe to Soil	-0.85	-1.04
5-00	TB-5 (N)	Pipe to Soil	-0.85	-1.13
7-00	TB-7 (N)	Pipe to Soil	-0.85	-1.09
8-00	TB-8 (N)	Pipe to Soil	-0.85	-1.23
9-00	TB-9 (N)	Pipe to Soil	-0.85	-1.20
11-00	TB-11 (N)	Pipe to Soil	-0.85	-1.04
12-00	TB-12 (N)	Pipe to Soil	-0.85	-1.35
14-00	TB-14 (N)	Pipe to Soil	-0.85	-1.13
15-00	TB-15 (N)	Pipe to Soil	-0.85	-1.11
16-00	TB-16 (N)	Pipe to Soil	-0.85	-1.20
18.1-00	TB-18.1 (N)	Pipe to Soil	-0.85	-1.13

Line Reading History

Reading Location		Read Type	Read Limit	Year(s) 2020
19-00	TB-19 NOTE:Rect-42	Pipe to Soil	-0.85	-1.41
20-00	TB-20 (N)	Pipe to Soil	-0.85	-1.18
21-00	TB-21 (N)	Pipe to Soil	-0.85	-1.17
22-00	TB-22 (N)	Pipe to Soil	-0.85	-1.18
23-00	TB-23 (N)	Pipe to Soil	-0.85	-1.34
23.05-03	RECT 43	Pipe to Soil	-0.85	-1.23
25-00	TB-25 (N)	Pipe to Soil	-0.85	-1.20
26-00	TB-26 (N)	Pipe to Soil	-0.85	-1.09
27-00	TB-27 (N)	Pipe to Soil	-0.85	-1.18
27.1-00	OT 27.1 OAKDALE	Pipe to Soil		-1.26
27.1-01	OT 27.1 OAKDALE	Pipe to Soil		-1.23
27.1-03	OT 27.1 OAKDALE	Pipe to Soil		-1.06
27.1-04	OT 27.1 OAKDALE	Pipe to Soil	-0.85	-1.26
27.1-05	OT 27.1 OAKDALE	Pipe to Soil		-1.26
27.1-06	OT 27.1 OAKDALE	Pipe to Soil		-1.06
30-00	TB-30LS NO 1	Pipe to Soil	-0.85	-1.34
30-02	TB-30LS NO 1	Pipe to Soil		-1.33
30-03	TB-30LS NO 1	Pipe to Soil		-1.33
31-00	TB031DS NO 1	Pipe to Soil	-0.85	-1.40
32-00	TB-32DS NO 1	Pipe to Soil	-0.85	-1.55

2020 Pipe-to-Soil Survey
London South Pipeline

Run Date: 11/12/2020 10:22:15 AM

ENBRIDGE

Begin Date:	1/1/2020	**District:**	London
End Date:	11/12/2020	**Work Area:**	Lon.South Ln Wht Vlv (450)
System:	Pipeline	**Line#/Section#/ServiceID:**	450-Lon.South Ln Wht Vlv

Report Version: 1.1

Line Reading History

Reading Location		Read Type	Read Limit	Year(s) 2020
33-00	TB-33S NO 1	Pipe to Soil	-0.85	-1.50
33-05	TB-33S NO 1	Pipe to Soil		-1.50
34-00	TB-34LS NO 1	Pipe to Soil	-0.85	-1.30
34.1-00	TB-34.1LS NO 1-LON	Pipe to Soil	-0.85	-1.30
34.1-01	TB-34.1LS NO 1-LON	Pipe to Soil		-1.30
35-00	TB-35LS NO 1	Pipe to Soil	-0.85	-1.28
36-00	TB-36LS NO 1	Pipe to Soil	-0.85	-1.27
37-00	TB-37LS NO 1 W OF	Pipe to Soil	-0.85	-1.38
39-00	TB-39DS LON STH-	Pipe to Soil	-0.85	-1.53
39-05	TB-39DS LON STH-	Pipe to Soil		-1.58
39-06	TB-39DS LON STH-	Pipe to Soil		-1.64
40-00	TB-40DS NO 1	Pipe to Soil	-0.85	-1.38
41-00	TB-41LS NO 1	Pipe to Soil	-0.85	-1.38
42-00	TB-42LS NO 1	Pipe to Soil	-0.85	-1.32
42.1-00	TB-42.1LS INLET NO	Pipe to Soil	-0.85	-1.26
42.1-01	TB-42.1LS INLET NO	Pipe to Soil		-1.26
43-00	TB-43DS LON STH-	Pipe to Soil	-0.85	-1.32
44-00	TB-44DS NO 1	Pipe to Soil	-0.85	-1.36
45-00	TB-45 NORTH LINE	Pipe to Soil	-0.85	-1.35
46-00	TB-46 NORTH LINE	Pipe to Soil	-0.85	-1.31

Line Reading History

Reading Location		Read Type	Read Limit	Year(s) 2020
46.1-00	OT 46.1 WARDSVILLE	Pipe to Soil	-0.85	-1.49
47-00	TB-47 NORTH LINE	Pipe to Soil	-0.85	-1.40
48-00	TB-48 NORTH LINE	Pipe to Soil	-0.85	-1.50
50-00	TB-50 NORTH LINE	Pipe to Soil	-0.85	-1.54
51-00	TB-51 NORTH LINE	Pipe to Soil	-0.85	-1.33
52-00	TB-52 NORTH LINE	Pipe to Soil	-0.85	-1.23
53-00	TB-53 NORTH LINE	Pipe to Soil	-0.85	-1.21
54-00	TB-54 SOUTH LN	Pipe to Soil	-0.85	-1.16
54-02	TB-54 SOUTH LN	Pipe to Soil		-1.16
55-00	TB-55(N) 10"LOND	Pipe to Soil	-0.85	-1.16
55-01	TB-55(N) 10"LOND	Pipe to Soil		0.00
56-00	TB-56 (N) NORTH	Pipe to Soil	-0.85	-1.40
57-00	TB-57 (N) NORTH	Pipe to Soil	-0.85	-1.25
57-02	TB-57 (N) NORTH	Pipe to Soil		-1.25
57-03	TB-57 (N) NORTH	Pipe to Soil		-1.25
58-00	TB-58 (N) NORTH	Pipe to Soil	-0.85	-1.32
58-02	TB-58 (N) NORTH	Pipe to Soil		-1.31
58-03	TB-58 (N) NORTH	Pipe to Soil		-1.32
58-05	TB-58 (N) NORTH	Pipe to Soil	-1.00	-1.33
58.1-00		Pipe to Soil	-0.85	-1.32
58.1-02		Pipe to Soil		-1.32

2020 Pipe-to-Soil Survey
London South Pipeline

Run Date: 11/12/2020 10:22:15 AM

ENBRIDGE

Begin Date:	1/1/2020	**District:**	London
End Date:	11/12/2020	**Work Area:**	Lon.South Ln Wht Vlv (450)
System:	Pipeline	**Line#/Section#/ServiceID:**	450-Lon.South Ln Wht Vlv

Report Version: 1.1

Line Reading History

Reading Location		**Read Type**	**Read Limit**	**Year(s)** 2020
58.2-01		Pipe to Soil		-1.39
58.3-00		Pipe to Soil	-1.00	-1.43
59-00	TB 59(N) WH WIRE	Pipe to Soil	-1.00	-1.51

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, pages 4, 5, and 6

Question:

a) What is the approximate length of London Dominion Line that has pipe joined with compression couplings and what is the length that has pipe joined with welds?

b) Have there been any instances of pull-out on the London Dominion Line? If the answer is yes, please provide number and year of occurrence.

c) When was the last time that Enbridge Gas or Legacy Union Gas conducted a pipe-to-soil survey of cathodic protection on the London Dominion Line?

d) Please file the report of the most recent pipe-to-soil survey of the London Dominion Line.

e) When was the last time Enbridge Gas or Legacy Union Gas conducted a leak survey of the London Dominion Line?

f) Please file the report of the most recent leak survey of the London Dominion Line.

g) Have there been any through wall corrosion leaks on the London Dominion Line? If the answer is yes, please provide the number and the year of occurrence.

Response:

a) Approximately 10 km of the London Dominion Line has pipe joined with compression couplings. The remaining 65 km of the London Dominion Line is welded.

b) There is no known record of pull-out on the London Dominion Line.

c) The last pipe-to-soil survey of cathodic protection was conducted in Q3 2020.

d) Please see Attachment 1 for the report.

e) The last Leak Survey completed was in April 2020.

f) The results from the Leak Survey are shown in the pre-filed evidence, Exhibit B, Tab 1, Schedule 1, Figure 2.

g) Please see the Leak Repair Summary filed at Exhibit I.APPrO.3 a), Attachment 1.

2020 Pipe-to-Soil Survey
London Dominion Pipeline

Run Date: 11/12/2020 10:14:54 AM

ENBRIDGE

Begin Date:	1/1/2020	**District:**	London
End Date:	11/12/2020	**Work Area:**	Lon.Dom Ln Black Vlv (510)
System:	Pipeline	**Line#/Section#/ServiceID:**	510-Lon.Dom Ln Black Vlv

Report Version: 1.1

Line Reading History

Reading Location		Read Type	Read Limit	Year(s) 2020
1-00	TB-1 SOUTH LINE	Pipe to Soil	-0.85	-1.14
1.1-00	TB-1.1 LOND-DOM LN	Pipe to Soil	-0.85	-1.12
2-00	TB-2 (S)	Pipe to Soil	-0.85	-1.23
3-00	TB-3 (S)	Pipe to Soil	-0.85	-1.02
4-00	TB-4 (S)	Pipe to Soil	-0.85	-1.07
4-03	TB-4 (S)	Pipe to Soil	-0.85	-1.10
5-00	TB-5 (S)	Pipe to Soil	-0.85	-1.12
6-00	TB-6 (S) 4 WHITE	Pipe to Soil	-0.85	-1.08
6-01	TB-6 (S) 4 WHITE	Pipe to Soil		-1.09
6-02	TB-6 (S) 4 WHITE	Pipe to Soil		-1.08
6-04	TB-6 (S) 4 WHITE	Pipe to Soil		-1.08
7-00	TB-7 (S)	Pipe to Soil	-0.85	-1.08
8-00	TB-8 (S)	Pipe to Soil	-0.85	-1.22
9-00	TB-9 (S)	Pipe to Soil	-0.85	-1.20
11-00	TB-11(S)	Pipe to Soil	-0.85	-1.03
12-00	TB-12 (S)	Pipe to Soil	-0.85	-1.35

Line Reading History

Reading Location		Read Type	Read Limit	Year(s) 2020
14-00	TB-14 (S)	Pipe to Soil	-0.85	-1.18
15-00	TB-15 (S)	Pipe to Soil	-0.85	-1.11
15.2-00	TB-15.2	Pipe to Soil	-0.85	-1.24
15.2-01	TB-15.2	Pipe to Soil		-1.20
15.2-02	TB-15.2	Pipe to Soil		-1.24
15.2-03	TB-15.2	Pipe to Soil		-1.24
16-00	TB-16 (S)	Pipe to Soil	-0.85	-1.19
18-00	TB-18 8TH CONC	Pipe to Soil	-0.85	-1.13
18-01	TB-18 8TH CONC	Pipe to Soil		-0.77
18-04	TB-18 8TH CONC	Pipe to Soil		-1.13
18-05	TB-18 8TH CONC	Pipe to Soil		-0.77
18.1-00	TB-18.1 SOUTH LINE	Pipe to Soil	-0.85	-1.13
18.1-01	TB-18.1 SOUTH LINE	Pipe to Soil		-1.13
19-00	TB-19 (S) Rect-42	Pipe to Soil	-0.85	-1.38
20-00	TB-20 (S)	Pipe to Soil	-0.85	-1.17
20.1-00	OT 20.1 STN 10H202	Pipe to Soil	-0.85	-1.15
21-00	TB-21 (S)	Pipe to Soil	-0.85	-1.17
22-00	TB-22 (S)	Pipe to Soil	-0.85	-1.19
23-00	TB-23 (S)	Pipe to Soil	-0.85	-1.33

2020 Pipe-to-Soil Survey
London Dominion Pipeline

Run Date: 11/12/2020 10:14:54 AM

ENBRIDGE

Begin Date:	1/1/2020	**District:**	London
End Date:	11/12/2020	**Work Area:**	Lon.Dom Ln Black Vlv (510)
System:	Pipeline	**Line#/Section#/ServiceID:**	510-Lon.Dom Ln Black Vlv

Report Version: 1.1

Line Reading History

Reading Location		Read Type	Read Limit	Year(s) 2020
23.05-03	RECT 43	Pipe to Soil	-0.85	-1.23
25-00	TB-25 (S)	Pipe to Soil	-0.85	-1.20
26-00	TB-26 (S)	Pipe to Soil	-0.85	-1.08
27-00	TB-27 (S)	Pipe to Soil	-0.85	-1.18
27.1-00	OT 27.1 OAKDALE	Pipe to Soil		-1.26
27.1-01	OT 27.1 OAKDALE	Pipe to Soil		-1.23
27.1-03	OT 27.1 OAKDALE	Pipe to Soil		-1.06
27.1-04	OT 27.1 OAKDALE	Pipe to Soil		-1.26
27.1-05	OT 27.1 OAKDALE	Pipe to Soil	-0.85	-1.26
27.1-06	OT 27.1 OAKDALE	Pipe to Soil		-1.06
27.1-07	OT 27.1 OAKDALE	Pipe to Soil		-1.26
30-00	TB-30LD NO 2	Pipe to Soil	-0.85	-1.34
30-02	TB-30LD NO 2	Pipe to Soil		-1.33
30-03	TB-30LD NO 2	Pipe to Soil		-1.33
31-00	TB-31DS NO 2	Pipe to Soil	-0.85	-1.40
32-00	TB-32DS NO 2	Pipe to Soil	-0.85	-1.55
32.1-00	OT 32.1 STN 11J401	Pipe to Soil	-0.85	-1.55
33-00	TB-33LD NO 2	Pipe to Soil	-0.85	-1.50
34-00	TB-34LD NO 2	Pipe to Soil	-0.85	-1.33
34.1-00	OT 34.1 STN 11J571	Pipe to Soil	-0.85	-1.33
35-00	TB-35LD NO 2	Pipe to Soil	-0.85	-1.33
36-00	TB-36LD DIR BOND WEST SD VALVE	Pipe to Soil	-0.85	-1.31

2020 Pipe-to-Soil Survey
London Dominion Pipeline

ENBRIDGE

Run Date:	11/12/2020	10:14:54 AM	
Begin Date:	1/1/2020	**District:**	London
End Date:	11/12/2020	**Work Area:**	Lon.Dom Ln Black Vlv (510)
System:	Pipeline	**Line#/Section#/ServiceID:**	510-Lon.Dom Ln Black Vlv

Report Version: 1.1

Line Reading History

Reading Location		Read Type	Read Limit	Year(s) 2020
36-01	TB-36LD DIR BOND	Pipe to Soil		-1.31
38-00	TB-38LD NO 2 E OF	Pipe to Soil	-0.85	-1.40
38-01	1756 Smith Falls, corn	Pipe to Soil	-0.85	-1.50
39-00	TB-39DS NO 2	Pipe to Soil	-0.85	-1.53
39-05	TB-39DS NO 2	Pipe to Soil	-0.85	-1.58
39-06	TB-39DS NO 2	Pipe to Soil		-1.64
40-00	TB-40DS NO 2	Pipe to Soil	-0.85	-1.38
41-00	TB-41LD NO 2	Pipe to Soil	-0.85	-1.47
42-00	TB-42LD NO 2	Pipe to Soil	-0.85	-1.37
42.1-00	OT 42.1 WEST SD	Pipe to Soil	-0.85	-1.32
42.1-01	OT 42.1 WEST SD	Pipe to Soil		-1.32
42.1-02	OT 42.1 WEST SD	Pipe to Soil		-1.37
44-00	TB-44DS NO 2	Pipe to Soil	-0.85	-1.36
45-00	TB-45 SOUTH LINE	Pipe to Soil	-0.85	-1.35
45-02	TB-45 SOUTH LINE	Pipe to Soil		-1.35
46-00	TB-46 SOUTH LINE	Pipe to Soil	-0.85	-1.31
46.1-00	OT 46.1 WARDSVIL	Pipe to Soil	-0.85	-1.34
46.1-01	OT 46.1 WARDSVIL	Pipe to Soil		-1.21
46.1-02	OT 46.1 WARDSVIL	Pipe to Soil		-1.34
46.1-04	OT 46.1 WARDSVIL	Pipe to Soil		-1.21
47-00	TB-47 SOUTH LINE	Pipe to Soil	-0.85	-1.40

Line Reading History

Reading Location		Read Type	Read Limit	Year(s) 2020
47.5-00	Rowe Energy	Pipe to Soil	-0.85	-1.46
47.5-01	Rowe Energy	Pipe to Soil	-1.00	-1.66
47.5-02	Rowe Energy	Pipe to Soil	-1.00	-1.66
48-00	TB-48 SOUTH LINE	Pipe to Soil	-0.85	-1.40
50-00	TB-50 SOUTH LINE	Pipe to Soil	-0.85	-1.64
50-02	TB-50 SOUTH LINE	Pipe to Soil		-1.64
51-00	TB-51 SOUTH LINE	Pipe to Soil	-0.85	-1.32
52-00	TB-52 GLENCOE STN	Pipe to Soil	-0.85	-1.23
52-03	TB-52 GLENCOE STN	Pipe to Soil		-0.80
52-05	TB-52 GLENCOE STN	Pipe to Soil		-1.23
53-00	TB-53 SOUTH LINE	Pipe to Soil	-0.85	-1.21
54-00	TB-54 SOUTH LINE	Pipe to Soil	-0.85	-1.16
55-00	TB-55(S) 8"LOND	Pipe to Soil	-0.85	-1.18
55-01	TB-55(S) 8"LOND	Pipe to Soil		-1.00
56-00	TB-56 (S) SOUTH	Pipe to Soil	-0.85	-1.36
57-00	TB-57 (S) SOUTH LINE	Pipe to Soil	-0.85	-1.30

2020 Pipe-to-Soil Survey
London Dominion Pipeline

Run Date: 11/12/2020 10:14:54 AM

ENBRIDGE

Begin Date:	1/1/2020	**District:**	London
End Date:	11/12/2020	**Work Area:**	Lon.Dom Ln Black Vlv (510)
System:	Pipeline	**Line#/Section#/ServiceID:**	510-Lon.Dom Ln Black Vlv

Report Version: 1.1

Line Reading History

Reading Location		Read Type	Read Limit	Year(s) 2020
58-00	TB-58 (S) SOUTH	Pipe to Soil	-0.85	-1.26
58.1-00	TB 58.1 SOUTH 6" RD	Pipe to Soil	-0.85	-1.22
58.1-01	TB 58.1 SOUTH 6" RD	Pipe to Soil		-1.22
58.2-00	TB 58.2 WEST 12"	Pipe to Soil	-0.85	-1.32
58.2-01	TB 58.2 WEST 12"	Pipe to Soil		-1.39
59-00		Pipe to Soil	-0.85	-1.51
59-02		Pipe to Soil		-1.52
59-03		Pipe to Soil		-1.48
60-00	TB-60	Pipe to Soil	-0.85	-2.33
60-04	TB-60	Pipe to Soil	-1.00	-1.24
61-00	TB-61 WEST	Pipe to Soil	-0.85	-1.65
61-02	TB-61 WEST	Pipe to Soil		-1.66
61.1-00	TB-61.1 BONDED	Pipe to Soil	-0.85	-1.45
61.1-01	TB-61.1 BONDED	Pipe to Soil		-1.20
61.2-00	TB-61.2 RES BOND	Pipe to Soil	-0.85	-1.39
61.2-01	TB-61.2 RES BOND	Pipe to Soil		-1.39
61.3-00	OT 61.3 MT BRYD	Pipe to Soil	-0.85	-1.07
61.3-01	OT 61.3 MT BRYD	Pipe to Soil		-0.58
61.3-02	OT 61.3 MT BRYD	Pipe to Soil		-1.07
62-00	TB-62	Pipe to Soil	-0.85	-1.38
62-03	TB-62	Pipe to Soil		-1.20
63-00	TB-63	Pipe to Soil	-0.85	-1.39

2020 Pipe-to-Soil Survey
London Dominion Pipeline

Run Date: 11/12/2020 10:14:54 AM

ENBRIDGE

Begin Date:	1/1/2020	**District:**	London
End Date:	11/12/2020	**Work Area:**	Lon.Dom Ln Black Vlv (510)
System:	Pipeline	**Line#/Section#/ServiceID:**	510-Lon.Dom Ln Black Vlv

Report Version: 1.1

Line Reading History

Reading Location		Read Type	Read Limit	Year(s) 2020
63.1-00	TB-63.1 WSD 402 BLK	Pipe to Soil		-1.59
63.1-01	TB-63.1 WSD 402 BLK	Pipe to Soil	-0.85	-1.59
63.2-00	TB 63.2 ESD 402 YLW	Pipe to Soil		-1.69
63.2-01	TB 63.2 ESD 402 YLW	Pipe to Soil	-0.85	-1.69
63.2-02	TB 63.2 ESD 402 YLW	Pipe to Soil		-1.69
64-00	TB-64	Pipe to Soil	-0.85	-1.05
65-00	TB-65	Pipe to Soil	-0.85	-1.26
65-04	TB-65	Pipe to Soil	-0.85	-1.45
65.5-00		Pipe to Soil	-1.00	-1.47
65.5-02		Pipe to Soil		-1.54
65.5-03		Pipe to Soil		-1.24
65.8-00		Pipe to Soil	-0.85	-1.13
66-00	TB-66	Pipe to Soil	-0.85	-1.12
67-00	TB-67	Pipe to Soil	-0.85	-1.01
67.1-00	OT 67.1 KOMOKA	Pipe to Soil	-0.85	-1.30
67.1-01	OT 67.1 KOMOKA	Pipe to Soil		-1.30
67.1-03	OT 67.1 KOMOKA	Pipe to Soil		-1.30
67.1-06	OT 67.1 KOMOKA	Pipe to Soil		-1.06
67.1-08	OT 67.1 KOMOKA	Pipe to Soil	-1.00	-1.29
68-00	TB 68, north of river	Pipe to Soil	-1.00	-1.34
69-00	TB 69, N/E corner Gideon/Komoka	Pipe to Soil	-1.00	-1.35

Line Reading History

Reading Location		Read Type	Read Limit	Year(s) 2020
70-00	TB 70	Pipe to Soil	-1.00	-1.36
71-02	At valve site	Pipe to Soil		-1.50
71-03	At valve site	Pipe to Soil		-1.35
71.1-00	Risers at valve site	Pipe to Soil	-1.00	-1.45
71.1-01	Risers at valve site	Pipe to Soil	-1.00	-1.45

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, page 6

Question:

a) Please list five lines with the highest leak rates with the leak rate for each one.

b) Please compare the leak rate of London Lines and The Windsor Line and discuss the reason for the difference

Response:

a) The Enbridge Gas distribution network is not typically grouped into collection of assets. There is no list of lines which can be provided. For comparison against Legacy Enbridge Gas Distribution leak rates please see Exhibit I.APPrO.2 a).

b) Based upon the available failure data and populations there were 47 leaks associated with the Windsor Lines between 2013 to 2019 across 54km of mains. Based upon the leak repair data available to DIMP, the Windsor Line leaks between 2014 and 2017 were predominantly caused by corrosion. Between 2011 to 2019 the majority (38%) of London Line leak repairs were due to coupling/clamp leaks. Corrosion occurs when adequate corrosion protection is not available. This could be a result of pipe coating damages, disbonded coatings causing cathodic protection shielding, or inadequate cathodic protection levels. Please see pictures below.


20. 8. 2002


20. 8. 2002


21. 8. 2002


IMG_0688


to go to fullscreen, ctrl+click to snap to video size

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, page 6

Preamble:

"Although there are currently 5 active Class C Leaks, Enbridge Gas has been monitoring as many as 29 active Class C Leaks since 2013."

Question:

a) Please describe the monitoring of active leaks including the process, monitoring frequency and approximate cost of monitoring per year.

b) Were leaks that are no longer monitored repaired? If the answer is yes, what was the method of repair and approximate cost or repair per leak? If the answer is no, please explain why not.

Response:

a) Leak monitoring is completed as a surface-based survey with approved gas detection equipment. Class A leaks are monitored continuously until repaired, Class B leaks are monitored within seven (7) days of the leak first being identified and within every fifteen (15) days following the initial leak monitor until the leak is repaired, and Class C Leaks are monitored annually until repaired.

   Assuming an average of two (2) Class B Leaks per year the approximate annual cost to monitor Class B leaks is $840.

   The approximate annual cost to monitor twenty-nine (29) Class C leaks is $750.

b) Class A and Class B leaks are monitored until they are repaired. Class C leaks are either monitored until they are repaired or can be considered resolved if two successive leak monitoring events are unsuccessful in verifying a leak at that specified location.

Between 2011 and 2019 the typical cost to repair Class A and Class B leaks is approximately $6,000 per leak; the repair cost has ranged as high as $165,000 to replace a section of piping. The method of repair is typically the installation of a split repair sleeve over the affected area or replacement of a section of piping.

Class C leaks typically have not been repaired however they generally progress over time in leak classification to Class A leaks or Class B leaks. Between 2011 and 2019 the typical repair cost for a Class C leak is approximately $7,000 per leak. The typical repair methods have been the installation of a split repair sleeve over the affected area or repair to an existing valve.

Split repair sleeve and pipe replacement repair strategies can be problematic, posing risk to employees and risk to system operability when excavating near an unrestrained dresser coupling or an area of significant corrosion. Broadening the isolation area may be required to mitigate risk relating to unexpected dresser pullout during excavation or to find suitable pipe to tie new pipe into; resulting in larger system outages and increasing the impacts to serviced customers.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, page 9

Question:

a) Have there been any instances where either the London South Line or the London Dominion line was damaged by heavy agricultural equipment due to insufficient depth of cover? If the answer is yes, please provide a list showing the year of occurrence and the description of damage and repair.

b) What lengths of London South Line and London Dominion Line are located on agricultural land?

Response:

a) Yes, there have been instances where the London Lines have been damaged due to insufficient depth of cover. In 2008, agricultural equipment struck an abandoned first stage cut and a repair fitting was used to encapsulate the damaged area. In 2011, a tiling machine struck the main and the section of pipe had to be replaced.

b) The total length of the London Dominion Line in agricultural fields is 70156 m. The total length of the London South Line in agricultural fields including the Abandoned portion on map is 23988 m. The total length of the London South Line in agricultural fields excluding the Abandoned portion on map is 14550 m.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, page 19

Question:

a) Why is a new NPS 6 line needed to connect London Line to the Strathroy Gate Station?

b) What is the approximate cost of this line?

c) Is the Strathroy Gate Station an existing station? If it is a new station or a rebuild of an existing station, please provide its cost of construction.

Response:

a) Please see Exhibit I.STAFF.1 a)

b) Please see Exhibit I.STAFF.1 b)

c) Strathroy Gate Station is an existing station and needs to be rebuilt to support the Project scope. The design work and quotes are underway, as such, the high-level estimate of the cost of to rebuild is approximately $2 million and contains contingency due to the uncertainty of a number of factors to be determined by the detailed design work.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibits F, Tab 1, Schedule 1, page 1 and Tab 2, Schedule 1; Exhibit B, Tab 1, page 19

Preamble:

"Enbridge Gas is not seeking approval for the ancillary facilities' costs (i.e. stations, services, abandonment) in this application. These costs have been included in the total Project cost for completeness."

Question:

Please provide a more detailed table that shows separately the cost of stations, services, and abandonment, and the cost of the 8.4 km new NPS 6 pipeline to Strathroy Gate Station.

Please list project costs that have already been spent such as the cost of survey, engineering, environmental route selection, indigenous consultation and purchased materials.

Response:

Please see Exhibit I.ED.13 for a breakdown of the project costs.

Below is the project spend to date. As of Oct 31, 2020, the spend to date was $3.961 million. This includes costs such as slot trenching (to confirm existing underground utility locations and depth for detailed design), yard preparation, field inspection, environmental (assessment report, permitting support, archeological assessment), other design work (such as topographical survey, crossing designs, etc.), company expenses and labour, and some preliminary landowner agreement payments. Additionally, the cost of interest during construction was $11,000 and the costs of estimated indirect overheads is projected to be $850,000 (these are not finalized until end of year).

Please see table below.

Particulars ($000's)	Project to Date Spend as at 2020/10/31
Materials	-
Construction and Labour	3,961
Contingencies	-
Interest During Construction	11
Estimated Incremental Project Capital Costs	3,972
Indirect Overhead	850
Total Estimated Project Capital Costs	4,822

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, page 14

Preamble:

EGI evidence states: "*The recent Risk Assessment performed on the London Lines showed that the imbalance between risk, cost and performance supports a move away from maintaining these assets and more towards renewal of the assets, as they are nearing end-of-life.*"

Question:

Please provide the date of the Risk Assessment referenced.

a) If there is an internal report, please file.
b) Please provide the previous Risk Assessment, its internal report and the date performed.

Response:

a) The Risk Assessment report is dated July 28, 2020 and is filed as Attachment 1 to this response.

b) There was no previous risk assessment.

Title: Qualitative Assessment of London Lines
Date: July 28th, 2020
Version: Version Number 3
Purpose: Director Review
Description: Version Three - Risk Approver Endorsement

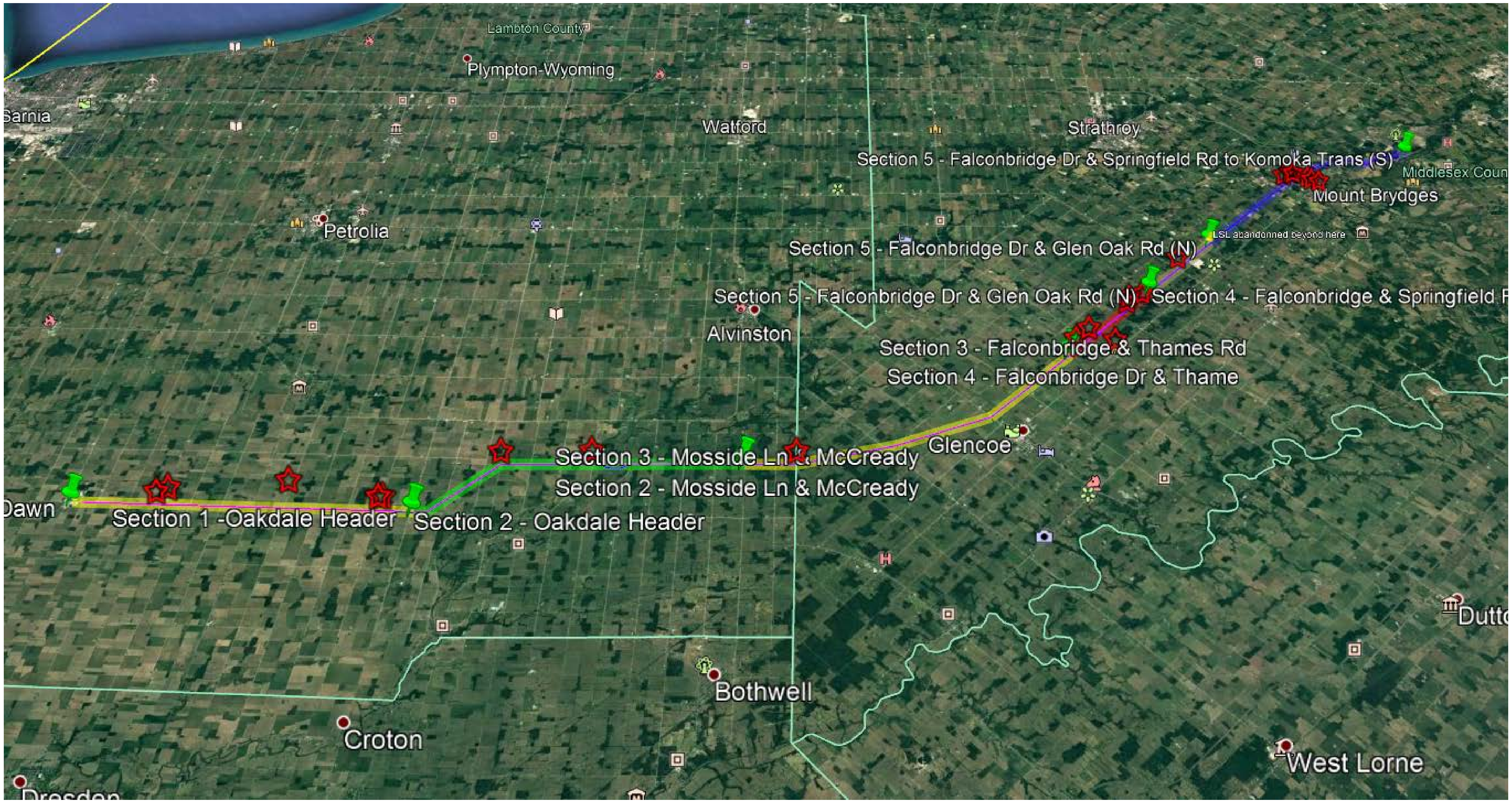
MAIN SECTION	Smaller Sub-Sections	Start and end coordinates	1930s	1940s	1950s	1960s	1970s	1980s	1990s	2000s	2010s	Other Factors		Comments	Customer Impact (Average Winter Day - 35 DD Conditions)	Customer Impact (Desing Winter Day - 43.1 DD Conditions)	Additional Plnanning Comments
			Vintage (Approximated Length Percentages)														
1	**Twin Pipelines** **Dawn to Oakdale Header** North Side Rd	**42.713365, -82.221683** **42.708629, -82.037787**	95%			4%	1%					Dia. Length Mainline Valves Avg. of <06m DOC Total Length of <0.6m cover % Length with <0.6m cover Sections with cover <0.3 Exposed Pipe Locations Unrestrained Dresser Couplings Current Active C Leaks Estmate of Historical C Leaks Land Use Corrosion Concerns	8/10 15100 NPS 8 Dawn Outlet Valve - Details unknown FID 521191891 (Yr Unknown) 0.47m 6569m 42.8% 12 8 Yes 3 5 Agricultural / Recreational	4.8mm & 7.0mm NPS 8 Gr 165, 5.6mm NPS 10 Gr 290 Dawn outlet valve identifies "Phantom Valve" For 2018-2020 The total number of C leaks for each section was equally assigned to the North and South lines. For 2013-2017 The average of the total number of C leaks was calculated and assigned to each section equally.	8323 *Note: due to the interconnected nature of the downstream system and the single fed nature of the London Lines, both the north and south options result in the same customer impact. Essentially the entire London Line will be isolated.	9882 *Note: due to the interconnected nature of the downstream system and the single fed nature of the London Lines, both the north and south options result in the same customer impact. Essentially the entire London Line will be isolated. The customer count increases due to the increased customer loss in downstream interconnected systems.	System isolated at Dawn loses 7763 customer
	Twin Pipelines **Dawn to Oakdale Header** South Side Rd	**42.713365, -82.221683** **42.708629, -82.037787**	88%		9%	1%	1%					Dia. Length Mainline Valves Avg. of <06m DOC Total Length of <0.6m cover % Length with <0.6m cover Sections with cover <0.3 Exposed Pipe Locations Unrestrained Dresser Couplings Current Active C Leaks Estmate of Historical C Leaks Land Use Corrosion Concerns	8 15100 NPS 8 Dawn Outlet Valve - Details unknown FID 521191892 (Yr Unknown) 0.51m 2682m 17.8% 7 8 Yes 1 5 Agricultural / Recreational	4.8mm, 6.4mm & 7.0mm NPS 8 Gr 165 Dawn outlet valve identifies "Phantom Valve" For 2018-2020 The total number of C leaks for each section was equally assigned to the North and South lines. For 2013-2017 The average of the total number of C leaks was calculated and assigned to each section equally. For 2018-2020 The total number of C leaks for each section was	8323 *Note: due to the interconnected nature of the downstream system and the single fed nature of the London Lines, both the north and south options result in the same customer impact. Essentially the entire London Line will be isolated.	9882 *Note: due to the interconnected nature of the downstream system and the single fed nature of the London Lines, both the north and south options result in the same customer impact. Essentially the entire London Line will be isolated. The customer count increases due to the increased customer loss in downstream interconnected systems.	System isolated at Dawn loses 7763 customer
2	**Twin Pipelines** **Oakdale Header to Mosside Ln & McCready** North Side Rd	**42.708629, -82.037787** **42.733298, -81.863210**	89%		9%	1%	1%					Dia. Length Mainline Valves Avg. of <06m DOC Total Length of <0.6m cover % Length with <0.6m cover Sections with cover <0.3 Exposed Pipe Locations Unrestrained Dresser Couplings Current Active C Leaks Estmate of Historical C Leaks Land Use Corrosion Concerns	10 15500 Oakdale Header NPS 10 Plug Valve FID 521184895 (Yr Unk) Dobbyn Rd NPS 10 Plug Valve FID 521245328 (Yr 1935) 0.49m 2367m 15.4% 2 2 Yes 0 2 Agricultural / Recreational	NPS 10 5.6mm & 7.0mm Gr 165 For 2018-2020 The total number of C leaks for each section was equally assigned to the North and South lines. For 2013-2017 The average of the total number of C leaks was calculated and assigned to each section equally.	9 *Note: this would require MLV FIDs 521243594, 521183844, 521246777, 521245333, 521184895. This would extend 2.3 km east of the indicated end point.	9 *Note: this is the same as the 35 DD scenario	System isolated at Oakdale Header loses 5835 Customer
	Twin Pipelines **Oakdale Header to Mosside Ln & McCready** South Side Rd	**42.708629, -82.037787**			98%	0.5%	0.5%	0.5%	0.5%			Dia. Length Mainline Valves Avg. of <06m DOC Total Length of <0.6m cover % Length with <0.6m cover Sections with cover <0.3 Exposed Pipe Locations Unrestrained Dresser Couplings	10 15500 Oakdale Header NPS 10 Plug Valve FID 521184885 (Yr Unk) Dobbyn Rd NPS 10 Plug Valve FID 521245330 (Yr 1952) 0.50m 61m 0.4% 0 5 No	NPS 10 5.6mm Gr 165 Dobbyn Rd Valve - GIS identified do not operate	519 *Note: this would include numerous MLV FIDs 522048663, 521622838, 521247727, 521183858, 805708850, 805163736, 521184885, 521223570, 521245334, 521243604. This would extend 24 km east of	519 *Note: this is the same as the 35 DD scenario	System isolated at Oakdale Header loses 5835 Customers

MAIN SECTION	Smaller Sub-Sections	Start and end coordinates	1930s	1940s	1950s	1960s	1970s	1980s	1990s	2000s	2010s	Other Factors		Comments	Customer Impact (Average Winter Day - 35 DD Conditions)	Customer Impact (Desing Winter Day - 43.1 DD Conditions)	Additional Plnanning Comments
			Vintage (Approximated Length Percentages)														
		42.733298, - 81.863210										Current Active C Leaks	0		the eastern extent (into section 3 and 4)		
												Estmate of Historical C Leaks	2	For 2018-2020 The total number of C leaks for each section was equally assigned to the North and South lines. For 2013-2017 The average of the total number of C leaks was calculated and assigned to each section equally.			
												Land Use	Agricultural / Recreational				
												Corrosion Concerns					
3	**Twin Pipelines** **Mosside Ln & McCready to Falconbridge & Thames Rd** North Side Rd	42.733298, - 81.863210 42.795687, - 81.675291	93%		7%							Dia.	10	NPS 10 7.0mm Gr 165	47 *Note: this would require MLV FIDs 522048629, 521247735, 521245328, 521223570, 804934717. This would extend 8.7 km east of the indicated end point and 6.9 km west of the western extent.	47 *Note: this is the same as the 35 DD scenario	System isolated at WatterWorth & Cameron Rd loses 5777 customers
												Length	15000				
												Mainline Valves	Watterworth Rd NPS 10 Nord Plug Valve FID 521246777 (Yr 1935) 4363 Falconbridge NPS 10 Nord Plug Valve FID 521476366 (Yr 1938) FID 521476381 (Yr 1938)				
												Avg. of <06m DOC	0.49m				
												Total Length of <0.6m cover	5312m				
												% Length with <0.6m cover	30.34%				
												Sections with cover <0.3	7				
												Exposed Pipe Locations	13				
												Unrestrained Dresser Couplings	Yes				
												Current Active C Leaks	1	For 2018-2020 The total number of C leaks for each section was equally assigned to the North and South lines. For 2013-2017 The average of the total number of C leaks was calculated and assigned to each section equally.			
												Estmate of Historical C Leaks	System isolated at WatterWorth & Cameron Rd loses 5777				
												Land Use	Agricultural / Recreational				
												Land Owner Concerns	Concerns expressed from a landowner that shallow main has compomised a famers field tiles.				
												Corrosion Concerns					
	Twin Pipelines **Mosside Ln & McCready to Falconbridge & Thames Rd** South Side Rd	42.733298, - 81.863210 42.795687, - 81.675291			100%							Dia.	10	NPS 10 5.6mm Gr 165	519 *Note: this would include numerous MLV FIDs 522048663, 521622838, 521247727, 521183858, 805708850, 805163736, 521184885, 521223570, 521245334, 521243604. This would extend 15.5 km west of the western extent indicated (into section 2) and 6.3 km east of the eastern extent (into section 4). Note this is the same as option 2 southern portion.	519 *Note: this is the same as the 35 DD scenario	System isolated at WatterWorth & Cameron Rd loses 5777 customers
												Length	15000				
												Mainline Valves	Cameron Rd NPS 12 Unknown FID 521246781 (Yr 1952) Old Airport Rd NPS 12 Gate Valve FID 521207451 (Yr 1952) 4363 Falconbridge NPS 8 Nord Plug Valve FID 521476374 (Yr 1952) FID 521476389 (Yr 1952)				
												Avg. of <06m DOC	NA				
												Total Length of <0.6m cover	NA				
												% Length with <0.6m cover	NA				
												Sections with cover <0.3	0				
												Exposed Pipe Locations	8				
												Unrestrained Dresser Couplings	No				
												Current Active C Leaks	0				
												Estmate of Historical C Leaks	1	For 2018-2020 The total number of C leaks for each section was equally assigned to the North and South lines. For 2013-2017 The average of the total number of C leaks was calculated and assigned to each section equally.			
												Land Use	Agricultural / Recreational				
												Land Owner Concerns	Concerns expressed from a landowner that shallow main has compomised a famers field tiles.				
												Corrosion Concerns					
4	**Twin Pipelines** **Falconbridge Dr & Thames to Falconbridge & Springfield Rd** North Side Rd	42.795687, - 81.675291 42.836882, - 81.619047	100% (NPS 10)									Dia.	10	7.0mm wall NPS 10 Gr 165	38 *Note: Would require MLV FIDs 522048629, 521247735, 521246777, 804934717, 521223570. Furthest valve to the western extent is FID 521246777 (~15.2 km to the west of the location indicated) Furthest valve to the eastern extent is FID 804934717 (~2 km east of location indicated)	38 *Note: this is the same as the 35 DD scenario.	System isolated at 4363 Falconbridge loses 4128 Customers
												Length	8800				
												Mainline Valves					
												Avg. of <06m DOC	0.46m				
												Total Length of <0.6m cover	1263m				
												% Length with <0.6m cover	19.5%				
												Sections with cover <0.3	7				
												Exposed Pipe Locations	0				
												Unrestrained Dresser Couplings	Yes				
												Current Active C Leaks	0				
												Estmate of Historical C Leaks	6	For 2018-2020 The total number of C leaks for each section was equally assigned to the North and South lines. For 2013-2017 The average of the total number of C leaks was calculated and assigned to each section equally.			
												Land Use	Agricultural / Recreational				
												Corrosion Concerns					
	Twin Pipelines **Falconbridge & Thames Rd to Falconbridge & Springfield Rd**	42.795687, - 81.675291 42.836882, -			98% (NPS 8)			1% (NPS8)			1% (NPS 8)	Dia.	8	4.8mm NPS 8 Gr 165	519 *Note: this would include numerous MLV FIDs 522048663, 521622838, 521247727, 521183858, 805708850, 805163736, 521184885, 521223570, 521245334, 521243604. This would extend 32.9 km west of the western extent indicated (into section 3 and 2)	519 *Note: this is the same as the 35 DD scenario	System isolated at 4363 Falconbridge loses 4128 Customers
												Length	8800				
												Mainline Valves					
												Avg. of <06m DOC	0.50m				
												Total Length of <0.6m cover	190m				
												% Length with <0.6m cover	2.90%				
												Sections with cover <0.3	0				
												Exposed Pipe Locations	3				
												Unrestrained Dresser Couplings	No				
												Current Active C Leaks	0				

MAIN SECTION	Smaller Sub-Sections	Start and end coordinates	1930s	1940s	1950s	1960s	1970s	1980s	1990s	2000s	2010s	Other Factors		Comments	Customer Impact (Average Winter Day - 35 DD Conditions)	Customer Impact (Desing Winter Day - 43.1 DD Conditions)	Additional Plnanning Comments
			Vintage (Approximated Length Percentages)														
	South Side Rd	81.619047										Estmate of Historical C Leaks Land Use Corrosion Concerns	6 Agricultural / Recreational	For 2018-2020 The total number of C leaks for each section was equally assigned to the North and South lines. For 2013-2017 The average of the total number of C leaks was calculated and assigned to each section equally.	Note: this is the same isolation as the southern portion of section 2 & 3.		
5	**Twin Pipelines** **Falconbridge Dr & Glen Oak Rd** North Side Rd	**42.836882, -81.619047** **42.870093, -81.573756** ***Dead End / Capped***	44% (NPS 10)					3% (NPS 12)	53% (NPS 12)			Dia. Length Mainline Valves Avg. of <06m DOC Total Length of <0.6m cover % Length with <0.6m cover Sections with cover <0.3 Exposed Pipe Locations Unrestrained Dresser Couplings Current Active C Leaks Estmate of Historical C Leaks Land Use Corrosion Concerns	10/12 5250 Melbourne Rd NPS 10 PN 50 Gate Valve FID 804934717 0.54m 157m 3.0% 0 0 Yes 0 5 Agricultural / Recreational	5.6mm & 7.0mm wall NPS 10, 5.6 & 9.5mm wall NPS 12 Grade split ~50% 165 MPA & ~50% 290MPa For 2018-2020 The total number of C leaks for each section was equally assigned to the North and South lines. For 2013-2017 The average of the total number of C leaks was calculated and assigned to each section equally.	4372 *NOTE - assuming isolation from valves FID 521681703 and 804934717 (approx. 2 km east of indicated start point). This is the nearest MLV. Downstream of this valve, the two parallel mains become single fed so all customers to the east would be lost.	4392 *NOTE - this is essentially the same isolation scenario as for the 35 DD situation, however there is a slight increase to customer count due to the small back-feeds between the Komoka and London systems.	System isolated at Melborne Rd loses 3758 Customers
	Twin Pipelines **Falconbridge Dr & Springfield Rd to Komoka Trans** South Side Rd	**42.836882, -81.619047** **42.938536, -81.422248**			91% (NPS 8)		0.5% (NPS 8)	0.5% (NPS 8)	7.5% (NPS 12)		0.5% (NPS 8)	Dia. Length Mainline Valves Avg. of <06m DOC Total Length of <0.6m cover % Length with <0.6m cover Sections with cover <0.3 Exposed Pipe Locations Unrestrained Dresser Couplings Current Active C Leaks Estmate of Historical C Leaks Land Use Corrosion Concerns	8/12 20550 Springfield Rd NPS 8 PN 50 Gate Valve FID 805708850 (Yr 2017) Christina Rd NPS 8 Gate Valve FID 521691602 (Yr 1952) 0.49m 1437m 7.06% 2 6 No 0 5 Agricultural / Recreational	4.8mm & 6.4mm wall NPS 8, 5.6mm NPS 12 Grade Primarily 165 MPa For 2018-2020 The total number of C leaks for each section was equally assigned to the North and South lines. For 2013-2017 The average of the total number of C leaks was calculated and assigned to each section equally.	There are two scenarios; If the isolation is between MLV FID 521681666, 521291696 and 805708850, there would be no customer impact. To the east of this, the two parallel mains become single fed. If the isolation is required to the east, the customer impact would be 4372 (same as above scenario)	There are two scenarios; If the isolation is between MLV FID 521681666, 521291696 and 805708850, there would be 3 customers impacted. To the east of this, the two parallel mains become single fed. If the isolation is required to the east, the customer impact would be 4392 (same as above scenario)	System isolated at Melborne Rd loses 3758 Customers

								Risk Ranking					
Pipeline	**Segment**	**Scenario Description**	**Context Comment**	**Failure Mode**	**Cause**	**Cause Comments**	**Consequence Comments**	**CAT**	**L**	**C**	**RR**	**Controls**	**Notes**
North Side (London South Line)	1a	Leaks result in repairs using clamps and mechanical fittings	Integrity Issue resulting in leak. Typical repair.	Leak	External Corrosion Internal corrosion Equipment Failure Valve malfunction (Valve) Construction - Defective joining		This is the risk of costs for ongoing repairs. Of the 28 repairs on record; 24 have been less than $10,000 and 4 have been between $10,000 and $100,000. The most recent repair in 2019 was $61,300. Replacements in 2016 and 2017 were $245,000 and $165,000 respectively. Consideration for the C3 (100K to 1M) was also given to the age and the condition of the line and that repairs in the future may increase in cost. Primary failure causes are corrosion leaks.	Fin	6	3	**Medium**	Mitigation - Emergency response 1st, 2nd, 3rd Party damages Prevention : Locate Prevention - Call before you dig (For 3rd Party damages)	There is CP on the pipeline. Of note however, it was installed a number of years (about the mid-60s) after installation. Factored into the liklihood rating.
South Side (Dominion Line)	1b	Leaks result in repairs using clamps and mechanical fittings	Integrity Issue resulting in leak. Typical repair.	Leak	External Corrosion Internal corrosion Equipment Failure Valve malfunction (Valve) Construction - Defective joining		This is the risk of costs for ongoing repairs. Of the 28 repairs on record; 24 have been less than $10,000 and 4 have been between $10,000 and $100,000. The most recent repair in 2019 was $61,300. Replacements in 2016 and 2017 were $245,000 and $165,000 respectively. Consideration for the C3 (100K to 1M) was also given to the age and the condition of the line and that repairs in the future may increase in cost. Primary failure causes are corrosion leaks.	Fin	6	3	**Medium**	Mitigation - Emergency response 1st, 2nd, 3rd Party damages Prevention : Locate Prevention - Call before you dig (For 3rd Party damages)	There is CP on the pipeline. Of note however, it was installed a number of years (about the mid-60s) after installation. Factored into the liklihood rating.
North Side (London South Line)	1a	Major damage to pipeline at aerial crossing due to environmental forces resulting in significant repair.	More likely to occur in the spring time.	Major release	Natural Forces (Geotechnical)	Exposed pipeline at the creek could be subjected to impact of debris during high water situation if there is mechanical fitting in the near vicinity of the pipe, it lead to major damage. Also, a leak at a crossing may require replacement of the entire crossing.	The scenario is if a washout, high water or flood were to do extensive damage to one of the aerial crossings or exposed mains. It would be unrepairable, so you would have to install a new crossing. In, 2008 – the Thames River Crossing was replaced due to a leak in the river at a cost of approximately $1.1 M.	Fin	3	**4**	**Medium**	Prevention - Repair work Detection - DoC Survey Mitigation - Emergency response	This risk is applied only to sections on the data sheet where exposed main has been identified. A large portion of the exposed mains identified are aerial crossings.
South Side (Dominion Line)	1b	Major damage to pipeline at aerial crossing due to environmental forces resulting in significant repair.	More likely to occur in the spring time.	Major release	Natural Forces (Geotechnical)	Exposed pipeline at the creek could be subjected to impact of debris during high water situation if there is mechanical fitting in the near vicinity of the pipe, it lead to major damage. Also, a leak at a crossing may require replacement of the entire crossing.	The scenario is if a washout, high water or flood were to do extensive damage to one of the aerial crossings or exposed mains. It would be unrepairable, so you would have to install a new crossing. In, 2008 – the Thames River Crossing was replaced due to a leak in the river at a cost of approximately $1.1 M.	Fin	3	**4**	**Medium**	Prevention - Repair work Detection - DoC Survey Mitigation - Emergency response	This risk is applied only to sections on the data sheet where exposed main has been identified. A large portion of the exposed mains identified are aerial crossings.
North Side (London South Line)	2a	Leaks result in repairs using clamps and mechanical fittings	Integrity Issue resulting in leak. Typical repair.	Leak	External Corrosion Internal corrosion Equipment Failure Valve malfunction (Valve) Construction - Defective joining		This is the risk of costs for ongoing repairs. Of the 28 repairs on record; 24 have been less than $10,000 and 4 have been between $10,000 and $100,000. The most recent repair in 2019 was $61,300. Replacements in 2016 and 2017 were $245,000 and $165,000 respectively. Consideration for the C3 (100K to 1M) was also given to the age and the condition of the line and that repairs in the future may increase in cost. Primary failure causes are corrosion leaks.	Fin	6	3	**Medium**	Non 1st, 2nd, 3rd Party damages Prevention - CP & CP Survey (Annual) Detection - Leak Survey (Annual) + Repair work Mitigation - Emergency response 1st, 2nd, 3rd Party damages Prevention : Locate Prevention : Dig before you call (For 3rd Party damages)	
South Side (Dominion Line)	2b	Leaks result in repairs using clamps and mechanical fittings	Integrity Issue resulting in leak. Typical repair.	Leak	External Corrosion Internal corrosion Equipment Failure Valve malfunction (Valve) Construction - Defective joining		This is the risk of costs for ongoing repairs. Of the 28 repairs on record; 24 have been less than $10,000 and 4 have been between $10,000 and $100,000. The most recent repair in 2019 was $61,300. Replacements in 2016 and 2017 were $245,000 and $165,000 respectively. Consideration for the C3 (100K to 1M) was also given to the age and the condition of the line and that repairs in the future may increase in cost. Primary failure causes are corrosion leaks.	Fin	5	3	**Medium**	Non 1st, 2nd, 3rd Party damages Prevention - CP & CP Survey (Annual) Detection - Leak Survey (Annual) + Repair work Mitigation - Emergency response 1st, 2nd, 3rd Party damages Prevention : Locate Prevention : Dig before you call (For 3rd Party damages)	
North Side (London South Line)	2a	Major damage to pipeline at aerial crossing due to environmental forces.	More likely to occur in the spring time.	Major release	Natural Forces (Geotechnical)	Exposed pipeline at the creek could be subjected to impact of debris during high water situation if there is mechanical fitting in the near vicinity of the pipe, it lead to major damage. Also, a leak at a crossing may require replacement of the entire crossing.	The scenario is if a washout, high water or flood were to do extensive damage to one of the aerial crossings or exposed mains. It would be unrepairable, so you would have to install a new crossing. In, 2008 – the Thames River Crossing was replaced due to a leak in the river at a cost of approximately $1.1 M.	Fin	2	**4**	Low	Prevention - Repair work Detection - DoC Survey Mitigation - Emergency response	This risk is applied only to sections on the data sheet where exposed main has been identified. A large portion of the exposed mains identified are aerial crossings. An L2 was selected here as only 2 exposed sections are identified.
South Side (Dominion Line)	2b	Major damage to pipeline at aerial crossing due to environmental forces.	More likely to occur in the spring time.	Major release	Natural Forces (Geotechnical)	Exposed pipeline at the creek could be subjected to impact of debris during high water situation if there is mechanical fitting in the near vicinity of the pipe, it lead to major damage. Also, a leak at a crossing may require replacement of the entire crossing.	The scenario is if a washout, high water or flood were to do extensive damage to one of the aerial crossings or exposed mains. It would be unrepairable, so you would have to install a new crossing. In, 2008 – the Thames River Crossing was replaced due to a leak in the river at a cost of approximately $1.1 M.	Fin	3	**4**	**Medium**	Prevention - Repair work Detection - DoC Survey Mitigation - Emergency response	This risk is applied only to sections on the data sheet where exposed main has been identified. A large portion of the exposed mains identified are aerial crossings.
North Side (London South Line)	3a	Leaks result in repairs using clamps and mechanical fittings	Integrity Issue resulting in leak. Typical repair.	Leak	External Corrosion Internal corrosion Equipment Failure Valve malfunction (Valve) Construction - Defective joining		This is the risk of costs for ongoing repairs. Of the 28 repairs on record; 24 have been less than $10,000 and 4 have been between $10,000 and $100,000. The most recent repair in 2019 was $61,300. Replacements in 2016 and 2017 were $245,000 and $165,000 respectively. Consideration for the C3 (100K to 1M) was also given to the age and the condition of the line and that repairs in the future may increase in cost. Primary failure causes are corrosion leaks.	Fin	6	3	**Medium**	Non 1st, 2nd, 3rd Party damages Prevention - CP & CP Survey (Annual) Detection - Leak Survey (Annual) + Repair work Mitigation - Emergency response 1st, 2nd, 3rd Party damages Prevention : Locate Prevention - Call before you dig (For 3rd Party damages)	
South Side (Dominion Line)	3b	Leaks result in repairs using clamps and mechanical fittings	Integrity Issue resulting in leak. Typical repair.	Leak	External Corrosion Internal corrosion Equipment Failure Valve malfunction (Valve) Construction - Defective joining		This is the risk of costs for ongoing repairs. Of the 28 repairs on record; 24 have been less than $10,000 and 4 have been between $10,000 and $100,000. The most recent repair in 2019 was $61,300. Replacements in 2016 and 2017 were $245,000 and $165,000 respectively. Consideration for the C3 (100K to 1M) was also given to the age and the condition of the line and that repairs in the future may increase in cost. Primary failure causes are corrosion leaks.	Fin	6	3	**Medium**	Non 1st, 2nd, 3rd Party damages Prevention - CP & CP Survey (Annual) Detection - Leak Survey (Annual) + Repair work Mitigation - Emergency response 1st, 2nd, 3rd Party damages Prevention : Locate Prevention - Call before you dig (For 3rd Party damages)	
North Side (London South Line)	3a	Major damage to pipeline at aerial crossing due to environmental forces, leading to significant repair.	More likely to occur in the spring time.	Major release	Natural Forces (Geotechnical)	Exposed pipeline at the creek could be subjected to impact of debris during high water situation if there is mechanical fitting in the near vicinity of the pipe, it lead to major damage. Also, a leak at a crossing may require replacement of the entire crossing.	The scenario is if a washout, high water or flood were to do extensive damage to one of the aerial crossings or exposed mains. It would be unrepairable, so you would have to install a new crossing. In, 2008 – the Thames River Crossing was replaced due to a leak in the river at a cost of approximately $1.1 M.	Fin	3	**4**	**Medium**	Prevention - Repair work Detection - DoC Survey Mitigation - Emergency response	
South Side (Dominion Line)	3b	Major damage to pipeline at aerial crossing due to environmental forces, leading to significant repair.	More likely to occur in the spring time.	Major release	Natural Forces (Geotechnical)	Exposed pipeline at the creek could be subjected to impact of debris during high water situation if there is mechanical fitting in the near vicinity of the pipe, it lead to major damage. Also, a leak at a crossing may require replacement of the entire crossing.	The scenario is if a washout, high water or flood were to do extensive damage to one of the aerial crossings or exposed mains. It would be unrepairable, so you would have to install a new crossing. In, 2008 – the Thames River Crossing was replaced due to a leak in the river at a cost of approximately $1.1 M.	Fin	3	**4**	**Medium**	Prevention - Repair work Detection - DoC Survey Mitigation - Emergency response	
North Side (London South Line)	4a	Leaks result in repairs using clamps and mechanical fittings	Integrity Issue resulting in leak. Typical repair.	Leak	External Corrosion Internal corrosion Equipment Failure Valve malfunction (Valve) Construction - Defective joining		This is the risk of costs for ongoing repairs. Of the 28 repairs on record; 24 have been less than $10,000 and 4 have been between $10,000 and $100,000. The most recent repair in 2019 was $61,300. Replacements in 2016 and 2017 were $245,000 and $165,000 respectively. Consideration for the C3 (100K to 1M) was also given to the age and the condition of the line and that repairs in the future may increase in cost. Primary failure causes are corrosion leaks.	Fin	6	3	**Medium**	Non 1st, 2nd, 3rd Party damages Prevention - CP & CP Survey (Annual) Detection - Leak Survey (Annual) + Repair work Mitigation - Emergency response 1st, 2nd, 3rd Party damages Prevention : Locate Prevention - Call before you dig (For 3rd Party damages)	

								Risk Ranking					
Pipeline	**Segment**	**Scenario Description**	**Context Comment**	**Failure Mode**	**Cause**	**Cause Comments**	**Consequence Comments**	**CAT**	**L**	**C**	**RR**	**Controls**	**Notes**
South Side (Dominion Line)	4b	Leaks result in repairs using clamps and mechanical fittings	Integrity Issue resulting in leak. Typical repair.	Leak	External Corrosion Internal corrosion Equipment Failure Valve malfunction (Valve) Construction - Defective joining		This is the risk of costs for ongoing repairs. Of the 28 repairs on record; 24 have been less than $10,000 and 4 have been between $10,000 and $100,000. The most recent repair in 2019 was $61,300. Replacements in 2016 and 2017 were $245,000 and $165,000 respectively. Consideration for the C3 (100K to 1M) was also given to the age and the condition of the line and that repairs in the future may increase in cost. Primary failure causes are corrosion leaks.	Fin	6	3	**Medium**	Non 1st, 2nd, 3rd Party damages Prevention - CP & CP Survey (Annual) Prevention - OTL was done in 1995 and Dec 2019 Detection - Leak Survey (Annual) + Repair work Mitigation - Emergency response 1st, 2nd, 3rd Party damages Prevention : Locate Prevention - Call before you dig (For 3rd Party damages)	
South Side (Dominion Line)	4b	Major damage to pipeline at aerial crossing due to environmental forces, leading to significant repair.	More likely to occur in the spring time.	Major release	Natural Forces (Geotechnical)	Exposed pipeline at the creek could be subjected to impact of debris during high water situation if there is mechanical fitting in the near vicinity of the pipe, it lead to major damage. Also, a leak at a crossing may require replacement of the entire crossing.	The scenario is if a washout, high water or flood were to do extensive damage to one of the aerial crossings or exposed mains. It would be unrepairable, so you would have to install a new crossing. In, 2008 – the Thames River Crossing was replaced due to a leak in the river at a cost of approximately $1.1 M.	Fin	3	**4**	**Medium**	Prevention - Repair work Detection - DoC Survey Mitigation - Emergency response	
North Side (London South Line)	5a	Leaks result in repairs using clamps and mechanical fittings	Integrity Issue resulting in leak. Typical repair.	Leak	External Corrosion Internal corrosion Equipment Failure Valve malfunction (Valve) Construction - Defective joining	Vintage of main and lower number of historical leaks drive the slightly lower likelihood rating.	This is the risk of costs for ongoing repairs. Of the 28 repairs on record; 24 have been less than $10,000 and 4 have been between $10,000 and $100,000. The most recent repair in 2019 was $61,300. Replacements in 2016 and 2017 were $245,000 and $165,000 respectively. Consideration for the C3 (100K to 1M) was also given to the age and the condition of the line and that repairs in the future may increase in cost. Primary failure causes are corrosion leaks.	Fin	5	3	**Medium**	Non 1st, 2nd, 3rd Party damages Prevention - CP & CP Survey (Annual) Prevention - OTL was done in 1995 and Dec 2019 Detection - Leak Survey (Annual) + Repair work Mitigation - Emergency response 1st, 2nd, 3rd Party damages Prevention : Locate Prevention - Call before you dig (For 3rd Party damages)	
South Side (Dominion Line)	5b	Leaks result in repairs using clamps and mechanical fittings	Integrity Issue resulting in leak. Typical repair.	Leak	External Corrosion Internal corrosion Equipment Failure Valve malfunction (Valve) Construction - Defective joining	Vintage of main and lower number of historical leaks drive the slightly lower likelihood rating.	This is the risk of costs for ongoing repairs. Of the 28 repairs on record; 24 have been less than $10,000 and 4 have been between $10,000 and $100,000. The most recent repair in 2019 was $61,300. Replacements in 2016 and 2017 were $245,000 and $165,000 respectively. Consideration for the C3 (100K to 1M) was also given to the age and the condition of the line and that repairs in the future may increase in cost. Primary failure causes are corrosion leaks.	Fin	5	3	**Medium**	Non 1st, 2nd, 3rd Party damages Prevention - CP & CP Survey (Annual) Detection - Leak Survey (Annual) + Repair work Mitigation - Emergency response 1st, 2nd, 3rd Party damages Prevention - Call before you dig (For 3rd Party)	
South Side (Dominion Line)	5b	Major damage to pipeline at aerial crossing due to environmental forces, leading to significant repair.	More likely to occur in the spring time.	Major release	Natural Forces (Geotechnical)	Exposed pipeline at the creek could be subjected to impact of debris during high water situation if there is mechanical fitting in the near vicinity of the pipe, it lead to major damage. Also, a leak at a crossing may require replacement of the entire crossing.	The scenario is if a washout, high water or flood were to do extensive damage to one of the aerial crossings or exposed mains. It would be unrepairable, so you would have to install a new crossing. In, 2008 – the Thames River Crossing was replaced due to a leak in the river at a cost of approximately $1.1 M.	Fin	3	**4**	**Medium**	Prevention - Repair work Detection - DoC Survey Mitigation - Emergency response	



Lambton County
Plympton-Wyoming
Sarnia
Watford
Strathroy
Section 5 - Falconbridge Dr & Springfield Rd to Komoka Trans (S)
Middlesex Coun
Mount Brydges
Petrolia
LSL abandoned beyond here
Section 5 - Falconbridge Dr & Glen Oak Rd (N)
Section 5 - Falconbridge Dr & Glen Oak Rd (N)
Section 4 - Falconbridge & Springfield R
Alvinston
Section 3 - Falconbridge & Thames Rd
Section 4 - Falconbridge Dr & Thame
Glencoe
Section 3 - Mosside Ln & McCready
Section 2 - Mosside Ln & McCready
Dawn
Section 1 -Oakdale Header
Section 2 - Oakdale Header
Dutto
Bothwell
Croton
West Lorne
Dresden

	C1	C2	C3	C4	C5	C6	C7
L7	Medium	Medium	High	Very High	Very High	Very High	Very High
L6	Medium	Medium	Medium	High	[illegible]	High	Very High
L5	Low	Medium	Medium	[illegible]	High	Very High	Very High
L4	[illegible]	[illegible]	Medium	Medium	Medium	High	Very High
L3	Low	Low	Low	Medium	Medium	Medium	High
L2	Low	Low	Low	[illegible]	[illegible]	Medium	Medium
L1	Low	Low	Low	Low	Low	Medium	Medium

Reputational [1]

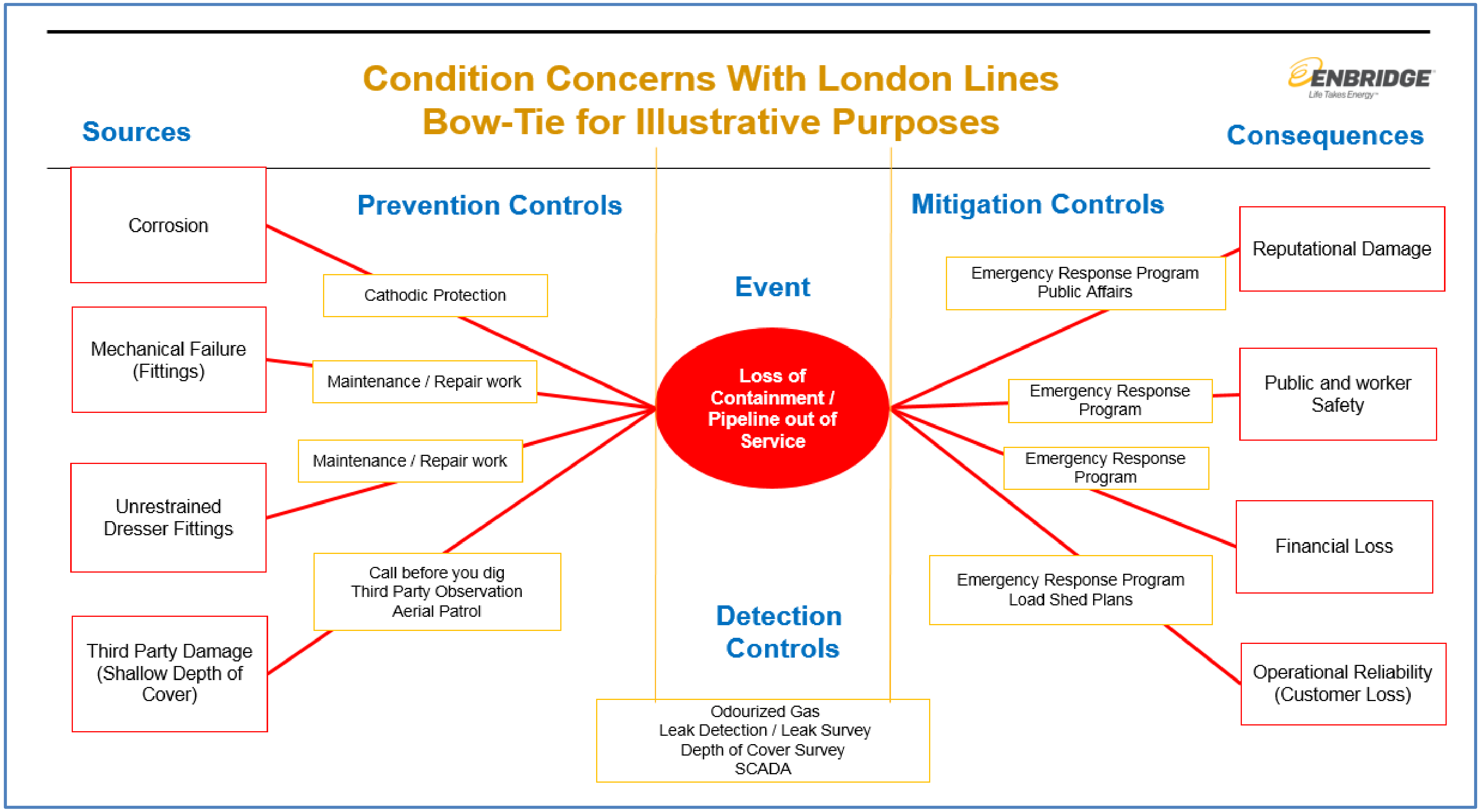
Financial [1]

Customer Loss [2]

Health and Safety [1]

1 – Fairly consistent and systemic throughout majority of pipeline.

2 – Confined to section between Dawn and Oakdale header, i.e. section, 1 for a high risk. Remaining sections are Medium and Low risk for customer loss.


Condition Concerns With London Lines
Bow-Tie for Illustrative Purposes
ENBRIDGE
Life Takes Energy
Sources
Consequences
Prevention Controls
Mitigation Controls
Event
Detection Controls
Corrosion
Mechanical Failure (Fittings)
Unrestrained Dresser Fittings
Third Party Damage (Shallow Depth of Cover)
Cathodic Protection
Maintenance / Repair work
Maintenance / Repair work
Call before you dig
Third Party Observation
Aerial Patrol
Loss of Containment / Pipeline out of Service
Odourized Gas
Leak Detection / Leak Survey
Depth of Cover Survey
SCADA
Emergency Response Program
Public Affairs
Emergency Response Program
Emergency Response Program
Emergency Response Program
Load Shed Plans
Reputational Damage
Public and worker Safety
Financial Loss
Operational Reliability (Customer Loss)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, page 15

Preamble:

EGI evidence states: "*The London Lines is on the list of prioritized projects, as identified in Enbridge Gas's Asset Management Plan. Replacing these pipelines is essential in managing the reliability and safety of the system.*"

Question:

Please file EGI's Gas Asset Management Plan.

Response:

Please see Exhibit I.ED.1, Attachment 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, page 20

Preamble:

EGI evidence states: *"Without indirect overheads included, the total estimated cost is $133.9 million. The proposed Leave to Construct application seeks approval for the mainline costs of $95.2 million as shown in the project economics filed at Exhibit F of this application.*

Question:

Please specifically clarify the difference between the two figures.

Response:

Please refer to Exhibit F, Tab 2, Schedule 1, Line 5. The estimated incremental Project capital costs, including mainline, stations, services, and abandonment of existing assets is $133.9 million. The estimated incremental capital cost of the mainline only, excluding stations, services, and abandonment of existing assets is $95.2 million.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, page 1 and Table 1

Preamble:

EGI evidence states: "*The London Lines represent 35% of pre-1950 installation pipes in the legacy Union Gas network and 18% of the total bare steel pipe population within the legacy Union Gas network. It should be noted that the Windsor Line, a pipeline that is similar in vintage, condition and risk raking, comprised of only 0.02% of bare pipe within the same system.*

Question:

If not in the Asset Management Plan requested above, please show a comparative risk assessment between the London Lines and the Windsor Line.

a) Please populate Table 1 for the Windsor Line.
b) Please describe the factors which contributed to the Windsor Line being applied for ahead of the London Lines.

Response:

a) The Windsor Line risk assessment was completed using the legacy Union risk standards and the legacy Union Gas risk matrix. The London Lines risk assessment was completed using the Enbridge Hazard Identification and Risk Assessment Procedure and the Enbridge 7X7 risk matrix. Due to the differences in techniques, Table 1 cannot be populated for the Windsor Line.

b) Windsor Line and London Lines were both under review for several years at legacy Union Gas. Both potential projects were identified in the Union Gas Asset

Management Plan 2018-2027, dated December 2017. In support of that Asset Plan, both projects were risk assessed at a high level in the early part of 2017. At that time, it was assessed that both projects had comparable risk levels. The primary difference between the pipelines was an increased challenge in completing repairs on the Windsor Line. This resulted in a slightly higher risk level for the Windsor Line for both financial and customer impacts. This was a key factor that elevated the initial risk level for the Windsor line. This led to further risk reviews and project development for the Windsor Line ahead of further risk reviews and project development for the London Lines.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Attachment 1

Preamble:

The DIMP Assessment in the above reference lists the version control copy as draft.

Question:

Please file the final DIMP Assessment signed off by the appropriate management.

Response:

Please see Attachment 1 for the Final DIMP Integrity Assessment report. Due to COVID, there were no physical reports signed off by Management. Management sign off was received through email on August 4th 2020 which finalized the draft report.

DIMP Integrity Assessment

London Lines

July 21, 2020

Project Manager: Daniel Zanini

Asset Class: Pipe

Version Control:

Date (dd/mm/yyyy)	Revision	Name of Person Making Change	Description of Changes
21/07/2020	A	D. Zanini	Initiation

Distribution List
Shawn Khoshaien
Angela Scott
Fred Butrico
Brad Patzer

Report

Company: Enbridge Gas Distribution

Owned by: Distribution Integrity Management Department

Controlled Location: Distribution System Integrity Teamsite

Table of Contents

1 Overview

This Integrity Assessment was completed to provide an updated reliability assessment of the London Lines for the purpose of determining a recommended mitigation plan based upon the reliability of the studied assets.

1.1 DESCRIPTION

The London Lines are comprised of 2 separate parallel steel main lines called London South and London Dominion predominantly installed in the 1930s. Based upon records and Subject Matter Advisor (SMA) feedback the 57,000m of main replacement on the London Dominion line in 1957 was reclaimed 1920s-1930s steel pipe refurbished at the Dawn facility.

1.2 PREVIOUS PROJECTS

The London Lines have been studied on other occasions. The following table summarizes the available historical reports that were produced.

Table 1-1 Historical Reports

TITLE	AUTHOR	DATE COMPLETED
The London Lines	Katie Hooper	2002
London Lines Report	Bob Wellington	2004
Engineering Asset Plan – The London Lines	Jack Chen	2016

1.3 SCOPE

This Integrity Assessment assesses the distribution mains identified as part of the London Lines Replacement Project. The assessment uses the best available information and data at the time of writing of the report. In order to provide context, the Windsor Line Replacement Project which was approved by the OEB and is currently under construction, is used for comparison purposes.

2 Population

The London Lines comprise of over 134,000m of steel mains. Appendix A includes the file which identifies the main segments which are considered part of the London Lines.

Table 2-1 London Lines Population

	Length (m)		
Decade of Install	London Dominion	London South	Grand Total
1930s	11,096	53,493	64,589
1940s	37	24	60
1950s	57,895*	2,379	60,274

1960s	3,650	209	3,858
1970s	247	120	367
1980s	314	229	543
1990s	1,686	3,044	4,731
2000s	56	-	56
2010s	134	-	134
	75,115	59,497	134,612

* *Based upon records and Subject Matter Advisor (SMA) feedback the 57,000m of main replacement on the London Dominion line in 1957 was reclaimed 1920s-1930s steel pipe refurbished at the Dawn facility.*

Figure 2-1 London Lines Plot (June 2020)

The approximately 64,000m of 1930s vintage steel pipe make up approximately 35% of 1930s vintage steel pipe within the electronic records for the Enbridge Gas Inc (EGI) distribution network.

According to electronic records approximately 62,000m of the pipe is bare, 50,000m of which are on the London South line. However according to SMA feedback there appears to be concerns regarding the mains with noted coatings as the mains installed in the 1950s could potentially be bare as well. The 62,000m makes up approximately 18% of the bare steel pipe within the electronic records for the EGI distribution network. In comparison the Windsor Line comprises of only 85m of bare pipe as per the electronic records which represents 0.02% of bare pipe within the system.

London Lines does not currently contain any steel mains which are both bare and unprotected. This was confirmed through the Corrosion Prevention department and by cross referencing the London Lines population against the bare and unprotected steel main population.

Also of note there are a large number of unrestrained mechanical couplings/compression couplings used during the construction of the London Lines. Depending on the assumption that random length pipe (approximately 20ft) was utilized versus double random length (approximately 40ft) there could be anywhere between 6,000 to 12,000 unrestrained compression couplings on the London Lines. Within the electronic records the London Lines comprise of 73,300m of coupled steel mains which represent 30% of all coupled steel mains within the EGI distribution network. This is in comparison to Windsor Lines which represents 12% of all coupled steel mains. Compression couplings are known to provide minimal pull-out resistance, depending on design could cathodically isolate pipe, and is a source of leaks especially if there is ground movement or large temperature fluctuations such as freeze/thaw cycles. SMA feedback indicates that the London Lines have C-leaks which appear and disappear which can be attributed to compression couplings. Additionally SMA input indicates that the barrels of the compression couplings corrode at a higher rate than the surrounding pipe they connect. This could be caused by the compression coupling not being adequately bonded to the piping and the Cathodic Protection (CP) for the piping not protecting components of the compression coupling. The SMA feedback also indicated piping surfaces on either side of the compression couplings appear to be the same indicating that the compression coupling is not electrically isolating the pipe.

3 Cathodic Protection

A report issued in 2016 regarding the London Lines state that Cathodic Protection (CP) did not begin until 1965. The London Lines are currently protected by rectifiers. The first section of London Lines which was rectifier protected occurred in 1988. The majority of London Lines' mains became rectifier protected in the 1990s with the final section of mains becoming rectifier protected in 2010.

Over the last twenty years (2000-2019) 7,925 test point readings have been made across the London South and London Dominion Lines, with 405 test point readings performed in 2019 alone. Of these over 7,900 readings only 2 readings were made which were below limit, which are 0.03% of all test point readings made on the London Lines. The CP history over the last 20 years for the London Lines indicate that they are receiving acceptable CP.

Bare pipe typically requires higher current for its CP due to the large amount of exposed steel. SMA feedback indicates consistently high amounts of corrosion across many meters of pipe. This has caused SMAs to indicate that there is difficulty to find a section of pipe which is acceptable to weld on when work is required to be completed on the London Lines. This could be caused by the initial lack of CP prior to 1965 or intermittent drops in CP levels due to depleted anodes prior to rectifier protection, power interruptions or soil conditions.

4 Depth of Cover and Exposed Piping

A recent depth of cover (DoC) survey (June 2020) indicated the occurrence of 53 sites of exposed piping on the London Lines and that 15% of DoC readings had a DoC of less than 0.60m.

Table 4-1 Depth of Cover Survey Findings

	Depth Of Cover <0.6m	Total	% of Readings
Count of Readings	956	6,305	15%
Length of Readings (m)	20,037	134,991	15%

Current standards for depth of cover requirements can be found in Section 12.4.7.1 as per Table 12.2 of CSA Z662-19.

The following are a few pictures of the exposed piping from the June 2020 depth of cover survey.

Figure 4-1 Examples of London Lines Exposed Piping (June 2020)

Based upon the 3rd Party Damage Model completed for distribution assets, there is a decrease in 3rd Party hit frequency when increasing DoC. The average DoC was 0.48m for all surveyed points which were less than 0.6m. Based upon the model there is a 20% increase in 3rd Party hit frequency when the DoC is 0.48m versus 0.6m. A new main installation following current EGI DoC standards would be installed at depths of 0.75m and 1.2m depending on environmental conditions. The 3rd Party hit frequency increases by 22% when the DoC is at 0.6m versus 0.75m and by 76% when the DoC is 0.6m versus 1.2m.

5 Failures

A repair summary report created during June 2020 indicates a total of 29 leak repairs between 2011 and 2019.

Of note, based upon the repair data, 38% (11 of 29 repairs) were due to compression couplings or the compression style repair sleeves used for previous repairs. Only 17% of the repairs could be directly attributed to corrosion leaks on the London Lines. SMA feedback indicates corrosion as the most common cause of leaks of the London Lines.

Table 5-1 Repair Summary

Year of Repair	Compression Coupling	Corrosion	Repair Clamp	Unknown	Valve	Weld	Grand Total
2011				1			1
2012	1		1	3			5
2013	1	1	3	1	1		7
2014	1	1	2		2		6
2015		1		1			2
2016		1					1
2017		1	1		2	1	5
2018				1			1
2019	1						1
Grand Total	4	5	7	7	5	1	29

Leak data reported to the Canadian Gas Association (CGA) indicate 40 leaks occurred on the current in-service London Line mains between 2013 and 2019. These leaks have been plotted as per the below map.

Figure 5-1 Plot of London Line Discovered Leaks

9 of the leaks, 2 class B and 7 class C, were discovered on a single main segment in 2013 (521247331) along Falconbridge Drive. This same main leg had an additional 3 C leaks between 2015-2017. The particular main segment has a length of 4.9km.

The London Lines had a leak rate 0.043 leaks/km/year between 2013-2019. This is in comparison to the Windsor Line which had a leak rate of 0.12 leaks/km/year over the same period (nearly 3 times higher than London Lines). The London Lines leak rate is a minimum of 10 times greater than the available average leak rate for the steel main population.

A mechanical model was applied to model corrosion leaks using available corrosion rates. Based upon the available electronic records the majority (89%) of pipe has a wall thickness of either 4.8mm, 5.6mm or 7.0mm. Using a corrosion rate of 0.046mm/yr, which is greater than 94% of the corrosion rate data points, for full wall loss the mains would have to be between 104 and 152 years of age

Based upon these calculations and corrosion rate data available we would not expect to see a significant increase in the number of corrosion leaks on this line for another 37 years. Unfortunately, due to the age, the long lengths of uncoated pipe, the large number of compression couplings and the unknown CP history there are concerns regarding the applicability of the corrosion rates.

6 Summary

London Lines represent 35% of 1930s steel pipe and 18% of bare pipe within the EGI network. Records of these lines are incomplete (filled in at a later date or not in paper files). Vintage steel (pre 1970s) have known quality issues when it comes to manufacturing and material specifications which include laminations, unspecified toughness values, and selective seam weld corrosion.

London Lines between 2013 and 2019 had a leak rate of 0.043 leaks/km/year, which is over 10 times greater than the available average leak rate for the steel main population. The available repair and leak information for London Lines indicates 38% of repairs since 2011 were due to compression couplings or repair clamps. 17% of repairs since 2011 could be attributed to corrosion leaks.

There are 53 sections of exposed piping and approximately 15% of DoC readings (6,300 m) show a DoC of less than 0.6m which have an average depth of 0.48m. Based upon the 3rd Party hit frequency model available there is a 20% increase in 3rd Party hit frequency when the DoC is 0.48m versus 0.6m.

There could potentially be anywhere between 6,000 and 12,000 unrestrained compression couplings on the London Lines. The London lines represents 30% of the coupled steel mains within the EGI distribution network. Compression coupling (or compression style repair clamps) leaks appear to account for 38% of the leak repairs on the London Lines between 2011 and 2019. Compression couplings are known to provide minimal to no mechanical resistance to pullout and can leak due to ground and pipe movement.

7 Conclusion and Recommendations

In conclusion, based upon the available data and information at this time, the London Lines represent some of the oldest and most vulnerable steel assets within the EGI distribution network. Additionally, London Lines comprises of 30% of all steel mains which are coupled together, 53 exposed pipe sections, 57,000m of reclaimed pipe, and 62,000m of bare steel, which are considered factors that impact condition and risk for the pipelines. From a condition standpoint the DIMP department supports the replacement of the London Lines within the next 1-3 years.

Appendix A

POPULATION FILE

London Line
Population Active and

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, pages 8-15 and Tab 2, Schedule 3

Preamble:

We would like to understand better the flows and pressures of the current system and alternatives considered to understand the proposed approach.

Questions:

1) Using the Schematic of the System in Schedule 3, please provide the existing and proposed pipe sizes and the peak winter day flows for the winter of 2020/21 for each of the lateral shown in blue in the schematic.
   a) In tabular form, please provide the following for the existing 1900 kPa system:
      i) Please provide the minimum pressure required at the station feeding lateral to meet design day flows.
      ii) For the Wardsville Line, keeping all other lateral flows constant, at the minimum inlet pressure to the station feeding, what is the incremental flow that could be available from the current system.
      iii) For the Komoka Line, keeping all other lateral flows constant, at the minimum inlet pressure to the station feeding, what is the incremental flow that could be available from the current system.

   b) In tabular form, please provide the following for the proposed 3450 kPa system:
      i) Please provide the minimum pressure required at the station feeding lateral to meet design day flows.
      ii) For the Wardsville Line, keeping all other lateral flows constant, at the minimum inlet pressure to the station feeding, what is the incremental flow that could be available from the proposed system.

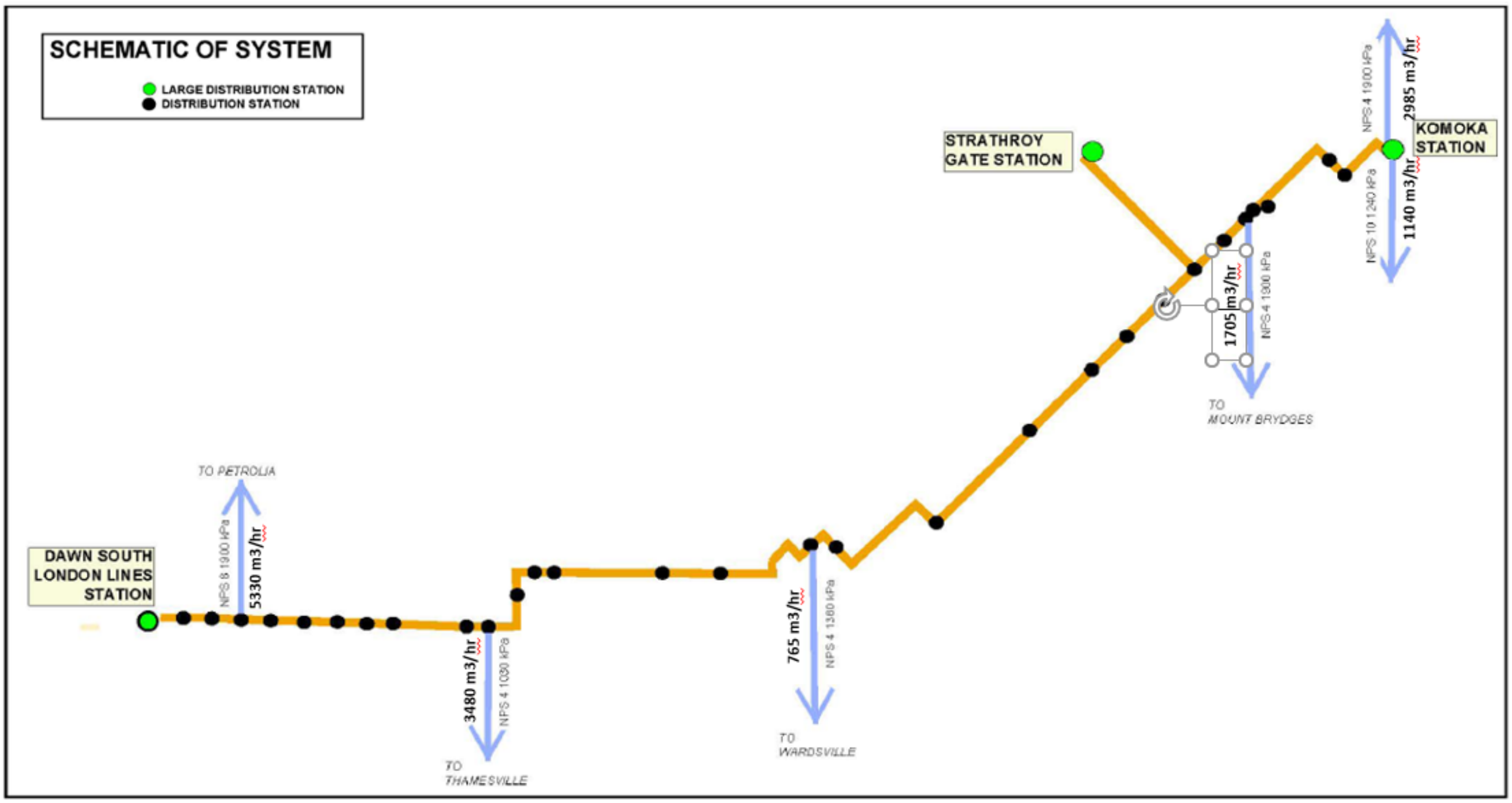
iii) For the Komoka Line, keeping all other lateral flows constant, at the minimum inlet pressure to the station feeding, what is the incremental flow that could be available from the proposed system.

c) In tabular form, please provide the following for the first alternative 3450 kPa system (with proposed pipe sizing) without the 8.4 km connection to the Strathroy Station:
   i) Please provide the minimum pressure required at the station feeding lateral to meet design day flows.
   ii) For the Wardsville Line, keeping all other lateral flows constant, at the minimum inlet pressure to the station feeding, what is the incremental flow that could be available from the first alternative system.
   iii) For the Komoka Line, keeping all other lateral flows constant, at the minimum inlet pressure to the station feeding, what is the incremental flow that could be available from the first alternative system.
   iv) Please provide an updated cost without the 8.4 km section in the first alternative.

d) In tabular form, please provide the following for the second alternative 3450 kPa system without the 8.4 km connection to the Strathroy Station but replacing the proposed NPS 4 with NPS 6:
   i) Please provide the minimum pressure required at the station feeding lateral to meet design day flows.
   ii) For the Wardsville Line, keeping all other lateral flows constant, at the minimum inlet pressure to the station feeding, what is the incremental flow that could be available from the second alternative system.
   iii) For the Komoka Line, keeping all other lateral flows constant, at the minimum inlet pressure to the station feeding, what is the incremental flow that could be available from the second alternative system.
   iv) Please provide an updated cost estimate for all NPS 6 in the second alternative.

Response:

The blue lines on the map in Exhibit B, Tab 2, Schedule 3 are not proposed to be replaced. Existing sizes are indicated as per the pre-filed evidence. See below for the 2020/2021 peak winter flows.



a)
- i) Approximately 1485 kPa
- ii) Approximately 8790 m3/hr
- iii) Approximately 4240 m3/hr

Note that ii) and iii) are independent and cannot occur simultaneously. They are considered for the winter design day scenario only, using maximum operational pressure at the source. Any future demands are not expected to occur as per these scenarios and therefore these values are for reference only.

All scenarios were completed for 2021 to stay consistent with part b).

b)

i) The lateral was designed with both stations feeding at 3380 kPa. This request cannot be completed as the two feeds are dependent on each other. To determine a pressure required at one feed, the pressure at the other would need to be pre-determined. Please see responses to ii) and iii) for a reference of system capabilities.

ii) Approximately 6200 m3/hr

iii) Approximately 5500 m3/hr

Note that ii) and iii) are independent and cannot occur simultaneously. They are considered for the winter design day scenario only, using design outlet pressure at the source. Any future demands are not expected to occur as per these scenarios and therefore these values are for reference only. 2021 was used as the reference year as it is the proposed install year for the project.

c)

i) The proposed 3450 kPa solution is infeasible in 2021 with the removal of the 8.4 km feed from Strathroy Gate Station. As per alternative 3, a single fed 3450 kPa line would need to be NPS 10, 8 and 6.

ii) to iv) See response to part c) i)

d)

i) The proposed 3450 kPa solution is infeasible in 2021 with the removal of the 8.4 km feed from Strathroy Gate Station, even if the NPS 4 was increased to NPS 6. As per alternative 3, a single fed 3450 kPa line would need to be NPS 10, 8 and 6.

ii) to iv) See response to part d) i)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, page 9

Preamble:

EGI evidence states: *In the proposed design, it will also feed an existing 1900 kPa MOP system serving Komoka and Kilworth. The Komoka Station will have a minimum inlet of 2347 kPa that must be maintained in order to feed the residential, commercial customers in Komoka and Kilworth. This station is the current constraint on the London Lines and will continue to be the constraint along the portion of the London Line Replacement between the new connection from Strathroy and Komoka.*

We would like to understand this statement better.

Question:

With the current inlet pressure to these laterals as provided in 6a), what is the flow to this system from the London Lines?

a) Is there another feed to the system Komoka and/or Kilworth systems?
b) What additional changes are being made that requires a minimum inlet of 2347 kPa when the existing system MAOP is 1900 kPa? Please explain completely.

Response:

Please see Exhibit I.APPrO.6 a) for approximate forecasted flows for winter 2020 and 2021.

a) Kilworth is fully served from the London Lines and does not have any connection to another system. Komoka is primarily served from the London Lines with two small NPS 2 connections into the London 420 kPa distribution system.

b) The increase in minimum inlet required for the new Komoka Station is a result of two items:

- Additional equipment required due to the higher MOP of the new line
- The new station will feed the existing 1900 kPa line to Komoka and Kilworth. This 1900 kPa line is not proposed to be replaced as part of the London Lines Replacement project. The station design requires adequate differential pressure to serve the 1900 kPa downstream MOP.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Ex. A, T2, Sch. 1

“The Existing Lines comprise the London South Line and London Dominion Line which are two pipelines that are parallel to each other, approximately 60 km and 75 km in length, respectively. These pipelines includes pipe segments that are NPS 8, 10 and 12 with a maximum operating pressure (“MOP”) of 1900 kPa (275 psig)”

Questions:

a) Please explain how two high pressure pipelines ranging from NPS 12 to NPS 8 can be replaced with one NPS 6 to NPS 4 pipeline.

b) Please provide a map showing the existing pipelines by NPS 12, 10 and 8 section. Please include the proposed pipeline on the map and show which sections are NPS 6 or NPS 4.

c) Please provide a map showing the customer area served by natural gas from the existing pipeline. Please confirm that the proposed pipeline will serve the same customer area, or if not please provide a map showing the area that pipeline will serve.

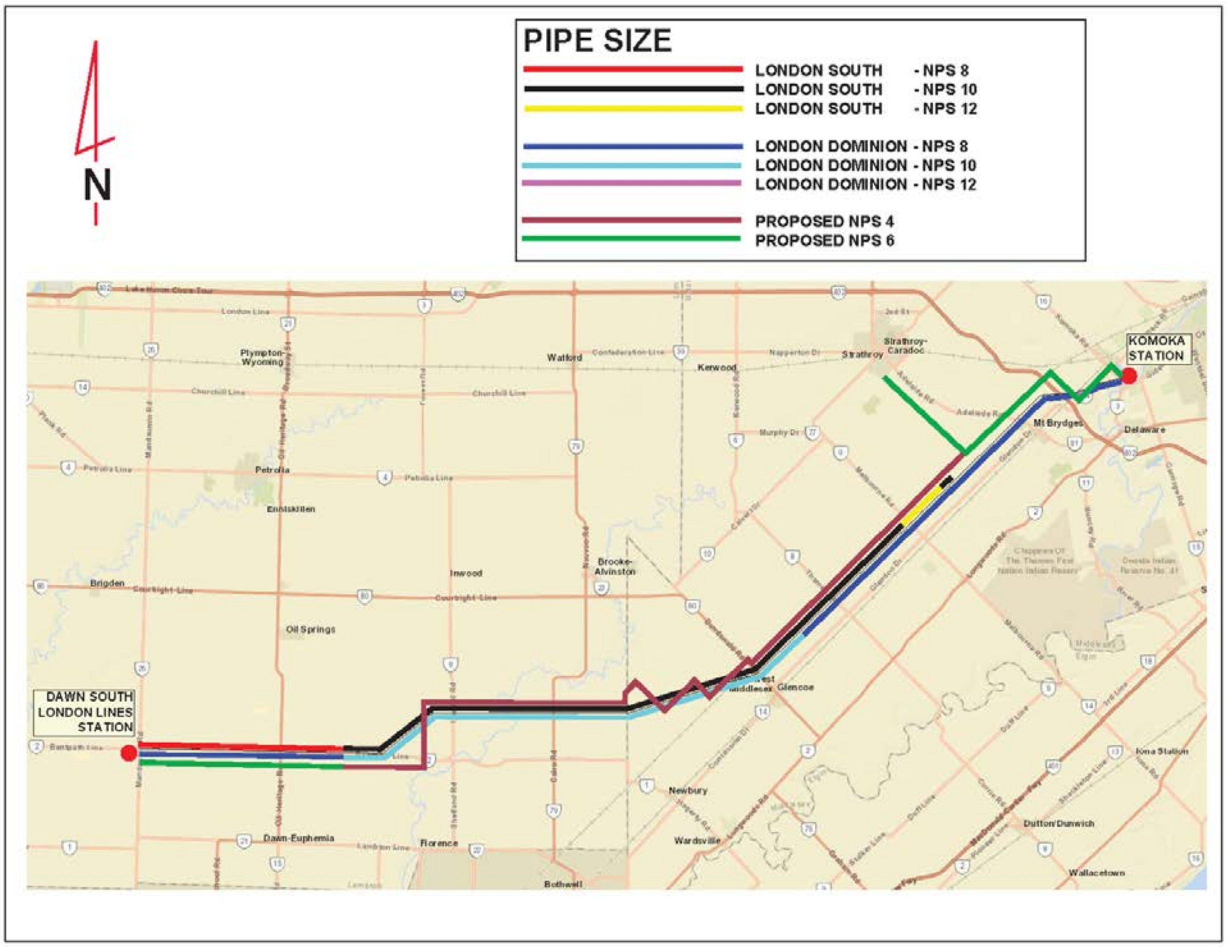
d) Please confirm that customers in the City of London are a significant load served by the existing and proposed pipelines.

e) Please confirm that the existing and proposed pipelines only serves Ontario Ratepayers or if not, please explain what other customers are served by gas from th ese pipelines.

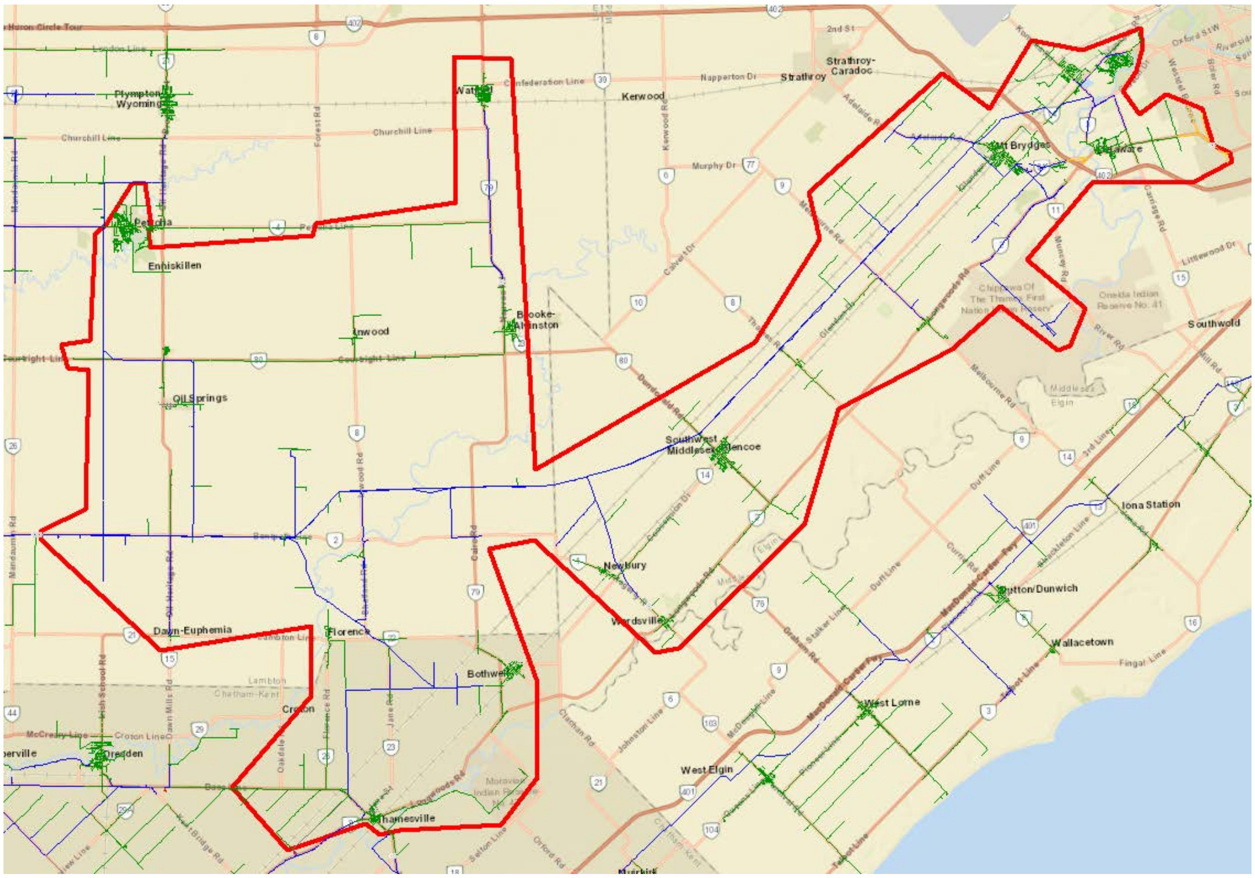
Response:

a) The increase in pressure from the current 1900 kPa MOP to the proposed 3450 kPa MOP allows the pipeline to flow significantly more gas while meeting downstream pressure requirements. Additionally, the proposed NPS 6 connection to Strathroy Gate station allows the system flow to be split between two sources instead of the existing single-fed system.

b)



c) The proposed pipeline will serve the same area as the existing pipeline. The attached map shows the area served in red.



d) The customers in the city of London will not be served by this pipeline. The pipeline will serve customers in Komoka, Kilworth and Delaware at the easternmost end.

e) Confirmed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Ex. A, T2, Sch. 2

Questions:

a) The proposed pipeline runs from the Dawn Compressor Station to the Komoka Transmission Station. Does this just provide a 2-way feed to supply customers between these two point or serve another purpose? Please explain.

b) It appears that the HP pipeline will move gas from the Dawn Hub to the Komoka Transmission Station which then supplies other parts of the Enbridge system. Enbridge has classified the proposed pipeline as a distribution line. Please provide a definition for a ‘distribution pipeline’ and ‘transmission pipeline’ to help differentiate why this is not considered a transmission line.

Response:

a) Please see Exhibit I.STAFF.1 a).

b) The proposed pipeline meets the definition of a distribution line provided in the Z662-15, which is reproduced below:

Line, distribution — a pipeline in a gas distribution system that conveys gas to individual service lines or other distribution lines.

Line, transmission — a pipeline in a gas transmission system that conveys gas from a gathering line, treatment plant, storage facility, or field collection point in a gas field to a distribution line, service line, storage facility, or another transmission line.

The TSSA Code Adoption Document specifically states that for the purpose of the Code Adoption Document, transmission lines are those lines that operate at or above 30% of the pipe's specified minimum yield strength ("SYMS"), which is reproduced below:

(3) Clause 2.2 is amended by adding the following clarification:

> For the purpose of this Code Adoption Document, within a gas pipeline system, transmission pipelines are those lines that operate at or above 30% of the pipe's specified minimum yield strength (SMYS) at MOP.

The London Line Replacement project provides distribution service to 116 services, connects multiple distribution lines and contains odourized gas, which are all indicative of a distribution line. The percentage of specified minimum yield strength for the minimum acceptable grade of the NPS 4 pipeline at Exhibit D, Tab 1, Schedule 2 is 14.2%. The percentage of specified minimum yield strength for the minimum acceptable grade of the NPS 6 pipeline at Exhibit D, Tab 1, Schedule 2 is 20.9%.

Based on the definitions above, the Project is a distribution line.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Ex. B, T1, Sch. 1

Questions:

a) Please file a copy of Enbridge's current Asset Plan and explain how the current proposed pipeline (NPS 6/4) are supported by that plan.

b) Has the TSSA reviewed and approved the proposed pipeline design and location. Please provide a copy of all correspondence with TSSA in relation to the proposed pipeline.

Response:

a) Please see Exhibit I.ED.1, Attachment 1 for Enbridge Gas current Asset Plan. The Asset Plan discusses the process by which risks are identified, evaluated and project scoping determined. It also details the strategies for each asset class and the anticipated spend. Please see Exhibit I.ED.1 a) and f).

b) Refer to Exhibit I.STAFF.2 c). The TSSA has oversight over Enbridge Gas' design and operation of its gas distribution system but does not review or "approve" pipeline design or location.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Ex. B, T2, Sch. 1

"Enbridge Gas's Distribution Integrity Management Program ("DIMP") continually evaluates assets to identify risks and determine the condition of pipelines in the distribution network. Analysis conducted by Enbridge Gas has shown that the existing London Lines are in poor condition and have several active degradation factors, including loss of containment, shallow depth of cover, and corrosion induced wall loss"

Questions:

a) Please provide a copy of all materials (analysis, presentations, reports, etc.) used to support the DIMP conclusion to decommission the existing NPS 12, 10 and 8 pipelines.

b) Please provide a copy of the Risk Assessment completed for the existing pipelines.

c) Please provide a copy of the Enbridge Standardized Operational 7X7 risk matrix and explain how the "medium" rating was determined for the existing pipelines.

d) Please explain the differences in the DIMP Reports completed in 2020, 2016, 2004 and 2002.

e) The Population file in Appendix A of the 2020 DIMP Report would not open in the filed evidence. Please provide a copy of the file.

f) Please explain what options are available to prolong the life of one or both of the existing pipelines.

g) The London lines include over 134 km of pipeline. Please explain why only part of the lines are proposed to be decommissioned if they are all of a similar vintage.

Response:

a) The Integrity Assessment report was included as Attachment 1 at Exhibit B, Tab 2, Schedule 1 and includes much of the support material. Any additional supporting documentation is included in the response to Exhibit I.EP.3 and Exhibit I.EP.4.

b) Please see Exhibit I.FRPO.1, Attachment 1 for the Risk Assessment report for the existing pipelines.

c) The Enbridge Standard Operational 7x7 risk matrix is contained in the Hazard Identification and Risk Assessment Procedure, and is filed as Attachment 1 to this response.

   The process to establish the Medium Rating is described in Exhibit I .APPrO.4 c).

d) Please see Exhibit I.BOMA 5 for the attached reports. The listing of prior reports in the current Integrity Assessment report in Exhibit B, Tab 2, Schedule 1, Attachment 1 was included to inform management of prior assessments on the London Lines. The original purpose of the 2002 report was to determine if an internal or external risk assessment would be required to confirm a remedial course of action for the London Lines. The 2004 report was a follow-up to the 2002 report to provide recommendations and prioritization of remedial actions for the London South and London Dominion Lines. The 2016 report was conducted to review system design, construction, operation and maintenance records, as well as hazards and consequences of failure. The 2020 report was completed to provide an updated reliability assessment of the London Lines and understand its condition in relation to other asset groupings and the Enbridge Gas distribution network. Please note that the reports created in 2002 and 2004 are several years old and will not be indicative of the current asset condition. The report from 2016 was considered in the development of the current Integrity Assessment in Exhibit B, Tab 2, Schedule 1, Attachment 1 and provided historical information such as the use of reclaimed pipe in the 1950's, when cathodic protection was implemented on the London Lines and concerns regarding depth of cover. The 2020 Integrity Assessment utilized the latest available information regarding population, cathodic protection, depth of cover measurements and leak history. The 2020 Integrity Assessment also compared the condition of the London Lines to other projects and the distribution network based upon the available data.

e) Please see Attachment 2 for the Population file in Appendix A of the 2020 DIMP.

f) As stated in the pre-filed evidence, Enbridge Gas has identified the existing London Lines as an operational risk and should be replaced to manage the safety and reliability of the natural gas distribution in the area served by these pipelines. Also, please see Exhibit I.ED 9 a).

g) As stated throughout the pre-filed evidence, the London Line Replacement project is a replacement of the entirety of the existing London Lines Pipelines. For example, see Exhibit B, Tab 1, Schedule 1, paragraph 39.

Hazard Identification and Risk Assessment for Common Register Procedure

Purpose

The Hazard Identification and Risk Assessment for Common Register Procedure defines a consistent approach and outlines the responsibilities for identifying hazards and assessing risks that may impact the health and safety of Gas Distribution and Storage (GDS) operations, its workers, and the public.

This procedure is written to ensure compliance with the following external requirements:

- ***Canada Energy Regulator, Onshore Pipeline Regulations – OPR 6.5(1)(c)(d)(e)(f)***
- ***Canadian Standards Association Oil and Gas Pipeline Systems – CSA Z662-15 (f)(l, v) and 3.2***

It is also in alignment with the following internal requirement:

- ***Management System Framework – 2.2.2, 2.2.3 (Issued August 17, 2017)***

This procedure supports alignment with the following internal requirements:

- ***Management System Framework – 2.2.1, 2.2.4 and 2.2.5 (Issued August 17, 2017)***
- ***Framework Standard – Risk Management (Effective September 21, 2018)***

Scope & Objectives

This procedure applies to GDS operations and activities that fall under the Integrated Management System (IMS) Management Programs (MP) where hazards have the potential to cause harm to people, property, and/or the environment. It provides a systematic process to:

- Identify hazards, analyze and evaluate risks, communicate risks, and drive treatment plans according to risk level
- Populate a common hazard/risk register to identify Top Operational Risks (TOR) within Safety & Reliability (S&R) as defined in the Framework Standard – Risk Management (see **Section 2**), which is reported to GDS's Top Management Review (TMR)
- Provide risk information to support Enbridge risk activities at the annual Corporate Risk Assessment (CRA)

Roles & Responsibilities

The following table lists the individuals and groups affected by this document and their responsibilities.

Roles	Responsibilities
Management Program (MP) Owner	• Identify hazards and potential hazards within the operation of their Program. • Support Risk Management to analyze and evaluate risks associated with identified hazards in the common register. • Report potential top operational risks during quarterly management reviews as outlined in the procedure. • Continually monitor the workplace and operations for emerging hazards. • Participate in annual hazard and risk review workshops for the Common Register, influencing the risk treatment and management of identified hazards and risks. • Support Risk Management on the identification of stakeholders to attend annual risk review workshops for the Common Register.
Risk Management	• Establishes the governance and oversees periodic review and improvement of the Hazard Identification and Risk Assessment Procedure to ensure it is current with business conditions. • Develop, maintain and conduct annual reviews of the Common Register. • Analyze and assess hazards and risks with MP Owners and stakeholders. • Manage the Common Register. • Publish and update the Common Register quarterly. • Present a summary of top operational risks at the Top Management Review quarterly meeting. • Draw from the Common Register as an input to the Corporate Risk Assessment (CRA).
Director, Asset Management	• Provide the required resources to maintain the Common Register and Process. • Owner of the common register.
Integrated Management System	• Support the development of the Common Register. • Ensure top operational risks or emerging risks are communicated at Management Reviews. • Support the annual review of the Common Register. • Control location of this procedure on the IMS TeamSite.

Roles	Responsibilities
Top Management (Utilities Leadership Team)	• Review top operational risks presented during the TMR quarterly meeting and provide direction, decision, and/or feedback if required. • Determine escalation to Enbridge Board of Directors or Operation and Integrity Committee (OIC) as required.

Terms and Definitions

The following is a list of terms found in this document and their definitions.

Terms Relating to Risk

Term	Definition
Risk	Effect of uncertainty on objectives, characterized by reference to events, sources and consequences, expressed in terms of a combination of the consequences of an event and the associated likelihood.
Effect	Result of a particular influence; typically expressed relative to one or more reference point(s).
Uncertainty	Imperfect understanding; typically attribute to inherent variability, lack of knowledge, or both.
Objective	Result to be achieved; typically specific, measurable, attainable, relevant and time-bound.
Event	Occurrence or change of specific circumstances; typically caused by one or more source(s).
Source	Element which alone or in combination has the potential to give rise to risk; see also **Hazard**.
Hazard	Source or situation with the potential for negative consequences. ***NOTE****: This is a general statement intended to be inclusive of the CSA use of the terms hazards and threats which is focused on harm to people, property and environment.*
Potential Hazard	Hazards reasonably having or showing the capacity to become or develop into hazards in the future.
Risk Control	Any existing measure or action that modifies or regulates risk. Risk controls include any policy, procedure, practice, process, technology, technique, method, or device that modifies or regulates risk.

Term	Definition
Risk Treatment	A risk modification process which will be in place to modify risks. ***NOTE****: At the time of creating this procedure, EGI is still going through integration activities - various terms could be used to represent risk treatments depending on risk analysis methodologies being used and/or existing legacy business processes. For example, a risk treatment can be called a "Recommendation", "Action Item", "Mitigation" and/or "Mitigating measures".*
Consequence	Outcome of an event that affects objectives.
Likelihood	Chance of something happening; typically expressed in terms of frequency or probability.

Terms Relating to Risk Categorization

Term	Definition
Environmental incident	Adverse impacts from an operational incident that causes environmental harm.
Workforce safety incident	Adverse impacts from the failure or the perceived failure of maintaining a safe operating environment to keep workers and contractors safe.
Public safety incident	Adverse impacts from the failure or the perceived failure of maintaining a safe operating environment to keep the public safe.
Operational reliability incident	Adverse impacts to operational reliability related to human error, third party reckless behavior, widespread illness, natural disasters or unavailable critical parts of external inputs.
Information technology (IT) systems incident	Adverse impacts resulting from IT system incidents resulting in the unavailability, disruption, or loss of key functionalities in critical systems.
Cyber security incident	Adverse impacts from a cyber-attack resulting in the unavailability, disruption, or loss of key functionalities in critical systems or a large-scale data breach.
Operational regulation	Adverse impacts related to changes in operational or environmental regulations or failing to comply with existing regulations.
Terrorism and asset security incident	Adverse impacts related to protests, violence, terrorism or malicious behavior.

Terms Relating to Risk Management Process

Term	Definition
Risk management process	Set of activities used to understand and address risks.
Establishing context (or establishing the context)	Activity to determine the factors that influence risks and their management.
Assess risk (or risk identification)	Activity to discover, recognize and describe risks.

Term	Definition
Analyze risk (or risk analysis)	Activity to understand the nature and extent of risks.
Evaluate risk (or risk evaluation)	Activity to determine whether to accept or treat risks.
Treat risk (or risk treatment)	Activity to modify or control the nature and extend of risks.
Communicate and consult (or communication and consultation)	Activities to exchange information regarding risks and their management.
Monitor and review (or monitoring and review)	Activities to provide oversight and assurance regarding risks and their management.
Record and report (or recording and reporting)	Activities to document risks and risk management and inform key stakeholders.
Risk Owner	Role accountable for ensuring that a risk within a given context is managed throughout the Risk Management Lifecycle - identification, analysis, evaluation, and treatment.

1. General

GDS's number one priority is safe and reliable operations. This procedure is an integral part of GDS's risk management system to ensure hazards and risks are managed effectively to protect the public, workforce, the environment, and the organization.

Hazards are conditions which have the potential to cause harm. Risks are the effect of uncertainty on objectives. For example, a GDS pressurized pipe with shallow depth of cover is a hazardous situation and has the potential of being damaged by excavation activities. If the pipe is struck and punctured by excavation activities, natural gas would release and it could ignite, leading to a flammable event which could impact public health and safety, damage property, and impact the environment due to release of greenhouse gases. The likelihood of the chain of events, from the pipeline being struck to the ultimate flammable event, combined with the quantification of consequences, is a risk.

The bow-tie diagram (**Figure 1**), as documented in Framework Standard – Risk Management, illustrates the relationship between hazards, risks, and controls. The left side of the bow-tie diagram identifies sources of the event (typically it would be hazards or causes of the event) and the right side shows potential consequences. The entire bow-tie diagram illustrates risk. Treatment measures, termed as controls, include all options used to modify and control risk to an acceptable level. There are several types of risk treatment options: avoid, prevent, detect, mitigate, and increase (further defined in **Section 4.3**) - one or more may be used to modify and control risk.

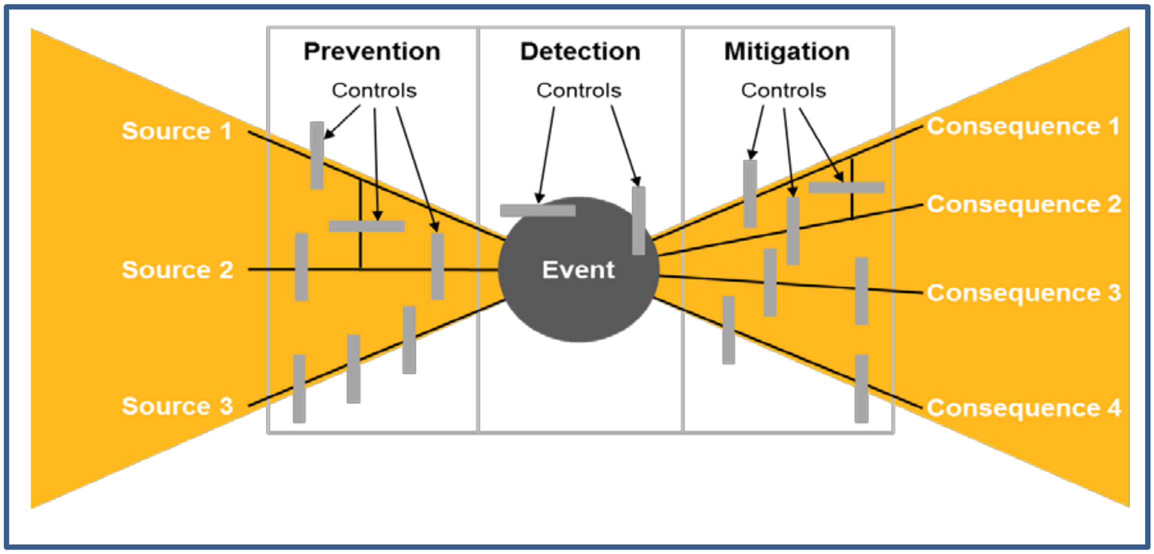


Figure 1: Enbridge Risk Elements (per Framework Standard – Risk Management)

2. Risk Categories within Safety & Reliability (S&R)

At Enbridge, there are 24 defined risk categories as outlined in Framework Standard – Risk Management. Eight risks are considered Safety & Reliability (S&R) risks as highlighted in **Figure 2** and as defined under **Terms and Definitions**.

Strategic Planning	Financial Resilience	Environmental Incident
Investment Analysis	Taxation	Workforce Safety Incident
Project Execution	Fraud	Public Safety Incident
Transformational Projects	Financial Reporting & Regulation	Operational Reliability Incident
Asset Utilization	Economic Regulation	IT Systems Incident
Credit	Legal	Cyber Security Incident
Operating Costs	Human Resources	Operational Regulation
Market Prices	Stakeholder Trust	Terrorism & Asset Security Incident

Figure 2: Enbridge Risk Categories (per Framework Standard – Risk Management Standard)

For definitions of risk categories outside of S&R, refer to the Framework Standard – Risk Management.

3. Enbridge Risk Management Process

The Risk Management Process 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. The eight major activities of the Risk Management Process are illustrated and described in **Figure 3**.

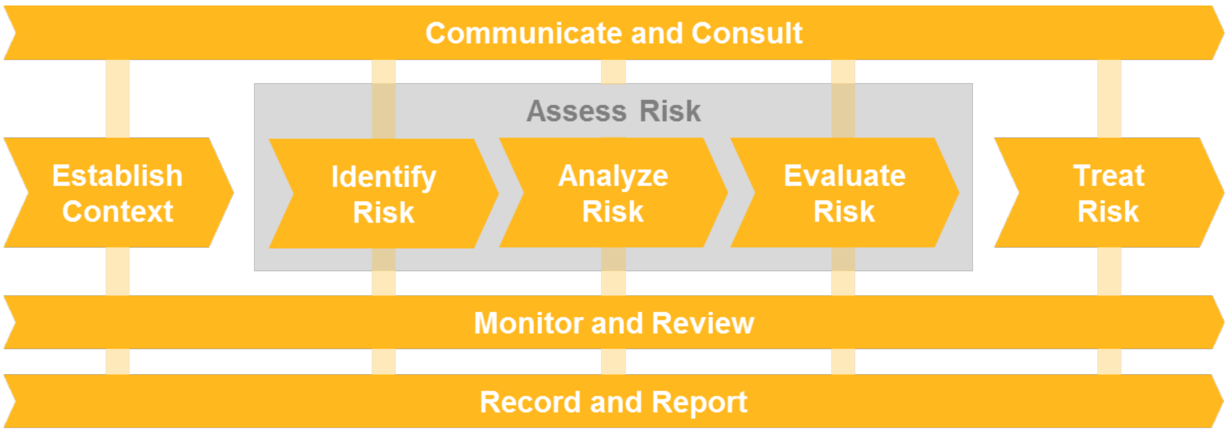


Figure 3: Enbridge Risk Management Process (per Framework Standard – Risk Management)

Definitions of these steps are provided in **Terms and Definitions**.

4. Hazard Identification and Risk Assessment Process for Common Register

4.1 Establish Context

The context of risk management activities is established in the **Scope & Objectives** of this procedure.

4.2 Assess Risks

Assessing Risk is supported by the following sub-steps:

- Identify Hazard and Relating Risk Elements
- Analyze Risk
- Evaluate Risk

1. MP owners identify new hazards and relating risk elements or changes to entries in the Common Register by contacting the Risk Management department.
2. Where applicable, MP owners gather required information to support the proposed new hazards and relating risk elements or changes to entries in the Common Register.
3. MP owners recommend stakeholders attend risk analysis workshops (see **Section 4.2.2)** to review proposed new hazards and relating risk elements or changes to entries in the Common Register.

4. The Risk Management Department facilitates risk analysis workshops (see **Section 4.2.2)** with MP owners/representatives and stakeholders to assess proposed new hazards and relating risk elements, or changes to entries in the Common Register.

5. The Risk Management Department discusses with MP owners the frequency of Register updates, which depend on various factors such as but not limited to:
   - Number of proposed new hazards and relating risk elements or changes to the Register
   - Alignment with various risk review activities (e.g. MP quarterly management review, TMR quarterly review)
   - Materiality at MP level on identifying hazards and relating risk elements

4.2.1 Identify Hazard and Relating Risk Elements

MP owners identify hazards and relating risk elements in two ways:

1. Databases and processes within Management Programs and GDS. Examples include but are not limited to:

   Databases:
   - Failure Classification Platform: Failure classification for leaks and repairs
   - Damage Prevention Records: Damages due to first-, second- and third-party damages
   - Encompass: Incident database

   Front Line Processes – hazards identified in the field:
   - Site Safety Hazard Assessments
   - Safety Observations
   - Survey, Maintenance and Inspection processes (e.g., In-line inspection, Leak Survey, Hazardous Waste Inspection, Station Maintenance Inspections)
   - Incident Investigations
   - Emergency Programs Office (EPO) - emergency management program exercise schedule

   Targeted Reviews / Assessments / Meetings
   - Joint Environment, Health & Safety Committee meetings
   - Joint Business Unit Enterprise Risk Council meetings
   - Asset Management Quarterly Risk reviews
   - MP quarterly Management Reviews
   - Top Management Review
   - Asset Health Review for Distribution System
   - Integrity Assessments for Distribution System
   - Threat identifications for Integrity Management Pipe (IMP), feeder stations and gate stations

- Physical and Information Security Reviews
- MP Hazard/Risk Registries such as Asset Management Risk Registries in Power Plan, Health & Safety Hazards Inventory, and Risk Registry
- Ad hoc Risk Assessments - Structured hazards and risks identification techniques such as those described in *ISO/EIC 31010:2009 Risk Management*. Risk assessment techniques can be used to identify hazards and risks.

GDS Processes

- Management of Change Process
- Engineering Proposal for Change Process
- Operational Processes

2. External sources to GDS. External sources include but are not limited to:
   - Published industrial incidents external to GDS
   - Canadian Gas Association (CGA)
   - American Gas Association (AGA)
   - Technical Standards and Safety Authority (TSSA)
   - The Canadian Disaster Database
   - Industry Standards and Best Practices
   - Municipal and Provincial Outreach (an action completed and tracked through EPO)
   - Incident Investigations Program
   - Enterprise-wide high value learning events
   - External crime statistics

4.2.2 Analyze Risk

The Enbridge Risk Elements illustrated in **Figure 1** are used as the basis for analyzing risks. Once a hazard and relating risk elements are identified, it must be analyzed to determine next steps.

During the risk analysis workshop, workshop participants will perform the following:

- Evaluate risks taking into consideration controls using the Enbridge Standardized Operational Risk Matrix (7x7) (see **Appendix A**).

Likelihood and consequence ratings can be based on a qualitative approach (such as experience from Subject Matter Advisors (SMAs)) or a quantitative approach (such as existing risk analyses, GDS failure rate databases, and published failure rate databases) or a combination of both. Other considerations would be whether to consolidate or separate a risk within or between Management Programs.

Risk analyses conducted from activities within Management Programs can be used as supporting information for the risk analysis workshop.

4.2.3 Evaluate Risk

Once risk levels are established, the workshop participants can:

- Propose a Risk Owner. The owner has hands-on management of the risk and is accountable for ensuring the risk is reduced to a level tolerable by the organization. In some cases, they have the authority to allocate resources to manage/treat the risk.
- Propose ideas to treat risk if treatment is required, however this is not mandatory. It is the Risk Owner's responsibility to determine the means of treating risks.

Risk Management will confirm the Risk Owner and communicate risk information to them. For risks at or above the **Medium** level, formal treatment plans should be considered. If risk treatment is required, the Risk Owner prepares the required information to seek approval on the proposed treatment per applicable business processes.

Risks which meet the reportable criteria as described in **Table 1** will be reported through the MP Quarterly Review. For risks which meet the first or second criteria in **Table 1**, they will be reported at the Top Management Review (TMR) meeting.

Table 1: Criteria for Reportable Risks for MP Quarterly Review and TMR

Definition	**Reportable Risks have the greatest potential to jeopardize the achievement of Enbridge's long-term strategic priorities**
Criteria	1. Risk Levels with Very High or High Post-Control ratings. 2. Risks are not tolerable per legacy EGD risk tolerable criteria. 3. Risk Levels with Medium Post-Control ratings and Consequence ratings of 5 and above and / or trending high MAY be reported. 4. Risk Levels with Medium Post-Control ratings which meet the Reportable Risk Definition requirement MAY also be reported.

4.3 Risk Treatment

Risk Treatment activities modify or control the nature and extent of risk. It involves evaluating, selecting, preparing and implementing one or more treatment options that affect the consequence, likelihood, or both sides of the risk equation. Options for risk treatment plans must follow Enbridge Risk Treatment Options as outlined in **Figure 4**. This applies to risks at all levels. Depending on the nature of the treatment plan, it could be developed, reviewed, monitored, and implemented through various GDS business processes such as:

- Asset Management Plan
- Management of Change
- Engineering's Proposal for Change Process
- Emergency Planning Exercise

When documenting a treatment plan against a risk, it is important to note which programs or processes will be used to implement the plan.

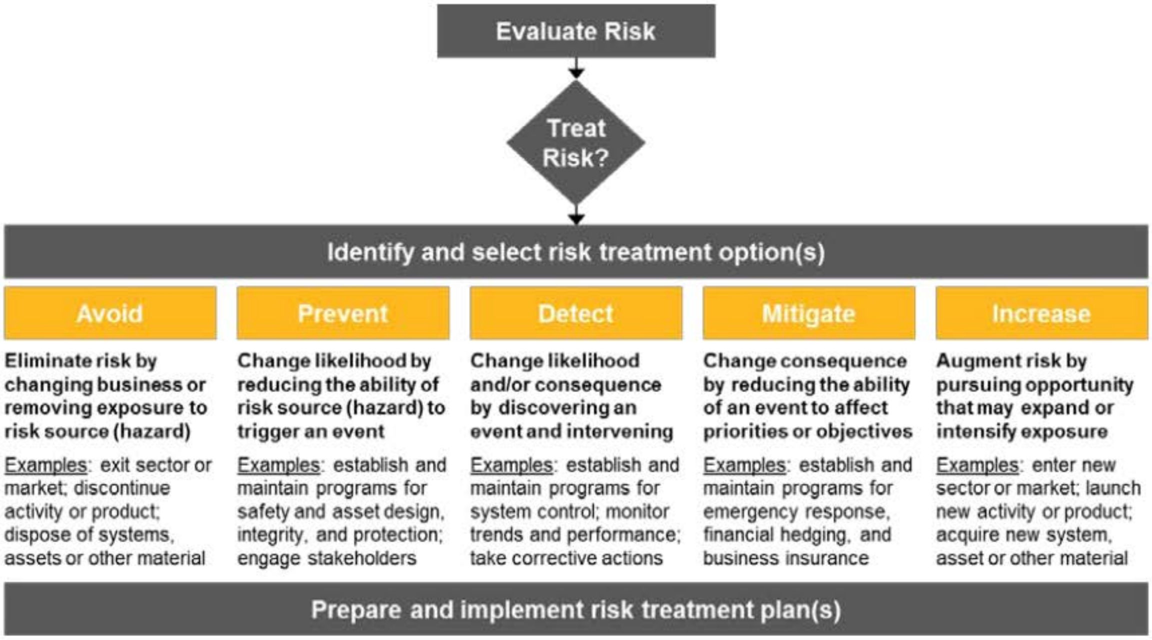


Figure 4: Enbridge Risk Treatment Options (Per Framework Standard – Risk Management)

4.4 Risk Review

Risks ranked as **Low** will be reviewed at the Management Program level per existing business processes or through the common register process described in this procedure. If there are changes to risks, a re-assessment is required per the steps listed in **Section 4.2**.

For risks meeting the reportable risks criteria listed in **Table 1**, Management Program owners present them at the MP Quarterly Management Reviews for the following purposes:

- Provide opportunities for Directors and stakeholders to review risks and address any questions.
- Seek inputs on risk levels assessed in risk assessment (**Section 4.2**)
- Determine what risks will be reported during the Top Management Review (TMR).
- Determine if any **High** risks need to be escalated before the next TMR meeting; for example, through the following meetings and any applicable business processes:
  - Asset Management Steering Committee
  - Safety and Reliability Governance Team (SRGT) meeting
  - Operations and Integrity Committee (OIC) meeting
- For approved risks ranked as **Very High**, they need to be communicated immediately to GDS's Executive Leadership Team for review, approval and determine immediate risk treatment.
- Review of risks will be captured in appropriate meeting review materials wherever appropriate as described above. Any questions or concerns regarding these identified risks will be captured in meeting minutes

When a reportable risk has been assigned to a Risk Owner, it is the owner's responsibility to present the status of risk and treatment plan to the appropriate audience.

In all cases, the Risk Management Department would provide guidance and support on developing and presenting the information for Risk Review.

4.5 Monitor Risk

To ensure the Risk Management objective has been realized, at a minimum, an annual review of the Common Register must take place.

4.6 Communication and Consultation

Internal communication is based on the following principles:

- Consistency in the use of hazard and risk terminology
- Consideration of stakeholders and integration between business areas
- Clarity of accountability and ownership of hazards and risks
- Communication as two-way dialogue
- Appropriate escalation of risks and selection of risk treatment options
- Engagement of appropriate levels of governance for monitoring and reporting on hazards and risks
- Consolidation and communication of risk information that follows internal policies and processes regarding privacy on disclosure and communication of sensitive information

The timing for communication will vary by the nature of the hazards and risks being assessed. Where applicable, risk communication will support and be integrated with risk review meetings identified in **Section 4.4**, Risk review meeting participants are required to share the relevant risk information to their teams and impacted parties.

If required, external communication is channeled through the appropriate internal stakeholder groups, depending on the nature of the external stakeholder request.

4.7 Record and Report

The Common Hazard and Risk Register is published at: https://esites.enbridge.com/sites/gd_im/working/_layouts/15/start.aspx#/Home/Risk%20Registries.aspx. It is updated on an as-needed basis by the Risk Management Department.

The Corporate Risk Assessment (CRA) and Top Operational Risks (TOR) listings will be drawn from the Common Register and communicated to the appropriate stakeholders by the Risk Management Department.

References

Framework Standard – Risk Management

Appendix A: Enbridge Standardized Operational Risk Matrix

ENBRIDGE

STANDARDIZED OPERATIONAL RISK MATRIX

Framework Standard - Risk Management
Effective Date September 17, 2018

Internal Information
Refer to the Framework Standard - Risk Management for additional information

		Annual Likelihood	1	2	3	4	5	6	7
7	Happens once to multiple times in a year	>= 1	Medium	Medium	High	Very High	Very High	Very High	Very High
6	Well known to potentially occur; or may have happened several times in business units in the last ten years	1 to 1/10	Medium	Medium	Medium	High	Very High	Very High	Very High
5	Event may have happened once every ten years	1/10 to 1/100	Low	Medium	Medium	Medium	High	Very High	Very High
4	Isolated prior cases at Enbridge	1/100 to 1/1,000	Low	Low	Medium	Medium	Medium	High	Very High
3	Occurs periodically in industry; or single known case at Enbridge	1/1,000 to 1/10,000	Low	Low	Low	Medium	Medium	Medium	High
2	Known to have happened once in the industry	1/10,000 to 1/100,000	Low	Low	Low	Low	Medium	Medium	Medium
1	Not known/No prior occurrences	< 1/100,000	Low	Low	Low	Low	Low	Medium	Medium

Consequence

	1	2	3	4	5	6	7
FINANCIAL	Total financial impact ≤$10,000	Total financial impact >$10k and ≤$100k	Total financial impact >$100k and ≤$1M	Total financial impact > $1M and ≤ $10M	Total financial impact >$10M and ≤$100M	Total financial impact >$100M and ≤$1B	Total financial impact of >$1B
HEALTH & SAFETY	Employee: No H&S impact Public: No H&S impact	Employee: Illness/injury requiring medical treatment; or highly elevated stress levels Public: No impact	Employee: Illness / injury requiring medical aid; OSHA recordable; modified work restriction or stress-related leave of absence Public: Minor injuries and/or reversible health impacts to members of the public	Employee: Incident resulting in injury or occupational illness requiring long-term rehabilitation (physical or psychological); lost time injury (LTI) or equivalent; overnight hospitalization Public: Requires hospitalization and/or long-term care to members of the public	Public or Employee: One fatality and/or permanent disability affecting one person	Public or Employee: Two to ten (2-10) fatalities and/or permanent disability affecting two to ten (2-10) people	Employee or public: > 10 fatalities and/or permanent disability affecting >10 people
ENVIRONMENTAL	No impact to environment	Impacts to surface gravel or soil within an Enbridge facility; able to be remediated by trained personnel quickly and effectively; no impact to offsite air quality	Offsite impact resulting in environmental damage covering 100m2 (1080 ft2) to 1000m2 (0.25 acre) Impact to upland environment (i.e. farmfield, forest, etc.)	Offsite impact resulting in environmental damage covering 1000m2 (0.25 acre) to 1.0 ha (2.5 acre) Impact to uplands and confined wetland	Offsite impact resulting in environmental damage covering 1 ha (2.5 acres) to 10 ha (25 acres) Impact to uplands and unconfined wetland or creek; no sensitive environmental receptors impacted (animal or plant species)	Offsite impact resulting in environmental damage covering 10 ha (25 acres) to 1 km2 (250 acres) Impact to uplands and lake or river; sensitive environmental receptors impacted (animal or plant species)	Offsite impact resulting in extreme environmental damage (>1 km2) Irreparable damage to lands or waterways; irreparable damage to sensitive environmental receptors (animal or plant species)
OPERATIONAL	No diversion of Enbridge resources No disruption to transportation customers No utility customer impact	Minor diversion of Enbridge resources Minor transportation customer disruption which can be quickly mitigated. Utility customer impact <100 customers	Moderate diversion of Enbridge resources Transportation customers impacted for a day or more to as much as one week. Utility customer impact 100-499 customers	Enbridge resources diverted and operational capability is significantly impacted. Short term disruption to transportation customers (1 week - 1 month) Utility customer impact 500-999 customers	Extended period of Enbridge resource diversion and operational capability impact (1-3 months) Considerable disruption and inconvenience to transportation customers (1-3 months) Utility customer impact 1000 - 4999 customers; or category B major customer	Long period of Enbridge resource diversion and operational capability impact (3-6 months) Long-term impact to transportation customers (3-6 months) Utility customer impact 5000 - 20,000 customers; or multiple category B customers; or a category A major customer	Enbridge resource diversion and operational capability impact exceeds 6 months. Indefinite unavailability of transportation assets (> 6 months) Utility customer impact > 20,000 customers; or multiple category A major customers
REPUTATIONAL	No known media coverage No unplanned regulatory engagement No public disruption	Isolated individual concern; at a municipal/county level. no media attention Regulator notification and/or informal and unplanned meetings or information requests from regulator; no monetary penalty imposed Minor public disruption	Localized concern with short term local media and interest group concerns A non-compliance issue identified by a regulator in writing without a monetary penalty. May require corrective actions; follow up communication with the regulator regarding the issue should be expected. Disruption or inconvenience affecting < 1,000 persons Evacuation of < 10 persons	State/Provincial concern, public and media attention beyond local area, Customer attention on the issue A non-compliance issue identified by a regulator in writing including a monetary penalty; may require corrective actions; follow up communication with the regulator regarding the issue should be expected; permit/approval conditions or approval agency change causing moderate operational impacts. Disruption or inconvenience affecting 1,000- <10,000 persons Evacuation of 10 - < 100 persons	National concern and extended media coverage; significant public response causing major impact on current and prospective customers A non-compliance issue identified by a regulator in writing that requires significant corrective actions; may include a monetary penalty; significant impacts to operation of a specific asset or facility and may require immediate steps to assure safety; operating permit/approval suspended causing significant operational impacts Disruption or inconvenience affecting 10,000-50,000 persons Evacuation of 100 - 1,000 persons	Extended national media coverage; significant public response causing major long term impact on customers; damaging reputation and resulting in the inability to expand operations A non-compliance issue identified by a regulator in writing and directs Enbridge to stop operating specific assets; includes criminal prosecutions Operating permit/approval canceled causing indefinite suspension to operations Disruption or inconvenience affecting > 50,000 persons Evacuation of > 1,000 persons	Extended national media coverage; severe public response causing potentially permanent impact on customers; irreparable reputation damage resulting in the inability to continue operations Unable to gain regulatory approval for continued operation; may require decomissioning of major facilities Criminal prosecution of Enbridge leadership

Standardized Operational Risk Matrix - Copy of Consequence Details

	1	2	3	4	5	6	7
FINANCIAL	Total financial impact ≤$10,000	Total financial impact >$10k and ≤$100k	Total financial impact >$100k and ≤$1M	Total financial impact > $1M and ≤ $10M	Total financial impact >$10M and ≤$100M	Total financial impact >$100M and ≤$1B	Total financial impact of >$1B
HEALTH & SAFETY	Employee: No H&S impact Public: No H&S impact	Employee: Illness/injury requiring medical treatment; or highly elevated stress levels Public: No impact	Employee: Illness / injury requiring medical aid; OSHA recordable; modified work restriction or stress-related leave of absence Public: Minor injuries and/or reversible health impacts to members of the public	Employee: Incident resulting in injury or occupational illness requiring long-term rehabilitation (physical or psychological); lost time injury (LTI) or equivalent; overnight hospitalization Public: Requires hospitalization and/or long-term care to members of the public	Public or Employee: One fatality and/or permanent disability affecting one person	Public or Employee: Two to ten (2-10) fatalities and/or permanent disability affecting two to ten (2-10) people	Employee or public: > 10 fatalities and/or permanent disability affecting >10 people
ENVIRONMENTAL	No impact to environment	Impacts to surface gravel or soil within an Enbridge facility; able to be remediated by trained personnel quickly and effectively; no impact to offsite air quality	Offsite impact resulting in environmental damage covering 100m2 (1080 ft2) to 1000m2 (0.25 acre) Impact to upland environment (i.e. farmfield, forest, etc.)	Offsite impact resulting in environmental damage covering 1000m2 (0.25 acre) to 1.0 ha (2.5 acre) Impact to uplands and confined wetland	Offsite impact resulting in environmental damage covering 1 ha (2.5 acres) to 10 ha (25 acres) Impact to uplands and unconfined wetland or creek; no sensitive environmental receptors impacted (animal or plant species)	Offsite impact resulting in environmental damage covering 10 ha (25 acres) to 1 km2 (250 acres) Impact to uplands and lake or river; sensitive environmental receptors impacted (animal or plant species)	Offsite impact resulting in extreme environmental damage (>1 km2) Irreparable damage to lands or waterways; irreparable damage to sensitive environmental receptors (animal or plant species)
OPERATIONAL	No diversion of Enbridge resources No disruption to transportation customers No utility customer impact	Minor diversion of Enbridge resources Minor transportation customer disruption which can be quickly mitigated. Utility customer impact <100 customers	Moderate diversion of Enbridge resources Transportation customers impacted for a day or more to as much as one week. Utility customer impact 100-499 customers	Enbridge resources diverted and operational capability is significantly impacted. Short term disruption to transportation customers (1 week - 1 month) Utility customer impact 500-999 customers	Extended period of Enbridge resource diversion and operational capability impact (1-3 months) Considerable disruption and inconvenience to transportation customers (1-3 months) Utility customer impact 1000 - 4999 customers; or category B major customer	Long period of Enbridge resource diversion and operational capability impact (3-6 months) Long-term impact to transportation customers (3-6 months) Utility customer impact 5000 - 20,000 customers; or multiple category B customers; or a category A major customer	Enbridge resource diversion and operational capability impact exceeds 6 months. Indefinite unavailability of transportation assets (> 6 months) Utility customer impact > 20,000 customers; or multiple category A major customers
REPUTATIONAL	No known media coverage No unplanned regulatory engagement No public disruption	Isolated individual concern; at a municipal/county level. no media attention Regulator notification and/or informal and unplanned meetings or information requests from regulator; no monetary penalty imposed Minor public disruption	Localized concern with short term local media and interest group concerns A non-compliance issue identified by a regulator in writing without a monetary penalty. May require corrective actions; follow up communication with the regulator regarding the issue should be expected. Disruption or inconvenience affecting < 1,000 persons Evacuation of < 10 persons	State/Provincial concern, public and media attention beyond local area, Customer attention on the issue A non-compliance issue identified by a regulator in writing including a monetary penalty; may require corrective actions; follow up communication with the regulator regarding the issue should be expected; permit/approval conditions or approval agency change causing moderate operational impacts. Disruption or inconvenience affecting 1,000- <10,000 persons Evacuation of 10 - < 100 persons	National concern and extended media coverage; significant public response causing major impact on current and prospective customers A non-compliance issue identified by a regulator in writing that requires significant corrective actions; may include a monetary penalty; significant impacts to operation of a specific asset or facility and may require immediate steps to assure safety; operating permit/approval suspended causing significant operational impacts Disruption or inconvenience affecting 10,000-50,000 persons Evacuation of 100 - 1,000 persons	Extended national media coverage; significant public response causing major long term impact on customers; damaging reputation and resulting in the inability to expand operations A non-compliance issue identified by a regulator in writing and directs Enbridge to stop operating specific assets; includes criminal prosecutions Operating permit/approval canceled causing indefinite suspension to operations Disruption or inconvenience affecting > 50,000 persons Evacuation of > 1,000 persons	Extended national media coverage; severe public response causing potentially permanent impact on customers; irreparable reputation damage resulting in the inability to continue operations Unable to gain regulatory approval for continued operation; may require decomissioning of major facilities Criminal prosecution of Enbridge leadership

Document Control and Maintenance

For document control and maintenance purposes, the following table captures important information related to this document.

Category	Value
Owned by:	Asset Management Department, Risk Team
Review interval:	Every 2 years
This is an MOC related document:	No

Revision History

Date	Summary of Changes	Prepared by:	Approved by:
2020-01	Initial version.	Angela Wong, Supervisor Risk Management	Hilary Thompson, Director Asset Management

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	1979.56	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2012.3	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0.8	2	3.9	STEEL	I	S	290	CAN/CSAZ245.1-95PS163PS153MS01	YJ	WELDED
1900	NULL	4	2	3.9	STEEL	I	S	290	CAN/CSAZ245.1-95PS163PS153MS01	YJ	WELDED
1900	NULL	1.9	10	7.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.2	10	7.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.9	10	7.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.2	10	7.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.9	10	7.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	3.9	10	7.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	10.66	2	3.9	STEEL	I	S	290	CSA Z245.1	YJ	WELDED
1900	NULL	8	2	3.9	STEEL	I	S	290	CAN/CSAZ245.1-95PS163PS153MS01	YJ	WELDED
1900	NULL	6.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	913.56	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	859.08	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	3.9	10	7.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	3.9	10	7.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	6.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	253.14	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	263.52	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2.84	2	3.9	STEEL	I	S	290	CSA Z245.1	YJ	WELDED
1900	NULL	1.9	10	7.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	3.9	10	7.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0	8	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	1326.86	8	7.04	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1325.06	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1297.99	8	7.04	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	2026.98	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1.2	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	C&W	WELDED
1900	NULL	4	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	C&W	WELDED
1900	NULL	9.8	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	C&W	WELDED
1900	NULL	4	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	C&W	WELDED
1900	NULL	8.2	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	4.9	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.3	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	18	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.3	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.9	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	23.5	10	0	STEEL	UNK	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	19	10	0	STEEL	UNK	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	14.53	8	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	8	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	8	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	8	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	8	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	8	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	8	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	8	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	30.9	8	7.04	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0.04	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	\N	WELDED
1900	NULL	206.7	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	152.7	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	716.6	8	7.04	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	31.2	8	4.78	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	COUPLED
1900	NULL	4.2	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	1.2	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	30	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.9	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.9	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	1219.5	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	24.8	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	YJ	WELDED
1900	NULL	435.87	8	7.04	STEEL	UNKNOWN	S	165	UNKNOWN	B	WELDED
1900	NULL	64.23	8	7.04	STEEL	UNKNOWN	S	165	UNKNOWN	B	WELDED
1900	NULL	0.9	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.9	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	30	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	1.2	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	2.1	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.9	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.6	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	33	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.6	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.9	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	12	2	3.9	STEEL	I	S	172	API 5L	YJ	WELDED
1900	NULL	3.12	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	WELDED
1900	NULL	3.5	8	7.04	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	20.1	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	8.5	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.2	8	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	94.9	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	134.4	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	7.6	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	13.84	8	7	STEEL	I	S	290	CAN/CSA Z245.1	B	COUPLED
1900	NULL	191.7	8	6.4	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	257.8	8	7.04	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	231.51	8	6.4	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	620.02	8	7.04	STEEL	UNKNOWN	S	UNK	UNKNOWN	B	COUPLED
1900	NULL	1356.45	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2.1	2	3.9	STEEL	I	S	172	CSA Z245.3	YJ	WELDED
1900	NULL	5.7	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	0.1	4	0	STEEL	UNK	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.1	2	0	STEEL	UNK	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	4	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	684.2	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
2757	NULL	0.9	8	7	STEEL	UNKNOWN	S	290	API 5L	B	WELDED
2757	NULL	1.2	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	8.5	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
2757	NULL	1.5	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
2757	NULL	1.2	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	14.2	8	7	STEEL	I	S	290	CAN/CSA Z245.1	B	FUSED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	4	8	4.78	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	COUPLED
2757	NULL	0.3	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	3.11	8	7.04	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	4684.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	11.99	2	3.9	STEEL	UNKNOWN	S	172	UNKNOWN	YJ	WELDED
1900	NULL	33	2	3.9	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.81	2	3.9	STEEL	I	S	290	CAN/CSAZ245.1-98 SP5132 PS156	YJ	WELDED
1900	NULL	32.8	2	3.9	STEEL	I	S	290	CAN/CSAZ245.1-98 SP5132 PS156	YJ	WELDED
1900	NULL	1307.39	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
2757	NULL	1.2	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
2757	NULL	0.3	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
2757	NULL	1.2	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	9.3	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	680.98	8	7.04	STEEL	UNKNOWN	S	UNK	UNKNOWN	B	COUPLED
1900	NULL	677.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	9	2	3.9	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	32.75	8	7.04	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	7.95	8	7.04	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
2757	NULL	8.4	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
2757	NULL	9.2	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
2757	NULL	15.5	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
2757	NULL	5	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	30.28	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1308.22	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1377.8	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	307	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	980.9	8	6.4	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	9.31	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
4964	NULL	0	3	5.5	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
4964	NULL	0	3	5.5	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
4964	NULL	0	3	5.5	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
4964	NULL	0	3	5.5	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	13.7	1	3.4	STEEL	I	S	290	CAN/CSAZ245.1-98 SP5132 PS156	YJ	WELDED
1900	NULL	13.8	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.4	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.4	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.6	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0.6	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	2.8	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	2	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0.6	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	2.7	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0.9	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.4	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0.9	8	4.78	STEEL	UNKNOWN	S	241	UNKNOWN	C&W	WELDED
1900	NULL	6.6	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.2	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.6	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0.9	8	4.78	STEEL	UNKNOWN	S	241	UNKNOWN	CT	WELDED
1900	NULL	4.9	8	4.78	STEEL	UNKNOWN	S	241	UNKNOWN	C&W	WELDED
1900	NULL	1009.36	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.4	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.2	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	4.3	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	679.8	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1.5	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0.6	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	2.4	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	5.5	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	2.4	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0.6	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	5.8	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.6	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.2	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1046.19	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.9	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0.6	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.4	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.2	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.2	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	684.84	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	603.9	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	11	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	468.8	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	5.7	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.4	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.6	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.2	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.2	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	0.9	8	4.78	STEEL	UNKNOWN	S	241	UNKNOWN	C&W	WELDED
1900	NULL	4.9	8	4.78	STEEL	UNKNOWN	S	241	UNKNOWN	C&W	WELDED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	5.8	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.4	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.2	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	5.8	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	4.3	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.4	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	3.7	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.9	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	4.9	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.9	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	3	8	4.78	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	5.8	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2.4	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	2.4	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0.6	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.5	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	4.7	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1.8	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	583.6	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	5.5	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	2.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	613.3	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	629.1	8	4.78	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	COUPLED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	6.2	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.4	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.2	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.4	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2.7	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.4	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.2	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	5.8	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.1	8	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
4960	NULL	1561.63	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	5531.4	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	16.9	2	3.9	STEEL	I	S	290	CAN/CSAZ245.1-98 SP5132 PS156	YJ	WELDED
1900	NULL	3.1	10	9.3	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	6.54	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	12.6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	872.55	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	98.92	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2072.06	10	5.56	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	COUPLED
1900	NULL	651.4	10	5.56	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	COUPLED
1900	NULL	258.7	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	1485	10	5.56	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	COUPLED
1900	NULL	4.4	10	9.3	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0.9	10	9.3	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	4	10	9.3	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0.9	10	9.3	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	5.8	10	5.56	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	3.9	10	5.56	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	3	10	5.56	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	3.6	10	5.56	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	3.1	10	5.56	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	7.9	10	5.56	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	6.7	10	5.56	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
4960	NULL	22.8	10	6.35	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
4960	NULL	9.1	10	6.35	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
4960	NULL	2.4	10	6.35	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
2758	NULL	2	10	6.35	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	7341.62	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2024.46	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	2558.32	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	WELDED
1900	NULL	0	10	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	9.51	10	7	STEEL	UNKNOWN	S	UNK	UNKNOWN	B	COUPLED
1900	NULL	0	4	4.8	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
740	NULL	2062.61	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2943.2	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1380	NULL	0.1	4	0	STEEL	UNK	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	B	COUPLED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	B	COUPLED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	5.3	2	3.9	STEEL	I	S	172	API 5L	YJ	WELDED
1900	NULL	7.35	2	3.9	STEEL	I	S	172	API 5L	YJ	WELDED
1900	NULL	0	4	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	13	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0	2	3.9	STEEL	I	S	172	API 5L	YJ	WELDED
1900	NULL	0	2	3.9	STEEL	I	S	172	API 5L	YJ	WELDED
1900	NULL	0	2	3.9	STEEL	I	S	172	API 5L	YJ	WELDED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	B	COUPLED
1900	NULL	957.67	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	978.59	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
1900	NULL	5.9	10	9.3	STEEL	I	S		290	CAN/CSA Z245.1-95 PS163 MS01	B	WELDED
1900	NULL	11.2	2	3.9	STEEL	I	S		290	CAN/CSAZ245.1-95PS163PS153MS01	YJ	WELDED
1900	NULL	18	10	5.56	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	1.7	10	5.56	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	4.6	10	5.56	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	2.9	10	5.56	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	18.6	10	5.56	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	0.8	1	3.4	STEEL	I	S		290	CAN/CSAZ245.1-95PS163PS156MS01	YJ	WELDED
1900	NULL	2.3	1	3.4	STEEL	I	S		290	CAN/CSAZ245.1-95PS163PS156MS01	YJ	WELDED
1900	NULL	1.1	2	3.9	STEEL	I	S		290	CAN/CSAZ245.1-95PS163PS153MS01	YJ	WELDED
1900	NULL	1	2	3.9	STEEL	I	S		290	CAN/CSAZ245.1-95PS163PS153MS01	YJ	WELDED
1900	NULL	17.2	10	5.6	STEEL	UNKNOWN	S		165	UNKNOWN	C&W	WELDED
1900	NULL	3.5	10	9.3	STEEL	I	S		290	CAN/CSA Z245.1-95 PS163 MS01	B	WELDED
1900	NULL	8	2	3.9	STEEL	I	S		290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	130.84	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
1900	NULL	1353.51	10	5.6	STEEL	UNKNOWN	S		165	UNKNOWN	C&W	WELDED
1900	NULL	1209.04	10	5.56	STEEL	UNKNOWN	S		165	UNKNOWN	C&W	COUPLED
1900	NULL	5.4	10	5.56	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	1.8	10	5.56	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	560	10	5.56	STEEL	UNKNOWN	S		165	UNKNOWN	C&W	COUPLED
1900	NULL	3.9	10	5.56	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	1.5	10	5.56	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	1.5	10	5.56	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	1.5	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
1900	NULL	4.6	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
1900	NULL	5.5	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
1900	NULL	34.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
1900	NULL	38	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
1900	NULL	6.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
1900	NULL	6.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
1900	NULL	0.6	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
1900	NULL	13.9	10	5.56	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	3.9	10	5.56	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	6.5	10	5.56	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	2.7	10	5.56	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	4.6	10	5.56	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	1131.86	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	535.79	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	B	COUPLED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	B	COUPLED
1900	NULL	0	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1478.63	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	766.77	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	1468.67	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	WELDED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	B	COUPLED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	WELDED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	B	COUPLED
1900	NULL	123	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	YJ	WELDED
1900	NULL	3.35	4	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	4	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	4	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	4	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	4	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	1378.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	302.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	689.7	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	398.85	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2.7	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	WELDED
1900	NULL	3.7	10	7	STEEL	UNKNOWN	S	UNK	UNKNOWN	B	WELDED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	2.7	10	7	STEEL	UNKNOWN	S	UNK	UNKNOWN	B	WELDED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	B	COUPLED
1900	NULL	0	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1265.93	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	60.8	8	5.56	STEEL	UNKNOWN	S	UNK	UNKNOWN	YJ	WELDED
1900	NULL	4832.01	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	15.24	2	0	STEEL	UNK	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	24	2	0	STEEL	UNK	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	915.3	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	3905.34	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2915.41	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
3433	NULL	4926.2	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	2235.65	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	58.5	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
3433	NULL	814.14	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1290.4	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	12.95	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.56	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.66	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.2	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.14	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1128.59	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2.37	6	7.1	STEEL	I	S	290	CAN/CSA Z245.1	B	WELDED
1900	NULL	3.33	6	7.1	STEEL	I	S	290	CAN/CSA Z245.1	B	WELDED
1900	NULL	4.31	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	2.92	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	164	12	9.5	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.4	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	4.17	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	1.5	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1.2	10	12.7	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	4.3	12	9.5	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
3000	NULL	2.06	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
3000	NULL	1.26	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
3433	NULL	0.8	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2.5	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
3000	NULL	1.16	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
3433	NULL	2.29	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0.8	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
3450	NULL	116.5	10	9.3	STEEL	I	S	290	CAN/CSAZ245.1-95PS163PS156MS01	YJ	WELDED
3450	NULL	13.3	10	5.6	STEEL	I	S	290	CAN/CSAZ245.1-95PS163PS156MS01	YJ	WELDED
3450	NULL	12.6	10	5.6	STEEL	I	S	290	CAN/CSAZ245.1-95PS163PS156MS01	YJ	WELDED
3450	NULL	12.4	10	5.6	STEEL	I	S	290	CAN/CSAZ245.1-95PS163PS156MS01	YJ	WELDED
2410	NULL	0.96	2	3.9	STEEL	I	S	290	CAN/CSAZ245.1-95PS163PS153MS01	YJ	WELDED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0.8	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0.8	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1.2	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
3000	NULL	0.73	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
3000	NULL	1.23	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
3433	NULL	0.8	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3000	NULL	1.06	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
3000	NULL	0.58	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
3000	NULL	1.32	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
3433	NULL	8	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3000	NULL	6.39	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
3000	NULL	1.46	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.1	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	968.73	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	56	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0.8	6	7.1	STEEL	I	S	290	CAN/CSA Z245.1	B	WELDED
1900	NULL	2.2	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	13.2	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
3000	NULL	0.65	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
3000	NULL	1.19	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	2.13	6	7.1	STEEL	I	S	241	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	878.4	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	13.56	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	134.82	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
3433	NULL	1559.8	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1.3	10	5.6	STEEL	I	S	290	UNKNOWN	YJ	WELDED
1900	NULL	1.7	10	5.6	STEEL	I	S	290	UNKNOWN	YJ	WELDED
1900	NULL	1.7	10	5.6	STEEL	I	S	290	UNKNOWN	YJ	WELDED
1900	NULL	5.3	10	5.6	STEEL	I	S	290	UNKNOWN	YJ	WELDED
3433	NULL	1587.49	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2.52	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
3433	NULL	1.2	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	152.96	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2328.8	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	COUPLED
1900	NULL	121.08	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	COUPLED
1900	NULL	213.4	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
3433	NULL	927.2	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	78	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.7	10	5.6	STEEL	I	S	290	UNKNOWN	YJ	WELDED
1900	NULL	4.5	1	3.4	STEEL	I	S	290	CAN/CSAZ245.1-98 SP5132 PS156	YJ	WELDED
1900	NULL	2418.82	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	COUPLED
1900	NULL	512.7	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	7.1	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
3433	NULL	3437.95	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	17.2	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
3433	NULL	3.7	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
1380	NULL	0.1	10	0	STEEL	UNK	S	UNK		UNKNOWN	N/A	COUPLED
1380	NULL	0.1	10	0	STEEL	UNK	S	UNK		UNKNOWN	N/A	COUPLED
1380	NULL	0.1	10	0	STEEL	UNK	S	UNK		UNKNOWN	N/A	COUPLED
1380	NULL	0.1	10	0	STEEL	UNK	S	UNK		UNKNOWN	N/A	COUPLED
3433	NULL	5.96	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
1380	NULL	0.33	10	6.4	STEEL	UNKNOWN	S		165	UNKNOWN	C&W	COUPLED
1380	NULL	0.98	10	6.4	STEEL	UNKNOWN	S		165	UNKNOWN	PTR	COUPLED
3433	NULL	1.58	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
1380	NULL	0.3	10	6.4	STEEL	UNKNOWN	S		165	UNKNOWN	C&W	COUPLED
3433	NULL	0.3	10	7	STEEL	UNKNOWN	S		165	UNKNOWN	B	COUPLED
1380	NULL	205.92	10	6.4	STEEL	UNKNOWN	S		165	UNKNOWN	C&W	COUPLED
1380	NULL	16.91	10	6.4	STEEL	UNKNOWN	S		165	UNKNOWN	C&W	COUPLED
1380	NULL	1.19	2	3.9	STEEL	I	S		290	CAN/CSA Z245.1	YJ	WELDED
1380	NULL	1	10	9.3	STEEL	I	S		241	CAN/CSA Z245.1	B	COUPLED
1900	NULL	3314.32	10	5.6	STEEL	UNKNOWN	S		165	UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK		UNKNOWN	C&W	WELDED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	3314.11	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0	8	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	WELDED
1900	NULL	0	10	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	COUPLED
1900	NULL	0	10	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	COUPLED
1900	NULL	0	8	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	8	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	8	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	8	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
3433	NULL	2.82	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	84.8	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
3433	NULL	903	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0.88	4	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0.98	4	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0.1	12	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	WELDED
1900	NULL	0.57	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	3.4	4	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1900	NULL	182.16	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	2244.41	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
3433	NULL	2420.6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	3.01	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0.1	8	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	WELDED
1900	NULL	0.1	8	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1900	NULL	0.1	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0.1	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1900	NULL	3381.74	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0.1	2	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	WELDED
1900	NULL	0	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1900	NULL	2.85	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.3	8	4.8	STEEL	UNKNOWN	S	UNK	CSA Z245.1	YJ	WELDED
1900	NULL	0.5	4	4.8	STEEL	I	S	290	CSA Z245.1	YJ	WELDED
1900	NULL	2.2	4	4.8	STEEL	I	S	290	CSA Z245.1	YJ	WELDED
1900	NULL	0.9	4	4.8	STEEL	I	S	290	CSA Z245.1	YJ	WELDED
1900	NULL	1.3	4	4.8	STEEL	I	S	290	CSA Z245.1	YJ	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1900	NULL	0.1	8	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	WELDED
1900	NULL	0.1	8	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	WELDED
1900	NULL	0.1	2	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	WELDED
1900	NULL	0	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1900	NULL	0	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1900	NULL	7.88	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1900	NULL	343.79	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	30.33	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
3433	NULL	3533.16	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1.6	4	4.8	STEEL	I	S	290	CSA Z245.1	YJ	WELDED
1900	NULL	0.6	4	4.8	STEEL	I	S	290	CSA Z245.1	YJ	WELDED
1900	NULL	0.3	4	4.8	STEEL	I	S	290	CSA Z245.1	YJ	WELDED
1900	NULL	2.5	4	4.8	STEEL	I	S	290	CSA Z245.1	YJ	WELDED
1900	NULL	0.66	4	4.8	STEEL	I	S	290	CSA Z245.1	YJ	WELDED
1900	NULL	0.4	4	4.8	STEEL	I	S	290	CSA Z245.1	YJ	WELDED
1900	NULL	14	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
3433	NULL	82.6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	247.9	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	32.2	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1900	NULL	4.7	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	8.1	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	48.4	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	1749.05	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
3433	NULL	1377.47	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0.35	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	2.2	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0.15	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
3433	NULL	351.14	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	627.6	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	45.73	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	1067	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	1.3	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
3433	NULL	1.3	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	1.4	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.1	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.1	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
3433	NULL	3.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
5894	NULL	6.1	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	COUPLED
3433	NULL	492.83	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
5894	NULL	6.1	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	COUPLED
1900	NULL	0.9	10	7.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	COUPLED
1900	NULL	4.3	10	7.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	COUPLED
1900	NULL	0.9	10	7.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	COUPLED
1900	NULL	137.3	10	7.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	COUPLED
1900	NULL	4.9	10	7.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	COUPLED
1900	NULL	1.2	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	COUPLED
3433	NULL	475	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	25.9	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	COUPLED
1900	NULL	32	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	COUPLED
1900	NULL	25.9	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	COUPLED
1900	NULL	4.8	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	COUPLED
3433	NULL	238.4	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	23	1	3.4	STEEL	I	S	172	API 5L	YJ	WELDED
1900	NULL	0.9	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	0.3	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	7.1	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0.8	8	4.8	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	26.5	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	2.74	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	18.3	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	10	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	530.8	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	13.85	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	2.2	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.1	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	5	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	1.1	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	522.8	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
3433	NULL	68.74	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	43.75	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	18.99	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	1.77	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
7349	NULL	6.1	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
7349	NULL	2.6	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
7349	NULL	41.1	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
7349	NULL	2.6	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
7349	NULL	6.1	8	4.78	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	766.8	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0.9	8	6.4	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	4.9	8	6.4	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	137.6	8	6.4	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	4.3	8	6.4	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0.9	8	6.4	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
5894	NULL	2.6	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	COUPLED
5894	NULL	2.6	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	COUPLED
5894	NULL	41.1	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	COUPLED
1900	NULL	33.7	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	39.05	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	23.1	1	3.4	STEEL	I	S	172	API 5L	YJ	WELDED
1900	NULL	28	2	3.9	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	864.76	12	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	3.8	2	3.9	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0.5	2	3.9	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0.5	2	3.9	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1900	NULL	0.1	2	3.91	STEEL	I	S	207	API 5L	C&W	UNKNOWN
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0.1	10	0	STEEL	UNK	S	UNK	UNKNOWN	B	COUPLED
1900	NULL	1.1	2	3.91	STEEL	I	S	207	API 5L	C&W	UNKNOWN
1900	NULL	0	2	3.91	STEEL	I	S	207	API 5L	C&W	UNKNOWN
1900	NULL	3.5	2	3.91	STEEL	I	S	207	API 5L	C&W	UNKNOWN
1900	NULL	5.44	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
420	NULL	0	3	5.73	STEEL	I	S	207	API 5L	C&W	WELDED
1380	NULL	0	12	9.53	STEEL	I	S	35	CAN/CSA Z245.3	B	WELDED
3977	NULL	0.03	12	5.56	STEEL	I	S	35	CAN/CSA Z245.3	B	WELDED
1380	NULL	0	1	0	STEEL	I	S	35	CAN/CSA Z245.3	B	WELDED
1380	NULL	0	12	9.53	STEEL	I	S	35	CAN/CSA Z245.3	B	WELDED
1380	NULL	0	10	9.53	STEEL	I	S	35	CAN/CSA Z245.3	B	WELDED
1380	NULL	0	10	9.53	STEEL	I	S	35	CAN/CSA Z245.3	B	WELDED
1380	NULL	0	12	9.53	STEEL	I	S	35	CAN/CSA Z245.3	B	WELDED
1380	NULL	0.01	10	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	COUPLED
1380	NULL	0.1	4	0	STEEL	I	S	35	CAN/CSA Z245.3	B	WELDED
3977	NULL	0.1	10	9.53	STEEL	I	S	35	CAN/CSA Z245.3	B	WELDED
1380	NULL	11.8	10	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	COUPLED
3450	NULL	0.4	4	4.8	STEEL	I	S	290	CAN/CSAZ245.1-98 PS163/156MS01	YJ	WELDED
3450	NULL	1.2	6	7.1	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1380	NULL	2.8	10	5.6	STEEL	I	S	290	CAN/CSA Z245.1	YJ	WELDED
1380	NULL	1.13	10	6.4	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	COUPLED
1380	NULL	1.16	10	6.4	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	COUPLED
1380	NULL	84.03	10	6.4	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	COUPLED
3450	NULL	0	8	8.2	STEEL	I	S	290	CAN/CSA Z245.1-98 SP5101	B	WELDED
3450	NULL	0	10	9.3	STEEL	I	S	359	CAN/CSAZ245.1-98 SP5101	B	WELDED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1900	NULL	1.1	8	4.8	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	2.4	8	4.8	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	29.3	8	4.8	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	2.4	8	4.8	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	1.1	8	4.8	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1380	NULL	4.5	10	9.3	STEEL	I	S	241	CAN/CSA Z245.1	YJ	COUPLED
1380	NULL	3.3	10	9.3	STEEL	I	S	241	CAN/CSA Z245.1	YJ	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	26.8	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	6.2	10	5.6	STEEL	I	S	290	UNKNOWN	YJ	WELDED
3433	NULL	398.8	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	4	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	2.4	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	COUPLED
1900	NULL	2.9	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	COUPLED
1900	NULL	29.1	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	COUPLED
1900	NULL	2.9	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	COUPLED
1900	NULL	2.3	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	COUPLED
3433	NULL	3.9	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
3433	NULL	6.1	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1380	NULL	0.5	3	4.8	STEEL	I	S	290	CSA Z245.1	YJ	WELDED
1380	NULL	2.79	10	6.4	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	COUPLED
1380	NULL	4.06	10	6.4	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	COUPLED
3450	NULL	1.1	10	5.6	STEEL	II	S	359	CAN/CSA Z245.1-98 SP5101 PS156	YJ	WELDED
3450	NULL	1	10	5.6	STEEL	II	S	359	CAN/CSA Z245.1-98 SP5101 PS156	YJ	WELDED
1380	NULL	2.09	10	6.4	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	COUPLED
3450	NULL	0.1	10	9.3	STEEL	I	S	359	CAN/CSAZ245.1-98 SP5101	B	WELDED
1900	NULL	0.1	8	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	WELDED
1900	NULL	39.51	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1900	NULL	0	10	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1900	NULL	0	8	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1900	NULL	0	8	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED

mop	prcnt_smys_at_mop	actual_length	pri_nominal_size	pri_wall_thick	material	material_category	material_flag	material_grade	material_spec	coating	JOINT_TYPE
3450	NULL	0.96	10	5.5	STEEL	UNKNOWN	S	UNK	UNKNOWN	CT	WELDED
1900	NULL	0	4	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	4	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	2729.02	10	5.6	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	1	6	7.1	STEEL	I	S	290	CAN/CSA Z245.1	B	WELDED
3433	NULL	88.22	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	7.6	10	5.56	STEEL	UNKNOWN	S	290	API 5L	C&W	WELDED
1900	NULL	3.5	8	7.04	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	252.33	10	7	STEEL	UNKNOWN	S	165	UNKNOWN	B	COUPLED
1900	NULL	0	3	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	C&W	WELDED
1900	NULL	0	2	3.91	STEEL	I	S	207	API 5L	C&W	UNKNOWN
1900	NULL	0	2	3.91	STEEL	I	S	207	API 5L	C&W	UNKNOWN
1900	NULL	4.2	8	4.8	STEEL	I	S	290	CAN/CSAZ245.1-98 SP5101 PS156	YJ	WELDED
1900	NULL	244.47	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	124	8	4.8	STEEL	I	S	290	CAN/CSAZ245.1-98 SP5101 PS156	YJ	WELDED
1900	NULL	2021.33	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	80	8	4.8	STEEL	UNKNOWN	S	165	UNKNOWN	C&W	WELDED
1900	NULL	5.8	8	4.8	STEEL	I	S	290	CAN/CSAZ245.1-98 SP5101 PS156	YJ	WELDED
1900	NULL	0	2	0	STEEL	UNKNOWN	S	UNK	UNKNOWN	PTR	WELDED
1380	NULL	0.01	10	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	COUPLED
1380	NULL	0.01	10	0	STEEL	UNK	S	UNK	UNKNOWN	N/A	COUPLED

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Ex. B, T1, Sch. 1]

In areas where it is not practical to remove the existing pipeline it will be abandoned in place.

Questions:

a) Please provide a copy of any policy, manuals, guidelines or other relevant material that Enbridge uses to determine when to abandon in place vs. remove an abandoned pipeline.

b) Has Enbridge received confirmation from the road authority that it will accept abandonment in place for portions of the pipeline? If so, please provide a copy of such approval.

c) Please explain how Enbridge will determine when it is not practical to remove sections of the existing pipelines and who at Enbridge will make that decision.

d) Are any 148 service connections off the proposed pipeline included in the scope of this Project? If yes, please provide the estimate costs associated with these.

e) How many of the 148 service connections off the existing NPS 12, 10 and 8 pipelines are newer than 40 years old and what is their residual capital value.

Response:

a) Please see Exhibit I.STAFF.3 b) for the description of the 2000 Model Franchise Agreement that describes the agreement that Enbridge Gas has in place and outlines abandon in place vs removal. If removal would require extensive disturbance to the surrounding area (e.g., if the pipeline is located under a river, under a highway, etc.), then the preference is to abandon it in place. If being left in place would present a hazard to the surrounding environment (e.g., aerial ditch crossings), the preference would be to remove it according to Enbridge Gas' Construction and Maintenance Manual.

b) Please see Exhibit I.STAFF.3 b).

c) As stated in the pre-filed evidence at Exhibit B, Tab 1, Schedule 1, paragraph 44, the direction to remove or abandon in place follows the municipal franchise agreements and agreements with landowners who have pipeline easements.

d) In Exhibit B, Tab 1, Schedule 1, paragraph 45, the number of services was incorrectly shown as 148. The correct number should be 135. Enbridge Gas will file a correction to this exhibit with the interrogatory responses. As shown in the pre-filed evidence at Exhibit F, Tab 1, Schedule 1, Table 1, the estimated cost to transfer the service connections to the proposed line is stated as $4.798 million. The re-evaluation of the number of service connections has resulted in a direct service cost reduction of approximately $0.5 million of the Estimated Incremental Project Capital Cost presented in Exhibit F, Tab 1, Schedule 1, Table 1. Enbridge Gas is not proposing to update the cost estimate at this time as the current estimate is based on high level quotes for the project. As detailed design progresses, these estimates will be substituted with quotes developed using more refined scopes of work, as such, the cost estimate will change. Any variances between the cost estimates and the actual costs of the project will be filed in the Post Construction Financial report.

e) 72 of the existing service connections are newer than 40 years old. Due to the method used to track and group assets, the residual capital value cannot be broken down to the specific asset level. Please see Exhibit I.EP.1 d) for additional details.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Ex. B, T1, Sch. 1

Question:

a) Has Enbridge contacted all impacted municipalities to determine of road widening projects are likely to occurs along the right-of-way? Please provide details of any potential road widening projects and what Enbridge has done to mitigate potential need for pipeline relocation in the future.

Response:

a) Enbridge Gas has engaged all impacted municipalities to determine plans for future municipal infrastructure projects, including road widening projects. In the Environmental Report, filed at Exhibit C, Tab 2, Schedule 1, Section 6.0 Cumulative effects assessments, Table 6-1: Project Inclusion List for Cumulative Effects, the project raised by the municipalities was included. The County of Middlesex has identified a road widening project (to be executed in 5-10 years) along Glendon Drive, east and west of Komoka Rd. The County has sent Enbridge Gas the preliminary plans (road alignment and depth) and Enbridge Gas is in currently in discussions with the County to refine the pipeline alignment to mitigate the need for pipeline relocation in the future.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Ex. B, T2, Sch. 2

Questions:

a) Please provide an explanation based on Enbridge's analysis how the current or future maximum design day needs were matched to the pipeline size chosen and whether there will be any excess peak capacity available.

b) Please outline any load growth or load decrease assumptions used in the modeling over the life of the proposed pipeline.

Response:

a) and b)

The pipeline was designed to replace the existing capacity of the London Lines. The new pipeline was sized for all existing customers served from the London Lines, plus the additional demand that could be accommodated by the existing system. The additional capacity of the system is negligible, but due to the introduction of the second feed, the available capacity has shifted in location. The pipe was not sized based on specific future demand, but the location of attachments in recent years was taken into consideration for location of capacity. Based on historical trends, it is likely for standard, small, future demands to occur mostly in the eastern end of the system.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Ex. B, T2, Sch. 2

Questions:

a) Enbridge indicated that the DSM option was "eliminated in preliminary assessment of facility and non-facility alternatives" [Exhibit B, Tab 2, Schedule 2 Page 13]. Please provide a timeline for the planning and decision to replace the existing pipelines with a new pipeline and include the point in time the DSM analysis was conducted and option eliminated.

b) Options for replacement included a full range of pipeline sizes which would impact throughput capacity and project costs. Please provide a table of per meter project cost assumptions that Enbridge uses (or would reasonably use) to assess and compare the cost of various HP ST pipeline size options including the range of sizes from NPS 12 to NPS 4. Please make the table comparable to the costs in this application for the proposed NPS 6 and NPS 4 pipeline option selected.

c) If Enbridge could delay the replacement option by 5 years, would that change the ability to leverage other options such as DSM? If not, why not.

Response:

a) In spring and summer 2020 the various alternatives were reviewed in more detail. The DSM option was eliminated in early summer due to the expected cost of DSM versus the savings of downsizing the pipe size. The detailed cost for DSM was confirmed in August 2020.

b) Enbridge Gas does not maintain a table of per meter pipeline size pricing including the range of sizes from NPS 12 to NPS 4. Variations in cost per metre are significantly influenced by specific project scope parameters (such as rural or urban setting, rock excavation, local land costs, etc). Generally speaking, project managers often reference somewhat similar historic projects and/or request courtesy quotes for complex/unfamiliar work. Please also see Exhibit I.STAFF.11 c).

c) DSM relates to gas demand. The driver for this project is the integrity of the pipeline. DSM may reduce demand at some point but it will not alleviate or slow the degradation of the pipeline. Due to the integrity concerns, delaying the replacement of the London Lines is not an option and replacing the Existing Lines as proposed in the application is the most effective way of managing its ongoing safety and reliability. Please see Exhibit I.STAFF.13 a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Ex. B, T2, Sch. 2

The City of London is reducing greenhouse gas emissions by at least 30% by 2030 and reach net-zero by 2050. Actions are supplemental to Enbridge DSM efforts and will include initiatives such as making replacement heating systems be net-zero energy/emission by 2030.

Question:

Please explain how the City of London energy and emissions actions were taken into account during Enbridge modelling for this project.

Response:

Plans to reduce greenhouse gas emissions in the City of London were not considered in this project. This pipeline does not serve customers in the City of London.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Ex. B, T2, Sch. 4

“Enbridge Gas found that the cost of investment in sufficient supplemental DSM programming to reduce system demands by 359 m3/h was approximately $4.3 million over two years. This solution would only provide peak hourly system demand reductions sufficient to defer the need for the proposed project or a further pipeline expansion project by two years based on Enbridge Gas’s current demand forecasts”

Questions:

a) Please confirm that Enbridge uses the ‘measure life’ to determine the total natural gas savings from a measure under its DSM program (and related net benefits of net TRC). If that is not correct, please explain.

b) Please provide a list of the programs and related measure lives used to model the DSM scenario mentioned above.

c) It appears that the project modelling above may have assumed that the DSM results from the programs only last for the period where DSM spending occurs (e.g. 2 years in this case). Please confirm that assumption was used for this project or if not, please clarify what persistence assumption was used for the DSM results.

d) Enbridge indicates that the DSM scenario to reduce pipe size would costs approximately $1.2 million (4.3 [DSM costs] – 2.9 [pipe cost reduction]) more than the proposed project. Please provide an NPV calculation from the Ratepayer perspective for the DSM scenario including the following:
   - Initial capital costs/saving (net incremental cost of $1.2)
   - Cumulative energy and commodity savings from customers over the entire measure lives
   - Reduction in other costs (e.g. carbon price)

- Other costs/benefits that may be appropriate (please make these clear, including the discount rate used)
- For simplicity, feel free to ignore any incremental shareholder incentive that Enbridge would receive due to the DSM option.

Response:

(a) Confirmed, Enbridge Gas uses measure life to determine total natural gas savings (CCM) under its DSM program. The analysis in Exhibit B, Tab 2, Schedule 4 does not consider measure life in the assessment of relative growth rates.

(b) This high-level analysis used Achievable Potential Study[1] ("APS") Scenario B savings incremental to Scenario A to arrive at an estimate of total potential savings as a proportion of reference case volume within Union Gas South. This data was derived from APS Appendix 1. It was not determined what mix of measures would generate this savings.

(c) This analysis did not make any determination around persistence of savings beyond what is assumed in the APS cumulative yearly savings estimates.

(d) The high level DSM analysis that was conducted for the proposed project was supplied in order to be responsive to OEB direction in the 2015 – 2020 DSM Framework that as part of any utility application for a leave to construct of future infrastructure projects, "the gas utilities must provide evidence of how DSM has been considered as an alternative at the preliminary stage of project development". A process for the Board to develop an integrated resource planning ("IRP") framework (EB-2020-0091) which would consider scope of alternatives as one item and a cost benefit approach as another.

[1] http://www.ieso.ca/2019-conservation-achievable-potential-study

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Ex. B, T2, Sch. 4

Reference: Enbridge indicates that it has committed to “net zero greenhouse gas (GHG) emissions by 2050; with an interim target to reduce GHG emissions intensity 35% by 2030” [https://www.enbridge.com/about-us/our-values/sustainability].

Questions:

a) If this pipeline is approved and built, it will be in service well past 2050. Please explain how this new policy changes the way Enbridge plans for new natural gas pipelines such as the one proposed in this proceeding.

b) Does this policy mean net zero for just Enbridge operations or also in relation to the product (i.e. natural gas) that you distribute to end users? Please define the scope.

c) Does Enbridge measure the emissions from construction of projects like the proposed London Replacement Project and how do those emission related to the net zero emission goal?

d) Similarly, the City of London has announced goals to reduce London’s greenhouse gas emissions by at least 30% by 2030 and reach net-zero by 2050. Please explain if the City of London’s goals or actions were considered when planning for this project.

Response:

a) Enbridge Gas’s sustainability goals around greenhouse gas (GHG) emissions are in relation to scope 1 emissions, which are direct GHG emissions from sources that are owned or controlled by the Company, and scope 2 emissions, which are GHG emissions from the generation of purchased electricity consumed by the Company. The goals do not include scope 3 emissions, which are GHG emissions from customers' use of natural gas. As such, the GHG reduction goals do not impact the proposed project.

b) See response to part a) above.

c) Enbridge Gas estimates the GHG emissions from certain construction activities, including purging activities related to tying in new lines to existing lines, energizing new lines and abandonment of old lines. These GHG emissions are included in the Company's scope 1 emissions, and therefore fall under the scope of the GHG reduction targets. Other GHG emissions during construction, such as fuel use in construction vehicles are not included in the Company's scope 1 emissions. The Company attempts to minimize the release of natural gas during construction projects where possible, for example drawing down the pressure in the lines as low as possible, using a portable compressor to move gas to another line when available, and using flares or incinerators to combust the gas.

d) Please see Exhibit I.PP.9.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Ex. C, T1, Sch. 1

Enbridge indicates that it has committed to "net zero greenhouse gas (GHG) emissions by 2050; with an interim target to reduce GHG emissions intensity 35% by 2030" [https://www.enbridge.com/about-us/our-values/sustainability].

Questions:

a) Enbridge indicates that the Environmental Report was developed to conform with the OEB Environmental Guidelines for Location, Construction and Operation of Hydrocarbon Pipelines in Ontario, 7th Edition, 2016 ("Environmental Guidelines). Some requirements in the Environmental Guidelines relate to activities other than the Environmental Report. Does Enbridge commit that all aspects of this project will comply with the Environmental Guidelines? If not, please explain why not.

b) Enbridge indicates that "An Environmental Protection Plan (EPP) will be developed for the Project". An EPP is typically filed with the LTC application to provide clarity on the specific mitigation plan and residual net impacts. Please file a copy if it is ready and if not please explain why the OEB should consider the project without the EPP.

c) Please provide an update of what permits have been received and the status of outstanding permits.

d) Please provide a copy of any DSM-related materials that were provided during public consultation and education for this project.

Response:

a) Enbridge Gas confirms that the Environmental Report was developed to conform to the environmental guidelines related to gas facilities applications of hydrocarbon pipelines leave to construct applications under section 90 of the OEB act. The

Guidelines are designed to provide direction to the applicant in the preparation of a project's Environmental Report.

b) The Environmental Protection Plan (EPP) is typically developed at the time of detailed design. Enbridge Gas will develop an EPP during the detailed design phase which will include site specific environmental management, monitoring and contingency plans as well as general mitigation and contingency measures identified in the Environmental Report. Environmental permit and approval conditions will also be included in the EPP.

c) Please see Exhibit I.STAFF.7 a).

d) The principal objective of the environmental study is to identify, manage and document environmental impacts of proposed alternative pipeline routes and document the preferred route from an environmental and socio-economic perspective. Please refer to the Environment Report, filed at Exhibit C, Tab 2, Schedule 1, Section 2.0 Consultation Program and Appendix B Consultation for a review of the consultation program.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Ex. C, T2, Sch. 1

"Due to the size of the Environmental Report (ER) the ER can be found electronically on Enbridge Gas's company website under the Project Tabs at the following link: https://www.enbridgegas.com/About-Us"

Question:

a) In Leave to Construct proceedings the Environmental Report is an important part of the public record. In limited circumstances it has been difficult for Enbridge to load a copy of the Environmental Report via RESS and OEB Staff have helped to ensure it is in the Webdrawer under the proceeding number. Please file a copy of the Environmental Report or arrange for it to be added to by OEB Staff.

Response:

a) The Environmental Report can be found on the OEB Webdrawer under EB-2020-0192 (dated 2020-09-15). The document was filed in sections due to the size of the file.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Ex. C, T2, Sch. 1

Questions:

a) The Environmental Report published July 2020 indicates that the project consists of "approximately 75 kilometers (km) of Nominal Pipe Size (NPS) 8" high Pressure steel". Please explain the analysis timeline that led to a reduction to NPS 6/4 following the completing of the Environmental Report.

b) Please provide a copy of the Stantec contract and bid (if tendered) for this project.

c) The ER approach outlined that an early step was to "Identify interested and potentially affected parties early in the process". Please provide a copy of the list that was developed.

d) Please provide a copy of all OPCC and permit authority correspondence received since the ER was completed.

e) Please provide a list of all OPCC and permit authorities where a response has not been received by Enbridge.

f) Please confirm the closest distance that the proposed pipeline will be to a Provincially Significant Wetland. If this is within the Provincial Policy Statement buffer area, please confirm what approvals have been received.

g) If the proposed pipeline crosses a Provincially Significant Wetland, please estimate the total cumulative length that is involved.

Response:

a) The reduction in pipe size is due to reduction in the growth forecast. The initial design was sized to accommodate some large volume customers that withdrew their inquiries for gas service. In July 2020, it was confirmed that there were no open customer inquiries to be serviced by the London Lines and the proposed design was finalized. Also, in early July 2020, the Environmental Assessment draft was circulated for internal review at Enbridge Gas. The approval of the scope change and the finalization of the Environmental Assessment occurred in parallel within days of each other. As the reduction in pipe size did not change the study area and reduced the footprint of the gas main on the land, it was determined that the results of the Environmental Assessment was not affected and, an addendum to the Environmental Report was not required and the size change was not incorporated, but would be addressed in the LTC filing.

b) Stantec Consulting Inc. provided the following response in regards to their contract and bid 'As per our agreement with Enbridge, Stantec's professional duties and our standard practice, such documents are considered confidential and proprietary so we respectively decline to disclose those documents.'

c) Please refer to the Environmental Report, filed at Exhibit C, Tab 2, Schedule 1, Appendix B1 for the contact list.

d) Please see Exhibit I.STAFF.5.

e) Please see Exhibit I.STAFF.5.

f) The majority of the Preferred Route is located within existing road allowances. The total distance of the Preferred Route that is adjacent to Provincially Significant Wetlands is 1,400.5 m and these areas are all within existing road allowances. The Conservation Authority permit applications are being prepared for all areas of the Preferred Route which intersect with Conservation Authority regulated lands. This includes applications to St. Clair Region Conservation Authority under O.Reg171/06, to Upper Thames Conservation Authority under O.Reg. 157/06 and to Lower Thames Conservation Authority under O.Reg.152/06.

g) Please see response to part f).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Ex. F, T1, Sch. 1

Questions:

a) Enbridge indicates that it will be seeking capital approval for this project in its 2021 IRM application, but then goes on to indicate that the “Enbridge Leave to Construct (“LTC”) seeks approval for the mainline costs of $95.2 million as shown at Exhibit F, Tab 2, Schedule 1, Line 5. Enbridge Gas is not seeking approval for the ancillary facilities’ costs (i.e. stations, services, abandonment) in this application.” Please confirm that Enbridge is not requesting any OEB capital approvals in this proceeding and that capital approvals would be part of EB- 2020-0181. If this is not correct, please explain.

b) Please provide a table of all costs related (only) to the Project as defined in this application (i.e. not including abandonment costs, etc.).

c) If the OEB does not approve costs related to this Project or the ancillary facilities in EB-2020-0181, what would be the outcome?

Response:

a) Please see Exhibit I.STAFF.11 a).

b) Estimated incremental Project capital costs for the mainline only as seen at Exhibit F, Tab 2, Schedule 1 are:

Line No.	Particulars ($000's)	Mainline
1	Materials	5,616
2	Construction and Labour	77,321
3	Contingencies	11,402
4	Interest During Construction	867
5	Estimated Incremental Project Capital Costs	95,206

c) Please see Exhibit I.APPrO.8.

PURPOSE, NEED, PROPOSED FACILITIES & TIMING

Introduction

1. Enbridge Gas Inc. ("Enbridge Gas" or the “Company”) has identified the need to replace the existing London Lines (“Existing Lines”) through County of Lambton, the Township of Dawn-Euphemia, Middlesex County, the Municipality of Southwest Middlesex, the Municipality of Strathroy-Caradoc and the Municipality of Middlesex Centre (“London Line Replacement Project”, “Proposed Pipeline” or the “Project”). Pursuant to Section 90. (1) and Section 97 of the *Ontario Energy Board Act* (“the Act”), Enbridge Gas requests approval from the Ontario Energy Board (the “Board” or “OEB”) for leave to construct approximately 51.5 kilometres of NPS 4 and 39 kilometres of NPS 6 hydrocarbon (natural gas) pipeline to replace the Existing Lines. Exhibit A, Tab 2, Schedule 2 shows the location of the Project.

2. The Existing Lines comprise the London South Line and London Dominion Line which are two pipelines that are parallel to each other, approximately 60 km and 75 km in length, respectively. These pipelines include pipe segments that are NPS 8, 10 and 12 with a maximum operating pressure (“MOP”) of 1900 kPa (275 psig). The existing London Lines are Enbridge Gas high pressure distribution lines that extend from the Dawn Compressor Station (“Dawn”) at Dawn South London Lines Station, located near Sarnia to Komoka Station, located near Komoka. Figure 1 shows the year of installation and coating used in the Existing Lines. Small replacements have been made along the pipelines, meaning that there are small areas where the coating/age of the pipe may differ.

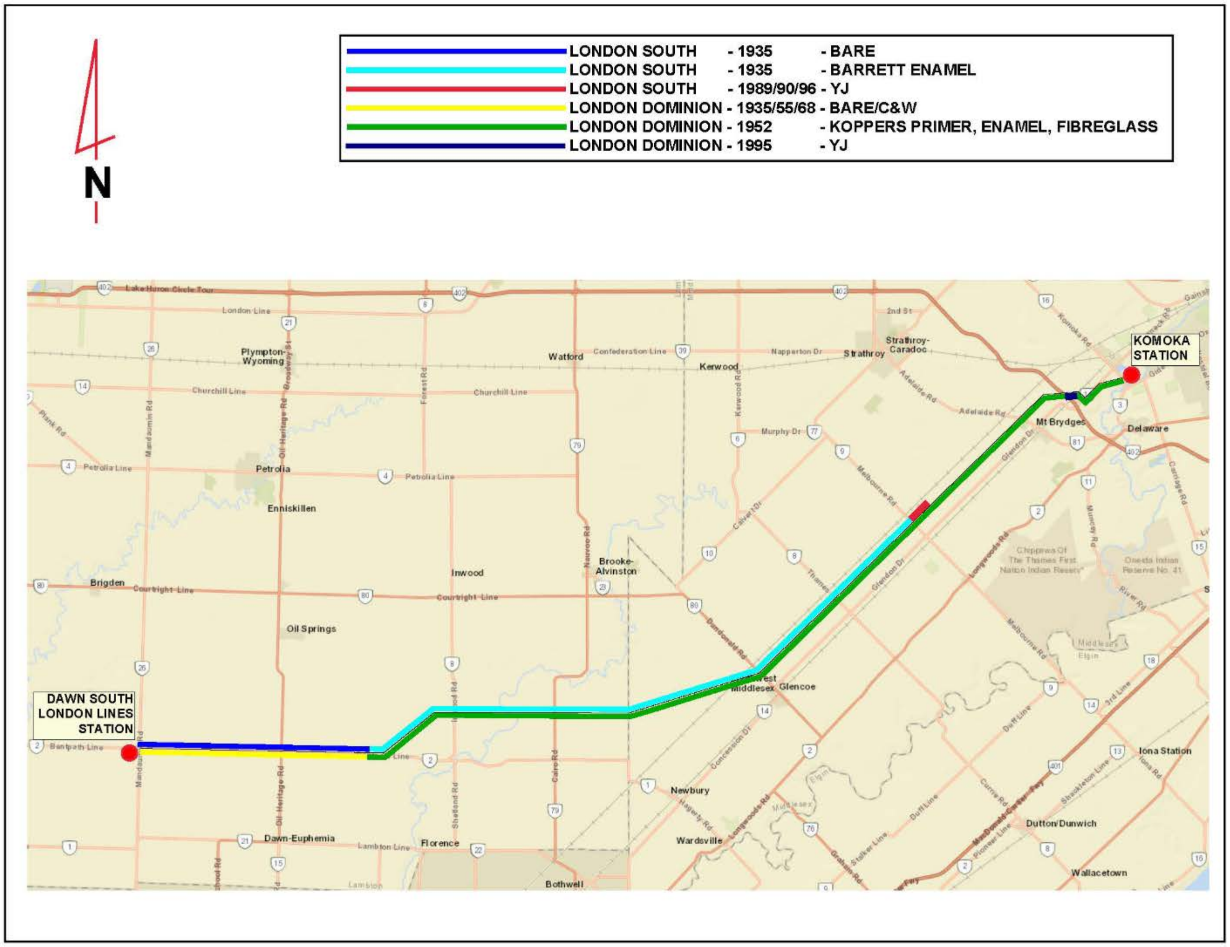


Figure 1: Graphical depiction of the year of installation and coating of the pipelines.

Purpose and Need

Condition of the Existing Line

3. The London Lines represent some of the oldest pipe in the legacy Union Gas network, accounting for nearly 135 km of the 384 km (35%) of the oldest pipe in the system (pre-1950 installation) and consists of 62 km of bare steel pipe (18% of the total bare steel pipe population).

4. Enbridge Gas's Distribution Integrity Management Program ("DIMP") continually evaluates assets to identify risks and determine the condition of pipelines in the distribution network. Analysis conducted by Enbridge Gas has shown that the existing London Lines are in poor condition and have several active degradation factors, including loss of containment, shallow depth of cover, and corrosion induced wall loss. Based on the results of the assessments, discussed further in Exhibit B, Tab 2, Schedule 1, Enbridge Gas has identified that the Existing Lines are an operational risk and should be replaced to manage the safety and reliability of the natural gas distribution in this area.

Physical Characteristics

5. The London South Line was originally installed in 1935. As shown in Figure 1, sections have been abandoned and replaced, and the line is currently comprised of approximately 15 km of NPS 8 bare steel pipe (grade 165, 7.0 mm wall thickness), approximately 43 km of NPS 10 coated steel pipe (grade 165, 7.0 mm wall thickness), and approximately 1 km of NPS 12 coated steel pipe (grade 290, sections of 5.6 mm and 9.5 mm wall thickness). The construction practice in place in 1935 used unrestrained compression couplings to connect pipe segments. Based on typical pipe segment lengths (12 m or 40 ft), there could be in excess of 6,000 unrestrained compression couplings.

6. Compression couplings (mechanical fittings not welded onto the main) that are not properly restrained could cause a loss of containment, such as a pipeline leak or failure, due to exposed points of thrust. Enbridge Gas has mitigation

practices in place to address existing known compression couplings when they are discovered. Some vintage gas mains, such as the London Lines, do not have sufficient records identifying the existence and location of these fittings.

7. Compression couplings are known to provide minimal pull-out resistance, and depending on design, could cathodically isolate pipe. They are also a source of leaks especially if there is ground movement or large temperature fluctuations such as freeze/thaw cycles.

8. Compression couplings are held in place by the weight of the soil. When the soil is disturbed, for example as a result of reduced depth of cover or via freeze/thaw of the surrounding soil, due to the fitting's minimal pull-out resistance, the pipe can shift or pull out of the fitting, resulting in gas escaping through the open pipe end.

9. Compression couplings on steel mains that are unknowingly isolated from the corrosion protection system could result in inadequate cathodic protection, leading to accelerated corrosion and potential loss of containment. The Existing Lines have experienced significant corrosion on the barrels of the compression couplings, further compromising their integrity and creating leaks.

10. The London Dominion Line was originally installed in 1936 but the majority of the line was subsequently replaced in 1952 using reclaimed and refurbished pipe from the 1920s and 1930s vintages (unknown grade, 5.6 mm wall thickness). Records indicate that the pipe used for reclaimation had multiple instances of laminations along with surface corrosion resulting in flaking of the pipe. Pipeline flaking can lead to coating disbondment during application thereby affecting the integrity of the coating. The replaced pipeline (1952) used a welded construction.

The Dominion Line is currently comprised of approximately 41 km of NPS 8 steel pipe, approximately 31 km of NPS 10 coated steel pipe and approximately 1.5 km of NPS 12 coated steel pipe. Similar to the London South Line, cathodic protection was first introduced in 1965. There is a 10 km section of the London Dominion Line that was originally installed in 1936 (unknown grade, 7.0 mm wall thickness) that is still in service and is bare steel pipe.

11. During the original 1935 London South and 1936/52 London Dominion Line installation, there were no records to confirm that a pressure test was completed. A project was initiated in 1956 to pressure test a large portion of the existing London Lines. Records of such test are incomplete. It is unknown what pressure test medium or duration was used.

Condition Assessment

12. Canadian Standards Association (CSA) standard Z662 provides guidance on when a pipeline operator should address pipeline integrity and condition concerns. It is the responsibility of the pipeline operator, in this case Enbridge Gas, to monitor the condition of its pipeline assets and compare the condition of those assets to the guidance set out in CSA Z662. Should the condition of a pipeline be such that it creates a risk pursuant to CSA Z662 guidance, the pipeline operator must address the condition of the pipeline. Enbridge Gas's Integrity Management Program incorporates the guidance set out in CSA Z662. Pipeline condition will typically be addressed via repairs or replacement. In the case of the London Lines, Enbridge Gas has determined, for the reasons set out later in this evidence, that the Existing Lines segment should be replaced.

Loss of Containment

13. As indicated above, the Existing Lines have several active degradation factors. The most predominant degradation issue is external corrosion resulting in loss of containment. Enbridge Gas classifies loss of containment using Class A, B and C levels. Class A Leaks are required to be repaired immediately. Class B Leaks are required to be repaired within a short amount of time. Class C Leaks are to be monitored at a regular frequency to identify any changes in leak rate. Class C Leaks are typically dependent on external factors (i.e., temperature, ground settlement, and others). Depending on conditions at the time of leak survey, the location of the Class C Leak may vary.

14. Since 2011, records indicate that 29 Class A or Class B Leaks have been repaired, and a leak survey completed in 2020 found an additional 5 active Class C Leaks. The extensive amount of compression couplings also leads to the development of Class C Leaks from ground settlement and frost heave. Although there are currently 5 active Class C Leaks, Enbridge Gas has been monitoring as many as 29 active Class C Leaks since 2013. The London Lines between 2013 and 2019 had a leak rate of 0.043 leaks/km/year, which is over 10 times greater /U
than the available average leak rate for the steel main population.

15. Due to the vintage, the quality of steel pipe and the general deteriorating conditions, the London Lines have not consistently operated near MOP of 1900 kPa for some time. The London Lines currently operate at a MOP of 1415 kPa to reduce the number of leaks.

16. Left unaddressed the deteriorating condition of the London Lines will result in additional leaks. The wall loss due to historical corrosion and large number of unrestrained compression couplings, including those with corrosion issues, present an increasing likelihood of loss of containment.

17. As Figures 2, 3, and 4 and the Assessment in Exhibit B, Tab 2, Schedule 2 show, the condition across the entirety of the London Lines identifies the need to replace the Existing Lines and that localized repairs would not be an efficient use of resources due to the challenges with making repairs to the Existing Lines as outlined in the *Consequences of Failure* section below.

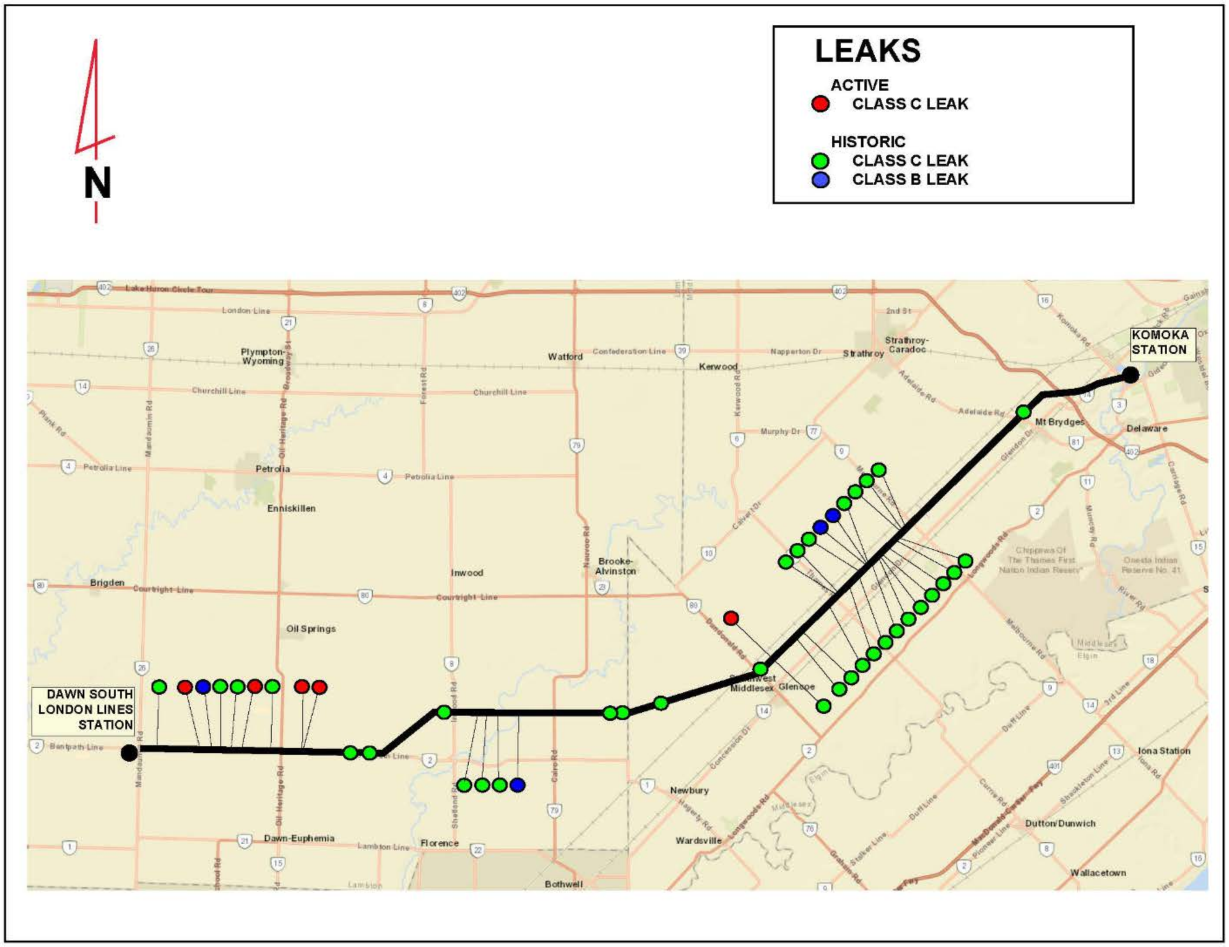


Figure 2: Active and Historical Leaks on the London Lines

Depth of Cover

18. Depth of cover is another significant risk driver. A depth of cover survey completed in June 2020 recorded measurements taken at regular intervals across the entire length of the London Lines. A summary of this data is shown in Figure 3. The figure identifies areas of the London Lines where incident of reduced depth of cover most like to occur. The study found 1067 measurement

locations of the total 6671 measurements taken (16% of the measurements) had a depth of cover measurement of 0.60 m or less[1].

19. Further analysis of the data shows that the areas where the pipe is within Agricultural land use (approximately 63% of the measurements), 85% of the measurements did not meet the minimum internal standard[2] for depth of cover to protect against heavy cultivation damage.

20. It should be noted that over 36% of the London Lines has a depth of cover less than 0.75 m[3]. Based on correlation models Enbridge Gas has performed with historical third party damages, it is predicted that the likelihood for damages has increased based on the reduced depth of cover for this system. For example, the modeling predicts a 22% increase in likelihood of a third party damage when comparing a depth of cover of 0.75 m versus 0.60 m.

21. Meeting the minimum depth of cover requirement provides protection for the pipeline from typical activities while providing sufficiently convenient access for Enbridge Gas maintenance and construction activities. Third party damages trigger repair work which, as discussed in *Consequences of Failure*, is becoming increasely resource-intensive, costly and time-consuming.

---

[1] As per the CSA Z662-15 Sect 12.4.7, Table 12.2, the minimum requirement standard for pipe is 0.60 m
[2] The minimum intenal standard for depth of cover for pipeline running in agricultural land is 1.2 m
[3] As per Enbridge Gas Construction and Maintenance Manual, the minimum depth of cover for a proposed pipeline in the untraveled portion of the road right-of-way is 0.75 m

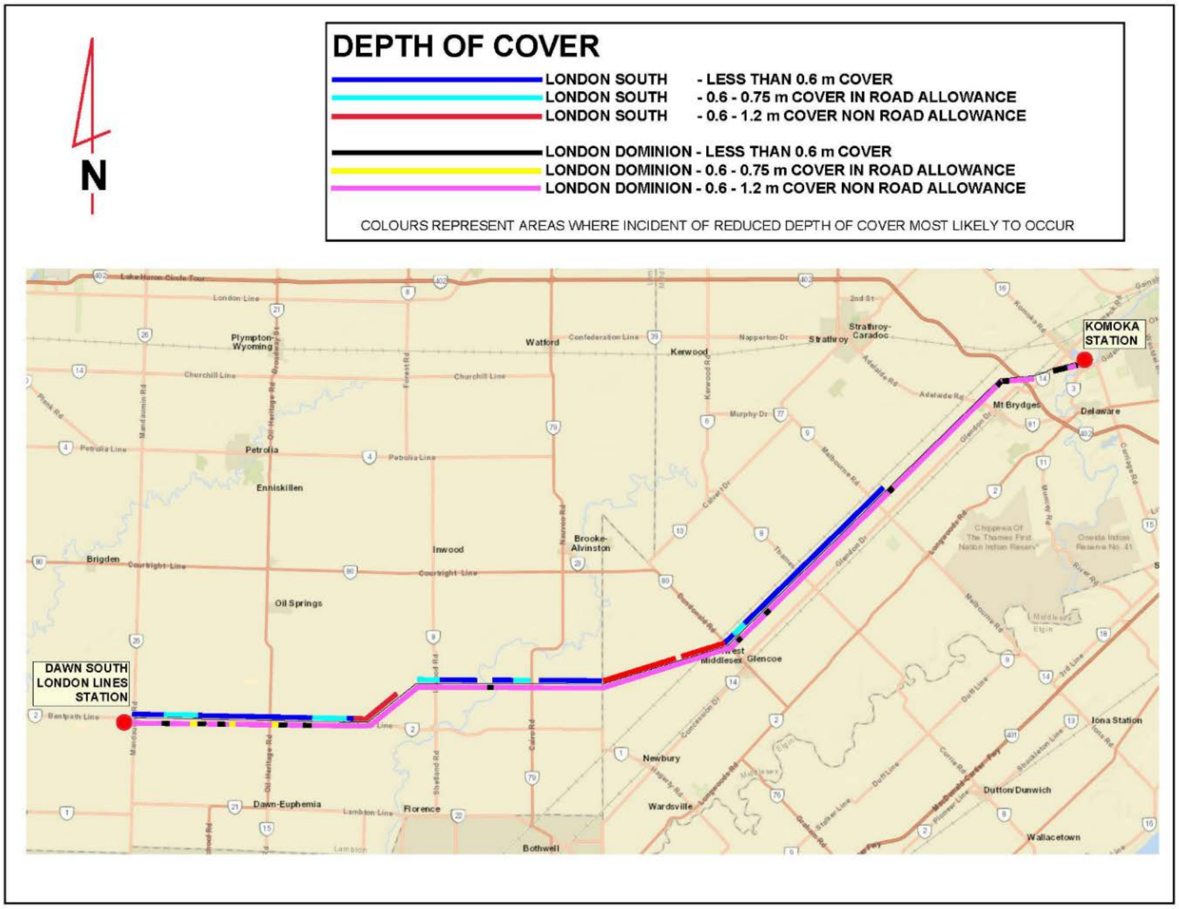


Figure 3: Visualization of the depth of cover of the mains, as collected during the 2020 Depth of Cover Survey.

22. The depth of cover of a pipeline also impacts the safe embedment distance required to safely work on a pipeline that is constructed using unrestrained compression couplings. The safe embedment distance is the distance at which the force at the exposed point of thrust is balanced by the sum of the pullout resistance plus the soil resistance.

23. A reduced depth of cover reduces the soil resistance thereby meaning a smaller thrust force is necessary to cause compression coupling pullout when the pipeline is exposed. A compression coupling pullout could cause loss of containment and potential severe health and safety consequences.

24. A consequence of reduced depth of cover is that a larger safe embedment distance from the unrestrained compression coupling is required before being able to safely expose the pipeline which limits repair location options.

25. Pipelines constructed using unrestrained compression couplings and with a reduced depth of cover, such as the London Lines, limits the Company's ability to complete a repair safely, efficiently and cost-effectively.

26. The reduced depth of cover concern of the London Lines was raised through Environmental Assessment Consultation which is provided in Exhibit C, Tab 2, Schedule 1.

27. Additionally, 53 aerial crossings, shown in Figure 4, were noted over ditches, river crossings, in agricultural fields and other locations. These aerial crossings are further complicated with added risk associated with bank erosion, debris strikes and potential vandalism concerns. Photos taken during the 2020 Depth of Cover Survey are included as Attachment 1. The photos show examples of the crossings' close proximity to the road, partial submersion at the drains, rusty exposed fittings as well as deteriorating coating.

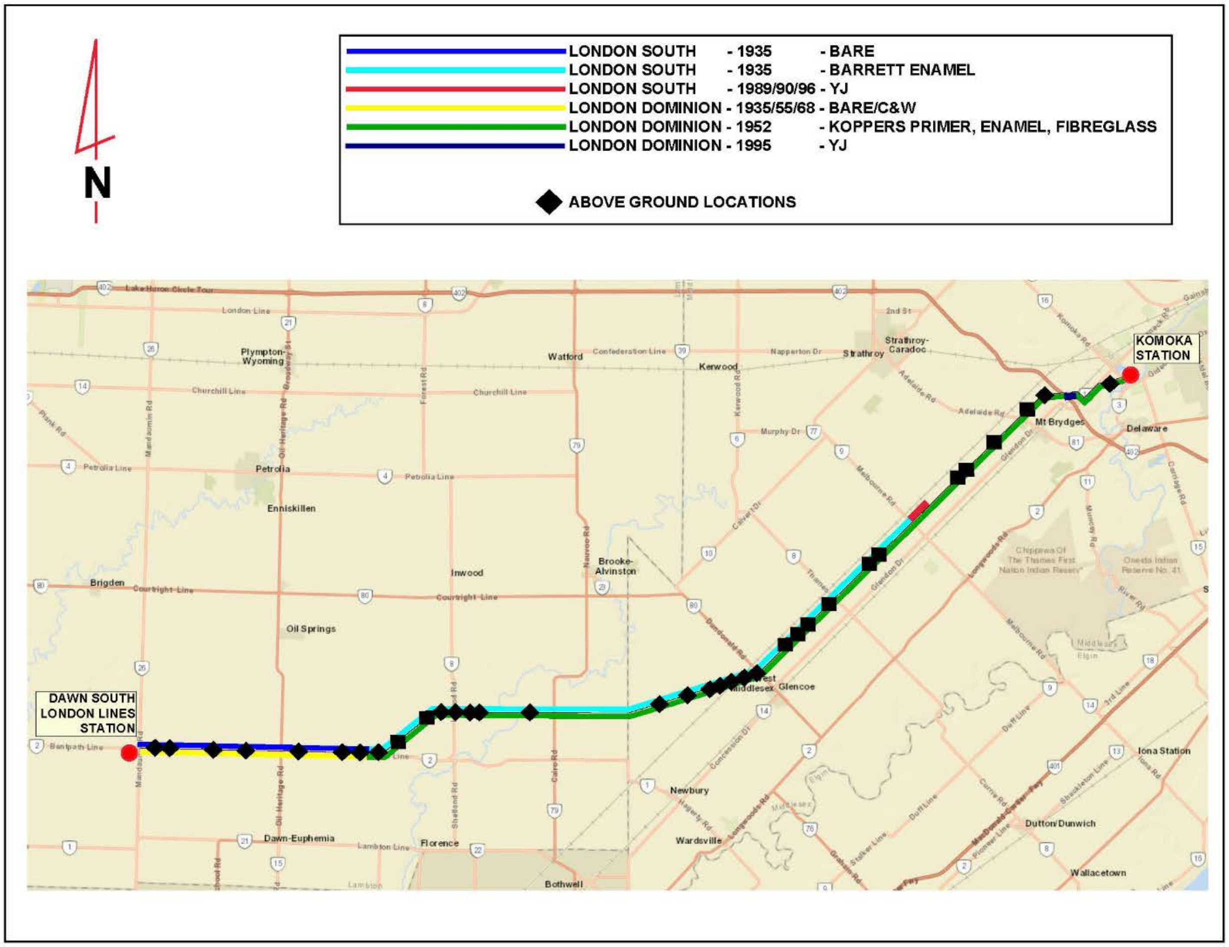


Figure 4: Locations of Above Ground Pipe, collected as part of the 2020 Depth of Cover survey

Corrosion

28. Wall loss due to corrosion has caused issues when welding work is needed on the London Lines, including for connecting new laterals to communities, for new customer service connections and for any required repair work. Cathodic Protection was not introduced until 1965. Bare pipe typically requires higher current for its Cathodic Protection due to the large amount of exposed steel.

Feedback gathered by the Company shows consistently high amounts of corrosion across many lengths of pipe which indicate that there is difficulty to find a section of pipe which is acceptable to weld on when work is required to be completed on the London Lines. This could be caused by the initial lack of Cathodic Protection prior to 1965 or intermittent drops in Cathodic Protection levels due to power interruptions or soil conditions. From Dawn South London Lines Station to Komoka Station, the London Lines are currently covered by Cathodic Protection.

29. Leak repairs are becoming more difficult due to the degradation of the pipe. For example, a Class A Leak repair in 2019 found that a first stage cut broke away from the main due to corrosion and weight of the soil as excavation was proceeding to expose the leak. Further complications arose in trying to find an adequate location to install a stopper fitting to perform the repair, as there were numerous corrosion pits preventing welding of the stopper fitting. In 2020, the Company was attempting to abandon a service when it discovered visible external corrosion pitting. Non-destructive testing analysis by a third party showed 40% wall loss.

Risk Based Assessment

30. Enbridge Gas uses a clear framework for asset investment decision-making which balances risk, cost and performance throughout the asset life cycle. Decisions are made using the support of assessments of asset condition and risk. Over the life cycle of an asset, a spectrum of Risk Treatment options are applied based on the identified maintenance strategy for the asset. As the asset progresses through its life cycle, the probability and consequence of failure

inform maintain versus renewal/retire decisions. The recent Risk Assessment performed on the London Lines showed that the imbalance between risk, cost and performance supports a move away from maintaining these assets and more towards renewal of the assets, as they are nearing end-of-life.

31. The internal risk assessment performed on the London Lines shows the system has a medium risk rating on the Enbridge Standardized Operational 7X7 risk matrix when considering the lenses of the Health and Safety, Customer Loss, Financial and Reputational risks. The risk assessment also identified that some segments of the London Lines have a high risk rating for Customer Loss. This is primarily for sections where the twin pipelines cannot be isolated independently to effectively manage customer outages on the system. This risk assessment was reviewed and agreed to by the appropriate Enbridge Gas technical and management personnel for the London Lines project. Exhibit B, Tab 2, Schedule 1 shows the Integrity Assessment that was completed to explain the pipeline integrity concerns in further detail.

Consequence of a Failure

32. The London Lines operate at less than 30% of the specific minimum yield stress, so a leak is the most likely failure mode. Due to the condition of the pipeline, the risk of failure of the pipe could have various effects depending on the location of the failure.

33. Customer Loss is a significant consequence, particularly for sections where the twin pipelines cannot be isolated independently to effectively manage customer outages on the system. Should the lines experience a loss of containment, the

repair would be challenging due to the lack of records that exist for the line. It is not clear what will be uncovered as various pipe materials and coatings that comprise the existing London Lines. These unknowns (quality of pipe material, coating, construction methods) create additional complexity, discussed below.

34. Additionally, due to the quality of the reclaimed pipeline, it is challenging to find a section of pipeline that is weldable as the flaking pipe material is not suitable for welding. It is possible for multiple or larger excavations would be required in order to uncover a segment of pipe that is weldable.

35. The pipeline segments constructed via compression couplings pose a challenge due to the large safe embedment distances required to expose these sections of main. Due to the uncertainty in the quality of the pipe that is exposed, the scale of the repair grows and becomes more time-intensive and costly.

36. The number of integrity issues and possible failure modes causes public and worker safety concerns. The exposed sections of main and reoccurring leaks also lead to community concerns. Reoccurring leaks could lead to dead vegetation and exposed sections of main could disrupt some farming activities.

37. Through comprehensive asset planning, Enbridge Gas has identified and prioritized expenditures over a long-term horizon, ensuring funds are appropriately allocated to maintain the safe and reliable delivery of natural gas to its customers. The London Lines is on the list of prioritized projects, as identified in Enbridge Gas's Asset Management Plan. Replacing these pipelines is essential in managing the reliability and safety of the system.

38. Upon placing the Project in-service, Enbridge Gas will de-commission the existing pipelines and restore affected lands to the appropriate state. The abandonment of the pipelines currently in municipal road allowance will follow requirements in the respective municipal franchise agreement. For the pipelines in easement, easement agreements will be followed and landowner input will be sought.

Proposed Facilities

39. The Project is a replacement of the entirety of the existing London Lines pipelines. Based on the concerns detailed above, the London Lines have been deemed an operational risk and replacing the Existing Lines is the most effective way of managing its ongoing safety and reliability.

40. A System Design Criteria Report can be found at Exhibit B, Tab 2, Schedule 2. This report describes the current state of the pipeline system and reviews the alternatives considered for the Project. Enbridge Gas also reviewed the alternative of implementing supplemental Demand Side Management (“DSM”) and Integrated Resource Planning (“IRP”) for customers along the London Lines in order to defer, avoid or reduce the scale of this replacement project. Further details on the alternatives considered and the option of implementing supplemental DSM and IRP can be found at Exhibit B, Tab 2, Schedule 5 and Exhibit B, Tab 2, Schedule 4 respectively.

41. As shown in the System Design Criteria Report, the pipe sizes, the lengths of pipe at these sizes, and maximum operating pressure (“MOP”) of the Project have been designed to match the current demand of the London Lines.

42. The Project will, for the majority of the route, follow the routing of the existing pipelines to ensure customers and communities along the route can easily be connected to the new main. For the locations where the pipeline is being relocated from private easement to municipal road allowance, this relocation will allow for easier access to the pipeline for future service connections, and operations and maintenance work. Locating the pipeline in municipal road allowance also increases the accessibility of gas for any customers along the new route. Any customers connected to the existing pipeline in an easement will have their service relocated to the new pipeline as part of the project.

43. The Existing Lines are located in both municipal road allowance and private easement. This existing easement and new easement is required for the Project. Negotiations with landowners for new easements in which the pipeline will be located will be initiated, as described further in Exhibit E in this application. On placing the Project into service and decommissioning the existing facilities (including removal and restoration efforts), the majority of the existing easement, except along Bentpath Line will no longer be required.

44. The Project involves construction of 39 km of new NPS 6 pipeline with a wall thickness of 4.8 mm and grade 290 MPa (min) and 51.5 km of new NPS 4 pipeline with a wall thickness of 4.8 mm and grade 290 MPa (min). Once the proposed pipeline is successfully hydrotested and is operational, the Existing Lines will be abandoned. The abandonment of the pipelines currently in municipal road allowance will follow agreements in the respective municipal franchise agreement. For the pipelines in easement, easement agreements will be followed and landowner input will be sought.

45. There are 135 services and 25 stations that will be upgraded and nine new stations installed to facilitate the new proposed pipeline pressure. In areas where it is not practical to remove the existing pipeline it will be abandoned in place. Areas where abandonment in place is likely to occur will be road crossings and water crossings. The 53 aerial crossings identified above in Figure 4 will be abandoned and removed. The TSSA abandonment guidelines and the applicable adopted edition of CSA Z662 will be followed for all pipelines abandoned in place. The service connections and service lines will be a mixture of NPS 1-1/4 to 1 steel depending on the load of the customer and length of service. Each service will run from the mainline connection to the building where it is delivering natural gas. For services connected to the 3447 kPa mainline, the service will be steel until the first stage pressure regulating cut. The remainder of the service could be steel or plastic. /U

46. There are seven services that are connected to the pipeline that is running through easement. The Proposed Pipeline will be installed in a new location, in road allowance. To provide delivery of gas to these customers, short sections of plastic pipe will be used to attached the customer to the Proposed Pipeline, a nearby intermediate pressure ("IP") system or a new IP network.

47. The Proposed Pipeline will be 15.1 km of NPS 6 along Bentpath Line (County of Lambton road in the Township of Dawn-Euphemia) from the tie-in at Dawn to the inlet of Oakdale Header Station. From the outlet of Oakdale Header station, the Proposed Pipeline will be NPS 4 and run for 51.5 km along Bentpath Line, Driessens Line, Forest Road, Mosside Line, Watterworth Road (County of Lambton, Township of Dawn-Euphemia), Argyll Drive, Big Bend Road, Oilfield Road, Pratt Siding Road, CPR Drive, Dundonald Road, Falconbridge Drive

(Middlesex County, Municipality of Southwest Middlesex) to a new valve site at the intersection of Sutherland Drive and Falconbridge Drive (Middlesex County, Municipality of Strathroy-Caradoc). The outlet of the new valve site at the intersection of Sutherland Road and Falconbridge Drive will begin 15.5 km of NPS 6 pipe that will run along Falconbridge Drive, Avro Drive, Amiens Road, (Middlesex County, Municipalty of Strathroy-Caradoc), Glendon Drive, Komoka Road (Middlesex County, Municipality of Middlesex Centre). The NPS 6 pipeline will tie into Komoka Station, located on Komoka Road.

48. A new Pipeline is also proposed to start at Strathroy Gate Station (Calvert Drive, Municipality of Strathroy-Caradoc). It will be NPS 6 and run for 8.4 km along Sutherland Road. At the intersection of Sutherland Road and Falconbridge Drive, it will tie into the NPS 6 main. This pipeline will provide a back-feed to the London Line corridor by adding a secondary feed from the Dawn to Parkway System via Strathroy Gate Station. This back-feed also provides the opportunity to install a smaller pipe size for the replacement, and provides operational flexibility in the future.

49. The pipeline will be placed in the existing easements starting from the west end of the Project for a distance of 15.1 km. The remainder of the pipeline will be placed in the municipal road allowance. At the intersection of Glendon and Komoka, 200 m of NPS 6 pipeline will be installed in private easement to avoid installing in the intersection; this will accommodate the future widening of Glendon and the installation of a roundabout at the intersection. This work was raised by staff at Middlesex County and with this routing selection, Enbridge Gas is attempting to minimize or eliminate future relocations due to the County’s planned work.

50. The total estimated cost of the Project is approximately $164.1 million. This total includes indirect overheads. Without indirect overheads included, the total estimated cost is $133.9 million. The proposed Leave to Construct application seeks approval for the mainline costs of $95.2 million as shown in the project economics filed at Exhibit F of this application.

51. Enbridge Gas has completed an Environmental Report for the Project, which is filed as Exhibit C, Tab 2, Schedule 1. The Environmental Report did not identify any long term significant environmental impacts as a result of the Project.

52. Enbridge Gas contacted the Ontario Ministry of Energy, Northern Development and Mines (“MENDM”) to determine if there are any Duty to Consult requirements for the Project. The details of Enbridge Gas’ correspondence with the MENDM and the consultation process can be found in Exhibit G, Tab 1, Schedule 1.

Timing

53. If the Project is approved, Enbridge Gas would install the new pipeline between May 2021 and December 2021. Abandonment of the existing pipelinesand site restoration would occur during 2022.

INTEGRITY AND RISK ASSESSMENT

INTEGRITY ASSESSMENT

1. Enbridge Gas's Distribution Integrity Management Program ("DIMP") continually evaluates assets to identify hazards and determine the condition and risk of pipelines in the distribution network. An integrity assessment (Attachment 1) was recently conducted on the London Lines as part of the proposed Replacement Project. The integrity assessment included review of the pipeline demographics, cathodic protection, depth of cover, historical failures, and a comparative analysis with respect to the the Windsor Line Replacement Project which was previously approved by the OEB and is currently under construction.

2. Population: The London Lines represent 35% of pre-1950 installation pipes in the legacy Union Gas network and 18% of the total bare steel pipe population within the legacy Union Gas network. It should be noted that the Windsor Line, a pipeline that is similar in vintage, condition and risk raking, comprised of only 0.02% of bare pipe within the same system. Overall, the London Lines is primarily comprised of vintage steel pipes which were fabricated prior to 1970s. Vintage steel pipes (pre-1970s) have known quality issues with respect to manufacturing and material specifications which include laminations[1], inadequate toughness values[2], and selective seam weld corrosion[3].

[1] Lamination is a defect found in the vintage steel pipes which forms a laminar disbondment within the pipe wall.
[2] Toughness is a mechanical property of steel that refers to ability of a metal to deform plastically and to absorb energy before fracture.
[3] Selective seam corrosion is a localized corrosion that occurs axially and along the weld line of electric resistance welded (ERW) pipes.

3. Compression Couplings: Compression couplings that are not properly restrained through the installation of a pressure containment sleeve or strapping could cause a loss of containment and potential for severe health and safety consequence due to exposed points of thrust. Moreover, compression couplings are known to provide minimal to no mechanical resistance to pullout and can leak due to ground and pipe movement.

4. Compression couplings on steel mains that unknowingly isolate the corrosion protection system could result in inadequate cathodic protection, leading to accelerated corrosion and potential loss of containment.

5. The population records indicate that there could potentially be in excess of 6,000 unrestrained compression couplings on the London Lines based upon the use of assumed 40 foot lengths of pipe. The London Lines represents 30% of the steel mains constructed with compression couplings (‘coupled steel mains’) within the legacy Union Gas network. This is in comparison to Windsor Lines which represents 12% of all coupled steel mains.

6. It is noteworthy that compression coupling (or compression style repair clamps) leaks account for 38% of the leak repairs on the London Lines between 2011 and 2019. Feedback from experienced field personnel at Enbridge Gas indicates that the barrels of the compression couplings corrode at a higher rate than the surrounding pipe they connect. This suggests that the compression coupling could be unknowingly isolated from the corrosion protection system and as such the cathodic protection of the piping does not protect the compression couplings fitting.

7. Failures: External corrosion is a dynamic hazard to the integrity of underground pipeline systems. Corrosion penetration reduces the residual strength of affected

pipes due to wall loss, and therefore, increases the likelihood of the failure over time. A repair summary report created in June 2020 indicated a total of 29 leak repairs between 2011 and 2019 for London Lines. The repair summary report indicates 38% of repairs since 2011 were due to compression couplings or repair clamps used for previous repairs, whereas 17% of repairs could be attributed to corrosion leaks. This is in part attributable to the fact that feedback from experienced field personnel at Enbridge Gas indicates corrosion is the most common cause of leak failures in the London Lines. Furthermore, review of historical failures indicated that between 2013 and 2019, the London Lines had a leak rate of 0.043 leaks/km/year, which is over 10 times greater than the available /U average leak rate for the steel main population within Enbridge Gas's distribution system.

8. Depth of Cover and Exposed Piping: Natural Gas Pipelines are installed to meet or exceed applicable minimum regulatory requirements at the time of construction. In some instances, cover may be altered due to excavation activities, erosion, construction, flooding, ground subsidence or other environment factors or human intervention. Over time this can increase the risk of third party damages (constructors believing there is more cover than what is actually there) as well as jeopardize the pipeline in high traffic areas through weight transfer of large vehicles and heavy equipment moving over top of a pipeline. Depth of cover also plays a role with the safe embedment distance pertaining to compression couplings and the restraining points of thrust. Enbridge Gas minimum depth is 0.75 m and CSA Z662-15 minimum depth is 0.6 m. A recent depth of cover survey (June 2020) indicated the occurrence of 53 sites of exposed piping on the London Lines and that 15% of depth of cover readings had a measurement of less than 0.6 m with an average depth of 0.48 m. As noted, a depth of cover of 0.6 m is the current standard for

distribution piping on private property for distribution lines.[4] Based on the third party hit frequency model developed by Enbridge Gas for distribution assets there is a 20% increase in third party hit frequency when the depth of cover is 0.48 m versus 0.6 m.

9. In conclusion, based upon the available data and information at this time, the London Lines represent some of the oldest and most vulnerable steel assets within the legacy Union Gas distribution network. Additionally, analysis conducted by Enbridge Gas's DIMP has shown that the London Lines are in poor condition and have several active degradation factors, including much higher rates of loss of containment, shallow depth of cover, and corrosion induced wall loss. As such, from a condition standpoint, the replacement of the London Lines is supported by the DIMP.

RISK ASSESSMENT

1. For the London Lines, a qualitative risk assessment was completed using the Enbridge Standardized Operational 7X7 risk matrix. The risk assessment followed the Enbridge Framework Standard – Risk Management and the GDS Procedure Hazard Identification and Risk Assessment for Common Register. For the purposes of the risk assessment, the pipeline was segmented into sections of comparable condition. The applicable risk information was documented for each section. This information included possible failure modes, causes, applicable controls and possible consequences. This information was used to asses the likelihood and consequence of each failure mode for each of

[4] The criteria for depth of cover is in reference to CSA Z662-15 Section 12.4.7, Table 12.2

the selected pipeline segments. The assessment was competed in a structured and systemic style using a “what if” workshop style approach.

2. The risk assessment was completed via three primary reviews. In the initial risk workshop, information was gathered to build out the risk scenarios, document existing controls and initially assess the risk. This risk workshop was followed by information gathering to further assess the risk scenarios identified in the workshop. This information gathering included an updated leak survey, an updated depth of cover survey, interviews with additional operations personnel and a review of pipe condition information. The GDS risk specialist compiled the information to complete the draft of the risk scenarios and risk rankings. A second risk review was held and the draft of the risk scenarios and the supporting information were reviewed and assessed to finalize the risk assessment. The third and final risk review was held with the London Lines Project Operating Committee. The purpose of the review with the London Lines Project Operating Committee was to request sign-off and approval of the risk assessment process and summary. The Operating Committee provided sign-off on the risk assessment, marking the formal completion of the risk assessment process.

3. The London Lines were assessed primarily as a medium risk on the Enbridge Operational Risk Matrix. Several different failure modes were identified, the majority of which were assessed as a medium risk. Some sections, where the twin pipelines cannot be isolated independently to effectively manage customer outages, were assessed as a high risk for customer loss. The risk ranking results at the time of risk endorsement are shown in Table 1. This table is

current at the time of risk sign-off, however some risk rankings may change over time as new information is obtained and reviewed.

Table 1

	Very High	High	Medium	Low
Financial	0	0	17	1
Health and Safety	0	0	26	0
Customer Loss	0	4	10	6
Stakeholder Concerns	0	0	10	0

Table 1: Summary of risk ranked scnarios for the London Lines.