Richard Wathy
Technical Manager
Regulatory Applications
Regulatory Affairs

Cell: 519-365-5376
Email: Richard.wathy@enbridge.com
EGIRegulatoryProceedings@enbridge.com

Enbridge Gas Inc.
P.O. Box 2001
50 Keil Drive N.
Chatham, Ontario, N7M 5M1
Canada

VIA RESS and EMAIL

March 1, 2022

Nancy Marconi
Acting Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Dear Nancy Marconi:

Re: EB-2022-0072 – Enbridge Gas Inc. ("Enbridge Gas")
2022 Annual Update to 5 Year Gas Supply Plan

Please find attached Enbridge Gas's 2022 Annual Update to its 5 Year Gas Supply Plan. This is the third Annual Update to the 5 Year Gas Supply Plan that Enbridge Gas has filed with the OEB pursuant to the Report of the Ontario Energy Board: Framework for the Assessment of Distributor Gas Supply Plans (EB-2017-0129) ("Framework").

In accordance with the Framework and its Filing Requirements, this Annual Update focuses on the Outlook section of the gas supply plan, a description of significant changes from previous updates and a historical comparison of actuals to Outlook.

As was the case for the 2021 Annual Update, Enbridge Gas will answer relevant written questions from stakeholders on the Annual Update at the Stakeholder Conference.

Should you have any questions on this matter please contact the undersigned.

Sincerely,

Richard Wathy
Digitally signed by Richard Wathy
Date: 2022.03.01 13:15:46 -05'00'

Richard Wathy
Technical Manager, Regulatory Applications

cc: David Stevens, Aird & Berlis LLP
All Interested Parties EB-2019-0137 (5 Year Gas Supply Review)

2022 Annual Gas Supply Plan Update

EB-2022-0072

Enbridge Gas Inc.
March 1, 2022

Table of Contents

1. Administrative Information

1.1 Introduction

Effective January 1, 2019, Union Gas Limited ("Union") and Enbridge Gas Distribution ("EGD") amalgamated to form Enbridge Gas Inc. ("EGI"). EGI provides natural gas distribution services to over 3.8 million residential, commercial, and industrial customers located throughout Ontario and Québec.

On October 25, 2018, the Ontario Energy Board ("OEB") issued its Report of the Ontario Energy Board: Framework for the Assessment of Distributor Gas Supply Plans ("Framework")[1] which set out a new requirement for all rate-regulated natural gas distributors in the Province of Ontario to file five-year gas supply plans. The Framework also requires distributors to file Annual Updates to the 5-Year Gas Supply Plan.

EGI filed its 5-Year Gas Supply Plan[2] ("5-Year Plan") for all rate zones on May 1, 2019 based on the 2018/19 Gas Supply Plan and most recently filed the 2021 Annual Gas Supply Plan Update ("2021 Annual Update") on Feb 1, 2021[3]. The 2021 Annual Update was prepared to include forecast impacts of the COVID-19 pandemic on infranchise demand. As EGI has not seen long term demand destruction materialize due to the pandemic, the demand forecast included in the 2022 Annual Gas Supply Plan Update ("Annual Update") does not include any adjustment specifically for COVID related impacts.

This document is the third Annual Update to the 5-Year Plan and addresses changes to the market outlook, planning and execution process, and integration updates, inclusive of the historical comparisons of actuals required by the Framework. EGI has considered all recommendations resulting from the OEB Staff Report on the 2022 Annual Update. The 5-Year Plan and Annual Update should be read in conjunction with one another. This update is based on the 2021/22 Gas Supply Plan ("Plan") for November 1, 2021 to October 31, 2026 which received internal senior management approval in Q3 2021.

EGI's Plan covers the EGD rate zone[4] and the Union rate zones (Union North West[5], Union North East[6] and Union South). The objective of EGI's Plan is to identify an efficient combination of upstream transportation, supply purchases, and storage assets to serve sales service and bundled direct purchase ("DP") customers' annual, seasonal and design day natural gas delivery requirements while adhering to the set of gas supply planning guiding principles as outlined in the Framework.

[1] EB-2017-0129
[2] EB-2019-0137
[3] EB-2021-0004 - EGI 2021Gas Supply Plan Update.
[4] Enbridge EDA, Enbridge CDA.
[5] Union MDA, Union SSMDA, Union WDA.
[6] Union EDA, Union NCDA, Union NDA.

1.2 Significant Changes

The 5-Year Plan contains in-depth descriptions of methodologies and related gas supply processes. This submission provides an update to the processes and portfolio detailed in the 5-Year Plan.

The Annual Update captures notable changes including:

1. Harmonization efforts;
2. Market changes and general impacts;
3. Public policy initiatives;
4. An updated demand forecast;
5. Energy transition initiatives; and
6. Contracting changes.

EGI continues to work towards harmonizing its two legacy gas supply planning processes and to make changes to existing processes including further improvements for transparency, efficiency, and alignment with OEB requirements. Refinements and progress on harmonization efforts are outlined in Section 2.

Overall natural gas market outlooks are provided in Section 4, with Section 4.1 detailing changes as they may affect EGI's supply option alternatives and analysis. The discussion on market changes includes those relevant to the North American natural gas market, natural gas price signals, and Ontario natural gas demand along with changes related to available assets.

Discussion of public policy initiatives can be found in Section 4.2, while dialogue on impacts to EGI's demand forecast including, but not limited to, the COVID-19 pandemic and generalized market risks are included in Section 5. The current forecast was produced in the spring of 2021 and reflects the best information available at the time. This includes actual 2020 consumption data, forecasted growth, and updated demand driver variables.

During 2020, EGI received OEB approval, on a pilot basis, for two low carbon energy initiatives that led to acquisitions of hydrogen supply for the 2021/2022 gas year. These initiatives are detailed in Section 6.2.

2. Harmonization Efforts

Gas Supply plays a major role in planning and execution of the gas supply plan for the utility, with expenditures of more than $2 billion annually. The gas supply planning process is an integrated process that begins months in advance of the upcoming gas year with multiple teams executing numerous internal processes. Gas Supply has placed an emphasis on cross-functional communication and project management best practices to ensure proper education, training and tasks are completed efficiently.

During the first three years of combining the legacy utility gas supply functions, EGI has accomplished many integration enhancements and efficiencies[7]. Integration-related accomplishments during 2021 include:

- Training and transitioning of responsibilities
- Coordination of the timeline for development of the gas supply plan for each rate zone, establishing improved communication and increasing overall efficiency of the planning process
- Applying the use of peaking services to the Union North rate zone
- Implementation of a project to incorporate the EGD rate zone into the automated gas accounting system
- Further progress on EGI's Gas Supply Plan Harmonization

2.1 IT System Integration

In support of the amalgamation of the two legacy utilities, one of the key integration requirements impacting Gas Supply is the integration of the IT systems used for contracting, invoice management, and accounting for gas supply related procurement. Prior to the implementation of the project described below, EGI had two distinct processes and systems for these functions for each of the legacy utilities.

In 2019, a project kicked off with the purpose of integrating underlying IT systems that support the gas supply purchasing and accounting functions for EGI. This initiative was implemented in February 2022.

The mandate of this initiative was to develop an integrated and automated utility gas purchasing and financial reporting solution. This includes an integrated solution to manage the contracting, invoicing, and nominations of gas supply purchases, as well as the financial processes required for credit, risk management, and associated regulatory accounting. Achieving integration synergies for the amalgamated utility depends on a single integrated and automated solution to address this entire stream of processes.

2.2 Gas Supply Plan Harmonization Efforts

EGI's gas supply plan harmonization activities in 2021 continued the work that was initiated in 2020. While EGI's harmonization efforts are still in development, this section provides an update on potential changes to weather and design day demand methodologies, as well as changes to annual demand forecasting methodologies. Other harmonization projects and initiatives that will impact future gas supply plans will be included with EGI's rebasing application. This content is for informational purposes only and EGI will ultimately seek OEB approval, where required, with its

[7] EB-2020-0135, page 11 and EB-2021-0004, page 8.

rebasing application. Until that approval is received, EGI will continue to use its existing methodologies for gas supply planning.

EGI is currently evaluating the alignment of the methodology for selecting design weather and estimating design day demand between the legacy utilities. Currently, the Union rate zones use a set temperature approach whereas the EGD zones use a probabilistic approach. Harmonizing to one modelling methodology will streamline planning functions within EGI and provide consistency for customers across EGI's franchise.

To assist with the review of EGI's weather and design day demand methodologies, EGI has engaged a third-party to provide a comparative analysis of industry practices used to determine weather and risk assumptions for gas supply planning, as well as common utility practices for design day demand modeling used for gas supply planning in upstream contract sizing. This analysis has found that two commonly used approaches are (1) probabilistic and (2) set temperature. Among similarly situated natural gas utilities, the majority use a set temperature approach similar to that used in the Union rate zones.

This information will be provided in EGI's rebasing application and will inform its proposal as it relates to the weather and design day methodology that is an input to the Gas Supply Plan. To align with the most common approach amongst its peer utilities, EGI intends to propose aligning the EGD zones to the set temperature approach used with the Union zones.

Harmonizing the weather and design day demand methodologies will impact the quantity of design day demand required. Since EGI is still developing its integration proposals for its Rebasing application, the potential impacts of weather and demand methodology changes had to be estimated in isolation of any other potential changes to upstream processes and methodologies. As such, EGI expects these impacts to change once the rebasing application is filed.

Assuming no other changes to processes upstream of the Gas Supply Plan, if EGI were to align weather and design day demand methodologies to a set temperature approach, EGI estimates that additional design day gas supply services would be required in the range of 100-150TJ/d, or approximately 2.5-3.7%, for the EGD delivery areas. To meet the potential increase in demand in the EGD rate zone, EGI would be required to contract for incremental gas supply services. This would include assessment of all gas supply options available at that time, including firm transportation and/or utilization of a third-party peaking service. Upon approval of EGI's rebasing application, EGI would contract for this shortfall in advance of winter 2024/25.

In addition to reviewing the weather and demand methodologies for design day demand forecast, EGI is currently evaluating its annual volumetric demand forecast methodologies and will provide the results and any proposed changes as part of its rebasing application.

To the extent other aspects related to harmonization and the gas supply plan require OEB approval, these items will be included with rebasing.

3. Load Balancing

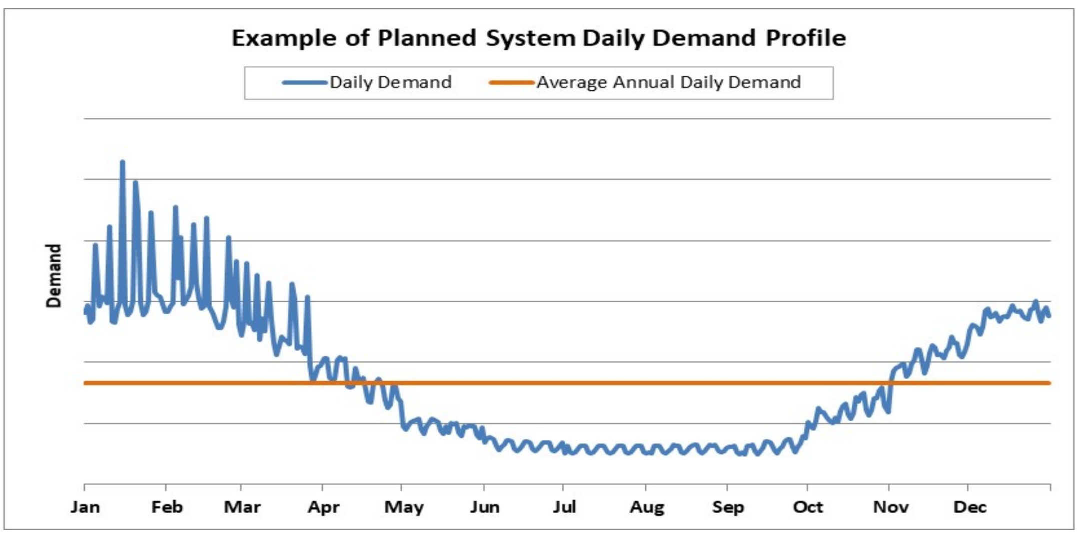
EGI has agreed to file evidence in its rebasing application demonstrating that it has fully considered the opportunity to reduce storage costs, through inclusion, as part of its load balancing portfolio, of cost-effective market-based alternatives to the purchase of third-party storage[8]. As part of that review, EGI is engaging ICF Consulting to evaluate storage and other market-based alternatives to meet EGI's load balancing needs and will consider their report as EGI evaluates potential changes.

To provide stakeholders background on EGI's current approach to load balancing, this section outlines how load balancing needs are currently considered within EGI's portfolio, and how EGI uses OEB recognized methodologies to determine load balancing requirements.

Current Approach to Planning for Load Balancing

EGI's gas supply planning process balances the demands of both its system and bundled DP customers on a daily basis.[9] EGI's general service market and a portion of contract market customers are heat sensitive and their demand can vary significantly throughout the year. The variability in heat sensitive load as compared to average annual daily demand is depicted below in Figure 1.

Figure 1 - System Demand Profile Example



For these customers, an optimal mix of load balancing assets are required. EGI considers a variety of tools to meet these requirements including:

- System supply and obligated DP daily pipeline deliveries;
- Gas in storage and associated deliverability; and
- Peaking, seasonal, and curtailment supplies.

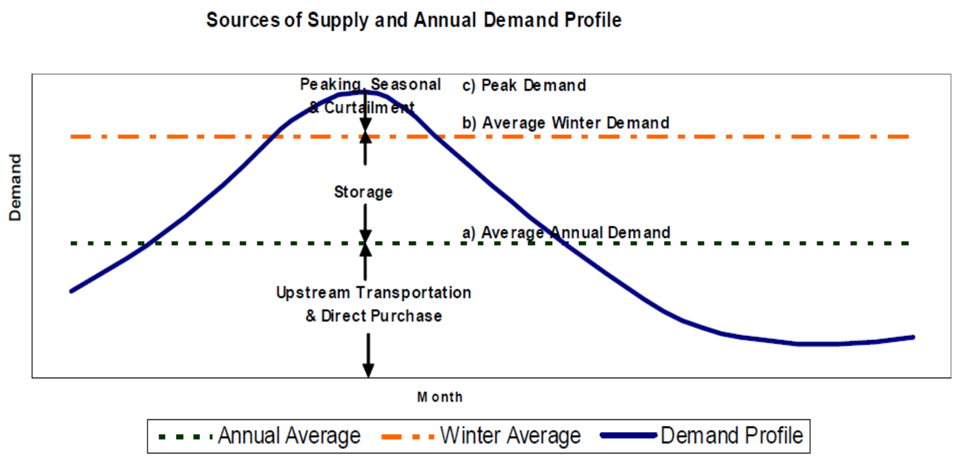
---

[8] EGI committed this during the 2021 Annual Update stakeholder conference, and subsequently in the Settlement of the Deferral and Variance Accounts (EB-2021-0149) – see Exhibit N1, Tab 1, Schedule 1, pages 11-12.

[9] EGI's Gas Supply Plan does not contemplate the balancing needs of the semi-bundled or unbundled customers since those customers are responsible for managing their own load balancing needs.

Figure 2 below, provides an example of how EGI uses load balancing assets to meet customers' demand across their entire demand curve (i.e. average annual demand, average winter demand, and peak winter demand).

Figure 2 - Demand Profile vs Average Winter and Annual Demand[10]



Currently, each rate zone relies on supply from storage withdrawals, seasonal or peaking services, and supply purchases to balance winter load requirements. The supply is delivered to the distribution system through the coordination and utilization of numerous upstream transportation services.

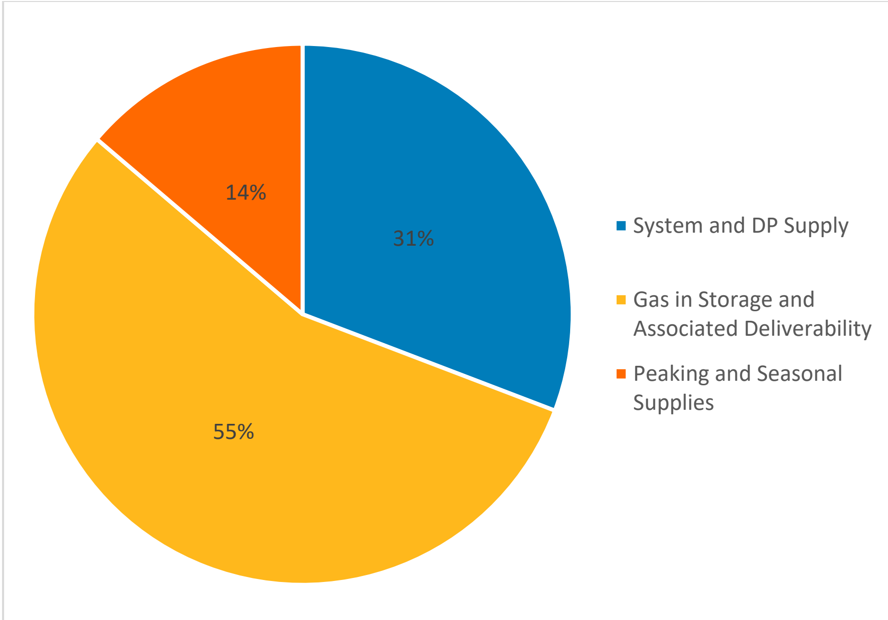
Overview of EGI Load Balancing

To ensure EGI's portfolio load balancing approach aligns with the utility's gas supply planning principles, Gas Supply ensures that forecast firm demand of all customers across the demand profile is met using firm services.

EGI's current portfolio strategy on design day consists of a combination of daily pipeline deliveries, storage supplies and seasonal and peaking supplies. As shown below in Figure 3, approximately half of EGI's design day demands are met with storage services, with the other half met by purchased or obligated supply to be delivered in the winter months.

[10] EB-2005-0551 – NGEIR – Exhibit G-1-1 Enbridge Storage Allocation Method Evidence.pdf, page 2.

Figure 3 - Design Day Supply



EGI Load Balancing Asset Overview

System Supply and Obligated DP Deliveries

System supply and obligated DP deliveries represent the base level of supply included in the Gas Supply Plan. These supplies are planned for on the basis that they will be sufficient to meet customers' average annual demand. However, given EGI's heat-sensitive load profile there are periods throughout the planning horizon when these baseline supplies exceed average demand. During these periods, the system supply and obligated DP deliveries will be injected into storage and will be withdrawn at a future date when demand is above annual average demand.

Gas in Storage and Associated Deliverability

Determining Storage Space Requirement

EGI uses the aggregate excess methodology to estimate customers' storage requirements. Aggregate excess has been the approach for both legacy utilities for calculating a standard amount of storage space to meet seasonal load balancing needs. Aggregate excess is an OEB approved methodology and has been used in the Union rate zones since 2000, approved in RP-1999-0017, and used by EGD since that same time.

Aggregate excess is designed for customers with a traditional seasonal load balancing need and fits well with the storage needs of many bundled customers. The aggregate excess method is based on the assumption that natural gas is delivered in equal amounts each day of the year.[11]

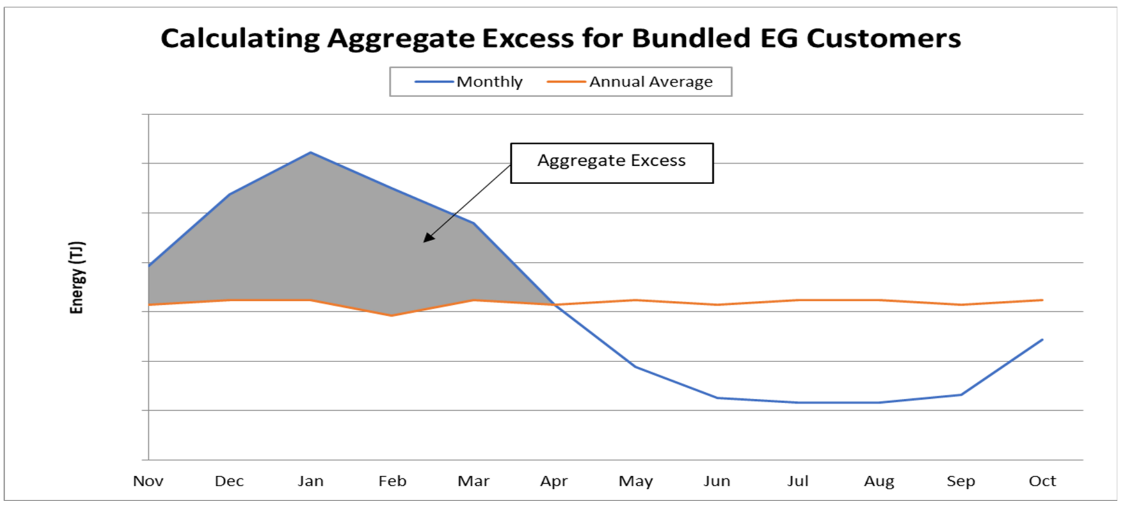
[11] EB-2005-0551 - NGEIR - Decision with Reasons, page 97.

This methodology calculates the difference between forecasted winter demand (November 1 through March 31) and the annual average daily demand for a 151-day period. The result is the required storage space allocation. As outlined in the 5-year Plan[12], the mathematical process to calculate aggregate excess is[13]:

$$Aggregate\ Excess = Forecast\ Winter\ Consumption - \left[\frac{151}{365} \times Forecast\ Annual\ Consumption\right]$$

Figure 4 below provides a visual depiction of the aggregate excess mathematical process and how it translates to the demand forecast profile.

Figure 4 - Aggregate Excess for Bundled EGI Customers Example



In addition to using aggregate excess to determine the amount of storage space for load balancing needs, EGI uses SENDOUT to determine if there is an economic benefit to holding more storage than the aggregate excess calculation determines.[14] By leveraging SENDOUT, EGI can determine if there are potential cost savings to contracting for additional storage or relying on incremental winter purchases.

Utilizing Gas in Storage

Once EGI has used aggregate excess to determine storage space needs, EGI needs to consider deliverability requirements and how inventory targets are used to maintain levels of deliverability at specific points in the winter to ensure safe and reliable services.

EGI needs to consider the volatility of balancing heat-sensitive demand on a day-to-day and intra-day basis and the risk of managing unforecasted balancing requirements late into the winter season.[15] The operational flexibility provided by physical storage capacity allows EGI to quickly respond to short-

[12] EB-2019-0137 - 5 Year Gas Supply Plan, page 81.
[13] For leap years, the formula changes to include a 366-day calendar in the denominator of the shown fraction
[14] See section 7-4 'Resource Mix Optimization' for a description of this process.
[15] Winter Storm Uri 2021 - https://comptroller.texas.gov/economy/fiscal-notes/2021/oct/winter-storm-impact.php

term demand variations. The inclusion of storage assets in the Gas Supply Plan provides a cost-effective and reliable way to balance this heat-sensitive demand. Developing a Gas Supply Plan in this way will limit the risk of EGI customers being exposed to extreme events, such as the high prices observed during the polar vortex winter of 2013/14[16], and during February 2021's winter storm Uri, which centered over Texas.

Since there is risk that peak and near-peak demand days can occur at any point during the winter, EGI's Gas Supply Plan uses storage to mitigate the risk of late-season demand spikes and the costs associated with buying spot gas when the availability of market supply is low.

Peaking, Seasonal, and Curtailment Supplies

In addition to storage, a large portion of the Gas Supply Plan's load balancing needs are met using seasonal supplies and peaking services.

On a planned basis, EGI's supply purchases are heavily weighted within the year to winter purchases. As demonstrated in Table 1, EGI specifically uses planned purchases at Dawn to shape supply deliveries, purchasing 70% of planned Dawn supply in the winter months. Although not as flexible as storage services for changes within the day, shaping purchases allows EGI flexibility to meet the volatility of heat sensitive loads.

Table 1 - Percentage of EGD Planned Dawn Purchases Example

Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
7%	23%	25%	14%	-	-	-	8%	9%	9%	5%	-

Although storage and supply purchases account for most of the Gas Supply Plan's load balancing needs over the course of the winter, peak and near peak days result in the need to make additional considerations.

As part of EGI's design day plan for each delivery area, regardless of rate zone, EGI only contracts for firm demand and plans on interruptible customers continuing to deliver their obligated supply, which EGI can use in lieu of purchasing gas supply and transportation services.

Even after interruptible customers have been curtailed, some delivery areas may have planned firm design day demand higher than contracted upstream assets. When these planned shortfalls are not large enough to justify a long-term firm transportation contract, EGI has historically met them by procuring short term third-party services (ex. peaking services), if they are available, in the EGD and, more recently, Union North rate zones. For the delivery areas where short-term third-party services are not available, EGI has historically procured firm transportation assets for a term of no more than

[16] Polar Vortex Review 2014 - https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

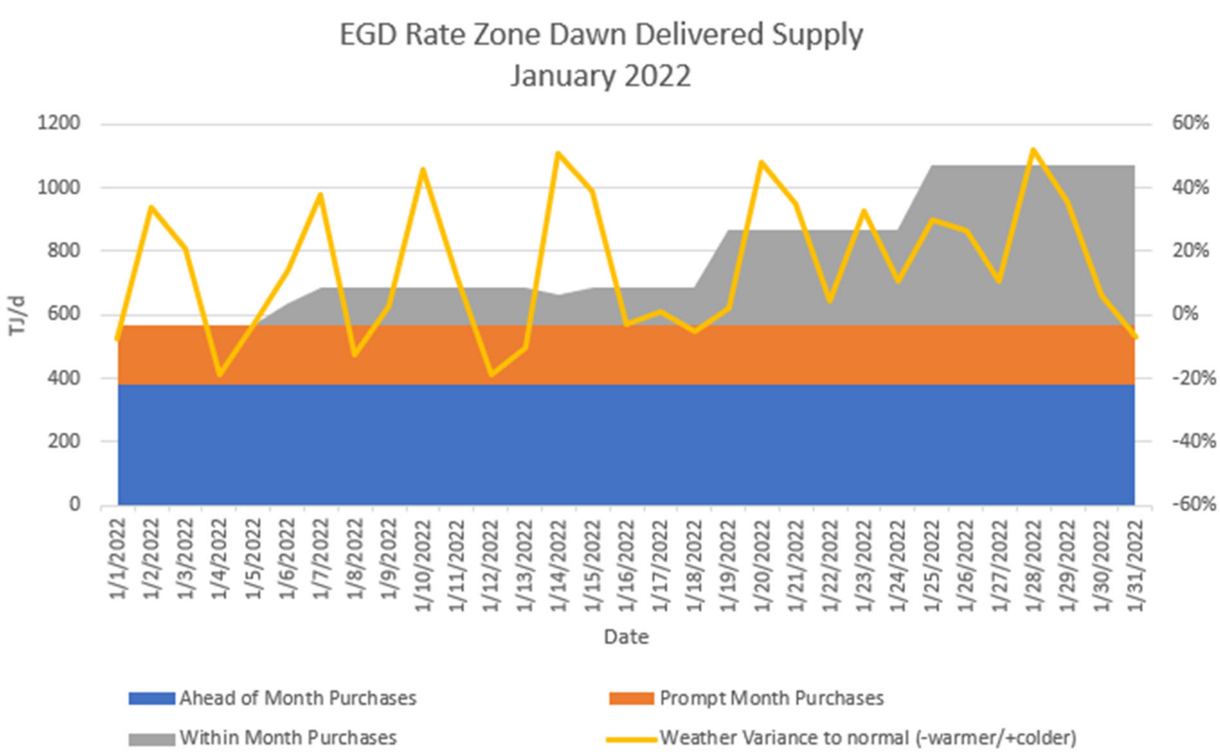
one year, if available. EGI currently relies on third-party services in the Union WDA, Union EDA and Union NCDA as well as the EGD EDA and EGD CDA.

Operationalizing the Load Balancing Portfolio

As with all aspects of the Gas Supply Plan, EGI constantly monitors weather, customers' demand, commodity prices, and market conditions to adjust the utilization of load balancing assets to balance the system. Decisions related to the continued execution of the Plan are made during operational planning meetings, held frequently throughout the year with decisions being made daily related to supply procurement and asset utilization. During the winter, the flexibility provided by the planned load balancing assets is essential in the daily decision-making process. EGI is able to execute supply purchases using a variety of delivery terms to adjust the quantity of gas delivered and ensure secure and reliable load balancing is provided to the system.

As an example, in January 2022 the weather forecast became increasingly colder than normal throughout the month, finishing at 15% colder than normal. EGI entered the month with executed supply deliveries at Dawn for the EGD rate zone of 566 TJ/d of Dawn supply, however as cold weather materialized EGI continued to layer in supply purchases with varying delivery terms to reach a peak of over 1 PJ/d of Dawn supply to the EGD rate zone for some days in January as shown in Figure 5.

Figure 5 - January 2022 Operationalization of Load Balancing



Considering Load Balancing Costs in Contracting Decisions

In the 2021 Annual Update Decision, OEB Staff requested EGI share more information on how load balancing costs are considered when evaluating supply options.

Outside of base supply, the cost of services purchased to meet a design day requirement are by their nature a load balancing cost. EGI's existing design day analysis methodology includes all incremental costs associated with the supply option, including the full cost of a peaking or transportation service.

For example, should EGI consider long-haul transportation to meet a delivery shortfall in a Union North rate zone, as described in Section 6.3, EGI would minimize costs by first including peaking services prior to contracting for long-haul transportation. Alternatively, if EGI were to consider additional storage above of the quantity determined through aggregate excess, EGI would compare this to other market-based alternatives.

To evaluate average day supply options, EGI uses a landed cost methodology. This method captures costs associated with Dawn purchase decisions that do not impact load balancing costs. Should the alternatives drive a requirement for more storage, redelivery or load balancing costs, EGI would factor that into the analysis.

4. Market Overview

4.1 Market Outlook

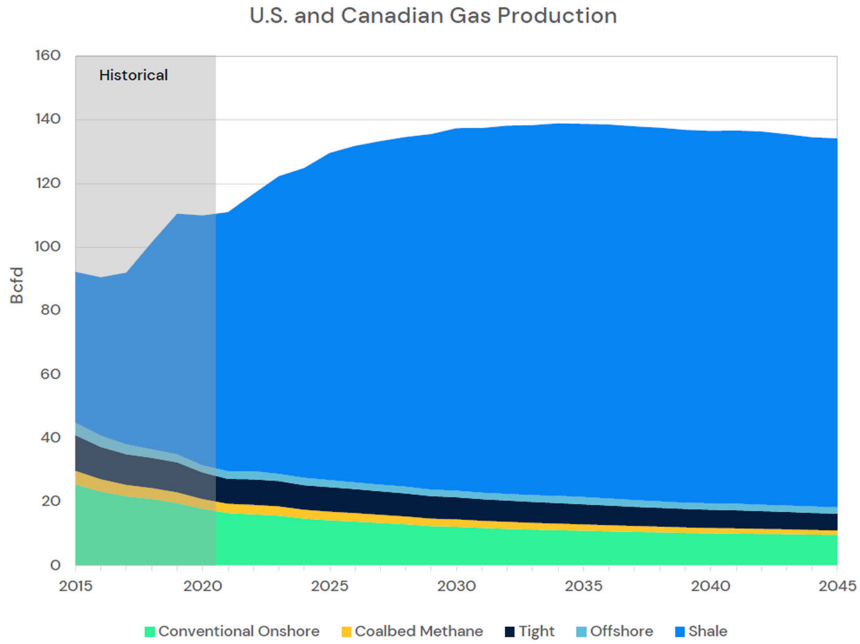
In 2021, North American energy markets continued to be impacted from the COVID-19 pandemic. For the first half of the year, markets reported lower overall sales volumes in a continuation of the past year's decline in the wake of production cuts imposed in response to the pandemic. In the second half of 2021, favorable economic indicators started to push energy prices upward. While not seeing movement from major producers yet, industry experts expect both rising production and higher sales volumes given mounting demand and tight global supplies following a record-breaking hot summer and an ongoing recovery from the pandemic.[17]

North American Supply

North American natural gas production will grow significantly over the next two years as drilling activities ramp up across major oil and gas plays in the U.S. and Canada. Total Canadian and U.S. gas production is expected to increase by 0.8% per year on average from 2021. Increased production is driven by growth in production of shale gas. By 2025, shale gas will account for about 79% of all U.S. and Canadian gas production. Conventional production is expected to decline by 2.1% annually.[18]

[17] ICF Q4 2021 Natural Gas Strategic Report.
[18] ICF Q4 2021 Natural Gas Strategic Report.

Figure 6 - U.S. and Canadian Natural Gas Production by Type



Source: ICF Q4 2021 Natural Gas – Strategic. Used with permission.

In its 2021 Energy Future ("EF2021") report, the Canada Energy Regulator ("CER") forecasts Canadian natural gas production to remain near current levels of 15.5 Bcf/d through much of the next two decades. The additional investment in production to feed liquefied natural gas ("LNG") export volumes increases production above what would otherwise occur given natural gas prices and the costs associated with domestic climate policies. After 2040, with LNG exports assumed to stay flat, total production begins to decline, falling to 13.1 Bcf/d by 2050. Much of the production growth related to LNG exports occurs in B.C. and production in B.C. surpasses that of Alberta by 2028.[19]

Natural Gas Demand

North American natural gas demand growth in 2021 mostly reflected economic recovery from the COVID-19 pandemic. The anticipated domestic growth in the following years will be driven equally by economic activity and by gas replacing other more carbon intense fuels such as coal and oil in sectors such as electricity generation, industry, and transport.

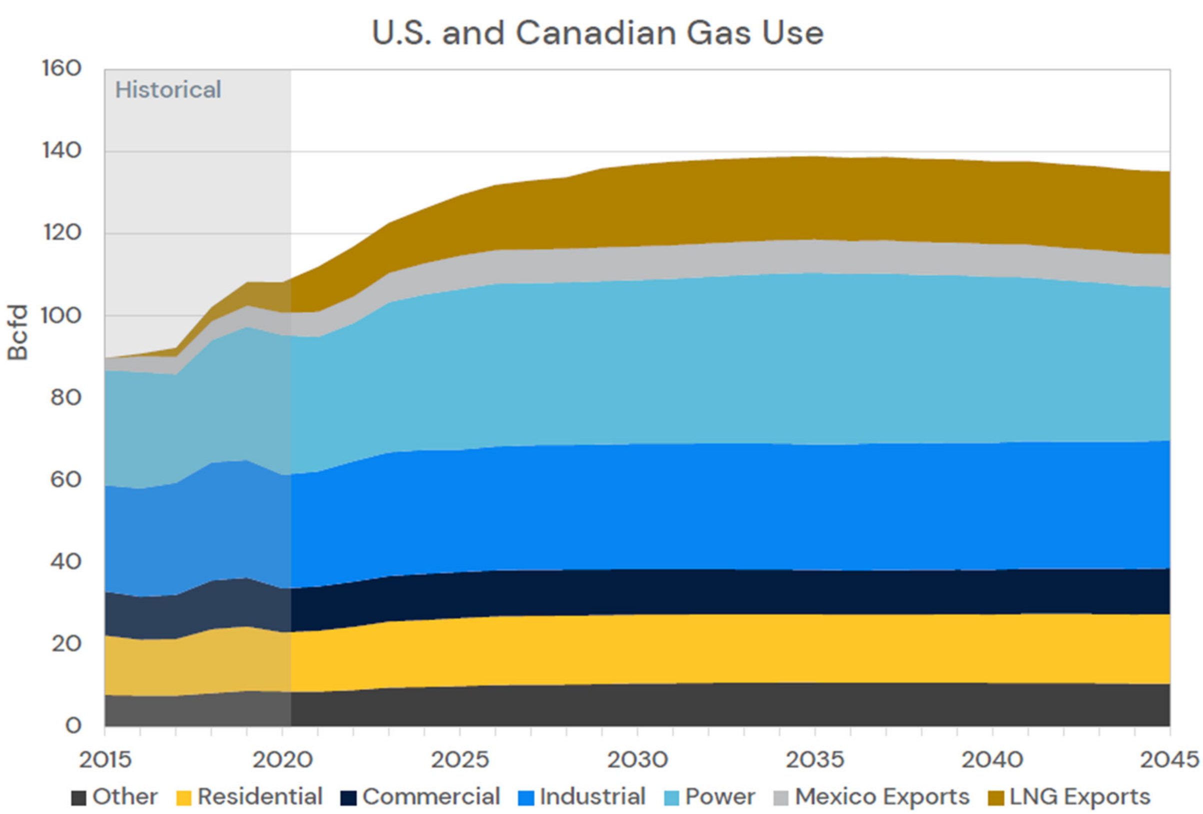
Almost half of the increase in worldwide gas demand between 2020 and 2024 comes from the Asia Pacific region which will drive additional natural gas exports from North America.[20] While North American LNG exports still have not reached pre-COVID levels, both Canadian[21] and American[22] export

[19] CER – Canada's Energy Future 2021.
[20] ICF Q4 2021 Natural Gas Strategic Report.
[21] Liquefied Natural Gas (LNG) – Imports and Exports - lng-exports-and-imports-monthly - Open Government Portal (canada.ca)
[22] Liquefied U.S. Natural Gas Exports (Million Cubic Feet) (eia.gov)

activity had already increased significantly towards the latter part of 2021 to meet some of this demand. Further increases in North American LNG export activity may potentially be seen if European nations begin relying more heavily on American and Canadian natural with the delay of gas flowing in Nord Stream II to October 2022, in large part due to geopolitical uncertainty.[23]

Gas demand domestically in the residential and commercial sectors was impacted in 2020-2021 due to a combination of pandemic lockdowns and a mild winter. The demand for natural gas has recovered due to a succession of extreme weather events that have generated additional gas power generation requirements. However, levels are not expected to be on par with 2019 until beyond 2022. Gas demand for residential and commercial use is expected to grow at a moderate rate of approximately 1.6% in the medium-term.[24] The EIA forecasts medium-term growth in the industrial sector to account for approximately 40% of the total increase in demand between 2020 and 2024. It is estimated that demand will grow at 3.4% annually due to industrial demand (Pan Asian markets) and demand as feedstock for chemical and fertilizers.

Figure 7 - U.S. and Canadian Gas Use

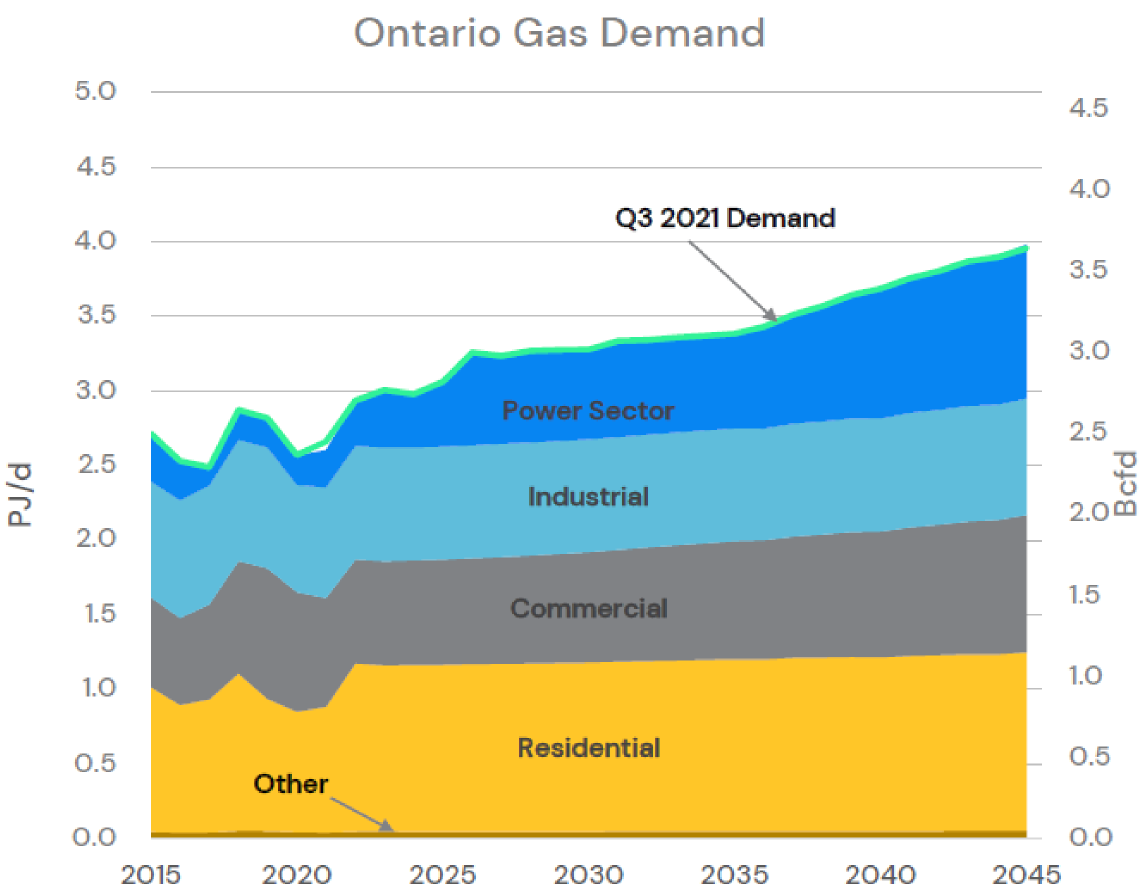


Source: ICF Q4 2021 Natural Gas – Strategic. Used with permission.

[23] Why The Latest Russia Crisis Might Be Worse For Berlin Than Moscow And Kyiv (forbes.com)
[24] EIA July – Gas Market Report Q3 2021_including Gas 2021 Analysis and forecast to 2024.pdf

In Ontario, gas use will increase at an annual average growth rate of 1.2% per year from 2021 through 2045. Demand from the residential and commercial sectors will experience annual modest growth of 1.47% and 0.97% respectively over the next two decades. The demand growth is greatest in the power sector which is expected to see a 6.11% average annual growth rate between 2022 and 2045.[25] IESO's Annual Planning Outlook from December 2021 shows the potential for considerable changes through the 2020s and 2030s due to the combined effect of nuclear retirements, expiring contracts, ongoing nuclear refurbishment outages and delays. The marginal cost of electricity production and electricity sector emissions are both forecast to increase over the period covered by the outlook, the first as a result of growing demand, the second due to nuclear refurbishments and retirements resulting in an increased use of Ontario's gas-fired generation fleet.[26]

Figure 8 - Ontario Natural Gas Demand



Source: ICF Q4 2021 Natural Gas – Strategic. Used with permission.

Natural Gas Price Signals

As the effects of the pandemic continue to impact natural gas markets worldwide, price volatility has become a primary concern. The futures market is continuing to project increases in the Henry Hub natural gas prices for the 2021/22 winter from historically low levels for the past several years.

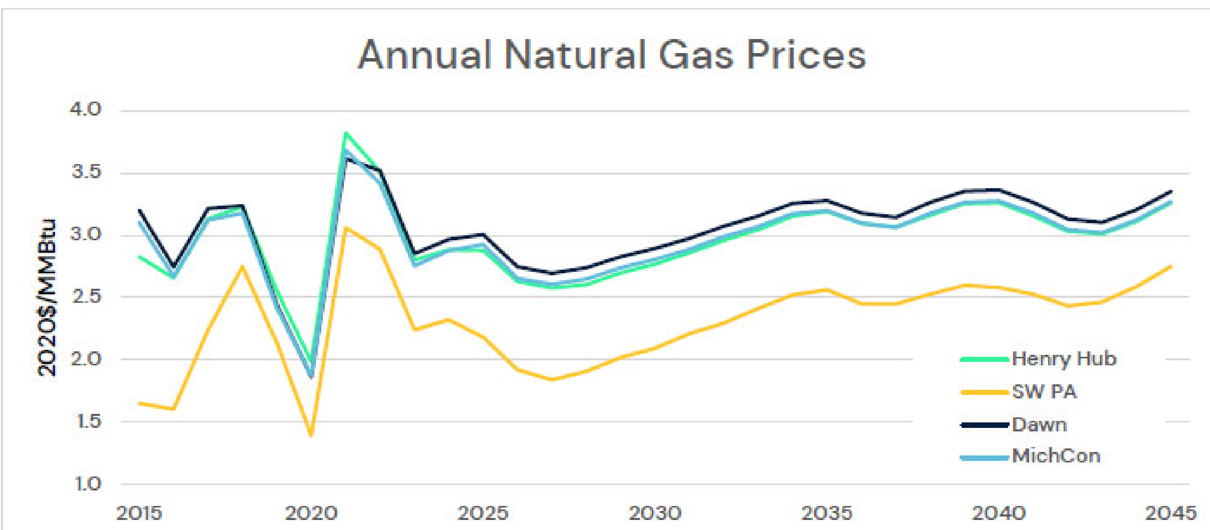
[25] ICF Q4 2021 Natural Gas Strategic Report.
[26] IESO December 2021 outlook.

It is expected that this will be driven by low oil and gas upstream activity for the rest of 2021 and higher storage withdrawals during this upcoming winter. Prices at Henry Hub had steadily increased throughout early spring and summer of 2021 and they are forecasted to remain high for the remainder of this winter.

ICF forecasts that the Henry Hub price will reach $4.54/MMBtu in January 2022 and average $3.37/MMBtu in the summer of 2022, under normal weather conditions, as producers ramp up production over the next year.[27] Below average natural gas inventories combined with a severe cold snap could see prices increase in areas in the U.S. that are routinely constrained for peak capacity this winter. Another significant pressure on pricing is the increased demand for natural gas in Europe. With high demand for U.S. natural gas exports, increases in global natural gas prices have resulted in small price increases at Henry Hub[28].

Natural gas prices set at Henry Hub are generally seen to be the primary price for the North American natural gas market with locational basis differentials based off the New York Mercantile Exchange ("NYMEX"). ICF's long term price forecast reflects the transition of the Henry Hub to a major demand center with prices between $2.52 and $3.73 per MMBtu in real terms.[29]

Figure 9 - Comparative Long Term Natural Gas Prices



Source: ICF Q4 2021Natural Gas – Strategic. Used with permission.

Transportation Market Overview

This section describes market changes relating to transportation which have a direct impact on EGI's Gas Supply Plan and related supply option analysis.

[27] ICF Q4 2021 Natural Gas Strategic Report.
[28] EIA – Short term outlook Oct 13, 2021.
[29] ICF Q4 2021 Natural Gas Strategic Report.

TransCanada PipeLines Limited ("TCPL")

TCPL continues to focus on making their existing capacity available to the market, completing facility upgrades at points of constraint, and creating services that help the Western Canadian Sedimentary Basin ("WCSB") supply reach eastern North American markets. During 2021, extensive maintenance and integrity work was completed on the Western Mainline ("WML") segment of the TCPL Canadian Mainline, lifting capacity restrictions and making marketable additional capacity available from the WCSB. In the Eastern Triangle ("ET"), Maple C6 compressor construction was completed on time to increase transportation capacity for winter of 2021/22.

2022 Mainline Tolls & Abandonment Surcharges

Despite increased flows on the Mainline, neither the WML nor ET Short-Term Adjustment Accounts reached a balance of +/- $100 million following 2021, so dispersal from the deferral accounts were not triggered. As a result, Mainline tolls remain as approved in order TG-014-2020 by the CER for 2022.

Unlike tolls, abandonment surcharges on the Mainline have decreased slightly from 2021 levels for 2022 due to increased contracting. Abandonment surcharges are as approved in CER order TG-008-2021.

Existing Mainline Capacity & Constraints

EGI reported in its last annual update that long-haul Firm Transportation ("FT") capacity has not been consistently available on the Mainline due to an increase in FT contracting. In 2021, despite the increase in marketed capacity on the WML, capacity to each of EGI's rate zones remains limited due to upstream FT contracting. EGI expects that long-haul capacity may be available at various times over the next five years through existing capacity open seasons because of de-contracting, line maintenance, and integrity work. This change of capacity availability is a consideration when EGI evaluates transportation alternatives, and EGI will continue to monitor what becomes available in the market.

New Service Offerings

In 2021, the first Market Driven Service ("MDS") open season was held by TCPL offering existing capacity made available as a result of the previously mentioned maintenance on the prairies section of the WML. The open season resulted in approximately 152 TJ of contracting between Empress and Emerson beginning November 1, 2022. This incremental contracting concurrently reduced long-haul availability to EGI's rate zones by the same capacity.

Panhandle

On August 30, 2019, Panhandle Pipelines ("Panhandle") filed a Section 4 application[30] with the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act. On September 30, 2019, FERC accepted and suspended the Section 4 NGA filing allowing interim rates to become effective March 1, 2020. At the same time, Panhandle's request to terminate FERC's section 5 proceeding[31] was denied and the two proceedings were merged for simplicity on October 1, 2019.

After over a year of activity in the virtual hearing, on March 26, 2021, the FERC provided their initial decision, indicating that PEPL's rates since 2019 have been unjust and unreasonable. While interim rates in effect are currently higher than 2019 levels, this indicates on finalization of the decision that shippers could be given a refund and see lower rates in the future.

4.2 Public Policy Updates

The following section provides information on impacts to the gas supply plan in order to adapt to public policy changes.

Community Expansion

In their report to the Government of Ontario released December 10, 2020, the OEB originally indicated that 200+ projects could be considered for potential funding. On June 9, 2021, the Government of Ontario announced that 28 projects across 43 communities were selected for potential funding in the second phase of the Natural Gas Expansion Program with 27 of these projects having been proposed by EGI. The government's goal with the passing of regulation (O.Reg. 451-21) identifying these 28 projects for phase 2 was to prioritize connecting the greatest number of customers as broadly as possible across Ontario, in the most economically feasible way.

The number of new customers anticipated to be added to EGI's system as part of these community expansion projects is negligible in comparison to its existing customer base and forecasted growth. As a result, the increased gas demand from these projects is easily accommodated within the existing Gas Supply Plan.

Federal Carbon Charge

EGI filed an application[32] on September 29, 2021, seeking OEB approval for rates effective April 1, 2022 to recover costs associated with meeting its obligations under the federal *Greenhouse Gas Pollution Pricing Act* ("GGPPA").

As of April 1, 2022, the Federal Carbon Charge that EGI must remit to the Government of Canada under the GGPPA for eligible volumes of natural gas will increase from \$40 per tonne of carbon dioxide equivalent ("tCO_2e") to \$50 per tCO_2e.

---

[30] RP19-1523-000
[31] RP19-78-000
[32] EB-2021-0209

The demand forecast underpinning the 2022 Annual Update includes this federal carbon charge in the price-related demand driver variables used in its regression equations. EGI assumes \$50 per tCO_2e in 2022. As the proposed increase to \$170/tCO_2e had not been federally legislated at the time the demand forecast was created, the Update contemplates a 2% per year inflationary factor after 2022.

Federal Clean Fuel Regulation

The federal government is developing a Clean Fuel Regulation ("CFR"), which will require fossil fuel producers, importers and distributors to reduce the carbon intensity of the fuels used in Canada. In December 2020, the federal government announced that the proposed CFR will not impose a compliance obligation on gaseous or solid fuels. The CFR will only impose a compliance obligation on the liquid fuels sector. However, gaseous fuel producers, importers and distributors may have the ability to participate in CFR by generating credits for production/import of low carbon fuels, such as RNG and hydrogen. As a result, EGI anticipates that any RNG or hydrogen procured as part of its supply portfolio may generate CFR credits, effectively lowering the cost of these fuels. As the CFR has not been finalized, impacts of the CFR have not been considered in the 2022 Annual Update.

Integrated Resource Planning

Since the 2021 Annual Update, there have been no impacts on the demand forecast or gas supply portfolio from IRPAs beyond what is already reflected in DSM impacts.

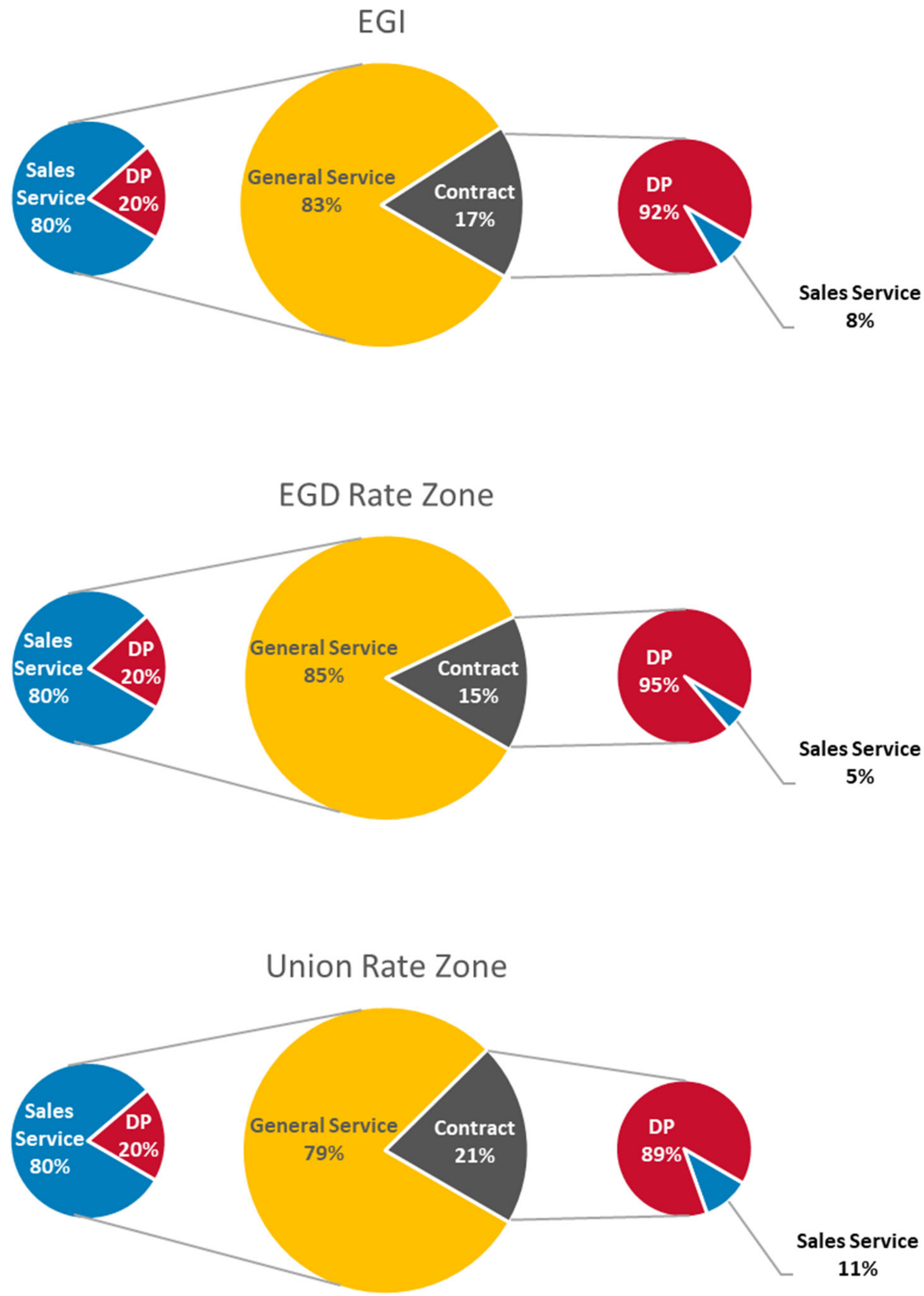
5. Demand Forecast Analysis

EGI's in-franchise customers are divided into two customer segments: the general service market and the contract market. General service customers in the EGD rate zone are billed on Rate 1 or Rate 6, and Rate M1, Rate M2, Rate 01 or Rate 10 for the Union rate zones. EGI's general service customers are mostly residential and small commercial customers who primarily use natural gas for space heating. As such, their consumption follows a seasonal consumption profile based on temperature throughout the year. The remaining rate classes make up the contract market. These customers are mostly large commercial and industrial firms, and their consumption tends to follow a steadier baseload pattern over the year.

EGI provides distribution services to all in-franchise customers, however customers have the option to purchase their supply from EGI as a sales service customer or arrange their own supply through a DP arrangement.

EGI's proportion of general service and contract customers volume is outlined in Figure 10. This is further split by sales service and DP customer types.

Figure 10 - EGI Service Types



5.1 Annual Demand

The 2022 Annual Update is based on the demand forecast for the general service market and contract market rate classes as prepared by EGI's Demand Forecasting and Analysis department. The annual demand forecasts are prepared separately for the EGD and Union rate zones using OEB approved methodologies[33]. EGI is currently evaluating its annual demand forecast methodologies and will provide the results and any proposed changes as part of its rebasing application.

The current forecast was produced in the summer of 2021 and reflects the best information available at the time. This includes actual 2020 consumption data, forecasted growth, and updated demand driver variables. At the time of filing this document, EGI does not expect any additional variance from what was included in the forecast related to the COVID-19 pandemic. Overall, the pandemic is not expected to reduce total annual demand in EGI's forecast in the contract market in 2022. EGI expects the pandemic to have a very modest impact to general service demand resulting from lower forecasted average use. Table 2 below illustrates the annual demand forecast for each rate zone included in the 2022 Annual Update[34].

Table 2 - Annual Demand Forecast

Line No.	Particulars (TJ)	2021/22	2022/23	2023/24	2024/25	2025/26
	EGD					
1	General Service	381,835	383,278	386,810	387,561	390,588
2	Contract	70,000	72,767	72,643	71,980	71,696
3	Total EGD	451,835	456,045	459,453	459,542	462,284
	Union North West					
4	General Service	14,579	14,621	14,743	14,722	14,778
5	Contract	1,441	1,436	1,432	1,427	1,422
6	Total Union North West	16,020	16,057	16,175	16,149	16,200
	Union North East					
7	General Service	39,107	39,221	39,537	39,485	39,624
8	Contract	3,554	3,556	3,532	3,519	3,507
9	Total Union North East	42,660	42,778	43,069	43,005	43,131
	Union South					
10	General Service	173,820	174,324	175,562	175,142	175,511
11	Contract	55,729	57,249	58,182	58,943	59,705
12	Total Union South	229,549	231,573	233,745	234,086	235,216
13	Total Demand Forecast	740,065	746,453	752,443	752,781	756,831

As shown in Table 3, the current annual demand forecast is showing approximately 1% lower demand compared to the 2021 Annual Update as a result of updated driver variables, recent actual consumption trends, and known and forecasted customer and contracted demand growth. Compared to the previous forecast, general service demands are about 1.4% lower on average, driven by updated average use and customer forecast. The contract market overall is an average of 0.8% higher than the previous plan as a result of updated sales information, higher firm contract demand in some

[33] RP-2000-0040, EB-2014-0276 for EGD, and EB-2011-0210 for Union.
[34] Annual demands include general service and contract market. Other volumes (i.e. Gazifere, unaccounted for gas, company use) are excluded.

markets and planned growth. EGI's total annual demand is expected to be almost flat, increasing by an average of 0.6% year over year within the forecast period.

Table 3 - 2022 Annual Demand Forecast vs 2021 Annual Demand Forecast

Line No.	Particulars (TJ)	2021/22			2022/23			2023/24			2024/25		
		2022 Update	2021 Update	Variance	2022 Update	2021 Update	Variance	2022 Update	2021 Update	Variance	2022 Update	2021 Update	Variance
	EGD												
1	General Service	381,835	390,299	(8,464)	383,278	392,361	(9,083)	386,810	395,340	(8,531)	387,561	396,176	(8,615)
2	Contract	70,000	70,148	(149)	72,767	69,784	2,983	72,643	69,513	3,131	71,980	68,861	3,120
3	Total EGD	451,835	460,448	(8,613)	456,045	462,145	(6,100)	459,453	464,853	(5,400)	459,542	465,037	(5,495)
	Union North West												
4	General Service	14,579	14,470	109	14,621	14,484	137	14,743	14,601	142	14,722	14,579	143
5	Contract	1,441	1,683	(242)	1,436	3,767	(2,331)	1,432	4,803	(3,371)	1,427	4,798	(3,371)
6	Total Union North West	16,020	16,153	(132)	16,057	18,252	(2,194)	16,175	19,404	(3,229)	16,149	19,377	(3,228)
	Union North East												
7	General Service	39,107	38,646	461	39,221	38,671	551	39,537	38,961	576	39,485	38,892	593
8	Contract	3,554	3,878	(324)	3,556	3,884	(328)	3,532	3,871	(339)	3,519	3,858	(339)
9	Total Union North East	42,660	42,524	137	42,778	42,555	223	43,069	42,832	237	43,005	42,750	255
	Union South												
10	General Service	173,820	175,430	(1,610)	174,324	175,133	(809)	175,562	175,944	(381)	175,142	175,170	(28)
11	Contract	55,729	56,738	(1,009)	57,249	57,587	(338)	58,182	55,609	2,573	58,943	54,407	4,537
12	Total Union South	229,549	232,168	(2,619)	231,573	232,720	(1,147)	233,745	231,553	2,192	234,086	229,577	4,509
13	Total Demand Forecast	740,065	751,292	(11,227)	746,453	755,671	(9,218)	752,443	758,642	(6,200)	752,781	756,741	(3,959)

With 1% colder/warmer weather assumed, the general service forecast for the Union rate zones would be approximately 0.8% higher/lower. In the EGD delivery areas, general service demand forecast for Rate 1 and Rate 6 customers would be approximately 0.81% and 0.77% higher/lower respectively with a 1% colder/warmer weather assumption. In the contract market, a 1% colder/warmer weather assumption would have negligible impact as customers in this market are predominantly not heat-sensitive.

Customer behaviour, energy efficiency advances, DSM savings, the expectation of higher gas prices mainly driven by the federal carbon charge[35], and market conditions continue to play a role on impacting both general service and contract market demand growth.

5.2 Design Day Demand

EGD rate zone design day demand weather conditions are based on a 1 in 5 recurrence interval[36] using a lognormal distribution. The Union rate zones design day demand weather conditions are based on

[35] The forecast assumes $50 per tCO_2e in 2022 with a 2% per year increase annually thereafter as described in section 4.2.

[36] A recurrence interval is defined as the average frequency, in years, in which an actual weather event or HDD level is expected to exceed that of the design level one time. For example, a 1 in 10 recurrence interval would mean that the HDD level assumed on peak day is expected to be exceeded once every ten years. Another way to express this statement is that there is a 10% probability that the specified peak day HDD value would be exceeded in any given year.

the coldest observed degree day.[37] Table 4 below illustrates the design day demand forecast for each rate zone. As the customer base continues to increase, EGI's design day demand is expected to increase relative to annual demand primarily because DSM and efficiency gains typically reduce annual demand as opposed to design day demand.

Table 4 - Design Day Demand Forecast

Line No.	Particulars (TJ/d)	2021/22	2022/23	2023/24	2024/25	2025/26
1	EGD	4,044	4,059	4,076	4,091	4,107
2	Union North West	131	132	133	133	133
3	Union North East	419	419	420	424	424
4	Union South	3,308	3,343	3,430	3,471	3,523

In comparison to the 2021 Annual Update shown in Table 5, design day demands have slightly increased in the EGD and Union North rate zones. The updated forecast for the Union South rate zone reflects changes in expected Sarnia Industrial Line growth and Panhandle Transmission System for 2023/24 and 2024/25.

Table 5 - 2022 Design Day Demand Forecast vs 2021 Design Day Demand Forecast

Line No.	Particulars (TJ/d)	2021/22			2022/23			2023/24			2024/25		
		2022 Update	2021 Update	Variance	2022 Update	2021 Update	Variance	2022 Update	2021 Update	Variance	2022 Update	2021 Update	Variance
1	Total EGD	4,044	4,040	4	4,059	4,057	2	4,076	4,074	2	4,091	4,074	17
2	Total Union North West	131	128	3	132	128	4	133	128	6	133	128	5
3	Total Union North East	419	404	14	419	406	13	420	410	11	424	410	15
4	Total Union South	3,308	3,269	39	3,343	3,325	18	3,430	3,351	79	3,471	3,540	(69)

6. Current Portfolios

6.1 Commodity Portfolio

EGI procures supply on behalf of its system sales service customers. The commodity portfolio reflects many years of planning which leverages much of the North American natural gas supply landscape, including supply from sources such as: the WCSB, Dawn, Chicago, Niagara, U.S. Midcontinent, Ontario Production and the Appalachian Basin. These supply sources, along with EGI's transportation contracts which move the supply to both the distribution system and storage assets, has resulted in a commodity portfolio which is diverse, flexible, reliable, and cost-effective.

To serve Union North West, EGI holds firm transportation contracts connecting to supplies in Western Canada via the TCPL Mainline. In addition, the Union North West rate zone can receive supply from

[37] In the coldest day method, the design day HDD value is selected by choosing the coldest day on record and utilizing this HDD value to derive the design day demand that is used to establish the gas supply and transportation portfolio.

third-party services, such as peaking services or delivered supply arrangements. EGI may also consider transportation on Great Lakes Pipeline.

For Union North East, EGI holds firm transportation contracts on multiple upstream pipelines providing access to supplies in Western Canada, Appalachia and Dawn. In addition, the Union North East rate zone can receive supply from third-party services, such as peaking services or delivered supply arrangements.

To serve the EGD rate zone, EGI holds firm transportation contracts on multiple upstream pipelines providing access to supplies in Western Canada, Chicago, Niagara, Dawn and Appalachia. In addition, the EGD rate zone can receive supply from third-party services, such as peaking services or delivered supply arrangements.

Similarly, EGI holds firm transportation contracts on multiple upstream pipelines to serve Union South, providing access to supplies in Western Canada, Chicago, Niagara, the U.S. Mid-Continent and Appalachia. Dawn purchases are also included as part of the Union South supply portfolio.

Table 6 provides the sources of supply assumed in EGI's Plan for sales service customers with an illustration in Figure 11.

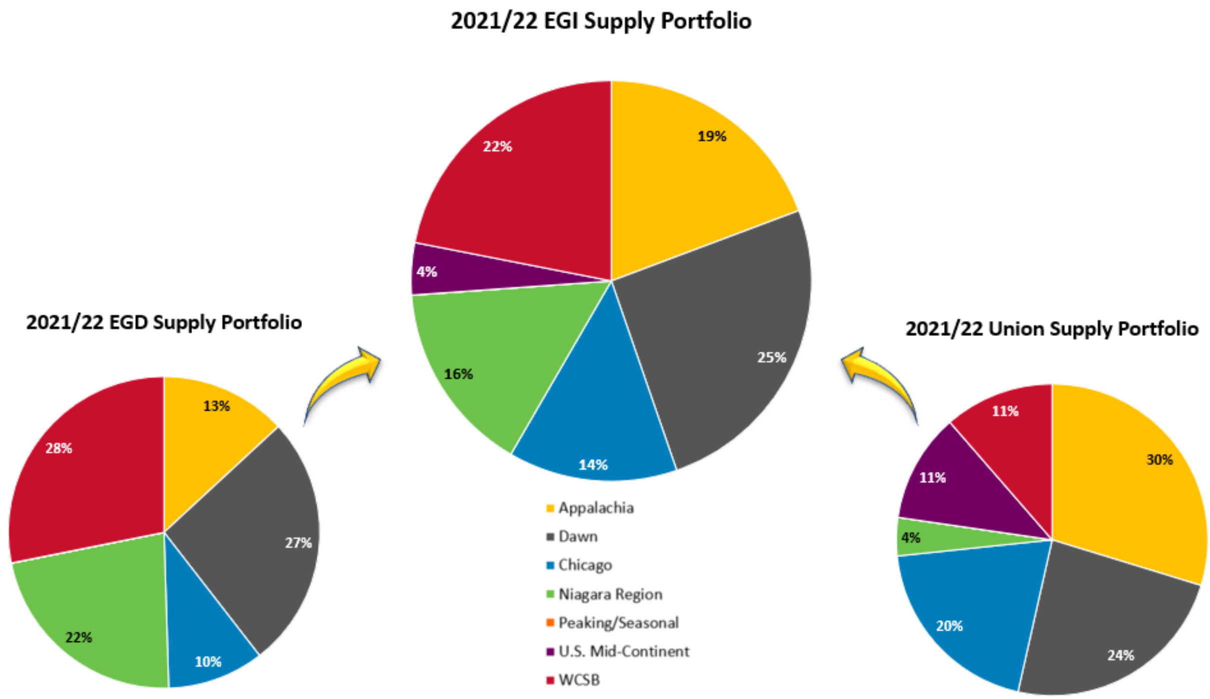
Table 6 - Sources of Supply

Supply Forecast

Line No.	Particulars (TJ)	2021/22	2022/23	2023/24	2024/25	2025/26
	EGD					
1	Appalachia	43,151	43,151	43,269	43,151	43,151
2	Chicago	32,980	32,980	33,070	32,980	32,980
3	Niagara Region	73,341	73,341	73,542	73,341	73,341
4	Dawn	86,748	90,964	93,355	94,488	97,355
5	Peaking/Seasonal	23	38	55	70	86
6	WCSB	92,580	92,595	92,927	92,638	92,580
7	Total EGD	328,823	333,069	336,219	336,668	339,493
	Union North West					
7	WCSB	11,851	12,126	12,299	12,320	12,413
	Union North East					
8	Appalachia	19,254	19,255	19,308	19,255	19,255
9	Dawn	11,432	11,520	11,725	11,558	11,773
10	WCSB	1,493	1,493	1,498	1,493	1,493
11	Total North East	32,180	32,268	32,531	32,306	32,521
	Union South					
12	Appalachia	38,510	38,510	38,615	38,510	38,510
13	Chicago	38,509	38,509	38,615	38,509	38,509
14	Niagara Region	7,702	7,702	7,723	7,702	7,702
15	Dawn	34,799	35,691	36,770	37,129	37,425
16	U.S. Mid-Continent	21,950	21,950	22,011	21,950	21,950
17	WCSB	8,797	8,797	8,821	8,797	8,797
18	Total South	150,267	151,159	152,554	152,597	152,893
19	Total Supply Forecast	523,121	528,623	533,602	533,891	537,321

*Ontario Production is included as part of Dawn number in Union South Total

Figure 11 - EGI Sources of Supply



6.2 Energy Transition in the Gas Supply Portfolio

EGI recognizes the importance of emissions reduction in Ontario, as well as the important role that EGI plays in supporting the achievement of GHG emission reduction targets. EGI intends to support energy transition through the inclusion of diverse sources of supply in alignment with the gas supply guiding principles. This includes the existing Voluntary Renewable Natural Gas ("RNG") program and its future evolution, the inclusion of Responsibly Sourced Natural Gas ("RSG"), and the Low Carbon Energy Project.

Responsibly Sourced Natural Gas

In its 2021 Annual Update, EGI discussed the development of natural gas certifications that, at the time, it called Sustainable Natural Gas ("SNG"). EGI agreed with stakeholder feedback that the label SNG could be viewed as misleading and committed to monitoring the market and adopting a different term. Over the past year, Responsibly Sourced Gas ("RSG") has emerged as a commonly used term.

EGI has continued to closely monitor the development of new RSG certifications which measure a natural gas producer's conformance to a number of standards. The standards measure the production impacts to environmental, social, and governance ("ESG") attributes including air and water quality, carbon and methane emissions, and relations with Indigenous communities. The RSG certifications provide transparency for customers, lowers emissions in the production process, and drives continued improvements to the supply chain. These certifications and the market dynamics surrounding them have developed rapidly through 2021.

In the 2021 Annual Update, EGI provided information stating that producers may seek an embedded premium for this certified gas as compared to what they would otherwise charge for uncertified gas they have produced. This premium would not always be explicitly known to the market. At the time, EGI noted that an embedded premium may be up to $0.15/GJ.

As the RSG market has developed over the last year, and producers have become increasingly more likely to certify their gas, EGI understands that any potential embedded premium that a producer would include has decreased and is now likely $0.05/GJ or less. As this market continues to develop, EGI expects the embedded premium to decrease further and RSG will eventually become a standard offering by producers and marketers.

In 2022, EGI has been able to procure RSG within its normal procurement practices and without paying a premium for that supply. More information on that purchase, as well as illustrative examples of how RSG fits within the procurement process, is outlined later in this section. In alignment with customer interest and the spirit of public policy initiatives, EGI will continue to seek economical RSG contracts with suppliers to provide a meaningful way for customers to begin improving ESG outcomes without increasing costs for customers.

Throughout 2021, several certifications have emerged. The Equitable Origins EO100, MiQ, and Project Canary's Trustwell certifications are examples that are actively used by producers to monitor their conformance to specific ESG standards that are different for each certification.

The Equitable Origin EO100 Certification process evaluates producers based on their impacts to water, air, wildlife, indigenous relations, and working conditions for employees. Equitable Origin provides a framework for responsible energy development based on census from industry, affected communities, governmental agencies, and encourages excellence in social and environmental performance.[38] Certification is granted after third-party verification of compliance with all parameters of the EO100 Standard at a specific energy development site (e.g. an oil or gas drilling pad, a hydroelectric dam, or a wind farm). These parameters include:

- Corporate governance, accountability & ethics
- Human rights, social impacts and community development
- Fair labour and working conditions
- Indigenous peoples' rights
- Climate change, biodiversity and environment
- Project life cycle management

Project Canary's Trustwell Certification evaluates producers based on four categories of responsibility: air, water, land and community. Through this certification, producers are assigned a platinum, gold or silver rating based on the analysis of their practices and through using continuous monitoring

[38] https://www.equitableorigin.org/eo100-for-responsible-energy/overview/

technology. The minimum requirements of any level of the certification include a third-party evaluation of:

- Environmental programs (water, air, land, community)
- Spill prevention
- Waste management
- Emergency response
- Well integrity

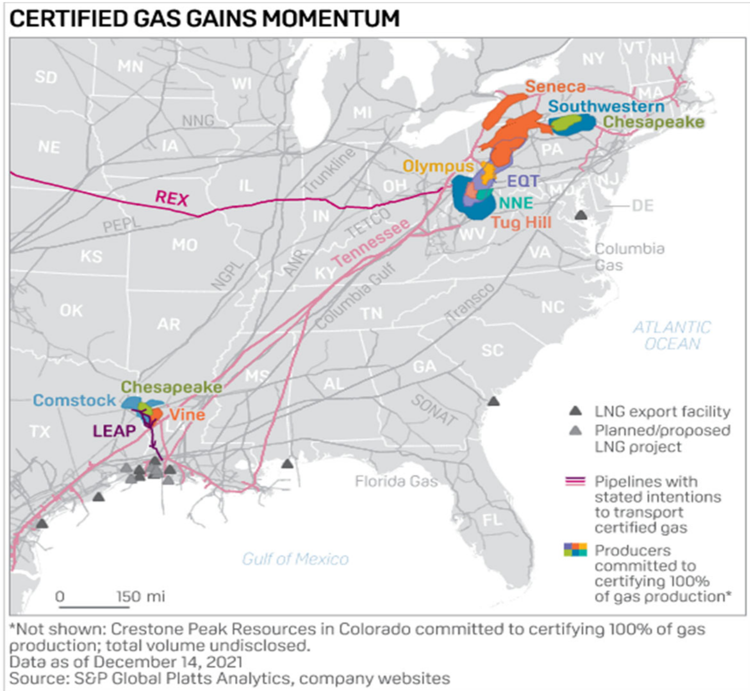
The MiQ Certification aims to provide transparency on methane emissions. It applies an A to F grade for methane emissions that is reviewed regularly as certified facilities are issued a monthly MiQ certificate for the gas that is produced. This certification looks at the calculated methane intensity, the monitoring technology deployment at facility and source levels and company practices. Third party auditors are required to audit and verify these specifications at various intervals to qualify for levels within the MiQ grading system. MiQ is also currently being extended to apply to the liquefaction process of natural gas, meaning that LNG will be able to be deemed RSG.

Over the past year, the supply and demand for RSG has developed rapidly. Suppliers have recognized certification as a means to improve their ESG performance and reduce emissions in the production process. Utilities and other large market participants have encouraged these responsible production practices through the procurement of RSG to align with customer interests in improving ESG outcomes and to reduce the carbon emissions of their customers.

According to S&P Global Platts, as of October 14, 2021, approximately 14% of US gas production is anticipated to be RSG by the end of 2022[39] and this is expected to increase as announcements and commitments from producers continue to be made. Western Canada, the Appalachian region and Permian basin have each had producers commit to certifying all or a portion of their production. As can be seen in the map below, many large producers have committed to certifying 100% of their production[40].

[39] Certified natural gas: Midstream sector begins embracing concept, standards | S&P Global Platts (spglobal.com)
[40] Commodities 2022: First US LNG cargo from certified gas could set sail | S&P Global Platts (spglobal.com)

Figure 12 - Map of RSG Development



Utilities have been among the early purchasers of RSG. In early 2020, Énergir, Québec's largest natural gas utility, entered into the first RSG supply agreement governed by the EO100 framework. Through this arrangement in 2020, Energir purchased 15% of its system gas as RSG and expected to exceed 20% in 2021[41]. As of November 1, 2019, Virginia Natural Gas, part of Southern Gas Company, committed to purchasing 20% of their supply as RSG certified by Project Canary from Southwestern Energy[42]. LNG importers in Europe and Asia are also seen as potential buyers of RSG as Project Canary seeks to expand their certification to LNG terminals and meet this market's demand[43].

Depending on the certification, RSG has various attributes that differentiate the value of the gas. RSG is a cost-effective solution to improving ESG in the natural gas sector. Purchasing RSG allows for transparency into the ESG practices, including in certain certifications, practices related to emission intensity of certified suppliers. Requirements vary by certification however, reducing methane intensity in production can lead to material reduction in emissions. For example, moving from a production methane intensity of 1% to 0.2%, a mid-level certification requirement by MiQ[44], results in an approximate reduction of 3 kgCO2/GJ.

[41] Market for responsibly sourced gas begins to take root, stakeholders say | S&P Global Market Intelligence (spglobal.com)
[42] Project-Canary-ESG-Profit-Center.pdf (projectcanary.com)
[43] Project Canary Says U.S. LNG Terminals in Talks to Environmentally Certify Trains - Natural Gas Intelligence
[44] The Technical Standard - MiQ

During EGI's RFP commodity procurement process, bids are solicited from many counterparties for gas at a location. During this process, and depending on the location, bids received can range in price by up to approximately $0.20/GJ from the highest to lowest offer.

EGI has provided some examples below to help illustrate how RSG bids may fit into common RFP spreads.

Example 1:

EGI is soliciting bids for prompt month Empress gas and received 4 offers:

Table 7 - RSG Bids Example 1

Supplier	Quantity Offered	Price
A	10,000	AECO Monthly Index + $0.82
B	10,000	AECO Monthly Index + $0.90
C	7,500	AECO Monthly Index + $0.76
D	15,000	AECO Monthly Index + $1.00

EGI requires 25,000 GJ of gas and may contract supply from suppliers as follows:

- Supplier C: 7,500 as the lowest price.
- Supplier A: 10,000 as the second-lowest price.
- Supplier B: 7,500 as the third-lowest price.

In this transaction, EGI has paid a range of $0.14/GJ to meet the required supply obligations by choosing the supply at the lowest cost from three suppliers based on availability. Had a producer with RSG fit within this range of bids, EGI would have been able to procure the RSG without any explicit incremental cost for the RSG.

As per the Gas Supply Procurement Policies and Practices, in considering bids through a request for proposal process, EGI may consider not only the price of a bid, but any offsetting risks or service attributes. EGI may also procure gas using a Straight Purchase, in which no RFP is conducted, where liquidity, diversity or other market conditions make direct negotiations with one or more suppliers more favorable than a bidding process[45]. As can be seen in Example 2, EGI may pay a small premium for gas to prioritize diversity.

Example 2:

EGI is soliciting bids for November-March Panhandle gas and received 3 offers:

[45] As most recently filed with the OEB August 27, 2021, pages 20-21

Table 8 - RSG Bids Example 2

Supplier	Quantity Offered	Price
A	10,000	NYMEX Monthly Index + $0.41
B*	20,000	NYMEX Monthly Index + $0.32
C	10,000	NYMEX Monthly Index + $0.37

**Supplier B is currently providing all gas that EGI has contracted at this location.*

EGI requires 20,000 MMBtu of gas and may contract supply from suppliers as follows:

- Supplier B: 10,000 as the lowest price, but may only take 50% of the offered volume.
- Supplier C: 10,000 as the second lowest price.

The diversity provided by contracting through multiple suppliers provides a benefit to customers in comparison to the lowest price bid as it diversifies the risks to provide reliability and security of supply to system customers.

Similar to the reliability and security of supply provided by diversity, procurement of RSG aligns well with EGI's Gas Supply guiding principles as it is aligned with the spirit of many public policy initiatives surrounding ESG and federal commitments to reduced emissions.

During January 2022, EGI procured EO100 Certified RSG as part of regular course of business through a purchase at Dawn. EGI solicited and received offers from suppliers offering fixed price gas with a range of $0.25 USD/MMBtu for the quantity of gas required by EGI for delivered within January. As part of this transaction, EGI received an offer for RSG near the mid-point of this range and was able to procure some RSG.

Although EGI intends to purchase RSG without increasing costs to customers, if 20% of the total portfolio of system gas was procured as RSG with a $0.05/GJ premium, the impact to the average residential customer would be less than $1.00 increase per year. As seen in Appendix A, through Customer Engagement, EGI received feedback from customers supporting the inclusion of RSG in the gas supply portfolio, even if an explicit premium is required. Of those customers surveyed, 61% were supportive of paying a premium for RSG. In their responses, 25% of customers supported EGI purchasing RSG as 50% of its portfolio.

Procuring RSG provides a way to allow EGI customers to have transparency into the ESG attributes of the gas they consume, including a lower carbon footprint of the natural gas they consume. This can be accomplished by using existing NAESB contracts, relationships with existing suppliers and no up-front costs to implement. Further, if EGI were to signal to the market that it is interested in procuring RSG, it would encourage more suppliers to implement practices to lower emissions and contribute to ESG attributes set by certification.

Renewable Natural Gas

The Renewable Natural Gas ("RNG") market is in its early days of development and lacks the liquidity that has evolved over decades in the conventional natural gas market. The maturity of the conventional natural gas market has come from the development of an adequate balance of supply and demand, an active marketplace to connect counterparties, and transparent pricing mechanisms.

Unlike conventional natural gas, RNG supply is scarce and there is currently no active RNG product that trades on the Intercontinental Exchange. Instead, projects are priced based on the producer's economics to support the viable production of RNG and cost recovery of project development. Though there has been an increase in media coverage and articles following the development of RNG, there are currently no commodity publications tracking its current market. Common in developing markets, having no standard reference price for producers, marketers, and end users to reference inhibits market transparency.

In addition, procuring RNG can be subject to a long lead times and high costs for RNG producers to connect to a local gas distribution system. Producers require long-term contracts to recoup costs associated with projects, while utilities and end users need assurance of cost recovery to make long-term commitments. Fortis BC has recognized the advantage it has from being a "first-mover" in the RNG market due to its ability to sign "long-term offtake agreements with a high degree of certainty of regulatory approval[46]."

As utilities such as Energir and Fortis BC continue to evolve their RNG programs to procure RNG supply, and potential new producers begin to enter the market, the opportunity to procure RNG at a reasonable cost is becoming increasingly competitive. As EGI does not have certainty of cost recovery for RNG beyond its voluntary program, Ontario natural gas customers are at a disadvantage as compared to other jurisdictions.

In accordance with the gas supply planning principle of aligning to public policy, EGI is evaluating how it can further support the development of an RNG market in Ontario.

Voluntary Renewable Natural Gas Program

The Ontario government released the Made-in-Ontario Environment Plan ("MOEP") on November 29, 2018, which outlines a requirement for natural gas utilities to implement a voluntary RNG option for customers. The Ontario government will also consult on the appropriateness of clean content requirements[47].

An application for EGI's proposed Voluntary RNG program was filed with the OEB on March 5, 2020[48] proposing to offer system gas general service customers the option to pay a fixed $2 monthly charge to fund the incremental cost of procuring RNG as part of the overall system gas supply. On September 25, 2020, the OEB granted EGI approval of the program on a pilot basis until the OEB issues a further decision on the program.

[46] 2021 Comprehensive Review and Application for Approval of a Revised Renewable Gas Program (fortisbc.com)
[47] Ontario Ministry of the Environment, Conservation and Parks, "Preserving and Protecting our Environment for Future Generations: A Made-in-Ontario Environment Plan", page 33, https://www.ontario.ca/page/made-in-ontario-environment-plan
[48] EB-2020-0066

EGI launched the program on April 1, 2021 and as of January 31, 2022, 835 customers have enrolled in the program.

RNG Supply

According to the Canadian Biogas Market Report, there is currently over 6 PJ of RNG being produced annually in Canada[49]. A study conducted in 2020 by Torchlight Bioscience estimated that it is practical to assume that 155 PJ of RNG is economically available annually, while an additional 654 PJ could be produced, but is not commercially viable at this point in time.[50]

There has been rapid development in RNG projects throughout Canada. Of the 155 operational RNG facilities in Ontario, most of the production is generated from wastewater treatment facilities[51]. One of the areas that shows the most potential for RNG is Southwestern Ontario, found within EGI's franchise area. A majority of prospective RNG production here would be derived from agricultural feedstocks (crop residue, silage, hog, and poultry manure) and could potentially connect to the EGI distribution system. Staton Bro's Dairy farm, based in Ilderton, Ontario, is a current producer building infrastructure to connect their RNG supply to the EGI distribution system. While Staton Farms is located in EGI's delivery area, it currently has a supply contract with British Columbia based Utility Fortis BC, which was approved in the Spring of 2020 by B.C.'s provincial regulator.[52] Another Southwestern Ontario producer StormFisher, located in London, Ontario, generates RNG from organic waste and is already connected to EGI's system, which also sells production to FortisBC.[53]

The growth of recent RNG production facilities has also continued in the United States. There has been a 42% increase in production projects from early 2019 through 2020[54]. Total RNG volumes are projected at 6,225 PJ with 1,055 PJ of RNG capacity under construction. Similar to how conventional natural gas is purchased today, EGI sees the potential to procure RNG from producers and suppliers across North America.

In November 2020, the Québec government unveiled its 2030 Plan for a Green Economy, which, among other things, aims to require a 10% blend of RNG in the natural gas network by 2030 and a 50% increase in bioenergy production by 2030. Québec has recently enacted a regulation that requires the natural gas distributors (Énergir and others) to annually increase the quantity of RNG from 2% in 2022 to 5% in 2025. This creates an opportunity to grow the province's RNG supply and reduce greenhouse gas emissions. Énergir buys RNG from producers with pricing based on the production capacity of the project ranging from $7-$22/GJ.[55]

---

[49] https://biogasassociation.ca/resources/canadian_2020_biogas_market_report, page 2.
[50] https://biogasassociation.ca/resources/canadian_2020_biogas_market_report, page 35.
[51] https://biogasassociation.ca/resources/canadian_2020_biogas_market_report, page 22.
[52] https://farmtario.com/news/stanton-bros-ltd-set-to-become-first-agricultural-supplier-into-ontario-grid/
[53] 2021 Comprehensive Review and Application for Approval of a Revised Renewable Gas Program (fortisbc.com)
[54] https://www.naturalgasintel.com/u-s-rng-production-sites-accelerate-in-2020/
[55] https://biogasassociation.ca/resources/canadian_2020_biogas_market_report, page 11.

FortisBC's RNG program has been procuring RNG since 2011. Over the past 10 years, this program has grown from delivering .04 PJ in 2011 to a forecast of 4 PJ in 2022[56]. As per British Columbia's Greenhouse Gas Reduction Regulation, FortisBC can allocate 5% of its portfolio to RNG.[57] In addition, the CleanBC Plan targets 15% renewable gas by 2030[58], which Fortis has stated is approximately 30 PJ of RNG and that it expects to be able to meet this requirement[59].

In November 2021, both Fortis and Énergir released RFPs for additional RNG supply closing in early 2022. In its RFP, Énergir indicated that it is looking for 50 million m^3 of RNG[60] by the end of 2023, and that it would be issuing 2 additional RFPs for supply for 2025. These RFPs are aimed at helping Énergir reach its mandated 2025 requirement of 5% of its portfolio. Fortis's RFP will aim to add to their growing number of RNG suppliers, as its strategy to ensure supply is available at reasonable cost is focused on securing "biogas-derived Renewable Gas supply early in this decade rather than waiting for the market to mature further[61]."

Low Carbon Energy Project

EGI submitted a revised Leave to Construct application for the Low Carbon Energy Project ("LCEP") with the OEB on March 31, 2020[62]. Following OEB approval in the fall of 2020, construction started on the hydrogen blending facilities to move the pilot project forward. Construction and commissioning were completed in September 2021, and the plant began blending up to 2% hydrogen by volume on October 1, 2021 for approximately 3,600 customers in Markham, Ontario. From the initial blend in October 2021 through the end of January 2022, the GJ equivalent of hydrogen that has been blended into the system and purchased as part of the gas supply plan is 503 GJ.

Blended gas, due to its hydrogen content, has a lower carbon intensity and will emit less greenhouse gas emissions than conventional natural gas. The experience gained through implementation of the LCEP will help EGI determine whether to expand hydrogen blending to other parts of the distribution system. The LCEP pilot project, and future projects of the same type, will expand EGI's ability to support current and future government policies and objectives aimed at reducing greenhouse gas emissions.

Hydrogen Production in Canada

In December of 2021, the Canadian Government released its Hydrogen Strategy for Canada. Within this strategy document, projections suggest that as much as 6% of Canada's energy end-use by 2030 will be accounted for by hydrogen, with clean or low-carbon hydrogen meeting up to 30% of the energy demand by 2050.[63]

---

[56] 2021 Comprehensive Review and Application for Approval of a Revised Renewable Gas Program (fortisbc.com)
[57] https://biogasassociation.ca/resources/canadian_2020_biogas_market_report
[58] CleanBC Roadmap to 2030 (gov.bc.ca)
[59] 2021 Comprehensive Review and Application for Approval of a Revised Renewable Gas Program (fortisbc.com)
[60] Request for proposals - RNG | Énergir (energir.com)
[61] 2021 Comprehensive Review and Application for Approval of a Revised Renewable Gas Program (fortisbc.com)
[62] EB-2019-0294
[63] The Hydrogen Strategy (nrcan.gc.ca)

Already, an estimated 3 Mt of conventional hydrogen is produced annually for industrial use, making Canada one of the top 10 global hydrogen producers. This includes 0.3 Mt of electrolytic hydrogen and hydrogen produced from natural gas with carbon abatement, making Canada one of the top producers of clean hydrogen in the world.[64] With Canada having launched the Clean Fuels Fund, the $1.5 billion CAD program aims to help support the buildout of new clean fuel production capacity, establish biomass supply chains, and develop enabling codes and standards.[65]

6.3 Transportation Portfolio

To manage risk, EGI holds a diverse portfolio of transportation contracts to meet the design day needs of each delivery area. The transportation portfolio of firm services provides direct and secure access to a diverse group of supply basins and market hubs across North America.

Maps 1-3 in Appendix B provide a visual representation of all contracted transportation services for the EGD and Union rate zones as of November 1, 2021. A complete listing of the transportation capacity currently contracted for EGD, Union North, and Union South rate zones is provided in Appendix C.

6.4 Transportation Portfolio Changes

EGI continuously monitors market conditions and service offerings and will enter into contracts throughout the planning period as required for the ongoing execution of the gas supply plan.

The following section addresses transportation portfolio changes since the time the 2020 Annual Update was developed. The format of this section is consistent with the Transportation Contracting Analysis filing requirements as outlined in EB-2005-0520.

Transportation Contracting Analysis

For the period of November 1, 2021 to October 31, 2032 EGI has made the following portfolio changes:

1. Vector Pipeline
    a. Effective November 1, 2021, 42,202 GJ/d capacity (21,101 for both the EGD rate zone and Union South rate zone from Chicago to Dawn) for a term of 5 years.
2. TCPL
    a. Effective November 1, 2021, 1,000 GJ/d capacity from Empress to the Union WDA for a term of 1 year.
    b. Effective November 1, 2021, 386 GJ/d capacity from Empress to the Union NDA for a term of 1 year.

[64] IEA Canada 2022 – Energy Policy Review, page 71.
[65] IEA Canada 2022 – Energy Policy Review, page 34.

c. Effective November 1, 2022, 4,000 GJ/d capacity from Empress to the Union EDA for a term of 5 years.

A comparison of landed costs for Vector Pipeline capacity relative to the viable alternatives can be found in Appendix D. A comparison of landed costs for the Union NDA is found in Appendix E, and for the Union EDA in Appendix F. As long-haul TCPL capacity was the only available option to the WDA no landed cost analysis was completed for the contracted capacity.

Rationale for Vector Pipeline Capacity

Vector provides a competitively priced, reliable, and flexible transportation option that offers supply diversity at Chicago as well as along the Vector route, including the ability to supply the Sarnia Industrial Line.

From January 14 to February 5, 2021 Vector Pipeline held a Non-Binding Open Season for a proposed 2023/2024 expansion project and existing capacity starting November 2021. This was Vector's first offering of existing eastbound capacity in several years. EGI bid for existing capacity from Chicago to Dawn and contracted for 40,000 Dth/d (42,202 GJ/d) of capacity at a toll of $0.16 USD/Dth/d for a term of 5 years. The new capacity is split 20,000 Dth/d for the EGD rate zone and 20,000 Dth/d for the Union South rate zone. Concurrently, EGI also negotiated a toll reduction of $0.015 USD/Dth/d for the Union South Vector contract renewal as discussed in Section 7.3. 7.3

The benefits of this capacity include:

i. Contract supports EGI's objective of structuring a portfolio with a diversity of contract terms and supply basins;
ii. Firm transportation purchase is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable cost;
iii. Landed cost of gas flowing from Chicago along this route is competitively priced and has an end date that aligns with the gas year;
iv. Provides a fixed-rate toll which provides toll certainty on a portion of EGI's upstream transportation portfolio;
v. Supports the acquisition of supply from upstream markets, maintaining diversity of contract terms and supply basins;
vi. Provides flexibility to access multiple supply sources at Joliet and other points along the path;
vii. Provides EGI with delivery point flexibility within the path including Michigan storage and Sarnia; and,
viii. Provides flexibility as the capacity can be segmented and used bi-directionally.

Rationale for TCPL WDA capacity

EGI's Gas Supply Plan identified a winter of 2021/2022 design day shortfall of 2,698 GJ/d in the Union WDA. EGI has purchased 1,700 GJ/d peaking services which represents 2% of the peak day requirement with the remaining 1,000 GJ/d with firm transportation. TransCanada was offering capacity to the Union WDA through an Existing Capacity Open Season.

The benefits of this capacity include:

i. Provides firm transportation capacity to meet the firm design day loads within the Union WDA to cover the design day shortfall;
ii. Contract is one-year in duration which aligns with the gas year and provides opportunity to recalculate needs in future years; and,
iii. Firm transportation contract is consistent with the gas supply principle of ensuring secure and reliable gas supply to EGI's service territory.

Rationale for TCPL NDA Capacity

In 2019, an industrial customer located in the Union NDA notified EGI that long-haul capacity assigned to them by EGI would be returned effective November 1, 2021. At the time, EGI elected to add this capacity into its transportation portfolio to meet the needs in the Union NDA as it was an economic option. EGI has notified TCPL of its intention to turn back this capacity effective November 1, 2022 and will be evaluating its long-haul capacity requirements on an annual basis.

Rationale for TCPL Union EDA Capacity

TCPL held an Existing Capacity Open Season from February 7 to 9, 2022 for long haul transportation with service dates beginning November 1, 2022. EGI's preferred planning strategy for meeting peak day shortfalls in the Union EDA is to purchase third party services for up to 2% of the peak day demand and to purchase firm transportation for shortfalls beyond that amount. EGI regularly monitors the availability of firm transportation and noted in January 2022, there was no FT capacity available to the Union EDA. EGI submitted a bid and was awarded 4,000 GJ/d of existing capacity for a term of 5 years. The 4,000 GJ/d is equal to the forecast peak day shortfall for the winter of 2022/23 and secures EGI's ongoing access to this transportation capacity without having to support a build project and commit for a 15-year term.

The benefits of this capacity include:

i. Contract supports EGI's objective of structuring a portfolio with a diversity of contract terms and supply basins;
ii. Contract aligns with the gas year and provides opportunity to recalculate needs in future years;
iii. Firm transportation purchase is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable cost;
iv. Provides a fixed-rate toll which provides toll certainty on a portion of EGI's upstream transportation portfolio; and,
v. Provides EGI with delivery point flexibility within the path.

6.5 Storage Portfolio

In accordance with the Natural Gas Electricity Interface Review ("NGEIR") Decision[66] and confirmed in the OEB's Decision and Order regarding the amalgamation of EGD and Union and the associated rate-setting mechanism ("MAADs decision")[67], the amount of cost-based storage reserved for EGD rate zone customers is 99.4 PJ and 100 PJ is reserved for Union rate zone customers.

The allocation of storage to natural gas distribution customers is based upon methodologies approved by the OEB as part of the Natural Gas Storage Allocation Policies Decision[68] and the quantity was confirmed in the MAADs decision.

Table 9 illustrates the in-franchise storage requirement for each rate zone. Union in-franchise storage requirement has increased as a result of the increasing demand forecast discussed in Section 5.1.

Table 9 - Storage Requirement Forecast

Line No.	Particulars (PJ)	2021/22	2022/23	2023/24	2024/25	2025/26
	EGD					
1	Infranchise Storage Requirement					
2	Infranchise Customer Requirement	125.9	125.9	125.9	125.9	125.9
3	Cost-Based Storage					
4	Tecumseh	99.4	99.4	99.4	99.4	99.4
5	Welland	0.3	0.3	0.3	0.3	0.3
6	Market Based Storage	26.2	26.2	26.2	26.2	26.2
7	Space Allocated for Infranchise Use	125.9	125.9	125.9	125.9	125.9
	Union					
8	Infranchise Storage Requirement					
9	Contingency	9.5	9.5	9.5	9.5	9.5
10	Infranchise Customer Requirement	87.5	88.1	88.2	88.1	88.2
		97.0	97.6	97.8	97.7	97.7
11	Cost-Based Storage					
12	Dawn	100.0	100.0	100.0	100.0	100.0
13	Excess Utility Space Available	3.0	2.4	2.2	2.3	2.3

In addition to the cost-based storage available to customers in the EGD rate zone, EGI holds 11 service agreements equaling 26.2 PJ of storage capacity at market-based rates. The size and term of each service agreement varies. Every year EGI conducts analysis to determine its storage requirements.

[66] EB-2005-0551 - Decision with Reasons, November 7, 2006.
[67] EB-2017-0306/0307 - Decision and Order, August 30, 2018.
[68] EB-2007-0724/0725 - Decision with Reasons, April 29, 2008.

Based on the results of the analysis, a blind storage RFP process is undertaken to replace expiring storage service agreements or add incremental storage capacity.

The inclusion of storage assets in the Gas Supply Plan provides a cost-effective, reliable and secure alternative to purchasing commodity when required by customers, which is consistent with the OEB's guiding principles. Storage provides further operational flexibility and aligns with the planning target to fill storage on November 1, maintain sufficient inventory on February 28 to meet the design day storage withdrawal requirement, and on March 31 to meet planning requirements.

6.6 Unutilized Capacity

EGI does not plan for any unutilized EGD rate zone capacity of its TCPL long-haul transportation, given the persistently low prices of supply procured in Alberta and the ability to use in-path diversions on long-haul transportation at no or limited incremental cost.

In the Union North rate zones, the upstream transportation portfolio is sized to meet design day demand. Logically, the amount of supply transported to meet average annual demand is less than the capacity needed to meet requirements on design day. As a result, a portion of EGI's contracted capacity is planned to be unutilized during the year. The difference between the total contracted capacity and total demand for both Union North sales service and bundled DP customers equals the planned unutilized capacity. If weather is colder than normal and/or annual consumption is greater than forecast, EGI will use this capacity to meet incremental supply requirements.

For the Union South rate zone, EGI plans for upstream pipeline capacity to flow at 100% utilization each day of the year. During times when usage is less than upstream supply, the excess supply is injected into storage at Dawn. When demands are greater than upstream supply, gas is withdrawn from storage and transported to Union South in-franchise customers. Consequently, there is no planned unutilized capacity in Union South.

Table 10 illustrates the total planned UDC by rate zone.

Table 10 - Planned UDC

Line No.	Particulars (PJ)	2021/22	2022/23	2023/24	2024/25	2025/26
1	EGD	-	-	-	-	-
2	North West	13.6	13.0	12.9	12.8	12.8
3	North East	1.8	1.7	1.7	1.8	1.6
4	South	-	-	-	-	-
5	Total Planned UDC	15.5	14.7	14.6	14.7	14.4

7. Supply Option Analysis

EGI's gas supply, storage, and transportation portfolio has been developed over time and is guided by its approved gas supply planning principles and North American natural gas market conditions. EGI's strategy is continuously evolving and contemplates both the North American market in its entirety and the impact that changes across the continent can have on the Ontario market, including Dawn, as outlined above in Section 4.1. Several other factors such as contract terms, renewal rights, operational requirements and supply source constraints are also significant factors influencing EGI's supply option analyses and decisions. Each individual gas supply, storage, and transportation evaluation cannot be considered independently and needs to be considered as part of the overall portfolio and strategy.

When evaluating alternatives for portfolio decisions, EGI balances its supply planning principles of reliability, flexibility, diversity and cost-effectiveness. Balancing these factors in evaluating gas supply options allows EGI to meet the OEB's guiding principles for assessment of the Plan. EGI's gas supply portfolio decisions are made based on market conditions at the time.

Evaluating the reliability and flexibility of a potential supply option includes the assessment of several qualitative and quantitative features.

Some of the features of a supply option's reliability that EGI may consider in its evaluation include:

- Supply liquidity, nomination performance, delivery performance, distance of haul, firmness of service, gate station connectivity; and,
- The level of third-party services (e.g. peaking and delivered services) held within the portfolio.

Some elements of flexibility that EGI may consider in its evaluation may include contracting lead time, transportation contract term, supply contract term, availability of third-party services, number of nomination windows, and renewal rights.

Assessing a supply option's ability to be reliable and flexible supports the OEB's guiding principle of reliability and security of supply.

When evaluating a supply option's impact on diversity, EGI assesses the ability to provide transportation capacity through multiple paths and the impact on overall supply diversity. Transportation path diversity and supply diversity are evaluated on a quantitative basis but also take qualitative factors into consideration.

EGI's consideration of diversity of transportation path and supply supports the OEB's guiding principles of reliability and security of supply and cost-effectiveness.

Finally, EGI's evaluation of the costs of a potential supply option is mainly a quantitative exercise. If the option is intended to satisfy average day needs, EGI will evaluate based on landed costs (i.e. $/GJ/d). If the option is intended to meet design day needs, annual costs (i.e. $/GJ/yr) are calculated.

EGI's consideration of costs supports the OEB's guiding principle of cost-effectiveness.

When EGI considers a new supply basin, new upstream transportation capacity, new storage assets, or renewals of existing transportation, multiple alternatives are considered. The supply option analysis provides a list of viable alternatives evaluated and the associated qualitative and quantitative considerations for incremental assets required for design day or average day.

In the event there are no viable alternatives to serve a delivery area, or if disclosing sensitive information will impact the market, EGI will not publicly file the analysis.

Once a decision has been made, the decision analysis will be filed in the Transportation Contracting Analysis section of the Transportation Portfolio within the next annual update or 5-Year Plan.

7.1 Design Day Analysis

Each year, EGI conducts a design day position analysis in which projected design day demand is compared against existing contracted assets for that rate zone's delivery areas. A design day shortfall occurs when there is more demand than capacity through existing assets to meet design day demand. Forecast shortfalls are monitored throughout the length of the Plan and analyzed on an annual basis. EGI evaluates the requirements over the entire forecast period.

EGI considers the availability of assets into the delivery area and assesses all viable alternatives. If there are no constraints in the delivery area or risk to the future availability of capacity, services will be acquired on a short-term basis. Contracting for one year or less gives EGI the flexibility to adjust contracted capacity as requirements and market conditions are subject to change over time. If the delivery area is constrained, EGI may contract for a longer period to ensure the required assets are available to meet design day demand long term. A requirement to secure long-term capacity could result in EGI bidding into an open season with a minimum commitment term (e.g. 15 years).

The Plan does not include any excess assets; only those necessary to meet firm customer requirements.

EGD Rate Zone

The EGD rate zone demand and supply balance, which identifies EGI's design day position, is outlined in Table 11. The forecast shows a shortfall in nearly every year resulting from growth in the Enbridge CDA.

Table 11 - EGD Rate Zone Design Day Position

Line No.	Particulars (TJ/d)	EGD CDA 2021/22	EGD CDA 2022/23	EGD CDA 2023/24	EGD CDA 2024/25	EGD CDA 2025/26	EGD EDA 2021/22	EGD EDA 2022/23	EGD EDA 2023/24	EGD EDA 2024/25	EGD EDA 2025/26
	Demand										
1	Gross Demand	3,414	3,423	3,434	3,444	3,455	729	735	741	746	751
2	Curtailment	(73)	(73)	(73)	(73)	(73)	(26)	(26)	(26)	(26)	(26)
3	Net Demand	3,341	3,350	3,361	3,371	3,382	703	709	715	720	725
	Supply Asset										
4	TCPL Long-haul	5	5	5	5	5	260	260	260	260	260
5	TCPL Short-haul	768	768	768	768	768	362	362	362	362	362
6	TCPL STS	284	284	284	284	284	81	81	81	81	81
7	EGI D-P	2,194	2,194	2,194	2,194	2,194	-	-	-	-	-
8	In-Franchise Supply	68	68	68	68	68	0	0	0	0	0
9	Third-Party Services	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
10	Total Supply	3,319	3,319	3,319	3,319	3,319	703	703	703	703	703
11	Excess(Shortfall)	(22)	(31)	(43)	(52)	(63)	(0)	(6)	(12)	(17)	(23)
12	*Shortfall % of Net Demand*	*0.7%*	*0.9%*	*1.3%*	*1.6%*	*1.9%*	*0.1%*	*0.9%*	*1.7%*	*2.4%*	*3.1%*

Enbridge CDA

Supply Options

Table 12 below provides a list of options which are expected to be available to EGI[69,70] at various times over the next five years to meet the shortfalls identified in Table 11. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 13 provides a representative map of the paths described in the options.

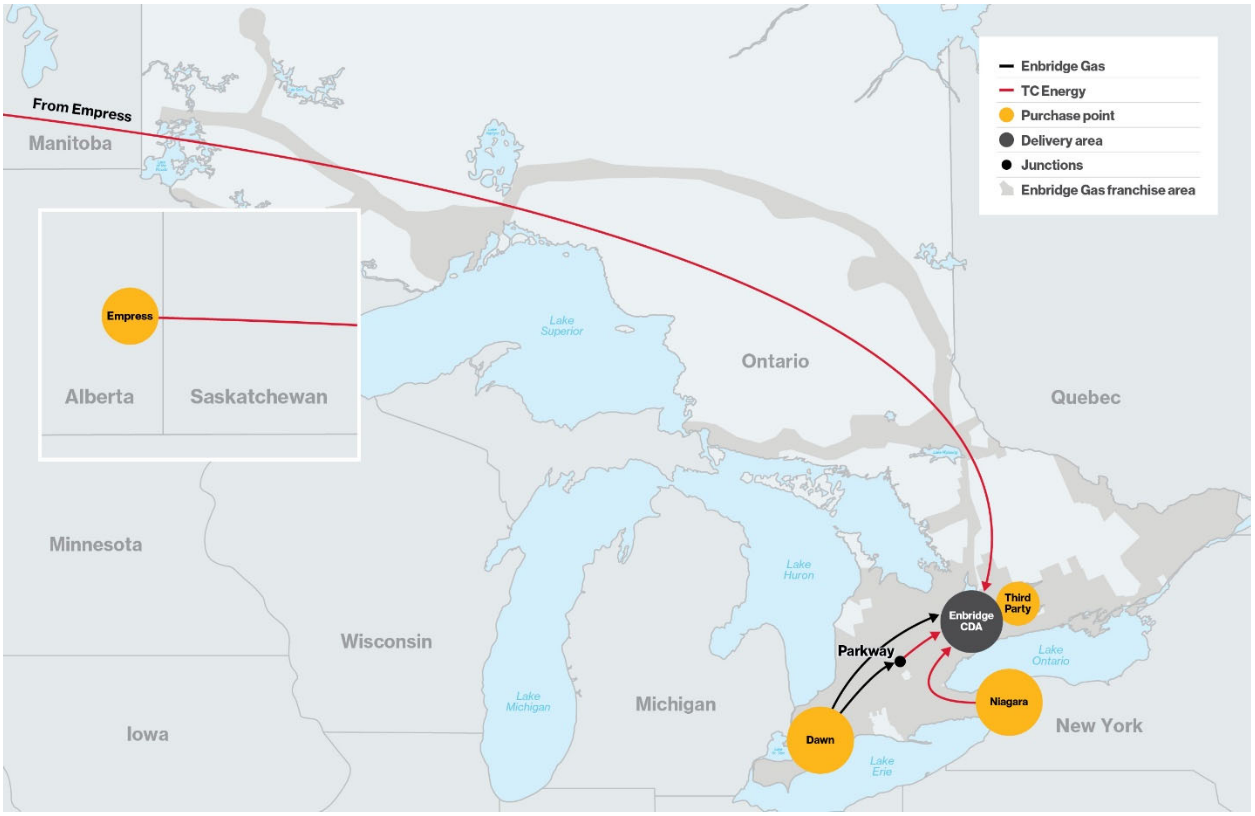
Table 12 - Enbridge CDA Supply Options

Option	Option Details: Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Long-haul	TCPL	FT-LH	Empress	-	Enb CDA
Short-haul: D-P	EGI + TCPL	D-P + FT-SH	Dawn	Parkway	Enb CDA
Short-haul: Dawn	EGI	D-P	Dawn	-	Enb CDA
Short-haul: Niagara	TCPL	FT-SH	Niagara	-	Enb CDA
Third-Party	Market Participants	Peaking, Del Serv	Enb CDA	-	Enb CDA

[69] The list of options in Table 12 is not an exhaustive list of all options. The list of options is a short-list of options that do not disclose commercially sensitive information and offers the reliability and flexibility required to manage a design day event, which is short-term and a temporary phenomenon.

[70] Third-Party considers both peaking service and delivered service. Delivered services have limited participants so disclosing costs could impact the market. Therefore, when considering costs, peaking service is the option being considered as there are more counterparties and disclosing pricing will not impact the market.

Figure 13 - Enbridge CDA Supply Options Map



Evaluation Matrix

Each of the options outlined in Table 12 above were evaluated for their reliability, flexibility, diversity and annual costs, as described at the beginning of Section 7. Table 13 summarizes the analysis.

Table 13 - Enbridge CDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	positive	neutral	positive	22.93	<1%	No
Short-haul: D-P	positive	neutral	neutral	5.48	<1%	No
Short-haul: Dawn	positive	neutral	neutral	3.08	<1%	No
Short-haul: Niagara	neutral	neutral	neutral	3.86	<1%	No
Third Party	neutral	negative	positive	1.43	<1%	Unknown

For reference, the symbols in Table 13 describe whether a particular option has a: positive, neutral, or negative impact on the ability of the option to satisfy a design day shortfall as compared to EGI's current portfolio.

Preferred Planning Strategy

Since the 5-Year Plan was filed, there have been no change in options to serve and no material differences in the evaluation matrix, therefore the preferred strategy is still to procure a third-party service. EGI will continue to monitor any shortfall positions and make decisions using the best available information at that time.

Enbridge EDA

Supply Options

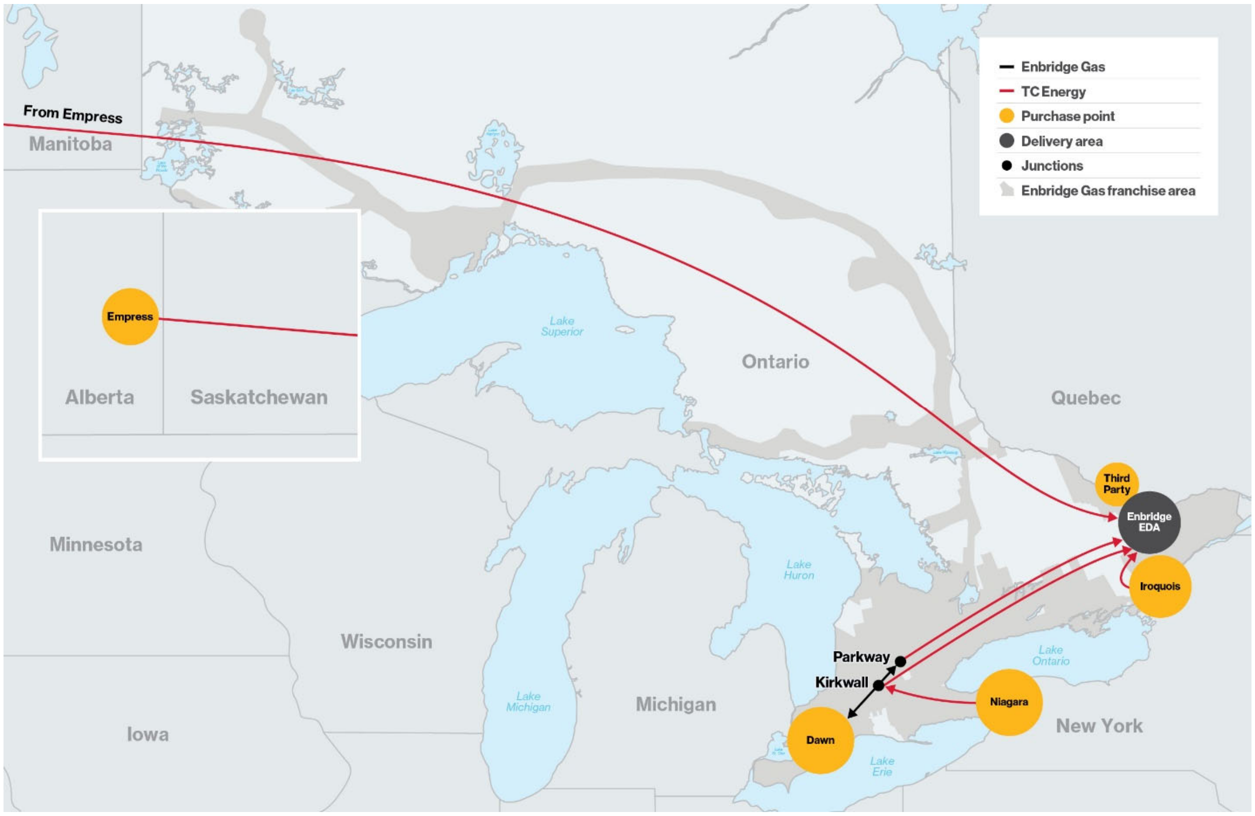
Table 14 below provides a list of options which are expected to be available to EGI[71] at various times over the next five years to meet the shortfalls identified in Table 11. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 14 provides a representative map of the paths described in the options.

Table 14 - Enbridge EDA Supply Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Long-haul	TCPL	FT-LH	Empress	-	Enb EDA
Short-haul: D-P	EGI + TCPL	D-P + FT-SH	Dawn	Parkway	Enb EDA
Short-haul: Niagara	TCPL	FT-SH	Niagara	Kirkwall	Enb EDA
Short-haul: Iroquois	TCPL	FT-SH	Iroquois	-	Enb EDA
Third-Party	Market Participants	Peaking, Del Serv	Enb EDA	-	Enb EDA

[71] The list of options in Table 14 is not an exhaustive list of all options. The list of options is a short-list of options that do not disclose commercially sensitive information and offers the reliability and flexibility required to manage a design day event, which is short-term and a temporary phenomenon.

Figure 14 - Enbridge EDA Supply Options Map



Evaluation Matrix

Each of the options outlined in Table 14 above were evaluated for their reliability, flexibility, diversity and annual costs, as described at the beginning of Section 7. Table 15 summarizes the analysis.

Table 15 - Enbridge EDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	↑	↑	→	6.63	<1%	No
Short-haul: D-P	↑	→	→	2.66	<1%	No
Short-haul: Niagara	→	→	↑	2.45	<1%	No
Short-haul: Iroquois	→	→	↑	1.05	<1%	No
Third Party	→	↓	↑	0.37	<1%	Unknown

For reference, the symbols in Table 15 describe whether a particular option has a: positive ↑, neutral →, or negative ↓ impact on the ability of the option to satisfy a design day shortfall as compared to the current portfolio.

Preferred Planning Strategy

Since the 5-Year Plan was filed, there has been no change in options to serve and no material differences in the evaluation matrix, therefore the preferred strategy is still to procure a third-party service. EGI will continue to monitor any shortfall positions and make decisions using the best available information at that time.

Union North Rate Zones

The Union North rate zones demand and supply balance which identifies EGI's design day position is outlined in Table 16. The North East forecast shows a 4 TJ/d shortfall (Union EDA, Union NDA and Union NCDA) starting in 2021/22 which grows to 7 TJ/d by 2025/26. The Union North West forecasts a shortfall of 3 TJ in the Union WDA in 2021/22 growing to 4 TJ in 2025/26.

Table 16 - Union North Rate Zone Design Day Position

Line No.	Particulars (TJ/d)	North West 2021/22	2022/23	2023/24	2024/25	2025/26	North East 2021/22	2022/23	2023/24	2024/25	2025/26
	Demand										
1	Union North	131	132	133	133	133	419	419	420	424	424
	Supply Asset										
2	TCPL Long-Haul	78	78	78	78	78	4	4	4	4	4
3	TCPL Short-Haul	-	-	-	-	-	120	120	120	120	120
4	North Dawn T-Service	-	-	-	-	-	33	33	33	33	33
5	LNG	-	-	-	-	-	10	10	12	11	12
6	Redelivery from Storage										
7	*From Parkway*										
8	STS Withdrawals	31	31	31	31	31	88	88	88	88	88
9	STS Pooled Withdrawals	-	-	-	-	-	16	16	15	15	15
10	Short-haul Firm	-	-	-	-	-	119	119	119	119	119
11	Enhanced Market Balancing	-	-	-	-	-	25	25	25	25	25
12	*From Dawn*										
13	STS Withdrawals	19	19	20	20	20	-	-	-	-	-
14	Third-Party Services	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
15	Total Supply	129	129	129	129	129	415	416	417	416	417
16	Excess(Shortfall)	-3	-3	-4	-4	-4	-4	-3	-3	-8	-7
17	*Shortfall % of Demand*	*2.1%*	*2.3%*	*3.0%*	*2.7%*	*3.0%*	*0.9%*	*0.8%*	*0.8%*	*1.9%*	*1.7%*

* includes Sales Service, Bundled DP, North Dawn T-Service

Union EDA

Supply Options

Table 17 below provides a list of options which are expected to be available to EGI[72] at various times over the next five years to meet the shortfall identified in Table 16. Some alternatives do not have sufficient available capacity with existing infrastructure.

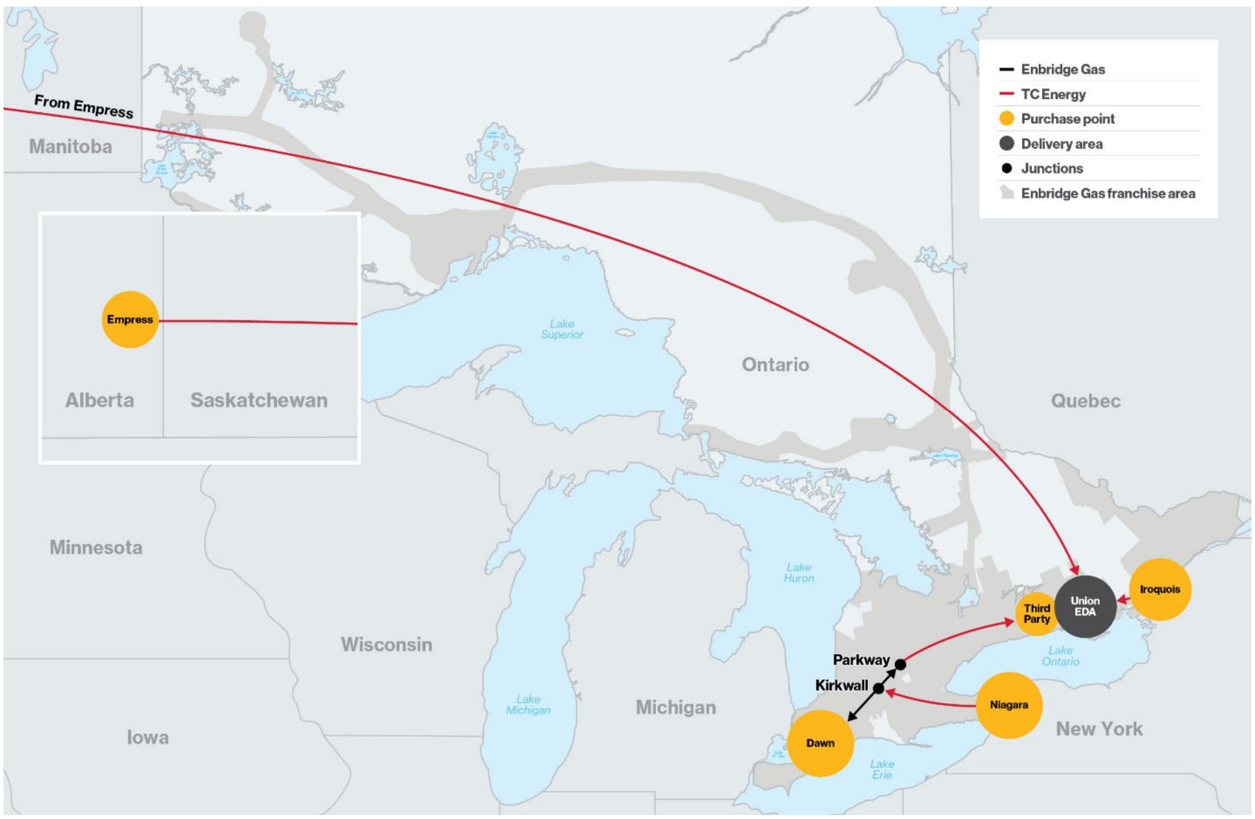
Figure 15 provides a representative map for the paths of the supply options.

[72] The list of options in Table 17 is not an exhaustive list of all options. The list of options is a short-list of options that do not disclose commercially sensitive information and offers the reliability and flexibility required to manage a design day event, which is short-term and a temporary phenomenon.

Table 17 - Union EDA Supply Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Long-haul	TCPL	FT-LH	Empress	-	Union EDA
Short-haul: D-P	EGI + TCPL	D-P + FT-SH	Dawn	Parkway	Union EDA
Short-haul: Niagara	TCPL	FT-SH	Niagara	-	Union EDA
Short-haul: Iroquois	TCPL	FT-SH	Iroquois	-	Union EDA
Third-Party	Market Participants	Peaking, Del Serv	Union EDA	-	Union EDA

Figure 15 - Union EDA Supply Options Map



Evaluation Matrix

Each of the options outlined in Table 17 above were evaluated for their reliability, flexibility, diversity and landed costs, as described at the beginning of Section 7. Table 18 summarizes the analysis.

Table 18 - Union EDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	↑	↑	↑	2.80	<1%	No
Short-haul: D-P	↑	→	→	0.95	<1%	No
Short-haul: Iroquois	→	→	↑	0.46	<1%	No
Third Party	→	↓	↑	0.15	<1%	Unknown

For reference, the symbols in Table 18 describe whether a particular option has a: positive ↑, neutral →, or negative ↓ impact on the ability of the option to satisfy design day shortfall as compared to the current portfolio.

Preferred Planning Strategy

Since the 5-Year Plan was filed, there has been no change in options to serve and no material differences in the evaluation matrix, therefore the preferred strategy is to procure a third-party service. EGI will continue to monitor any shortfall positions and make decisions using the best available information at that time.

Union NDA

Supply Options

Table 19 below provides a list of options which are expected to be available to EGI[73] at various times over the next five years to meet the shortfall identified in Table 16. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 16 provides a representative map for the paths of the supply options.

Table 19 - Union NDA Supply Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Long-haul	TCPL	FT-LH	Empress	-	Union NDA
Short-haul: D-P	EGI + TCPL	D-P + FT-SH	Dawn	Parkway	Union NDA
LNG	EGI	Liquefaction	Union NDA	-	Union NDA
Third-Party	Market Participants	Peaking, Del Serv	Union NDA	-	Union NDA

[73] The list of options in Table 19 is not an exhaustive list of all options. The list of options is a short-list of options that do not disclose commercially sensitive information and offers the reliability and flexibility required to manage a design day event, which is short-term and a temporary phenomenon.

Figure 16 - Union NDA Supply Options Map

Evaluation Matrix

Each of the options outlined in Table 19 above were evaluated for their reliability, flexibility, diversity and landed costs, as described at the beginning of Section 7. Table 20 summarizes the analysis.

Table 20 - Union NDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	↑	↑	→	4.56	<1%	Yes
Short-haul: D-P	↑	→	→	2.76	<1%	No
LNG	↑	↑	↑	0.21	<1%	Yes
Third Party	↓	↓	↑	0.35	<1%	Unknown

For reference, the symbols in Table 20 describe whether a particular option has a: positive ↑, neutral →, or negative ↓ impact on the ability of the option to satisfy design day shortfall as compared to the current portfolio.

Preferred Planning Strategy

As stated in EGI's 2020 update to the 5-year Gas Supply Plan, third-party services will be considered as an option to meet a shortfall[74] and will utilize LNG to meet shortfalls in the Union NDA within the capabilities of the LNG system and recognizing that the LNG system is also relied upon for system integrity purposes.

Union NCDA

Supply Options

Table 21 below provides a list of options which are expected to be available to EGI[75] at various times over the next five years to meet the shortfall identified in Table 16. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 17 provides a representative map for the paths of the supply options.

Table 21 - Union NCDA Supply Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Long-haul	TCPL	FT-LH	Empress	-	Union NCDA
Short-haul: D-P	EGI + TCPL	D-P + FT-SH	Dawn	Parkway	Union NCDA
Third-Party	Market Participants	Peaking, Del Serv	Union NCDA	-	Union NCDA

[74] EB-2020-0135
[75] The list of options in Table 21 is not an exhaustive list of all options. The list of options is a short-list of options that do not disclose commercially sensitive information and offers the reliability and flexibility required to manage a design day event, which is short-term and a temporary phenomenon.

Figure 17 - Union NCDA Supply Options Map

Evaluation Matrix

Each of the options outlined in Table 21 above were evaluated for their reliability, flexibility, diversity and landed costs, as described at the beginning of Section 7. Table 22 summarizes the analysis.

Table 22 - Union NCDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	positive	positive	neutral	0.57	<1%	Yes
Short-haul: D-P	positive	neutral	neutral	0.18	<1%	No
Third Party	negative	negative	positive	0.03	<1%	Unknown

For reference, the symbols in Table 22 describe whether a particular option has a: positive, neutral, or negative impact on the ability of the option to satisfy design day shortfall as compared to the current portfolio.

Preferred Planning Strategy

Since the 5-Year Plan was filed, there has been no change in options to serve and no material differences in the evaluation matrix, therefore the preferred strategy is to procure a third-party service. EGI will continue to monitor any shortfall positions and make decisions using the best available information at that time.

Union WDA

Supply Options

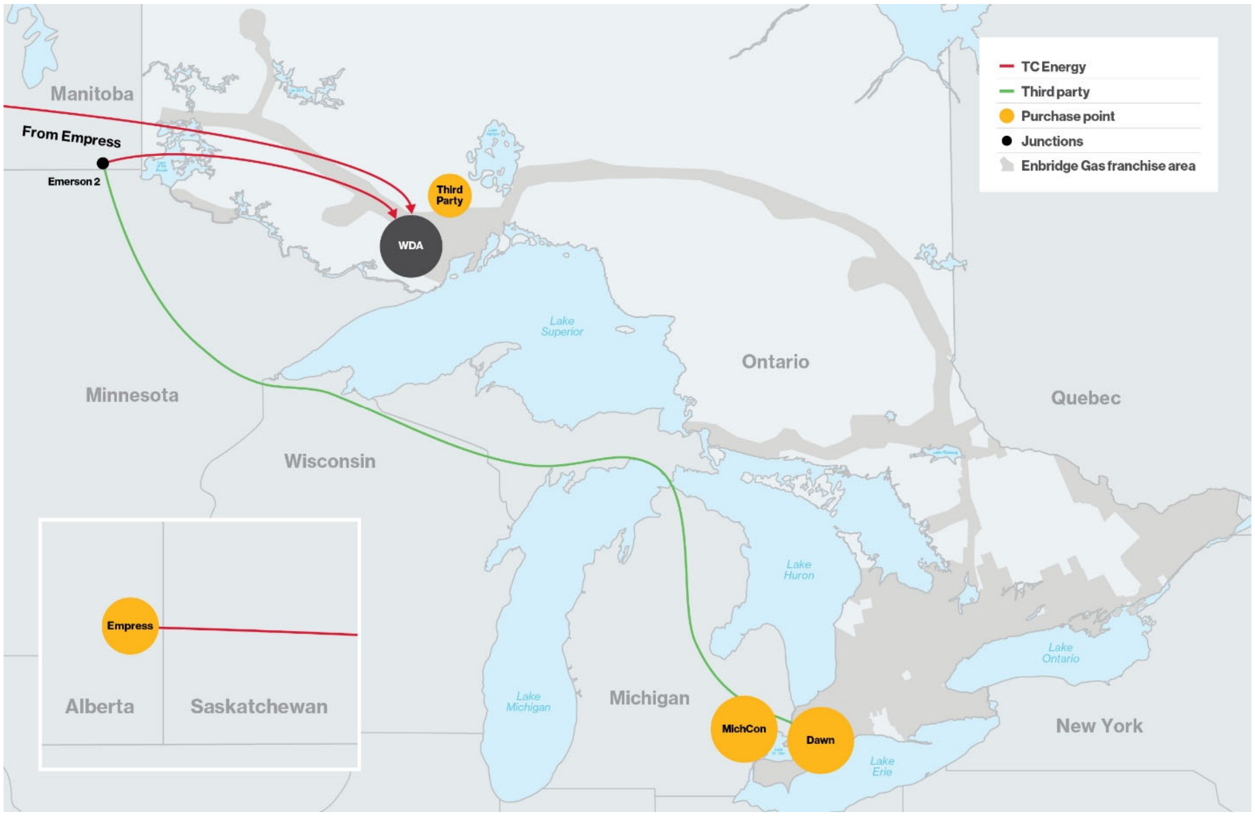
Table 23 below provides a list of options which are expected to be available to EGI[76] at various times over the next five years to meet the shortfall identified in Table 16. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 18 provides a representative map for the paths of the supply options.

Table 23 - Union WDA Supply Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Long-haul	TCPL	FT-LH	Empress	-	Union WDA
Short-haul: D-P	EGI + TCPL	D-P + FT-SH	Dawn	Parkway	Union WDA
Great Lakes	GLGT + TCPL	FT	SE Michigan	Emerson II	Union WDA
Third-Party	Market Participants	Peaking, Del Serv	Union WDA	-	Union WDA

[76] The list of options in Table 23 is not an exhaustive list of all options. The list of options is a short-list of options that do not disclose commercially sensitive information and offers the reliability and flexibility required to manage a design day event, which is short-term and a temporary phenomenon.

Figure 18 - Union WDA Supply Options Map



Evaluation Matrix

Each of the options outlined in Table 23 above were evaluated for their reliability, flexibility, diversity and landed costs, as described at the beginning of Section 7. Table 24 summarizes the analysis.

Table 24 - Union WDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	➡	➡	➡	0.90	<1%	Yes
Short-haul: D-P	➡	➡	⬆	1.32	<1%	No
Great Lakes	➡	➡	⬆	0.99	<1%	No
Third Party	⬇	⬇	⬆	0.10	<1%	Unknown

For reference, the symbols in Table 24 describe whether a particular option has a: positive ⬆, neutral ➡, or negative ⬇ impact on the ability of the option to satisfy design day shortfall as compared to the current portfolio.

Preferred Planning Strategy

EGI will monitor the requirement for incremental transportation services to the Union North West rate zone. Since the 5-Year Plan was filed, the option of serving the Union WDA from a supply source in Michigan and GLGT transportation looks more attractive and EGI will monitor the availability of this option. At this time the preferred strategy is to procure third-party services for up to 2% of the Union WDA peak day demand and FT Long-Haul transportation for the remainder EGI will continue to monitor any shortfall positions and make decisions using the best available information at that time.

Union South Rate Zone

EGI's Union South rate zone design day demand to supply position is outlined below in Table 25. EGI currently forecasts no excess or shortfall in the Union South rate zone over the term of the Plan.

Table 25 - Union South Rate Zone Design Day Position

Line No.	Particulars (TJ/d)	2021/22	2022/23	2023/24	2024/25	2025/26
	Demand					
1	Union South	3,308	3,343	3,430	3,471	3,523
	Supply Asset					
2	Great Lakes	21	21	21	21	21
3	Nexus	106	106	106	106	106
4	Non-obligated (e.g. Power Plants)	254	254	254	273	273
5	Ontario Dawn	530	539	552	551	561
6	Ontario Parkway	252	247	243	242	248
7	Panhandle	60	60	60	60	60
8	Storage	1,956	1,988	2,065	2,088	2,125
9	TCPL Long-Haul	3	3	3	3	3
10	TCPL Niagara	21	21	21	21	21
11	Vector	106	106	106	106	106
12	Total Supply	3,308	3,343	3,430	3,471	3,523
13	Excess(Shortfall)	-	-	-	-	-

* includes Sales Service, Bundled DP, T-Service

7.2 Average Day Requirement

Beyond forecasting design day demand, it is also important for EGI to understand the average day demand requirements within each rate zone, as this can help to inform EGI's approach for procuring supply throughout the year. EGI can purchase supply at Dawn or upstream of Dawn and transport it into each rate zone. The average day analysis places a greater emphasis on determining if a need exists for transportation capacity from particular supply basins and hubs (e.g. WCSB, Appalachia, Chicago, Dawn).

Consistent with the annual demand forecast developed by EGI found in Section 5.1, Table 26 shows both the annual and marginal average day demand growth expected over the five-year period of the Plan for system sales service customers.

Table 26 - Average Day Demand Analysis for System Sales Service Customers

Line No.	Particulars (TJ)	2021/22	2022/23	2023/24	2024/25	2025/26	Growth 2021 → 2025
	EGD						
1	Annual Demand	307,391	311,601	315,009	314,702	317,840	10,449
2	Daily Demand	842	854	863	860	871	29
	Union						
3	Annual Demand	189,727	191,069	192,971	192,653	193,390	3,663
4	Daily Demand	520	523	529	526	530	10

As Table 26 shows, the average annual demand for the EGD rate zone is expected to increase by roughly 10,449 TJ over the five years, or roughly 29 TJ/d of average day demand and Union rate zone is expected to increase by 3,663 TJ over the five years or roughly 10 TJ/d. As a result, EGI will consider purchasing additional gas supply assets to serve annual demand changes. A supply option analysis for average day requirements is presented to determine if additional transportation assets upstream of Dawn may provide additional reliability, flexibility, diversity and cost effectiveness.

Supply Options

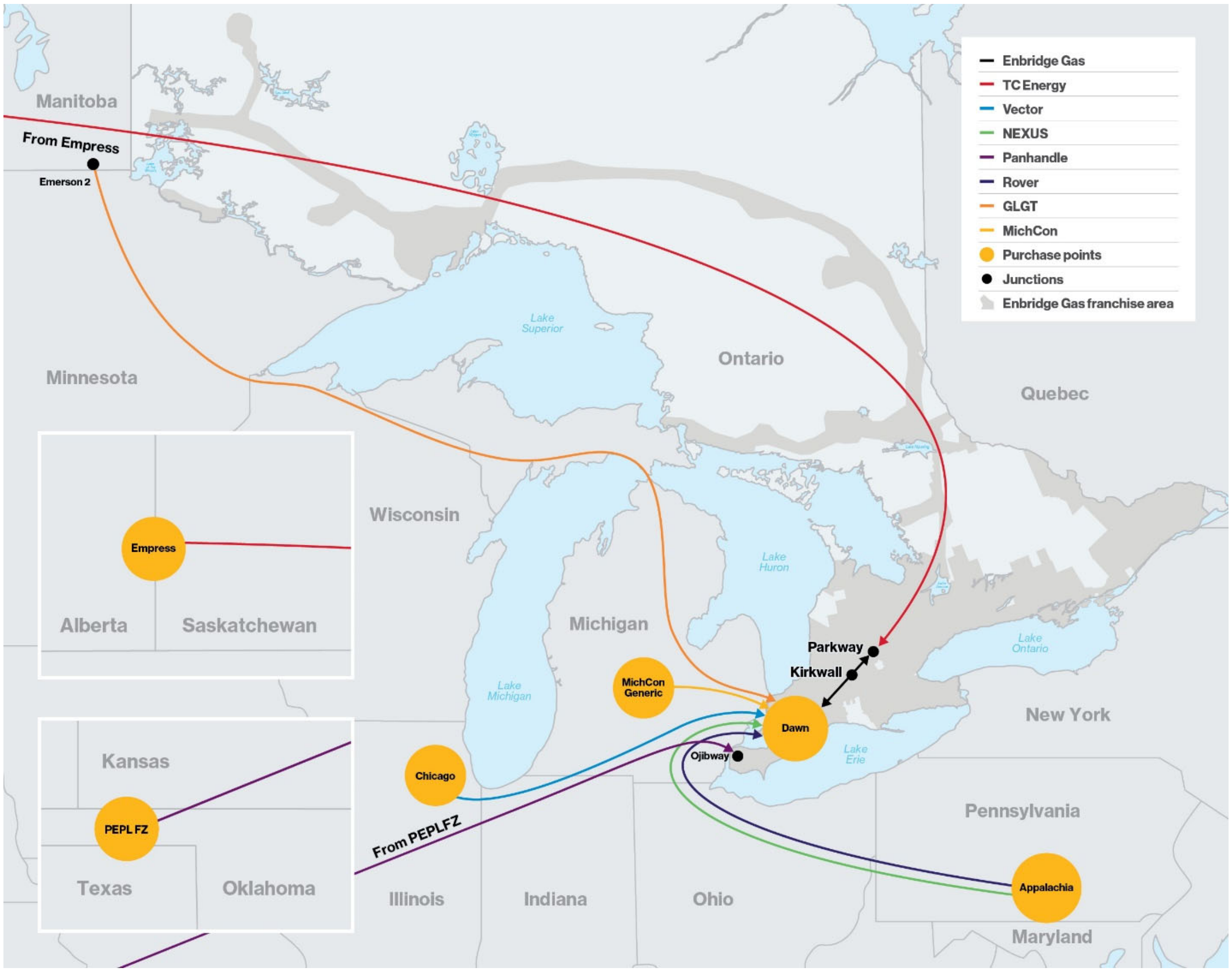
Table 27 below provides a list of options which are expected to be available to EGI[77], at various times over the five-year period. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 19 provides a representative map for the paths of the supply options.

Table 27 - Average Day Growth Supply Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Dawn	-	-	Dawn	-	Dawn
Dawn LTFP[78]	TCPL	LTFP	Empress	-	Union SWDA
Great Lakes	TCPL + GLGT	FT-LH + FT	Empress	Emerson	Dawn
MichCon	DTE	FT	MichCon	St. Clair	Dawn
Vector	Vector	FT-1	Chicago	-	Dawn
Panhandle	PEPL+EGI	FT	Panhandle FZ	Ojibway	Dawn
NEXUS	NEXUS	FT	Dominion	-	Dawn
Rover	Rover	FT	Dominion	-	Dawn
Niagara	TCPL + EGI	FT	Niagara	Kirkwall	Dawn

[77] Table 27 is not an exhaustive summary of all options, but rather is a short-list of options that do not disclose commercially sensitive information and offers the reliability and flexibility required to manage average day demand growth.
[78] TCPL held an Open Season for LTFP 2 service from March 10 until April 3, 2020. The toll for this offering was $0.02 lower than the original Dawn LTFP offering.

Figure 19 - Average Day Growth Supply Options Map



Evaluation Matrix

Each of the options outlined in Table 27 above were evaluated for their reliability, flexibility, diversity and landed costs, as described at the beginning of Section 7. Table 28 summarizes the analysis.

Table 28 - Average Day Growth Evaluation Matrix

Option	Relative to Status Quo			Available Capacity	Average Cost/Customer Impact - Relative to Status Quo	Available Capacity
	Reliability	Flexibility	Diversity			
Dawn	-	-	-	3.81	-	Yes
Dawn LTFP	→	→	→	4.30	<1%	Likely[79]
Great Lakes	→	→	→	4.33	<1%	Yes
MichCon	→	→	↑	3.93	<1%	No
Vector	→	→	→	3.92	<1%	Yes[80]
PEPL	→	→	→	4.53	<1%	Yes
NEXUS	→	→	→	4.00	<1%	Yes
Rover	→	→	↑	4.06	<1%	No
Niagara	→	→	→	3.77	<1%	No

For reference, the symbols in Table 28 describe whether a particular option has a: positive ↑, neutral →, or negative ↓ impact on the ability of the option to satisfy average day growth as compared to the current portfolio.

Preferred Planning Strategy

When the 5-year Plan was filed, EGI forecasted no material change in demand growth, options to serve or material differences in the evaluation matrix. EGI's Plan shows average day increases in the Union and EGD rate zones. Therefore, the preferred strategy is to manage changes in average day demand through purchases at Dawn or by adding upstream transportation. EGI will continue to monitor any market offerings and its position at Dawn and make decisions using the best available information at that time.

7.3 Transportation Contract Renewals

EGI evaluates its expiring contracts within the term of the Plan and determines whether these contracts should be renewed. There are 31 contracts requiring renewal analysis and these have been organized into two categories below.

Design Day Renewals

Each of the contracts in Table 29 are included within the design day analyses previously presented for each rate zone and have been required to serve each rate zone on a design day for many years.

[79] Although not offered by TCPL recently, EGI believes Dawn LTFP service could be available upon request
[80] Vector held an open season for service in 2021

Table 29 - Design Day Contract Expiries

Summary of Contracts Expiring within the 2022 Annual Update
As of November 1, 2021

Category	Rate Zone	Path	Pipeline	Contract Quantity		Expiry Date
Design Day	Union North West	Sprague to Baudette	Centra Pip	5,281	Mcf	31-Oct-22
Design Day	Union North West	Spruce to Union MDA	Centra Tra	150	10^3	31-Oct-22
Design Day	Union North West	Empress to Centrat MDA	TCPL	4,522	GJ	31-Oct-23
Design Day	Union North West	Empress to Union WDA	TCPL	39,880	GJ	31-Oct-23
Design Day	Union North West	Empress to Union WDA	TCPL	11,527	GJ	31-Oct-23
Design Day	Union North East	Empress to Union NDA	TCPL	4,442	GJ	31-Oct-23
Design Day	Union North East	Empress to Union NCDA	TCPL	1,412	GJ	31-Oct-23
Design Day	Union North West	Empress to Union SSMDA	TCPL	2,700	GJ	31-Oct-23
Design Day	Union North West	Empress to Union SSMDA	TCPL	6,143	GJ	31-Oct-23
Design Day	Union North West	Empress to Union SSMDA	TCPL	12,800	GJ	31-Oct-23
Design Day	Union North East	Empress to Union EDA	TCPL	1,089	GJ	31-Oct-23
Design Day	Union North West	STS - Union WDA	TCPL	3,150	GJ	31-Oct-26
Design Day	Union North East	STS - Union EDA	TCPL	1,000	GJ	31-Oct-26
Design Day	Union North East	STS - Union NDA	TCPL	49,100	GJ	31-Oct-26
Design Day	Union North East	STS - Union NCDA	TCPL	13,704	GJ	31-Oct-26
Design Day	Union North West	STS - Union WDA	TCPL	31,420	GJ	31-Oct-26
Design Day	Union North West	STS - Union SSMDA	TCPL	35,022	GJ	31-Oct-26
Design Day	Union North East	STS - Union NDA	TCPL	48,375	GJ	31-Oct-26
Design Day	Union North East	STS - Union EDA	TCPL	26,351	GJ	31-Oct-26
Design Day	Union North East	Union Parkway Belt to Union EDA	TCPL	30,000	GJ	31-Oct-26
Design Day	Union North East	Union Parkway Belt to Union EDA	TCPL	5,000	GJ	31-Oct-26
Design Day	Union North West	Empress to Centrat MDA	TCPL	1,043	GJ	31-Oct-23
Design Day	Union North West	Empress to Union WDA	TCPL	1,000	GJ	31-Oct-22

As of today, the viable alternatives available to replace the expiring contracts listed above are restricted to firm transportation options.

Preferred Planning Strategy

Each of the firm contracts identified above are key components in ensuring the reliability of EGI's plan. Further, when coupled with an increasing need for assets on design day, EGI's preferred planning strategy is to continue to renew each contract on an annual basis. This approach supports the OEB's guiding principles by ensuring security of supply, flexibility and the reliability of the Plan. EGI will retain significant flexibility to respond to changing design day demand requirements should a need arise to reduce the amount of firm transportation capacity to the distribution system. EGI will continue to monitor market conditions and make renewal decisions using the best available information at that time.

Average Day Renewals

The average day contracts due for renewal over the term of the Plan listed in Table 30 are assets held upstream of Dawn or provide diversity of supply.

Table 30 - Average Day Contract Expiries

Summary of Contracts Expiring within the 2022 Annual Update
As of November 1, 2021

Category	Rate Zone	Path	Pipeline	Contract Quantity		Expiry Date
Average Day	Union South(1)	Clarington to St. Clair (Union)	Nexus Gas Transmission	75,000	Dth	31-Oct-22
Average Day	Union South	FZ (Markwest) to Ojibway	Panhandle	35,000	Dth	31-Oct-25
Average Day	Union South	Union Dawn to Union ECDA	TCPL	8,000	GJ	31-Oct-23
Average Day	EGD	Union Parkway Belt to Enbridge CDA	TCPL	153,700	GJ	31-Oct-26
Average Day	Union South	Empress to Union ECDA	TCPL	3,000	GJ	31-Oct-23
Average Day	Union South	Niagara Falls to Kirkwall	TCPL	21,101	GJ	31-Oct-23
Average Day	Union South	Emerson to St. Clair	Great Lakes Gas Transmission	20,000	Dth	31-Oct-24
Average Day	Union South	St. Clair to Union SWDA	Great Lakes Pipeline Canada	21,101	GJ	31-Oct-24
Average Day	Union South	Empress to Emerson 2	TCPL	21,418	GJ	31-Oct-23
Average Day	EGD	AECO to Empress	NOVA Transmission	50,000	GJ	31-Oct-24
Average Day	EGD	AECO to Empress	NOVA Transmission	75,000	GJ	31-Oct-25
Average Day	EGD	Union Parkway Belt to Enbridge CDA	TCPL	92,822	GJ	31-Oct-26
Average Day	EGD	Union Parkway Belt / Kirkwall to Enbridge EDA	TCPL	35,089	GJ	31-Oct-26
Average Day	EGD	Union Parkway Belt / Kirkwall to Enbridge EDA	TCPL	35,806	GJ	31-Oct-26
Average Day	EGD	Union Dawn to Iroquois	TCPL	40,000	GJ	31-Oct-26
Average Day	EGD	Union Parkway Belt to Enbridge CDA	TCPL	37,370	GJ	31-Oct-26
Average Day	EGD	Union Dawn to Enbridge CDA	TCPL	4,818	GJ	31-Oct-26
Average Day	EGD	Union Parkway Belt to Enbridge EDA	TCPL	9,716	GJ	31-Oct-26
Average Day	EGD	Union Dawn to Enbridge CDA	TCPL	145,000	GJ	31-Oct-26
Average Day	EGD	Union Parkway Belt to Enbridge CDA	TCPL	572	GJ	31-Oct-26
Average Day	EGD	Union Parkway Belt to Vic Square #2 CDA	TCPL	85,000	GJ	31-Oct-26
Average Day	EGD	Union Dawn to Enbridge EDA	TCPL	114,000	GJ	31-Oct-26
Average Day	EGD	Alliance to St. Clair (US Interconnect)	Vector Pipeline	20,000	Dth	31-Oct-24
Average Day	EGD	Northern Border to St. Clair (US Interconnect)	Vector Pipeline	45,000	Dth	31-Oct-24
Average Day	EGD	St. Clair (Canada) to Dawn	Vector Pipeline	68,579	GJ	31-Oct-24
Average Day	Union South	Clarington to Kensington (M1)	Nexus Gas Transmission	25,000	Dth	31-Mar-22
Average Day	Union South	Alliance to St. Clair (US Interconnect)	Vector Pipeline	20,000	Dth	31-Oct-26
Average Day	Union South	St. Clair (Canada) to Dawn	Vector Pipeline	21,101	GJ	31-Oct-26
Average Day	EGD	Alliance to St. Clair (US Interconnect)	Vector Pipeline	20,000	Dth	31-Oct-26
Average Day	EGD	St. Clair (Canada) to Dawn	Vector Pipeline	21,101	GJ	31-Oct-26
Average Day	Union South	Bluewater/Intl Border to Bluewater/Intl Border	St. Clair Pipelines L.P. (Bluewate	127,000	GJ	31-Oct-23
Average Day	Union South	St.Clair/Intl Border to St.Clair/Intl Border	St. Clair Pipelines L.P. (St.Clair Pi	214,000	GJ	31-Oct-23
Average Day	Union South	Chicago to US/Cdn Border	Vector Pipeline	80,000	Dth	31-Oct-25
Average Day	Union South	US/Cdn Border to Dawn	Vector Pipeline	84,404	GJ	31-Oct-25

Note:
(1) EGI has allocated the capacity as 2/3 to Union South and 1/3 to Union North East. Clarington to St. Clair expires and converts back to Kensington to St. Clair.

Great Lakes, NEXUS, TCPL, NOVA and Vector transportation capacities all provide increased diversity through multiple supply basins, transportation paths, counterparties, receipt and delivery points, and flexible contract terms for EGI to de-contract should requirements change. This approach appropriately balances the OEB's guiding principles, ensuring cost-effective, reliable and secure supply for customers.

Preferred Planning Strategy

As noted in Section 7.2, the options to serve average day have not changed and there are no material differences in the evaluation matrix, therefore the preferred strategy is to continue to renew the contracts on an annual basis. EGI will continue to monitor market conditions and will make renewal decisions using the best available information at that time.

Union Average Day Contract Renewals

1. Vector Pipeline
    a. Effective November 1, 2022, EGI has renewed a contract for 80,000 Dth/d capacity from Chicago to the US/Canadian border and associated 84,404 GJ/d contract from the US/Canadian border to Dawn for a period of 3-years

A comparison of landed costs for Vector Pipeline capacity relative to the viable alternatives can be found in Appendix G.

Rationale for Vector Pipeline Renewal

Vector provides a competitively priced, reliable and flexible transportation option that offers supply diversity at Chicago as well as along the Vector pipeline route. All other available options would reduce EGI's diversity by reducing Chicago purchases and increasing either Empress or Appalachia purchases. EGI negotiated a toll reduction to this contract renewal from $0.18/Dth/d to $0.165/Dth/d during the negotiation of the additional capacity detailed in Section 6.4 along with an additional 3-year renewal period for this contract.

The benefits of this capacity include:

i. Contract supports EGI's objective of structuring a portfolio with a diversity of contract terms and supply basins;
ii. Firm transportation purchase is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable cost;
iii. Landed cost of gas flowing from Chicago along this route is competitively priced and has an end date that aligns with the gas year;
iv. Provides a fixed-rate toll which provides toll certainty on a portion of EGI's upstream transportation portfolio;
v. Supports the acquisition of supply from upstream markets, maintaining diversity of contract terms and supply basins;
vi. Provides flexibility to access multiple supply sources at Joilet and other points along the path;
vii. Provides EGI with delivery point flexibility within the path including Michigan storage and Sarnia; and,
viii. Provides flexibility as the capacity can be segmented and used bi-directionally.

7.4 Storage Capacity Renewals

EGI holds 26.2 PJ of market storage capacity for use in the EGD rate zone. This storage capacity is held across 11 different non-renewable service agreements of varying terms and volumes. This diversity in term and volume allows EGI the flexibility to issue its annual RFP without needing to approach the market for all required storage capacity in any one year.

Storage is an integral upstream asset for the EGI portfolio. Storage is located close to the EGD rate zone increasing reliability and security of supply. Storage assets are a cost-effective means to manage the purchase of supply, as it allows for the purchase of the commodity in the summer, when prices tend to be lower, and withdrawal in the winter when prices tend to be higher. Further, storage service agreements provide a reliable asset that the utility can typically nominate within the day to help balance demand requirements.

Preferred Planning Strategy

EGI's preferred planning strategy for storage expiries is to continue to issue blind storage RFPs to the market each year to replace any capacity that is expiring as discussed in Section 6.5.

EGI held a blind RFP from November 10 to December 1, 2021 to replace 7 PJ of storage services that expire at the end of March 2022. EGI used the blind RFP process discussed in the 2021 Annual Update and contracted for 7 PJ of new storage services starting April 1, 2022 with terms between 1 and 3 years.

7.5 Summary of Supply Option Analysis

EGI's approach to diversifying its portfolio is analogous to a prudent investment portfolio where diversity of assets, supply, risk, and term are critical to a successful portfolio, and where market conditions are continuously evolving. The portfolio contemplates the North American market as a whole, as well as the resulting impacts on the Ontario market. To serve each rate zone, EGI uses capacity on multiple upstream pipelines to access several supply basins and market hubs. These pipelines provide access to supplies in Western Canada, Chicago, Dawn, U.S. Mid-continent, Niagara and Appalachia.

As part of its ongoing process, EGI will continue to evaluate each rate zone's portfolio to ensure it meets the needs identified in the Plan, balancing the guiding principles set forth by the OEB in the Framework. This ongoing work will include monitoring the impacts of in-service delays for new transportation projects and evaluating potential transportation alternatives.

A summary of EGI's preferred planning strategies to manage changes include:

- Design day
    - Enbridge CDA – acquire third-party services to manage design day shortfalls
    - Enbridge EDA – acquire third-party services to manage design day shortfalls
    - Union EDA – acquire third-party services to manage design day shortfalls
    - Union NDA – use LNG to manage shortfalls and potentially third-party services or absorbing capacity turned back by T-Service customers.
    - Union WDA – acquire third-party services and FT transportation to manage design day shortfalls
    - Union NCDA – acquire third-party services to manage design day shortfalls

   - Remaining delivery areas[81] – no action required
- Average day
   - Purchase supply at Dawn and potentially acquire incremental transportation capacity to manage average day growth
- Transportation contracts renewals
   - Renew existing transportation contracts on an annual basis
- Storage capacity renewals
   - EGD rate zone – Replace existing level of storage service agreements on an annual basis for varying terms

8. Gas Supply Plan Execution

EGI's Plan is updated annually for each rate zone and is approved internally by senior management. Once approved, the Gas Supply procurement team prepares a strategy to procure the necessary assets identified in the Plan. EGI executes the Plan while balancing reliability, diversity and flexibility, to achieve a cost-effective solution for ratepayers, in accordance with the OEB's guiding principles.

EGI frequently monitors customers' demand, commodity prices, and market conditions to adjust the strategy to execute the Plan. Decisions related to the continued execution of the Plan are made during operational planning meetings, held frequently throughout the year. A diverse, cross-functional team operates with oversight from the Director of Gas Supply to make purchasing decisions related to the execution of the Plan through gas supply procurement and transportation capacity utilization decisions. The execution of the Plan is monitored at a granular level to ensure flexibility is maintained to account for shifts in demand or changing market conditions.

Long-term, annual and seasonal supply arrangements are contracted prior to entering a season. These are contracted to a level that still allows for flexibility through prompt month and shorter-term purchases to manage changes in demand due to weather, usage patterns, market conditions or other factors. EGI regularly procures gas on shorter terms to ensure appropriate supply arrangements are in place to account for potential changes in the demand forecast.

An important input into these decisions is the short and mid-term weather forecast available at the time decisions are made. The weather forecast is used as a means of assessing potential demand impacts and required adjustments to the supply plan for the upcoming month. The use of medium-term weather forecasts provides EGI with the ability to adjust planned month-ahead supplies earlier, allowing EGI more flexibility in purchase terms. Conversely, in a warmer than normal year, the medium-term forecast gives EGI the opportunity to reduce planned purchases earlier.

To manage risk, EGI procures supply regularly throughout the year from creditworthy counterparties at multiple trading points using a layered approach with consideration to diversity of delivery term and supplier. Appendix H provides supplier diversity by basin for 2020/2021 by highlighting the

[81] Includes Union SSMDA, Union MDA, and Union South.

number of counterparties and the range of supply provided by each counterparty. This appendix highlights the diversity of supplier available at the most liquid trading points and the locations with less diversity of supplier.

Contracting for supply in this manner allows EGI to provide a stable, cost-effective solution for ratepayers while still maintaining the flexibility required to manage to seasonal storage inventory targets. This flexibility is also valuable when demand uncertainties present themselves, such as extreme weather swings.

8.1 Procurement Process and Policy

EGI purchases natural gas for system operations and the regulated system gas supply portfolio for all rate zones. On August 27, 2021, the updated *Gas Supply Procurement Policies and Practices* document was filed with the OEB. This update reflected a change in the responsibility of contract entry from middle office to front office. The objectives of the Policy continue to remain consistent with past versions.

The Gas Supply department continues to develop the monthly procurement plan. Per the *Gas Supply Procurement Policies and Practices,* EGI's Director and Manager of Gas Supply sign the monthly procurement plan authorizing the execution of the transactions in the procurement plan. EGI's procurement plan layers in annual, seasonal and monthly purchases each month leaving flexibility should requirements change. Gas supply for all rate zones continues to be purchased using both fixed and indexed price contracts. EGI is authorized to use an RFP process (written and verbal), electronic gas trading platforms or a brokerage house, and straight purchases directly with a counterparty under both the North American Energy Standards Board ("NAESB") contract or a Gas Electronic Data Interchange ("gas EDI") contract.

As system operator, EGI also manages many operational factors for all rate zones including:

- Actual and forecast consumption relative to planned consumption for its sales service customers (97% of all 3.8 million customers);
- Seasonal balancing requirements for sales service customers at key control points;
- Weather variances for all sales customers and outside of checkpoint balancing for bundled DP customers in the Union rate zones;
- Changes in supply and balancing requirements as customers move between sales service and DP;
- Unaccounted for gas and compressor fuel variances; and
- Planned and unplanned supply or pipeline disruptions.

9. Three-Year Historical Review

The following section provides a review of the prior three gas years, comparing the Plan for each year to the actuals experienced[82].

9.1 Heating Degree Days

The purpose of this section is to provide a brief review of the prior three years, comparing the forecasted HDD underlying each gas supply plan to the actual HDD experienced. The forecasted HDD are prepared according to OEB approved methodologies for each region.

Table 31 - Actual vs Plan Annual HDDs

		2018/19			2019/20			2020/21		
Line No.	Particulars (HDD)	Actual	Plan	Variance	Actual	Plan	Variance	Actual	Plan	Variance
1	EGD Central	3,841	3,640	6%	3,648	3,621	1%	3,277	3,645	-10%
2	EGD Eastern	4,707	4,325	9%	4,418	4,336	2%	3,917	4,373	-10%
3	EGD Niagara	3,637	3,417	6%	3,424	3,417	0%	3,087	3,429	-10%
4	Union North West	5,460	4,948	10%	5,173	4,941	5%	4,650	4,964	-6%
5	Union North East	5,100	4,948	3%	4,864	4,941	-2%	4,349	4,964	-12%
6	Union South	3,909	3,782	3%	3,726	3,763	-1%	3,399	3,772	-10%

As shown in Table 31:

- 2018/19 – HDDs were higher than budget across all weather zones due to colder than expected temperatures
- 2019/20 – HDDs were relatively close to budget across most weather zones: colder than expected in EGD Central, Eastern, Niagara, and Union North West; and warmer in Union North East and Union South
- 2020/21 – HDDs were lower than budget across all weather zones due to warmer than expected temperatures

9.2 Annual Demand

The purpose of this section is to provide a brief review of the prior three years, comparing the demand forecast underlying each gas supply plan to the actual throughput volume. Actual volumes have not been normalized for weather variances.

[82] Tables presented on gas year for all rate zones.

Table 32 - Actual vs Plan Annual Demand

Line No.	Particulars (TJ)	2018/19			2019/20					2020/21				
		Actual	2018 GSP	Variance to 5-Yr	Actual	5-Year GSP	Annual Update	Variance to 5-Yr	Variance to Update	Actual	5-Year GSP	Annual Update	Variance to 5-Yr	Variance to Update
	EGD													
1	General Service	413,685	379,759	33,926	381,268	384,494	378,189	(3,226)	3,079	358,982	384,233	388,193	(25,251)	(29,211)
2	Contract	67,770	67,245	525	64,216	73,664	66,821	(9,448)	(2,605)	71,594	73,227	70,625	(1,633)	969
3	Total EGD	481,456	447,004	34,452	445,484	458,158	445,010	(12,674)	474	430,576	457,460	458,819	(26,884)	(28,243)
	Union North West													
4	General Service	14,994	14,008	986	14,176	14,022	14,375	154	(199)	12,943	13,886	14,335	(943)	(1,392)
5	Contract	2,172	1,347	825	1,879	1,338	1,418	541	461	3,250	1,330	1,636	1,920	1,614
6	Total Union North West	17,165	15,355	1,811	16,055	15,360	15,793	695	262	16,193	15,216	15,971	977	222
	Union North East													
7	General Service	40,199	36,329	3,871	38,477	36,339	38,248	2,138	229	35,057	35,967	38,290	(910)	(3,233)
8	Contract	4,003	3,663	340	4,004	3,644	4,227	360	(223)	4,355	3,683	3,763	672	592
9	Total Union North East	44,203	39,992	4,211	42,481	39,983	42,474	2,498	7	39,412	39,650	42,053	(238)	(2,641)
	Union South													
10	General Service	180,218	164,995	15,223	169,670	164,963	173,530	4,707	(3,860)	159,712	163,321	175,431	(3,609)	(15,719)
11	Contract	53,593	50,015	3,578	53,990	51,379	51,814	2,611	2,176	56,972	51,720	54,127	5,252	2,845
12	Total Union South	233,811	215,010	18,801	223,660	216,342	225,344	7,318	(1,684)	216,684	215,041	229,558	1,643	(12,874)
13	Total Demand Forecast	776,634	717,360	59,274	727,680	729,843	728,622	(2,163)	(942)	702,865	727,367	746,401	(24,502)	(43,536)

As shown in Table 32:

- 2018/19 – Colder than normal weather increased demand above budget
- 2019/20 – Actual demand was relatively close to both the Gas Supply Plan and the Annual Update
- 2020/21 – Warmer than normal weather decreased demand below both the Gas Supply Plan and Annual Update

9.3 Commodity Portfolio

The purpose of this section is to provide a brief review of the prior three years, comparing the supply forecast underlying each gas supply plan to the actual supply procured.

Table 33 - Actual vs Plan Commodity Purchases

Line No.	Particulars (TJ)	2018/19			2019/20			2020/21		
		Actual	2018 GSP	Variance	Actual	Annual Update	Variance	Actual	Annual Update	Variance
	EGD									
1	Appalachia	42,152	43,466	(1,314)	38,500	43,585	(5,085)	40,393	43,117	(2,725)
2	Chicago	24,418	25,233	(815)	20,866	25,192	(4,325)	25,892	25,194	698
3	Niagara Region	72,483	73,085	(603)	72,319	73,303	(984)	72,989	73,355	(366)
4	Ontario/Dawn	124,929	98,601	26,327	105,287	89,687	15,599	86,802	101,670	(14,868)
5	Peaking/Seasonal	1,013	166	847	-	96	(96)	-	82	(82)
6	WCSB	86,322	82,303	4,018	87,922	89,903	(1,981)	89,780	90,562	(781)
7	Link Supply	-	-	-	-	-	-	-	-	-
8	Total EGD Supply	351,316	322,855	28,461	324,893	321,766	3,127	315,856	333,980	(18,124)
	Union North West									
9	WCSB	19,242	11,541	7,701	19,327	16,975	2,352	19,294	16,314	2,980
10	Ontario/Dawn	4,602	-	4,602	359	-	359	137	-	137
11	Total Union North West Supply	23,844	11,541	12,303	19,685	16,975	2,710	19,431	16,314	3,117
	Union North East									
12	Appalachia	19,228	19,255	(27)	18,750	19,308	(558)	18,040	19,255	(1,214)
13	Chicago	-	-	-	-	-	-	-	-	-
14	Ontario/Dawn	15,039	10,783	4,256	9,419	7,206	2,214	12,010	11,867	143
15	WCSB	1,491	1,364	127	1,495	1,368	127	1,483	1,364	118
16	Total Union North East Supply	35,758	31,402	4,356	29,664	27,882	1,782	31,533	32,486	(953)
	Union South									
17	Appalachia	38,275	38,510	(235)	37,546	38,615	(1,069)	36,618	38,510	(1,892)
18	Chicago	30,332	30,807	(475)	27,412	30,892	(3,479)	26,194	30,807	(4,613)
19	Local Production	-	-	-	-	-	-	-	-	-
20	Niagara	6,879	7,702	(823)	7,722	7,723	(1)	7,316	7,702	(386)
21	Ojibway	7,702	7,702	0	-	-	-	-	-	-
22	Ontario/Dawn	54,963	44,158	10,805	33,411	42,287	(8,876)	30,282	43,992	(13,710)
23	U.S. Mid-Continent	13,470	13,478	(8)	18,232	22,011	(3,779)	21,938	21,950	(12)
24	WCSB	1,095	1,095	-	8,821	8,821	0	8,791	8,797	(5)
25	Total Union South	152,716	143,452	9,264	133,144	150,348	(17,205)	131,140	151,758	(20,619)
26	Total Supply Forecast	563,634	509,250	54,384	507,387	516,971	(9,585)	497,960	534,538	(36,578)

As shown in Table 33:

- 2018/19 – Colder than normal weather increased demand and gas supply deliveries above budget.
- 2019/20 – Warmer than normal weather decreased demand and gas supply deliveries above budget
- 2020/21 – Warmer than normal weather decreased demand and gas supply deliveries above budget

9.4 Unutilized Capacity

The purpose of this section is to provide a brief review of the prior three years, comparing the UDC underlying each gas supply plan to the actual UDC incurred.

Table 34 - Actual vs Plan UDC

Line No.	Particulars (PJ)	2018/19 Actual	2018/19 Annual Update	2018/19 Variance	2019/20 Actual	2019/20 Annual Update	2019/20 Variance	2020/21 Actual	2020/21 Annual Update	2020/21 Variance
1	North West	1.4	14.4	(13.0)	5.7	8.4	(2.7)	6.0	8.4	(2.5)
2	North East	0.9	4.3	(3.4)	4.4	7.1	(2.7)	3.0	7.1	(4.2)
3	South		-	-	16.7	-	16.7	19.6	-	19.6
4	Total UDC	2.3	18.7	(16.4)	26.9	15.6	11.3	28.5	15.6	13.0

As shown in Table 34:

- 2018/19 – The actual UDC incurred was lower than planned due to colder than normal weather
- 2019/20 – The actual UDC incurred was higher than planned primarily due to warmer than normal weather
- 2020/21 – The actual UDC incurred was higher than planned primarily due to warmer than normal weather

10. Performance Measurement

EGI has developed performance metrics that reflect the criteria the OEB has established to monitor effectiveness of the Plan and how the guiding principles have been achieved, and to drive continuous improvements. As part of this year's update, EGI's performance metrics now include a rolling 3-year average of historical levels of each measure where applicable as a benchmark for comparison, and clearer information on supply diversity and price signals. EGI's performance metrics for 2020/21 can be found in Appendix I with a brief explanation of each measure's intent.

INNOVATIVE
RESEARCH GROUP

2024 Rate Rebasing Customer Engagement

ENBRIDGE

Fuel Choices Report :
General Service Customers

January 2022

Table of Contents

Project Overview & Methodology

Enbridge Gas 2024 Rate Rebasing Customer Engagement

Innovative Research Group Inc. (INNOVATIVE) was engaged by Enbridge Gas to assist in meeting its customer engagement requirements for its 2024 Rate Rebasing Application requirement. This engagement had three phrases:

- Phase One was an exploratory phase that used qualitative tools to identify the range of needs and outcomes that matter to customers and to explore some of the trade-offs that Enbridge Gas expected to deal with in their planning process.
- Phase Two used surveys to draw generalizable conclusions regarding the findings from Phase One.
- Following Phase Two, Enbridge Gas developed a draft plan that built on the findings of the first two phases of the customer engagement as well as other business objectives. The Phase Three survey was then designed to provide feedback on that plan that can be used by Enbridge Gas as it finalizes its plan and its submission to the Ontario Energy Board (OEB).

This report summarises the findings of the Fuel Choices section of the Phase Three representative online workbook-style survey with residential and business customers. In particular, this section covers customer preferences related to Responsibly Sourced Gas and Renewable Natural Gas. Other sections of the workbook are covered in a different report.

Research Objectives

There are four key objectives for the Phase Three survey:

1. To acquire feedback on key choices in the development of Enbridge Gas' business plan that involve trade-offs between customer outcomes.
2. To secure customer reaction to the potential rate impacts of the draft plan.
3. To obtain customer input on rate design choices.
4. To assess customer interest in improving Environmental, Social and Governance outcomes by pursuing responsible gas sourcing and renewable gas sourcing.

Project Overview & Methodology

Survey Development

INNOVATIVE used a “workbook-style” survey to ensure the opinions collected on these issues were informed opinions. Through the workbook, customers were provided key background information on Enbridge Gas and its network as well as background relevant to key business planning, rate design and sourcing choices. The workbook was tested to ensure the material and questions were understandable for customers with limited knowledge of the Enbridge Gas system as well as to assess whether the workbook found the right balance between too much and too little information.

The surveys were developed by Enbridge Gas and finalized with input from INNOVATIVE. All survey participants were sent an invitation from Enbridge Gas containing a unique survey URL.

All residential data was collected between December 6th, 2021 and January 7th, 2022. All business data was collected between December 10th, 2021 and January 10th, 2022.

INNOVATIVE
RESEARCH GROUP

Sample Design

Sample Design - Residential

Sample Design and Weighting

Sample Design

The representative residential survey sample was stratified based on known variables, including region and consumption. The target completes for each sample strata are shown below.

Consumption Quartile	Target Completes					
	LEG Region		LUG Region			
	GTA	Other	South/ West	Central	North/ East	Total
Low	413	376	202	231	115	1338
Med Low	459	295	196	251	128	1330
Med High	582	241	158	243	128	1352
High	709	191	131	228	121	1381
Total	**2164**	**1104**	**687**	**953**	**493**	**5400**

Weighting the Data

The final data for the representative residential survey were then weighted to be proportionate based on the actual distribution of residential customers in each region, as well as by consumption quartile. *Weighted and unweighted sample sizes are outlined below. Minimal weighting was required to arrive at a representative sample.*

Consumption Quartile	Unweighted N						Weighted N					
	LEG Region		LUG Region				LEG Region		LUG Region			
	GTA	Other	South/ West	Central	North/ East	Total	GTA	Other	South/ West	Central	North/ East	Total
Low	579	658	329	402	178	2146	413	376	202	231	115	1338
Med Low	514	477	293	374	192	1850	459	295	196	251	128	1330
Med High	589	364	180	231	168	1532	582	241	158	243	128	1352
High	544	198	133	222	152	1249	709	191	131	228	121	1381
Total	**2226**	**1697**	**935**	**1229**	**690**	**6777**	**2164**	**1104**	**687**	**953**	**493**	**5400**

Weighting the Data - Business

In order to get as many completed surveys as possible from this group of business customers, all customers were invited to complete the survey.

We then compared the breakdown of survey respondents by region and consumption volume to the breakdown of the entire population of small and medium-large business customers. The final data for the business survey were then weighted to be proportionate based on the actual distribution of business customers in each region, as well as by consumption volume. *Weighted and unweighted sample sizes are outlined below. Minimal weighting was required to arrive at a representative sample of 3,500.*

Consumption Volume	Unweighted N						Weighted N					
	LEG Region		LUG Region				LEG Region		LUG Region			
	GTA	Other	South/ West	Central	North/ East	Total	GTA	Other	South/ West	Central	North/ East	Total
Low	356	158	146	190	86	936	440	146	86	121	49	842
Med Low	327	149	160	172	105	913	405	140	91	116	61	813
Med High	307	170	155	158	129	919	383	140	89	124	78	814
High	351	170	148	171	106	946	406	143	79	117	68	814
Med-Large	98	27	32	40	11	208	128	34	17	28	10	217
Total	**1439**	**674**	**641**	**731**	**437**	**3922**	**1763**	**602**	**362**	**506**	**267**	**3500**

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

INNOVATIVE RESEARCH GROUP

INNOVATIVE
RESEARCH GROUP

Online Workbook Results

General Service Residential

Enbridge Gas Customer Engagement

2024 Rate Rebasing Customer Engagement Workbook

Cost of the fuel

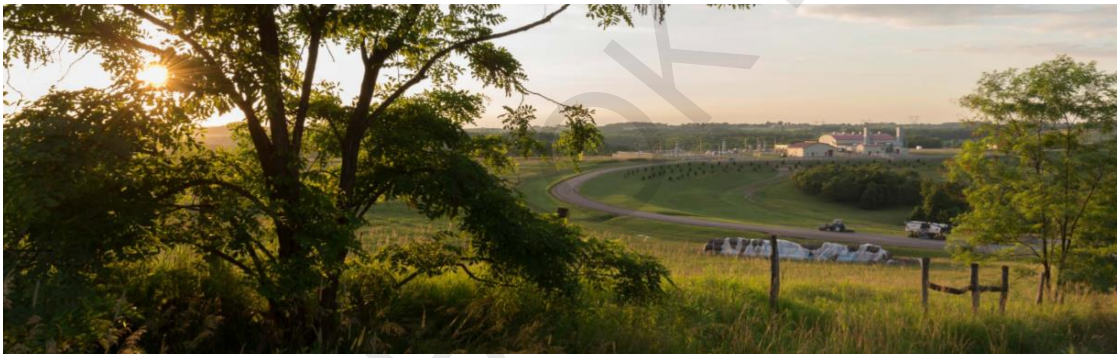
Fuel Choices

As previously discussed, the costs of buying natural gas and transporting it to Ontario are overseen by the Ontario Energy Board and are passed on to customers at cost. However, Enbridge Gas can make some choices about the natural gas it purchases, beyond focusing on the lowest price in the market. We would like to ask you a couple of questions about gas supply options.

Responsibly Sourced Gas

Enbridge Gas is looking at options to ensure that the natural gas it purchases is responsibly sourced. This means that the companies who produce the natural gas adhere to higher standards than the minimum government standards. This relates to areas such as:

- minimizing impacts to air and water quality
- lowering GHG emissions during production
- stronger engagement with Indigenous communities, etc.

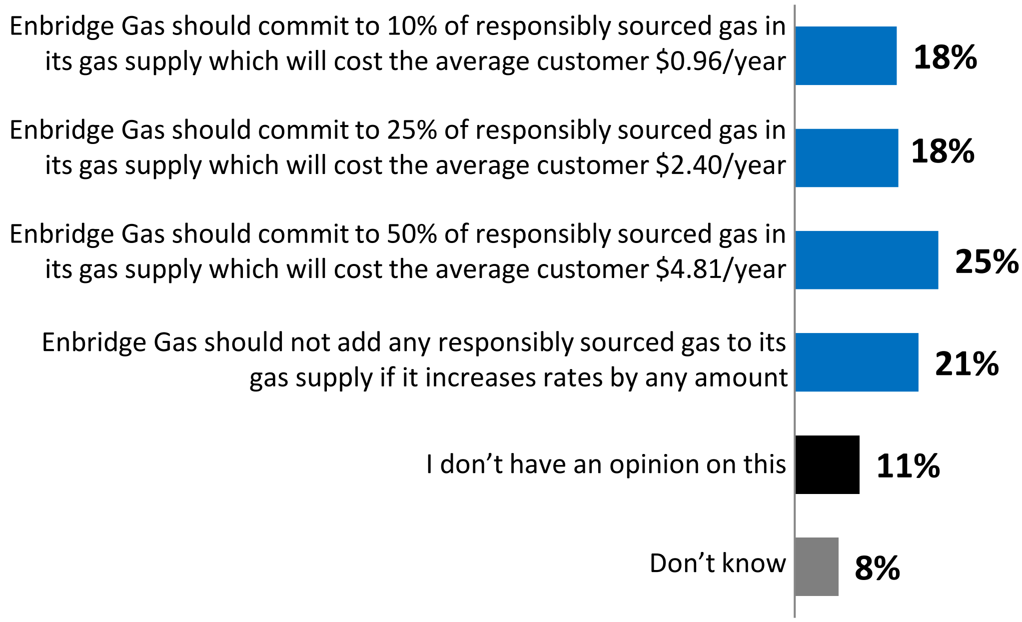


Enbridge Gas can offer some options to include Responsibly Sourced Gas in its portfolio, which can be purchased at a small premium. Responsibly Sourced Gas is a new and emerging trend in the North American natural gas industry. For this reason, current supply options are limited.

Cost of the Fuel

Responsibly Sourced Gas

Q Considering this, which of the following is closest to your view?
[asked of all respondents; n=5,400]



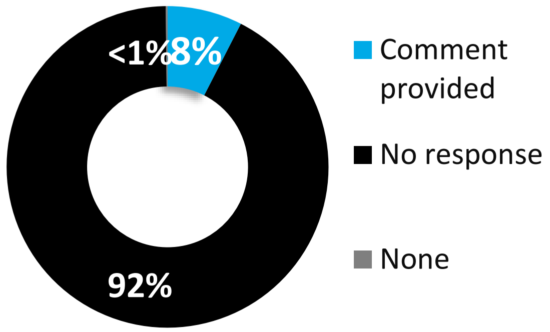
		Legacy		LUG Region		Consumption				LEAP Qualification		
	Total	LEG	LUG	North	South	Low	Med-low	Med-high	High	Yes	No <$52K	No >$52K
Commit to 10% of responsibly sourced gas	18%	18%	17%	18%	16%	20%	17%	16%	17%	17%	21%	18%
Commit to 25% of responsibly sourced gas	18%	17%	19%	20%	18%	18%	19%	18%	16%	14%	19%	19%
Commit to 50% of responsibly sourced gas	25%	24%	26%	24%	26%	24%	24%	25%	26%	11%	21%	32%
Not add any responsibly sourced gas	21%	22%	21%	20%	21%	20%	21%	21%	23%	25%	19%	19%
I don't have an opinion on this	11%	11%	11%	10%	11%	11%	12%	12%	10%	18%	12%	8%
Don't know	8%	8%	7%	8%	7%	7%	8%	8%	8%	16%	8%	4%

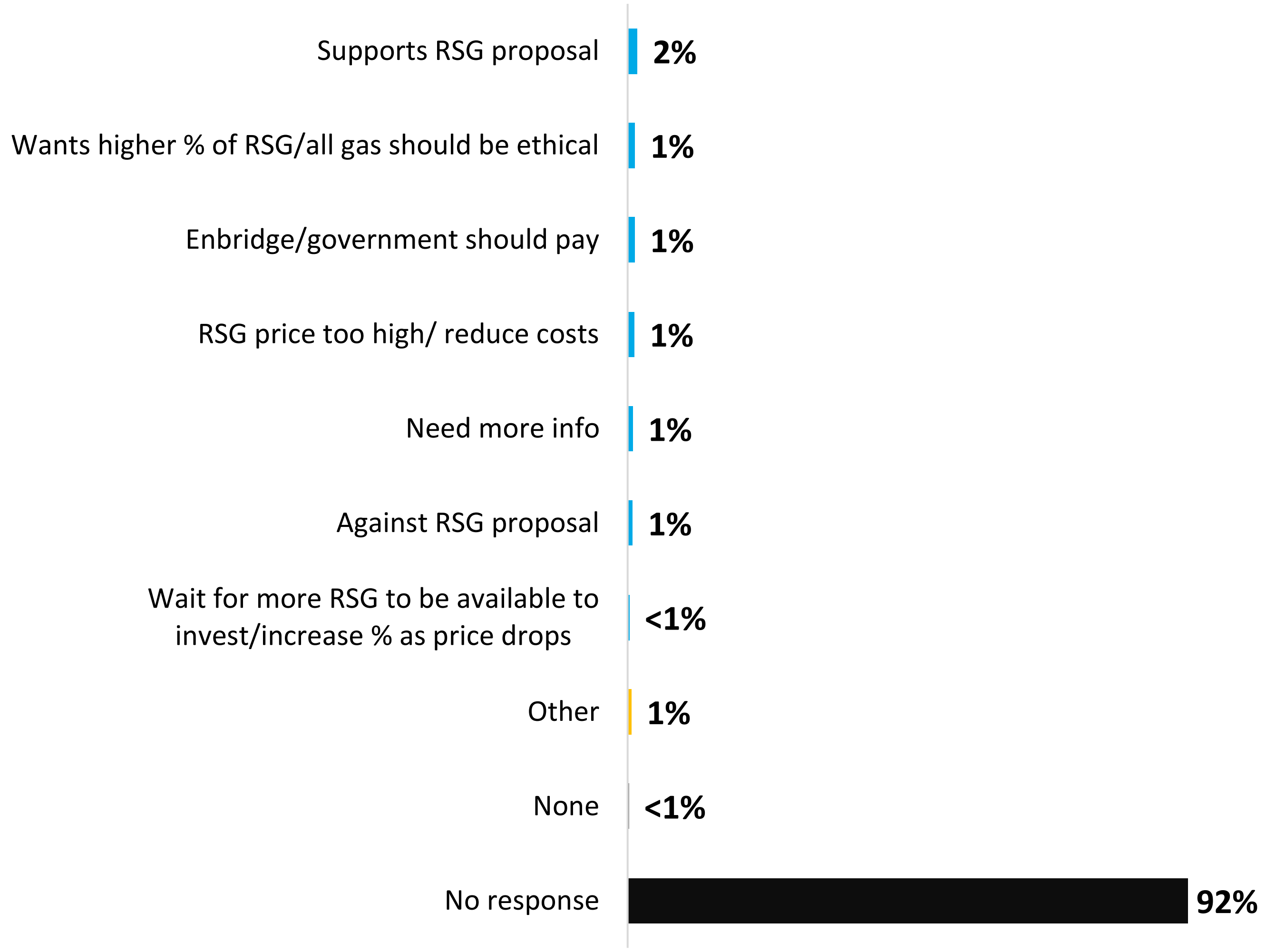
INNOVATIVE RESEARCH GROUP

Cost of the Fuel

Responsibly Sourced Gas - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





INNOVATIVE RESEARCH GROUP

Enbridge Gas Customer Engagement

2024 Rate Rebasing Customer Engagement Workbook

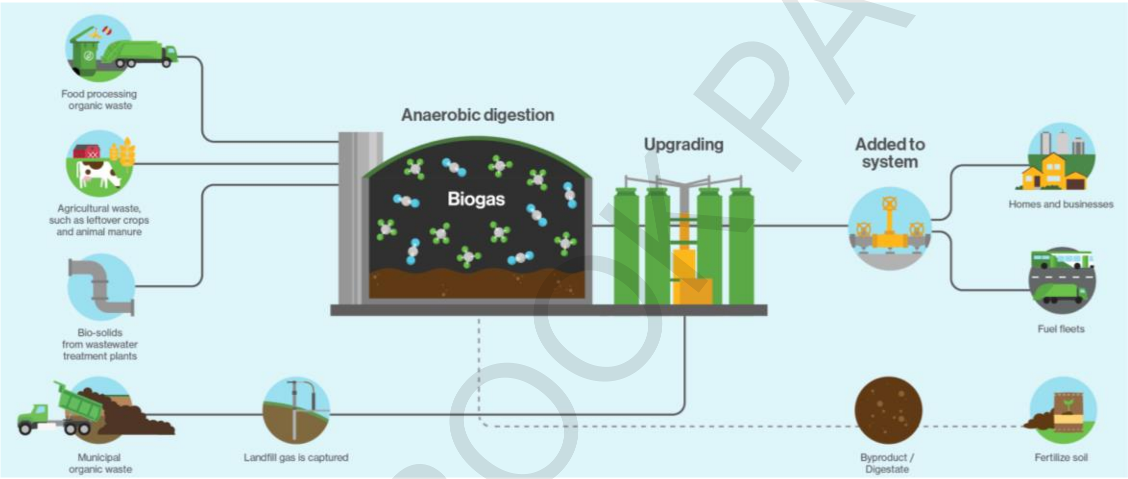
Cost of the fuel

Fuel Choices

Renewable Natural Gas

Enbridge Gas is looking at options to blend more Renewable Natural Gas (RNG) into the natural gas it delivers to green the gas supply. The gas is derived from organic waste from farms, landfills, and water treatment plants. The gas is then blended with traditional natural gas and supplied to customers using existing natural gas infrastructure.

RNG is considered to be carbon neutral and would reduce GHG emissions to help meet climate change targets. Every one percent of RNG in the gas supply reduces GHG emissions by one percent, in a 1:1 ratio. That means every additional 1% of RNG reduces your natural gas GHG emissions by 1%, and across the Enbridge Gas system, this is equivalent to taking 55,000 cars off the road.



Enbridge Gas is developing a plan to increase the blend of RNG in the gas system from 0.5% in 2025 to a higher amount over the course of the 2024 to 2028 plan and beyond. This amount is limited by the amount of RNG available in the market. Since the cost to produce RNG is currently higher than that of traditional natural gas it could have an impact on your rates.

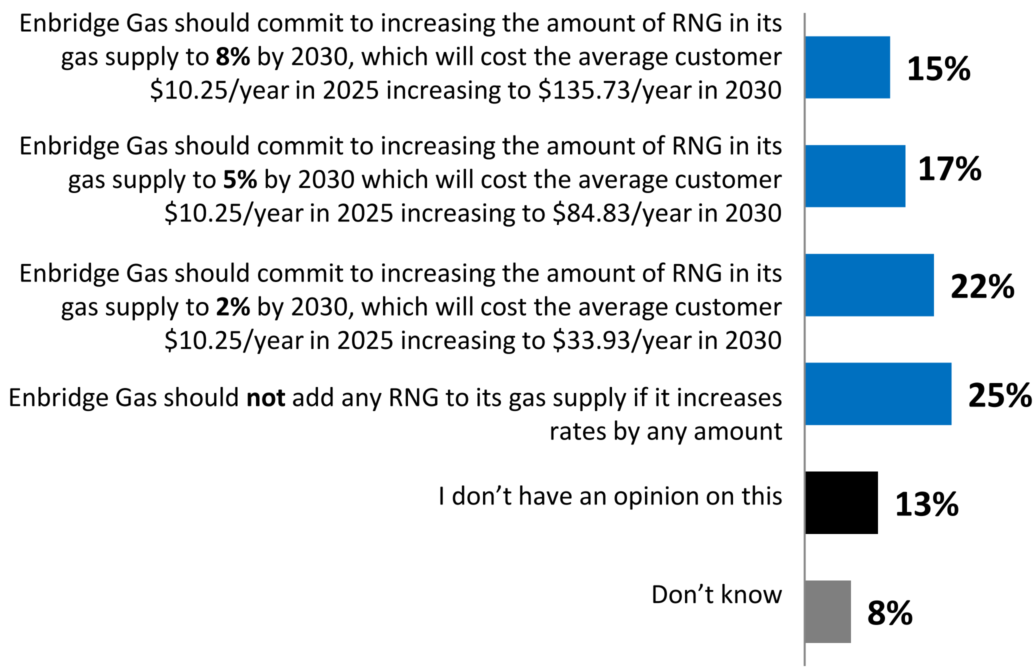
The federal carbon charge would not be applied to the volume of RNG on customer bills, which is accounted for in the costs shown below.

Cost of the Fuel

Renewable Natural Gas

Q Considering this, which of the following is closest to your view?

[asked of all respondents; n=5,400]



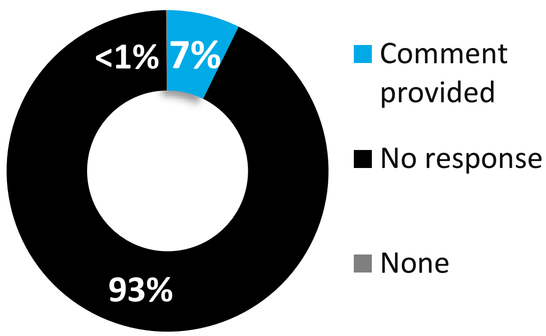
		Legacy		LUG Region		Consumption				LEAP Qualification		
	Total	LEG	LUG	North	South	Low	Med-low	Med-high	High	Yes	No <$52K	No >$52K
Increasing the amount of RNG in its gas supply to **8%**	15%	15%	14%	12%	15%	13%	15%	15%	15%	8%	12%	20%
Increasing the amount of RNG in its gas supply to **5%**	17%	17%	18%	18%	18%	18%	17%	18%	16%	7%	17%	21%
Increasing the amount of RNG in its gas supply to **2%**	22%	22%	23%	24%	22%	23%	22%	21%	22%	18%	23%	24%
Should not add any RNG to its gas supply	25%	26%	24%	25%	24%	24%	24%	25%	28%	31%	26%	21%
I don't have an opinion on this	13%	13%	12%	13%	12%	13%	13%	13%	12%	21%	13%	10%
Don't know	8%	8%	9%	8%	9%	8%	8%	9%	7%	16%	9%	5%

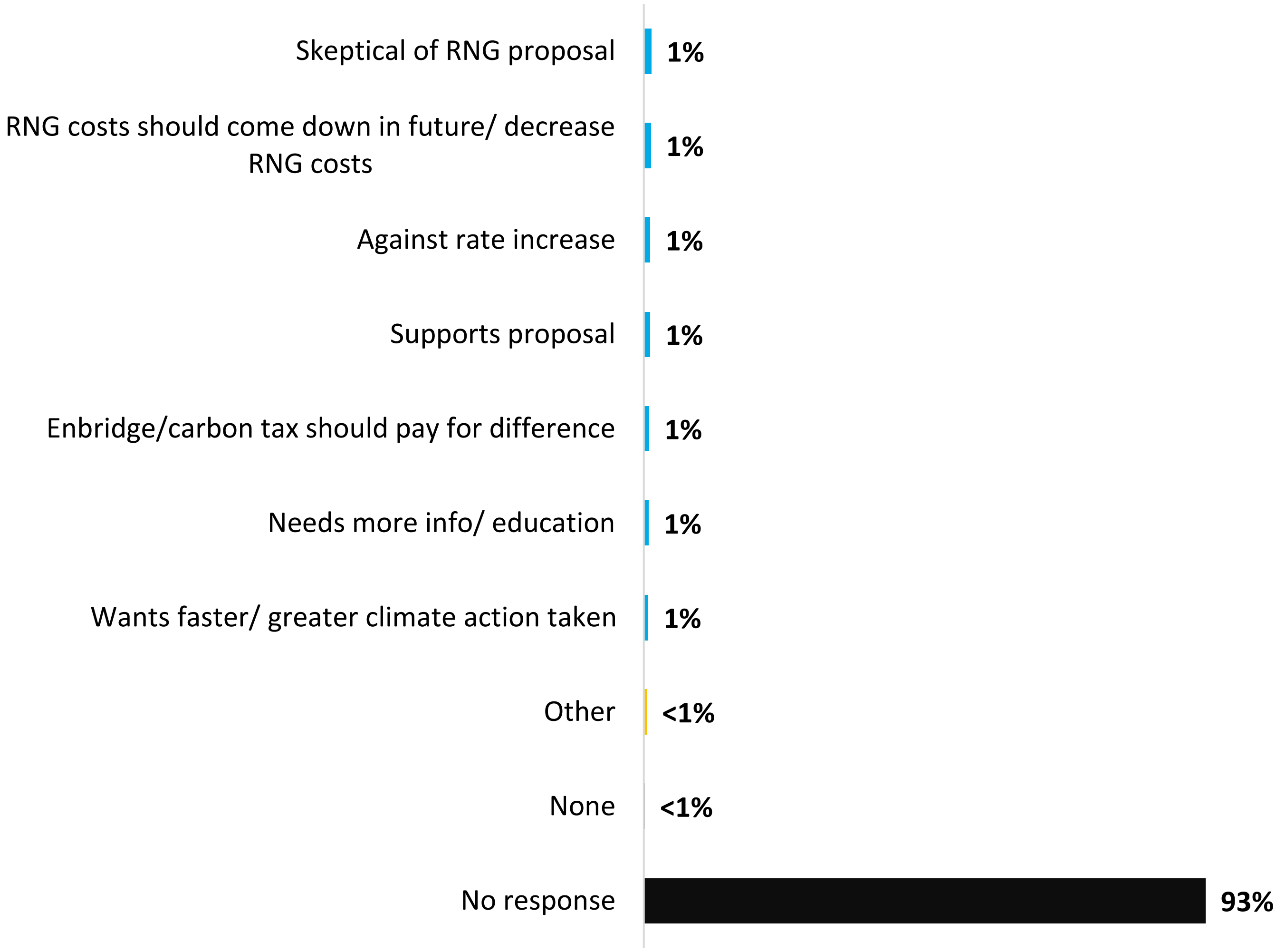
INNOVATIVE RESEARCH GROUP

Cost of the Fuel

Renewable Natural Gas - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





INNOVATIVE RESEARCH GROUP

INNOVATIVE
RESEARCH GROUP

Online Workbook Results

General Service Business

Cost of the fuel

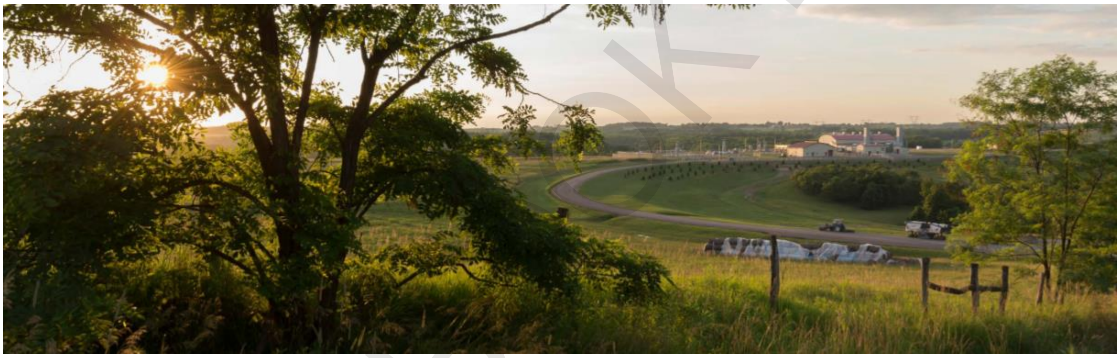
Fuel Choices

As previously discussed, the costs of buying natural gas and transporting it to Ontario are overseen by the Ontario Energy Board and are passed on to customers at cost. However, Enbridge Gas can make some choices about the natural gas it purchases, beyond focusing on the lowest price in the market. We would like to ask you a couple of questions about gas supply options.

Responsibly Sourced Gas

Enbridge Gas is looking at options to ensure that the natural gas it purchases is responsibly sourced. This means that the companies who produce the natural gas adhere to higher standards than the minimum government standards. This relates to areas such as:

- minimizing impacts to air and water quality
- lowering GHG emissions during production
- stronger engagement with Indigenous communities, etc.

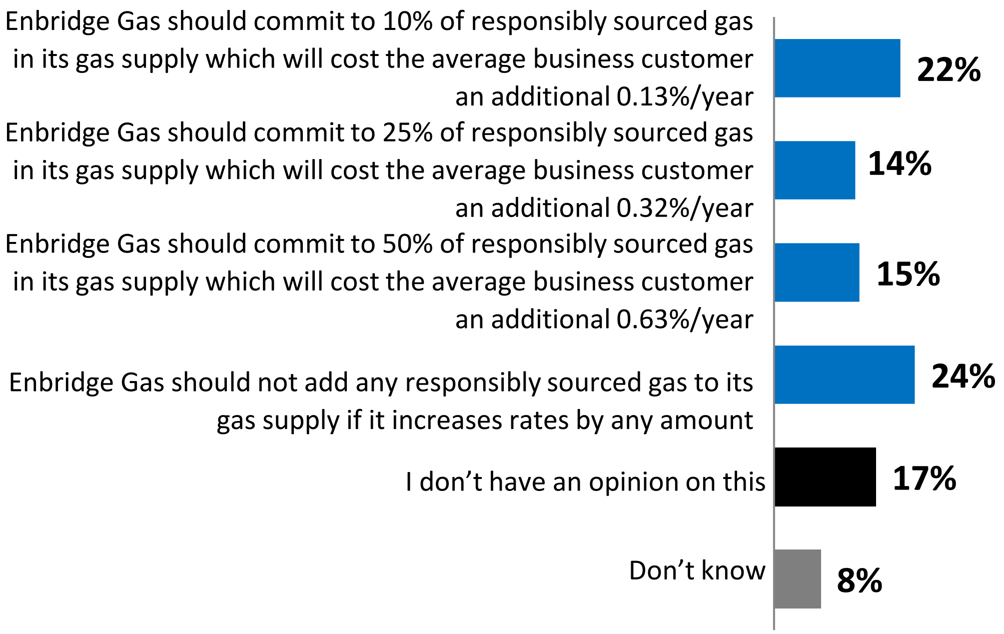


Enbridge Gas can offer some options to include Responsibly Sourced Gas in its portfolio, which can be purchased at a small premium. Responsibly Sourced Gas is a new and emerging trend in the North American natural gas industry. For this reason, current supply options are limited.

Cost of the Fuel

Responsibly Sourced Gas

Q Considering this, which of the following is closest to your view?



		Legacy		LUG Region		Business Size		Small Business Consumption Quartile			
	Total	LEG	LUG	North	South	Med-Large	Small	Low	Med-low	Med-high	High
Commit to 10% of responsibly sourced gas	22%	23%	20%	23%	19%	25%	21%	20%	21%	22%	23%
Commit to 25% of responsibly sourced gas	14%	14%	15%	17%	14%	12%	14%	13%	16%	14%	14%
Commit to 50% of responsibly sourced gas	15%	14%	16%	12%	17%	13%	15%	15%	15%	14%	14%
Not add any responsibly sourced gas	24%	24%	25%	25%	25%	27%	24%	25%	23%	24%	23%
I don't have an opinion on this	17%	18%	16%	17%	16%	16%	18%	19%	17%	17%	17%
Don't know	8%	8%	8%	7%	8%	6%	8%	7%	8%	9%	8%

Cost of the Fuel

Responsibly Sourced Gas (Cont'd)

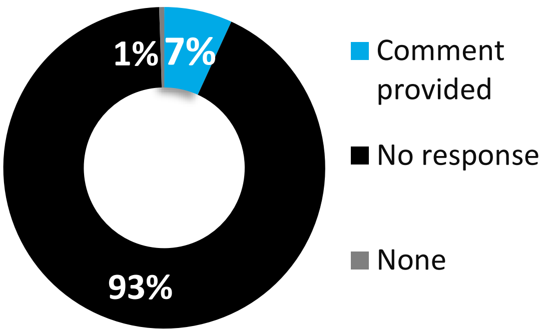
Q Considering this, which of the following is closest to your view?

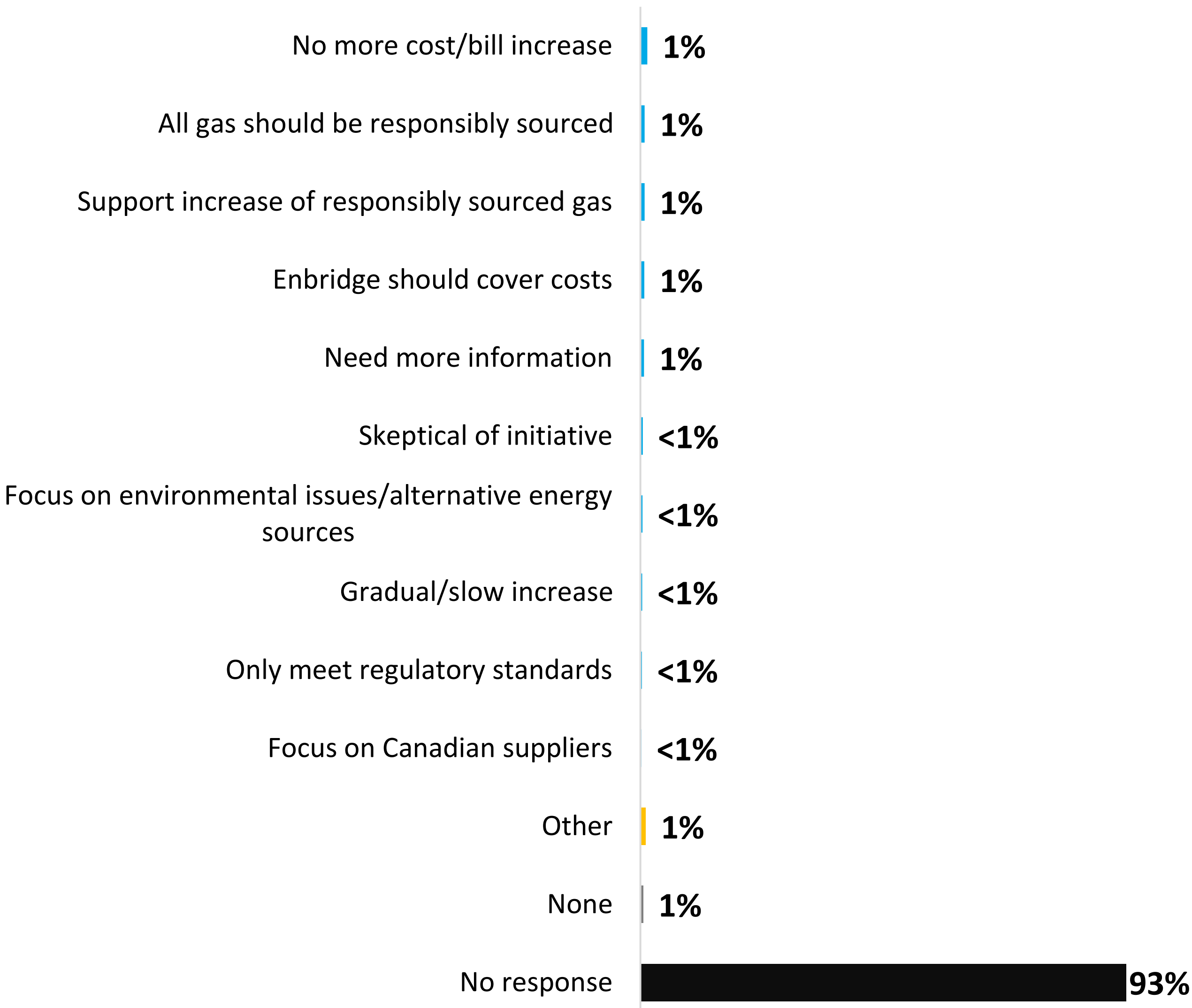
	Sector										Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Commit to 10% of responsibly sourced gas	22%	22%	23%	20%	21%	21%	20%	23%	26%	23%	23%	25%	24%	18%
Commit to 25% of responsibly sourced gas	14%	11%	9%	16%	12%	14%	15%	14%	13%	15%	6%	17%	18%	17%
Commit to 50% of responsibly sourced gas	15%	14%	12%	16%	20%	14%	14%	14%	11%	17%	9%	14%	17%	27%
Not add any responsibly sourced gas	24%	33%	29%	22%	28%	24%	25%	24%	16%	23%	35%	24%	19%	20%
I don't have an opinion on this	17%	14%	16%	20%	10%	19%	19%	18%	20%	15%	18%	16%	15%	13%
Don't know	8%	6%	10%	6%	9%	7%	8%	7%	14%	7%	8%	5%	8%	6%

Cost of the Fuel

Responsibly Sourced Gas - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





INNOVATIVE RESEARCH GROUP

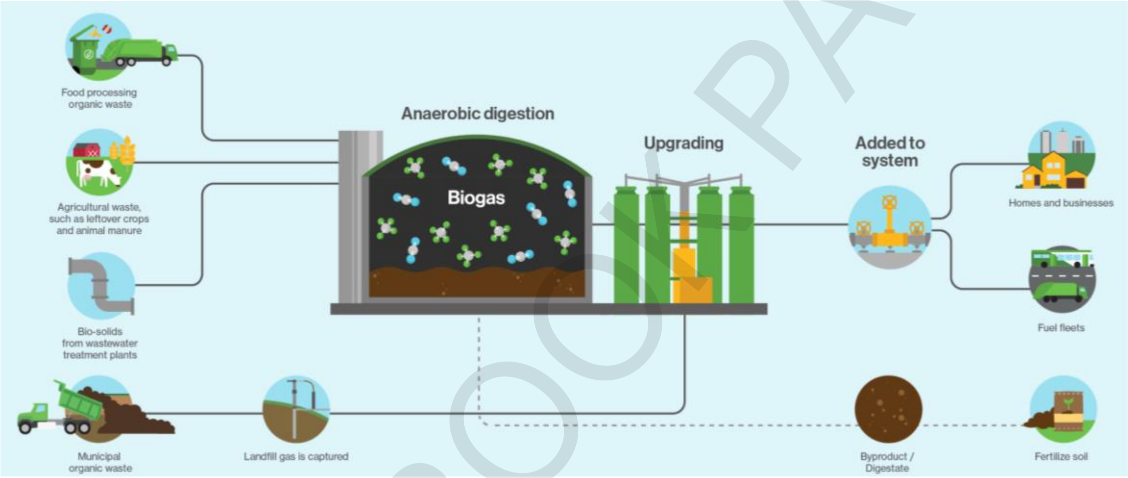
Cost of the fuel

Fuel Choices

Renewable Natural Gas

Enbridge Gas is looking at options to blend more Renewable Natural Gas (RNG) into the natural gas it delivers to green the gas supply. The gas is derived from organic waste from farms, landfills, and water treatment plants. The gas is then blended with traditional natural gas and supplied to customers using existing natural gas infrastructure.

RNG is considered to be carbon neutral and would reduce GHG emissions to help meet climate change targets. Every one percent of RNG in the gas supply reduces GHG emissions by one percent, in a 1:1 ratio. That means every additional 1% of RNG reduces your natural gas GHG emissions by 1%.



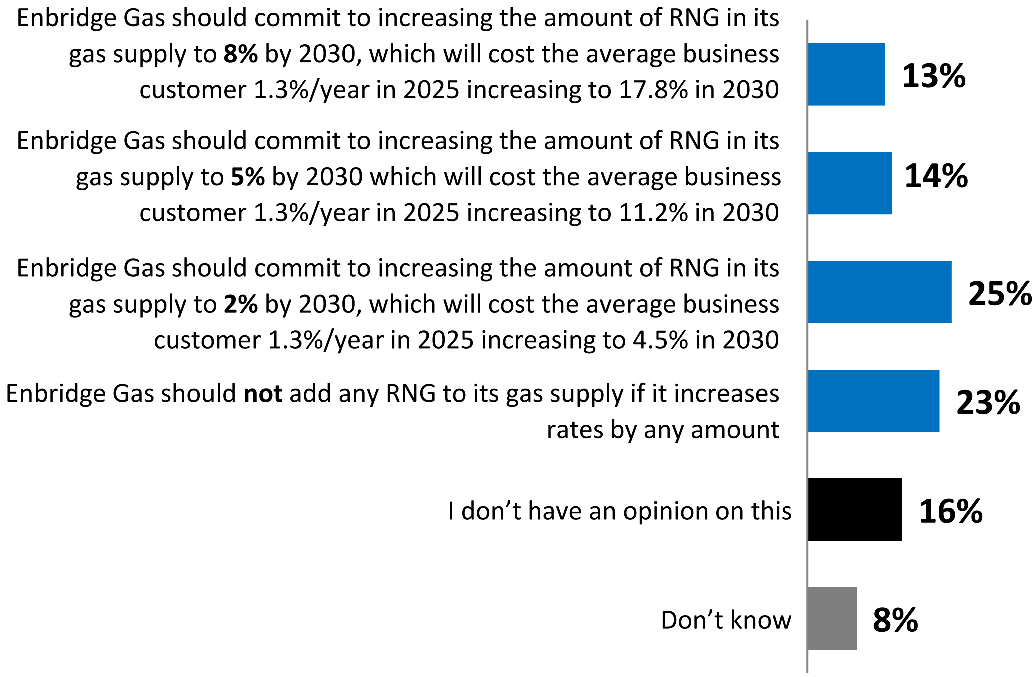
Enbridge Gas is developing a plan to increase the blend of RNG in the gas system from 0.5% in 2025 to a higher amount over the course of the 2024 to 2028 plan and beyond. This amount is limited by the amount of RNG available in the market. Since the cost to produce RNG is currently higher than that of traditional natural gas it could have an impact on your rates.

The federal carbon charge would not be applied to the volume of RNG on customer bills, which is accounted for in the costs shown below.

Cost of the Fuel

Renewable Natural Gas

Q Considering this, which of the following is closest to your view?



		Legacy		LUG Region		Business Size		Small Business Consumption Quartile			
	Total	LEG	LUG	North	South	Med-Large	Small	Low	Med-low	Med-high	High
Increasing the amount of RNG in its gas supply to **8%**	13%	14%	13%	12%	13%	14%	13%	14%	13%	15%	12%
Increasing the amount of RNG in its gas supply to **5%**	14%	14%	16%	17%	16%	14%	15%	12%	16%	14%	16%
Increasing the amount of RNG in its gas supply to **2%**	25%	25%	24%	24%	24%	21%	25%	24%	25%	24%	27%
Should not add any RNG to its gas supply	23%	22%	23%	22%	24%	25%	23%	24%	22%	23%	22%
I don't have an opinion on this	16%	17%	15%	16%	15%	20%	16%	18%	15%	16%	14%
Don't know	8%	8%	8%	9%	8%	7%	9%	8%	9%	8%	8%

INNOVATIVE RESEARCH GROUP

Cost of the Fuel

Renewable Natural Gas (Cont'd)

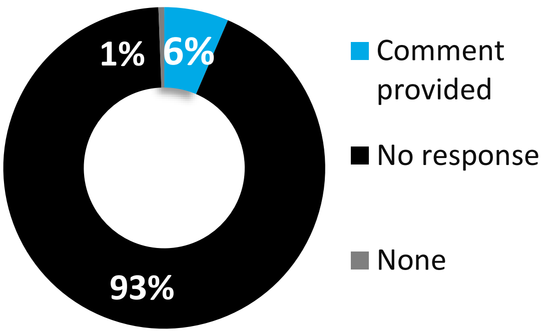
Q Considering this, which of the following is closest to your view?

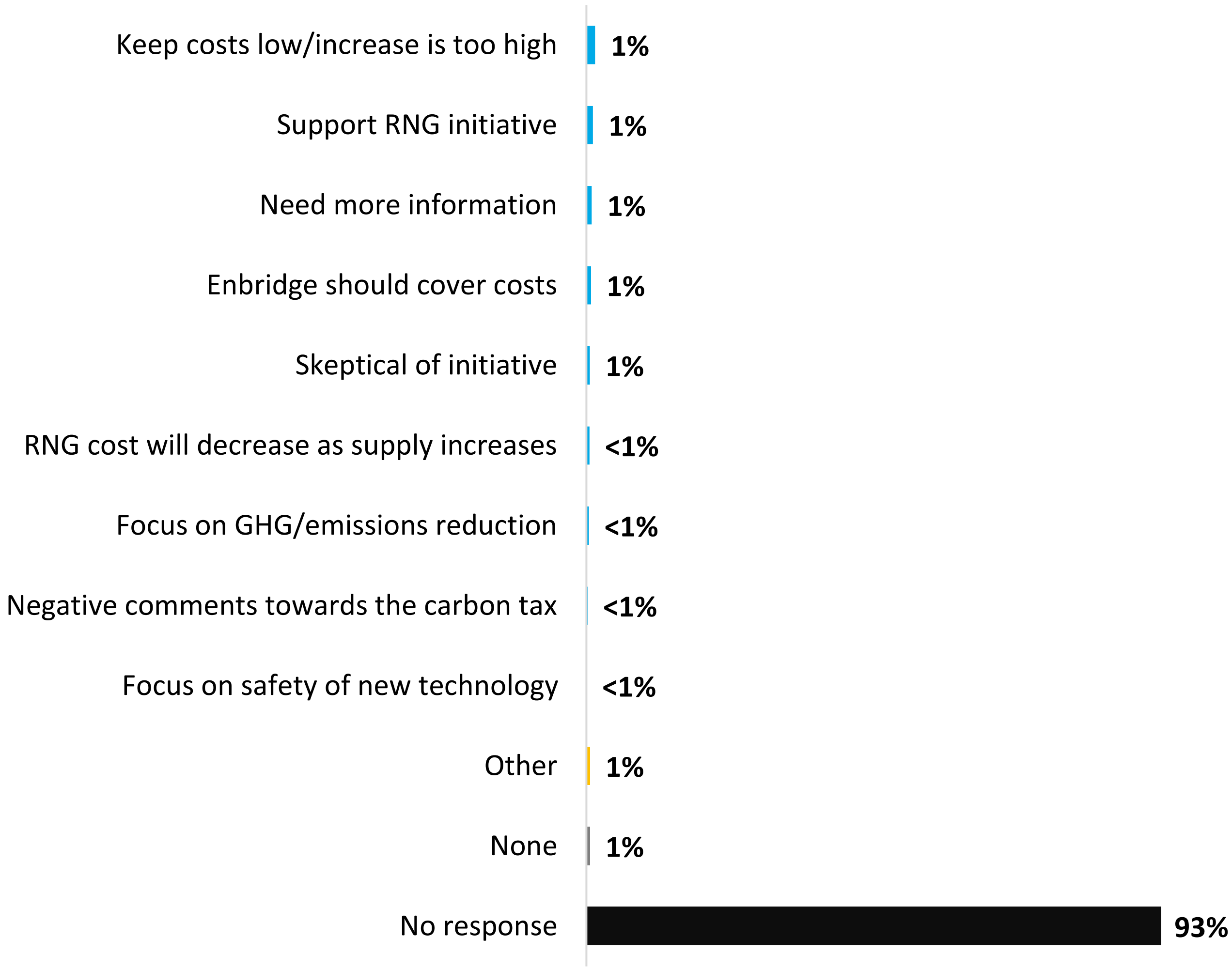
		Sector									Enbridge Gas Bill Impacts Finances			
	Total	Agriculture/ Greenhouse	Food Services	Manufacturing	Multiresidential	Office	Other Commercial	Retail	Transportation/ Warehouse	Other	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Increasing the amount of RNG in its gas supply to **8%**	13%	11%	12%	11%	19%	11%	14%	13%	13%	15%	10%	12%	16%	22%
Increasing the amount of RNG in its gas supply to **5%**	14%	16%	11%	16%	14%	17%	14%	14%	13%	16%	8%	17%	18%	19%
Increasing the amount of RNG in its gas supply to **2%**	25%	23%	24%	25%	21%	24%	25%	25%	21%	28%	22%	28%	27%	25%
Should not add any RNG to its gas supply	23%	31%	24%	23%	21%	21%	23%	23%	21%	23%	34%	23%	16%	16%
I don't have an opinion on this	16%	13%	19%	19%	15%	18%	17%	16%	18%	12%	18%	14%	15%	11%
Don't know	8%	6%	11%	6%	10%	8%	8%	9%	14%	6%	8%	6%	8%	6%

Cost of the Fuel

Renewable Natural Gas - Additional Comments

After making their choice, respondents were given an opportunity to make any additional comments they may have.





INNOVATIVE
RESEARCH GROUP

Building Understanding.

Personalized research to connect you and your audiences.

For more information, please contact:

Susan Oakes
Vice President
(t) 416-642-6341
(e) soakes@innovativeresearch.ca

Greg Lyle
President
(t) 416-642-6429
(e) glyle@innovativeresearch.ca

Figure 1 - EGD Rate Zone Transportation Map

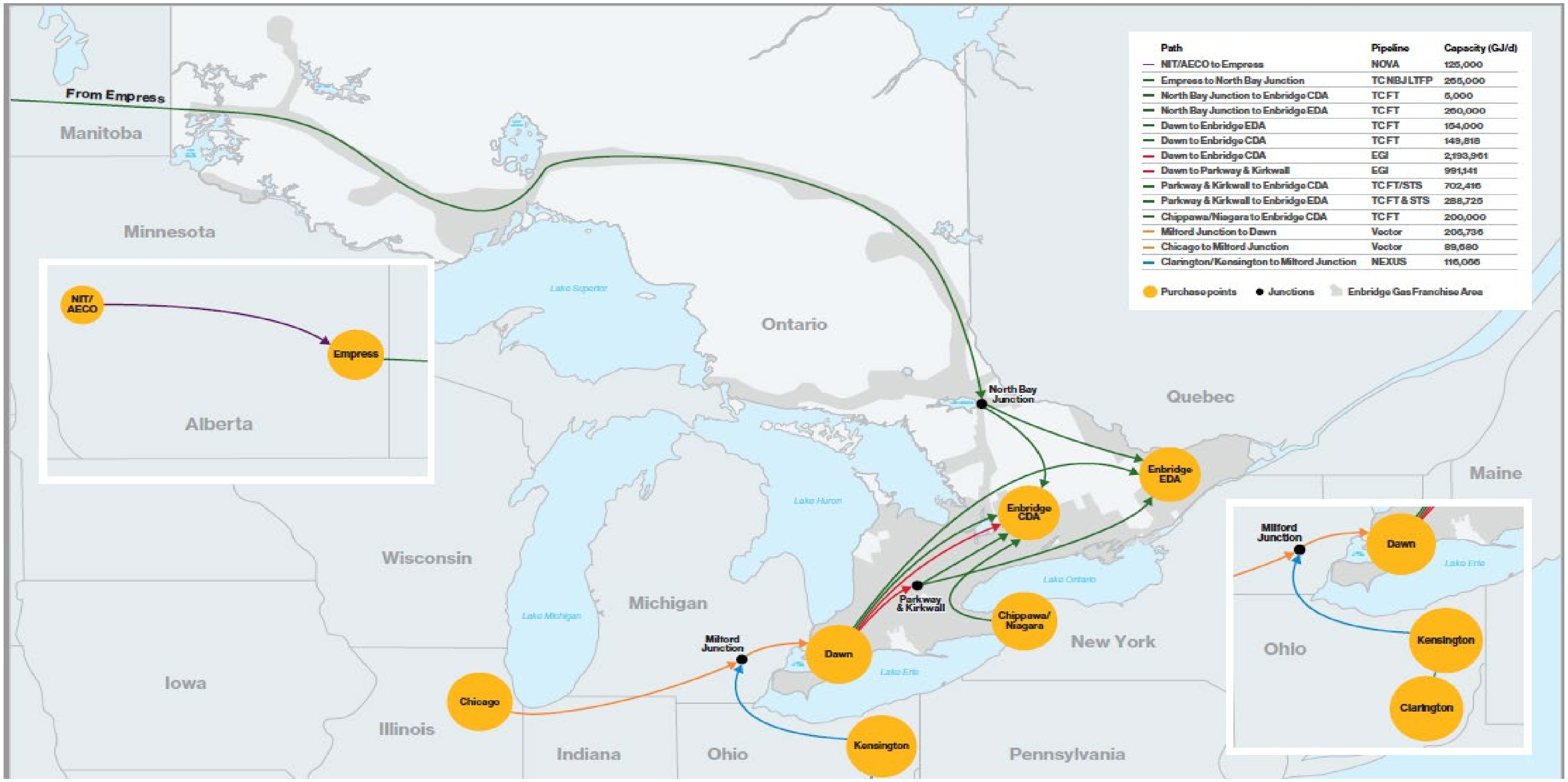
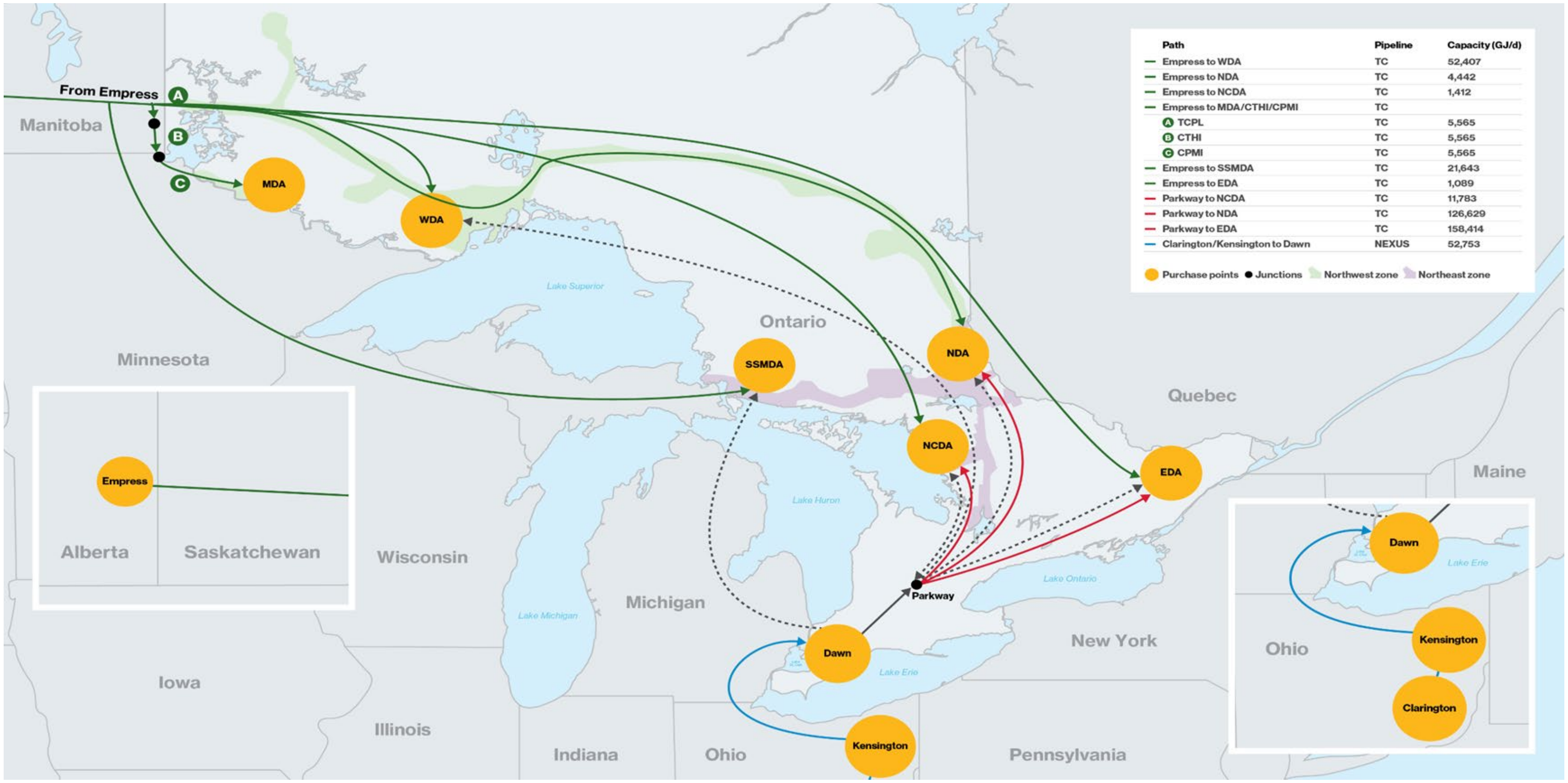
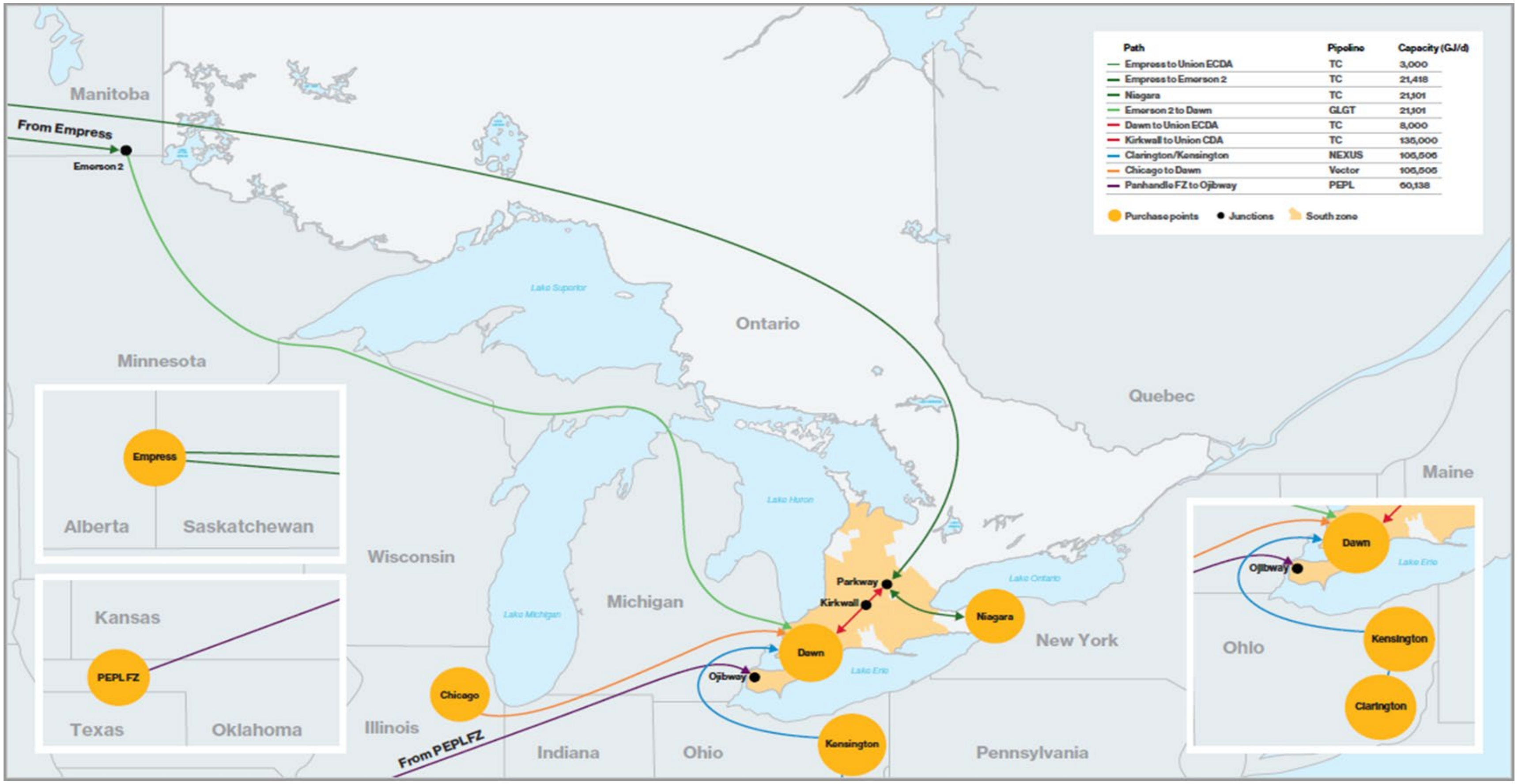


Figure 2 - Union North Rate Zones Transportation Map



Path	Pipeline	Capacity (GJ/d)
Empress to WDA	TC	52,407
Empress to NDA	TC	4,442
Empress to NCDA	TC	1,412
Empress to MDA/CTHI/CPMI	TC	
A TCPL	TC	5,565
B CTHI	TC	5,565
C CPMI	TC	5,565
Empress to SSMDA	TC	21,643
Empress to EDA	TC	1,089
Parkway to NCDA	TC	11,783
Parkway to NDA	TC	126,629
Parkway to EDA	TC	158,414
Clarington/Kensington to Dawn	NEXUS	52,753

Figure 3 - Union South Rate Zone Transportation Map



Summary of November 1, 2021 Upstream Transportation Contracts(1)

Union North Rate Zone

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
	TransCanada Pipeline					
1	Empress to Union NCDA FT	Empress	Union NCDA	1,412	GJ	31-Oct-2023
2	Empress to Union EDA FT	Empress	Union EDA	1,089	GJ	31-Oct-2023
3	Empress to Union NDA FT	Empress	Union NDA	4,442	GJ	31-Oct-2023
4	Empress to Union WDA FT	Empress	Union WDA	39,880	GJ	31-Oct-2023
5	Empress to Union WDA FT	Empress	Union WDA	11,527	GJ	31-Oct-2023
6	Empress to Union WDA FT	Empress	Union WDA	1,000	GJ	31-Oct-2022
7	Empress to Union SSMDA FT	Empress	Union SSMDA	2,700	GJ	31-Oct-2023
8	Empress to Union SSMDA FT	Empress	Union SSMDA	12,800	GJ	31-Oct-2023
9	Empress to Union SSMDA FT	Empress	Union SSMDA	6,143	GJ	31-Oct-2023
10	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	31-Oct-2023
11	Empress to Union MDA FT	Empress	Union MDA	1,043	GJ	31-Oct-2023
12	Parkway to Union EDA FT	Parkway	Union EDA	30,000	GJ	31-Oct-2026
13	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	31-Oct-2026
14	Parkway to Union EDA FT	Parkway	Union EDA	75,000	GJ	31-Oct-2031
15	Parkway to Union EDA FT (EMB)	Parkway	Union EDA	25,000	GJ	31-Oct-2031
16	Parkway to Union EDA FT	Parkway	Union EDA	181	GJ	31-Oct-2031
17	Parkway to Union EDA FT	Parkway	Union EDA	9,105	GJ	31-Oct-2031
18	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	31-Oct-2032
19	Parkway to Union EDA FT	Parkway	Union EDA	9,128	GJ	31-Oct-2033
20	Parkway to Union NCDA FT	Parkway	Union NCDA	661	GJ	31-Oct-2031
21	Parkway to Union NCDA FT	Parkway	Union NCDA	439	GJ	31-Oct-2031
22	Parkway to Union NCDA FT	Parkway	Union NCDA	887	GJ	31-Oct-2032
23	Parkway to Union NCDA FT	Parkway	Union NCDA	2,000	GJ	31-Oct-2032
24	Parkway to Union NCDA FT	Parkway	Union NCDA	6,912	GJ	31-Oct-2033
25	Parkway to Union NCDA FT	Parkway	Union NCDA	884	GJ	31-Oct-2033
26	Parkway to Union NDA FT	Parkway	Union NDA	10,000	GJ	31-Oct-2031
27	Parkway to Union NDA FT	Parkway	Union NDA	67,000	GJ	31-Oct-2031
28	Parkway to Union NDA FT	Parkway	Union NDA	24,000	GJ	31-Oct-2031
29	Parkway to Union NDA FT	Parkway	Union NDA	9,000	GJ	31-Oct-2031
30	Parkway to Union NDA FT	Parkway	Union NDA	10,401	GJ	31-Oct-2031
31	Parkway to Union NDA FT	Parkway	Union NDA	6,228	GJ	31-Oct-2031
32	TCPL FT - Total			383,384	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
33	NCDA	Parkway	Union NCDA	13,704	GJ	31-Oct-2026
34	WDA	Parkway	Union WDA	31,420	GJ	31-Oct-2026
35	SSMDA	Dawn	Union SSMDA	35,022	GJ	31-Oct-2026
36	NDA	Parkway	Union NDA	48,375	GJ	31-Oct-2026
37	EDA	Parkway	Union EDA	26,351	GJ	31-Oct-2026
38	TCPL Firm STS Withdrawal - Total			154,872	GJ	
	TransCanada Storage Transportation Service Firm Injection					
39	WDA	Union WDA	Parkway	3,150	GJ	31-Oct-2026
40	EDA	Union EDA	Parkway	1,000	GJ	31-Oct-2026
41	NDA	Union NDA	Parkway	49,100	GJ	31-Oct-2026
42	TCPL Firm STS Injection - Total			53,250	GJ	
	Centra Transmission Holdings Inc.					
43	Centra Transmission Holdings Inc.	Spruce	Union MDA	149.6	10^3m^3	31-Oct-2022
44	Centra Pipelines Minnesota Inc.	Sprague	Baudette	5,281	MCF	31-Oct-2022
45	CTHI FT - Total			5,791	GJ	

Conversion Factor	1.055056
Heat Content (as of April 1/21)	38.71

Note:

(1) Excludes NEXUS capacity allocated from the South portfolio.

Summary of November 1, 2021 Upstream Transportation Contracts

Union South Rate Zone

Line	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract	Contract	Contract
	TransCanada Pipeline Ltd.					
1	Empress to Union ECDA FT	Empress	Union ECDA	3,000	GJ	31-Oct-2023
2	Dawn to Union CDA FT	Dawn	Union ECDA	8,000	GJ	31-Oct-2023
3	Niagara to Kirkwall FT	Niagara	Kirkwall	21,101	GJ	31-Oct-2023
4	Kirkwall to Union CDA FT	Kirkwall	Union CDA	135,000	GJ	31-Oct-2032
5	Empress to Emerson 2 FT	Empress	Emerson 2	21,418	GJ	31-Oct-2023
6	TCPL FT - Total			188,519	GJ	
	Panhandle Eastern Pipe Line Company L.P.					
7	PEPL FT	Panhandle Field Zone	Ojibway (Union)	35,000	DTH	31-Oct-2025
8	PEPL FT	Panhandle Field Zone	Ojibway (Union)	22,000	DTH	31-Oct-2027
9	PEPL - Total			60,138	GJ	
	Vector Pipelines L.P.					
10	Vector US FT1	Chicago	Cdn/US Interconnect	80,000	DTH	31-Oct-2025
11	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,404	GJ	31-Oct-2025
12	Vector US FT1	Chicago	Cdn/US Interconnect	20,000	DTH	31-Oct-2026
13	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	21,101	GJ	31-Oct-2026
14	Vector - Total			105,505	GJ	
	NEXUS Gas Transmission, LLC					
15	NEXUS - FT(1)(2)	Kensington	St. Clair (Union)	150,000	DTH	31-Oct-2033
16	NEXUS - FT	Clarington	Kensington	25,000	DTH	31-Mar-2022
				184,635	GJ	
	Great Lakes Gas Transmission					
17	GLGT	Emerson	St. Clair	20,000	DTH	31-Oct-2024
				21,101	GJ	
	Great Lakes Pipeline Canada Ltd.					
18	Great Lakes Pipeline Canada Ltd.	St. Clair	Union SWDA	21,101	GJ	31-Oct-2024
	Other:					
19	St. Clair Pipelines L.P. (St. Clair Pipeline)	St. Clair/Intl Border	St. Clair/Intl Border	214,000	GJ	31-Oct-2023
20	St. Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Intl Border	Bluewater/Intl Border	127,000	GJ	31-Oct-2023

Conversion Factor 1.055056

Note:
(1) EGI has contracted for 150,000 DTH/day and allocates 50,000 DTH/day to the Union North portfolio.
(2) Effective November 1, 2018, Union has obtained a 4 year contract for primary receipt at Clarington for up to 75,000 dth/day with a cost of $0.15US/dth.

Summary of November 1, 2021 Upstream Transportation Contracts

EGD Rate Zone

Line No.	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Contract Units	Contract Termination Date
	TransCanada Pipeline					
1	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	163,044	GJ	31-Dec-2030
2	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	70,000	GJ	31-Dec-2030
3	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	5,000	GJ	31-Dec-2030
4	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	26,956	GJ	31-Dec-2030
5	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	163,044	GJ	31-Dec-2030
6	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	70,000	GJ	31-Dec-2030
8	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	26,956	GJ	31-Dec-2030
7	NBJ to Enbridge CDA	North Bay Junction	Enbridge CDA	5,000	GJ	31-Dec-2030
9	Dawn to CDA FT	Union Dawn	Enbridge CDA	4,818	GJ	31-Oct-2026
10	Dawn to CDA FT	Union Dawn	Enbridge CDA	145,000	GJ	31-Oct-2026
11	Dawn to EDA FT	Union Dawn	Enbridge EDA	114,000	GJ	31-Oct-2026
12	Dawn to Iroquois FT	Union Dawn	Iroquois	40,000	GJ	31-Oct-2026
13	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	572	GJ	31-Oct-2026
14	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	40,093	GJ	31-Oct-2032
15	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	75,000	GJ	31-Oct-2034
16	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	70,000	GJ	31-Oct-2032
17	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	15,000	GJ	31-Oct-2032
18	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	8,375	GJ	31-Oct-2032
19	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	24,484	GJ	31-Oct-2032
20	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	100,000	GJ	31-Oct-2036
21	Parkway to CDA FT-SN	Union Parkway Belt	Victoria Square #2 CDA	85,000	GJ	31-Oct-2026
22	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	170,000	GJ	31-Oct-2031
23	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	13,114	GJ	31-Oct-2032
24	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	25,000	GJ	31-Oct-2036
25	Niagara Falls to CDA	Niagara Falls	Enbridge Parkway CDA	76,559	GJ	31-Oct-2030
26	Chippawa to CDA	Chippawa	Enbridge Parkway CDA	123,441	GJ	31-Oct-2030
27	TCPL FT - Total			1,660,456	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
28	CDA	Parkway	Enbridge CDA	153,700	GJ	31-Oct-2026
29	CDA	Parkway	Enbridge CDA	92,822	GJ	31-Oct-2026
30	CDA	Parkway	Enbridge CDA	37,370	GJ	31-Oct-2026
31	EDA	Parkway/Kirkwall	Enbridge EDA	35,089	GJ	31-Oct-2026
32	EDA	Parkway	Enbridge EDA	35,806	GJ	31-Oct-2026
33	EDA	Parkway	Enbridge EDA	9,716	GJ	31-Oct-2026
34	TCPL Firm STS Withdrawal - Total			364,503	GJ	
	TransCanada Storage Transportation Service Firm Injection					
35	CDA	Parkway	Enbridge CDA	153,700	GJ	31-Oct-2026
36	CDA	Parkway	Enbridge CDA	92,822	GJ	31-Oct-2026
37	CDA	Parkway	Enbridge CDA	37,370	GJ	31-Oct-2026
38	EDA	Parkway/Kirkwall	Enbridge EDA	35,089	GJ	31-Oct-2026
39	EDA	Parkway	Enbridge EDA	35,806	GJ	31-Oct-2026
40	EDA	Parkway	Enbridge EDA	9,716	GJ	31-Oct-2026
41	TCPL Firm STS Injection - Total			364,503	GJ	
	NOVA Transmission					
42	NIT to Empress	NIT	Empress	50,000	GJ	31-Oct-2024
43	NIT to Empress	NIT	Empress	75,000	GJ	31-Oct-2025
44	Nova Transmission - Total			125,000	GJ	
	Vector Pipeline					
45	Vector US FT1	Milford Junction	St. Clair	110,000	DTH	31-Oct-2033
46	Vector Canada FT1	St. Clair	Dawn	116,056	GJ	31-Oct-2033
47	Vector US FT1	Alliance	St. Clair	20,000	DTH	31-Oct-2024
48	Vector US FT1	Northern Border	St. Clair	45,000	DTH	31-Oct-2024
49	Vector Canada FT1	St. Clair	Dawn	68,579	GJ	31-Oct-2024
50	Vector US FT1	Chicago	Cdn/US Interconnect	20,000	DTH	31-Oct-2026
51	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	21,101	GJ	31-Oct-2026
52	Vector - Total			205,736	GJ	
	NEXUS					
53	NEXUS - FT	Kensington	Milford Junction	55,000	DTH	31-Oct-33
54	NEXUS - FT	Clarington	Milford Junction	55,000	DTH	31-Oct-33
55	NEXUS - Total			116,056	GJ	

Conversion Factor 1.055056

2021-2026 Transportation Contracting Analysis

Route (A)	Point of Supply (B)	Basis Differential $US/mmBtu (C)	Supply Cost $US/mmBtu (D) = Nymex + C	Unitized Demand Charge $US/mmBtu (E)	Commodity Charge $US/mmBtu (F)	Fuel Charge $US/mmBtu (G)	100% LF Transportation Inclusive of Fuel $US/mmBtu (I) = E + F + G	Landed Cost $US/mmBtu (J) = D + I	Landed Cost $Cdn/G (K)	Point of Delivery (L)	Comments
Dawn	Dawn	0.0971	3.1672				0.0000	$3.17	**$3.80**	Dawn	
TC: Dawn LTFP	Empress	-0.2935	2.7766	0.64	0.00	0.0971	0.7388	$3.52	**$4.22**	Union SWDA	
TC: Great Lakes to Dawn	Empress	-0.2935	2.7766	0.68	0.01	0.0971	0.7855	$3.56	**$4.27**	Dawn	
TC: Niagara to Dawn	Niagara	-0.0877	2.9824	0.19	0.00	0.0174	0.2060	$3.19	**$3.83**	Dawn	
MichCon: MichCon to Dawn	SE Michigan	0.0032	3.0734	0.16	0.00	0.0381	0.2025	$3.28	**$3.93**	Dawn	
Vector: Chicago to Dawn	Chicago	-0.0024	3.0677	0.16	0.00	0.0128	0.1743	$3.24	**$3.89**	Dawn	
Panhandle: Panhandle FZ to Dawn	Panhandle Field Zone	-0.2064	2.8637	0.75	0.06	0.1468	0.9572	$3.82	**$4.58**	Dawn	
NEXUS via St. Clair: Kensington to Dawn	Dominion South Point	-0.6382	2.4319	1.09	0.00	0.0758	1.1677	$3.60	**$4.32**	Dawn	
Rover: Rover SZ to Dawn	Dominion South Point	-0.6382	2.4319	0.98	0.05	0.0758	1.1053	$3.54	**$4.24**	Dawn	

Supply Assumptions used in Developing Transportation Contracting Analysis:

Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2021 - Oct 2022	Nov 2022 - Oct 2023	Nov 2023 - Oct 2024	Nov 2024 - Oct 2025	Nov 2025 - Oct 2026	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
Henry Hub	**Henry Hub**	**$ 2.86**	**$ 2.92**	**$ 3.09**	**$ 3.25**	**$ 3.23**	**$ 3.07**	
Dawn	Dawn	$ 2.94	$ 3.02	$ 3.15	$ 3.36	$ 3.37	$ 3.17	
TC: Dawn LTFP	Empress	$ 2.55	$ 2.61	$ 2.72	$ 3.03	$ 2.96	$ 2.78	3.50%
TC: Great Lakes to Dawn	Empress	$ 2.55	$ 2.61	$ 2.72	$ 3.03	$ 2.96	$ 2.78	2.93%
TC: Niagara to Dawn	Niagara	$ 2.79	$ 2.88	$ 2.98	$ 3.14	$ 3.12	$ 2.98	0.58%
MichCon: MichCon to Dawn	SE Michigan	$ 2.83	$ 2.91	$ 3.07	$ 3.28	$ 3.27	$ 3.07	1.24%
Vector: Chicago to Dawn	Chicago	$ 2.81	$ 2.90	$ 3.06	$ 3.28	$ 3.28	$ 3.07	0.42%
Panhandle: Panhandle FZ to Dawn	Panhandle Field Zone	$ 2.67	$ 2.71	$ 2.86	$ 3.05	$ 3.02	$ 2.86	5.13%
NEXUS via St. Clair: Kensington to Dawn	Dominion South Point	$ 2.35	$ 2.45	$ 2.49	$ 2.51	$ 2.36	$ 2.43	3.12%
Rover: Rover SZ to Dawn	Dominion South Point	$ 2.35	$ 2.45	$ 2.49	$ 2.51	$ 2.36	$ 2.43	0.61%

Sources for Assumptions:

Gas Supply Prices (Col D):	ICF Q1 2021 Base Case			
Fuel Ratios (Col G):	Average ratio over the previous 12 months or Pipeline Forecast			
Transportation Tolls (Cols E & F):	Tolls in effect on Alternative Routes at the time of Union's Analysis			
Foreign Exchange (Col K)	$1 US =	$1.266	CDN	From Bank of Canada Closing Rate March 8, 2021
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056		
EGI's Analysis Completed:	Mar-20			

Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

2022-2025 Transportation Contracting Analysis

Route (A)	Point of Supply (B)	Basis Differential $US/mmBtu (C)	Supply Cost $US/mmBtu (D) = Nymex + C	Unitized Demand Charge $US/mmBtu (E)	Commodity Charge $US/mmBtu (F)	Fuel Charge $US/mmBtu (G)	100% LF Transportation Inclusive of Fuel $US/mmBtu (I) = E + F + G	Landed Cost $US/mmBtu (J) = D + I	Landed Cost $Cdn/G (K)	Point of Delivery (L)	Comments
TC-Emp2NDA(LH)	Empress	-0.2736	2.6662	0.89	0.00	0.0866	0.9814	$3.65	**$4.35**	Union NDA	
TC-Dawn2NDA	Dawn	0.0958	3.0356	0.50	0.00	0.0485	0.5531	$3.59	**$4.28**	Union NDA	

Supply Assumptions used in Developing Transportation Contracting Analysis:

Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2022 - Oct 2023	Nov 2023 - Oct 2024	Nov 2024 - Oct 2025	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
TC-Emp2NDA(LH)	Empress	$ 2.55	$ 2.51	$ 2.78	$ 2.61	3.25%
TC-Dawn2NDA	Dawn	$ 2.99	$ 2.91	$ 3.08	$ 2.99	1.60%

Sources for Assumptions:

Gas Supply Prices (Col D):	ICF Q2 2021 Base Case		
Fuel Ratios (Col G):	Average ratio over the previous 12 months or Pipeline Forecast		
Transportation Tolls (Cols E & F):	Tolls in effect on Alternative Routes at the time of Union's Analysis		
Foreign Exchange (Col K)	$1 US =	$1.257 CDN	From Bank of Canada Closing Rate August 16, 2021
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
EGI's Analysis Completed:	Aug-21		

Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

2022-2027 Transportation Contracting Analysis

	Route (A)	Point of Supply (B)	Basis Differential $US/mmBtu (C)	Supply Cost $US/mmBtu (D) = Nymex + C	Unitized Demand Charge $US/mmBtu (E)	Commodity Charge $US/mmBtu (F)	Fuel Charge $US/mmBtu (G)	100% LF Transportation Inclusive of Fuel $US/mmBtu (I) = E + F + G	Landed Cost $US/mmBtu (J) = D + I	Landed Cost $Cdn/G (K)	Point of Delivery (L)	Comments
	TC-Empress to Union EDA(LH)	Empress	-0.3236	2.7276	1.28	0.00	0.0933	1.3775	$4.11	**$4.94**	Union EDA	
	TC-Empress to Union EDA(NBJ)	Empress	-0.3236	2.7276	1.14	0.00	0.1024	1.2423	$3.97	**$4.77**	Union EDA	
	TC-Dawn to Union EDA	Dawn	0.1183	3.1695	0.38	0.00	0.0456	0.4323	$3.60	**$4.33**	Union EDA	

Supply Assumptions used in Developing Transportation Contracting Analysis:

	Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2022 - Oct 2023	Nov 2023 - Oct 2024	Nov 2024 - Oct 2025	Nov 2025 - Oct 2026	Nov 2026 - Oct 2027	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
	Henry Hub	**Henry Hub**	**$ 3.05**	**$ 3.07**	**$ 3.20**	**$ 2.98**	**$ 2.96**	**$ 3.05**	
	TC-Empress to Union EDA(LH)	Empress	$ 2.59	$ 2.66	$ 2.99	$ 2.72	$ 2.67	$ 2.73	3.42%
	TC-Empress to Union EDA(NBJ)	Empress	$ 2.59	$ 2.66	$ 2.99	$ 2.72	$ 2.67	$ 2.73	3.76%
	TC-Dawn to Union EDA	Dawn	$ 3.11	$ 3.16	$ 3.35	$ 3.12	$ 3.11	$ 3.17	1.44%

Sources for Assumptions:

Gas Supply Prices (Col D):	ICF Q4 2021 Base Case			
Fuel Ratios (Col G):	Average ratio over the previous 12 months or Pipeline Forecast			
Transportation Tolls (Cols E & F):	Tolls in effect on Alternative Routes at the time of Union's Analysis			
Foreign Exchange (Col K)	$1 US =	$1.269	CDN	From Bank of Canada Closing Rate February 7, 2022
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056		
EGI's Analysis Completed:	Feb-22			

Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

2022-2025 Transportation Contracting Analysis

Route (A)	Point of Supply (B)	Basis Differential \$US/mmBtu (C)	Supply Cost \$US/mmBtu (D) = Nymex + C	Unitized Demand Charge \$US/mmBtu (E)	Commodity Charge \$US/mmBtu (F)	Fuel Charge \$US/mmBtu (G)	100% LF Transportation Inclusive of Fuel \$US/mmBtu (I) = E + F + G	Landed Cost \$US/mmBtu (J) = D + I	Landed Cost \$Cdn/G (K)	Point of Delivery (L)	Comments
Dawn	Dawn	0.0912	3.1768				0.0000	\$3.18	**\$3.81**	Dawn	
TC: Dawn LTFP	Empress	-0.2974	2.7883	0.64	0.00	0.0975	0.7392	\$3.53	**\$4.23**	Union SWDA	
TC: Great Lakes to Dawn	Empress	-0.2974	2.7883	0.68	0.01	0.0975	0.7859	\$3.57	**\$4.29**	Dawn	
TC: Niagara to Dawn	Niagara	-0.0849	3.0008	0.19	0.00	0.0175	0.2061	\$3.21	**\$3.85**	Dawn	
MichCon: MichCon to Dawn	SE Michigan	0.0021	3.0878	0.16	0.00	0.0383	0.2027	\$3.29	**\$3.95**	Dawn	
Vector: Chicago to Dawn	Chicago	-0.0027	3.0829	0.16	0.00	0.0129	0.1744	\$3.26	**\$3.91**	Dawn	
Panhandle: Panhandle FZ to Dawn	Panhandle Field Zone	-0.2116	2.8741	0.75	0.06	0.1474	0.9578	\$3.83	**\$4.60**	Dawn	
NEXUS via St. Clair: Kensington to Dawn	Dominion South Point	-0.6014	2.4843	1.09	0.00	0.0775	1.1693	\$3.65	**\$4.38**	Dawn	
Rover: Rover SZ to Dawn	Dominion South Point	-0.6014	2.4843	0.98	0.05	0.0775	1.1070	\$3.59	**\$4.31**	Dawn	

Supply Assumptions used in Developing Transportation Contracting Analysis:

Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2022 - Oct 2023	Nov 2023 - Oct 2024	Nov 2024 - Oct 2025	Average Annual Gas Supply Cost \$US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
Henry Hub	**Henry Hub**	**\$ 2.92**	**\$ 3.09**	**\$ 3.25**	**\$ 3.09**	
Dawn	Dawn	\$ 3.02	\$ 3.15	\$ 3.36	\$ 3.18	
TC: Dawn LTFP	Empress	\$ 2.61	\$ 2.72	\$ 3.03	\$ 2.79	3.50%
TC: Great Lakes to Dawn	Empress	\$ 2.61	\$ 2.72	\$ 3.03	\$ 2.79	2.93%
TC: Niagara to Dawn	Niagara	\$ 2.88	\$ 2.98	\$ 3.14	\$ 3.00	0.58%
MichCon: MichCon to Dawn	SE Michigan	\$ 2.91	\$ 3.07	\$ 3.28	\$ 3.09	1.24%
Vector: Chicago to Dawn	Chicago	\$ 2.90	\$ 3.06	\$ 3.28	\$ 3.08	0.42%
Panhandle: Panhandle FZ to Dawn	Panhandle Field Zone	\$ 2.71	\$ 2.86	\$ 3.05	\$ 2.87	5.13%
NEXUS via St. Clair: Kensington to Dawn	Dominion South Point	\$ 2.45	\$ 2.49	\$ 2.51	\$ 2.48	3.12%
Rover: Rover SZ to Dawn	Dominion South Point	\$ 2.45	\$ 2.49	\$ 2.51	\$ 2.48	0.61%

Sources for Assumptions:

Gas Supply Prices (Col D):	ICF Q1 2021 Base Case		
Fuel Ratios (Col G):	Average ratio over the previous 12 months or Pipeline Forecast		
Transportation Tolls (Cols E & F):	Tolls in effect on Alternative Routes at the time of Union's Analysis		
Foreign Exchange (Col K)	\$1 US =	\$1.266 CDN	From Bank of Canada Closing Rate March 8, 2021
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
EGI's Analysis Completed:	Mar-20		

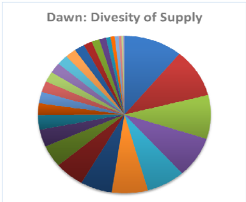
Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

Enbridge Gas Inc.

Supplier Diversity by Baisn

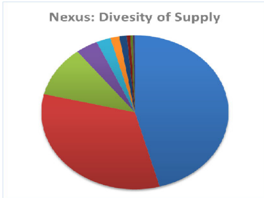
Dawn

Supply Provided	Number of Suppliers
0-2 PJs	0
2-5PJs	1
5 + Pjs	27



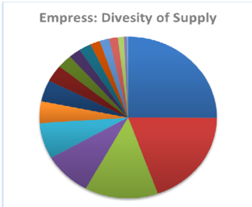
Nexus

Supply Provided	Number of Suppliers
0-2 PJs	3
2-5PJs	1
5 + Pjs	7



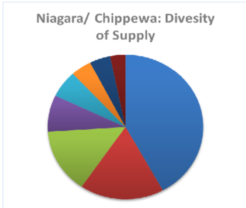
Empress

Supply Provided	Number of Suppliers
0-2 PJs	9
2-5PJs	4
5 + Pjs	5



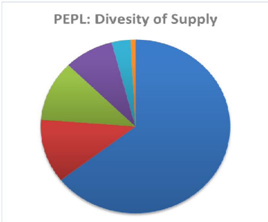
Niagara/ Chipewa

Supply Provided	Number of Suppliers
0-2 PJs	0
2-5PJs	4
5 + Pjs	4



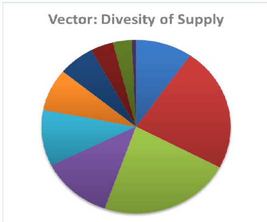
PEPL

Supply Provided	Number of Suppliers
0-2 PJs	5
2-5PJs	0
5 + Pjs	1



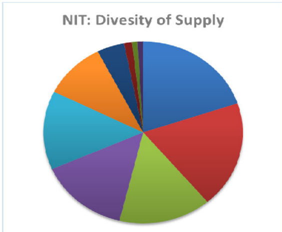
Vector

Supply Provided	Number of Suppliers
0-2 PJs	3
2-5PJs	4
5 + Pjs	3



NIT

Supply Provided	Number of Suppliers
0-2 PJs	4
2-5PJs	2
5 + Pjs	4



2020/21 PERFORMANCE METRICS Enbridge Gas Inc.

OEB Guiding Principle	Performance Categories	Intent of Measures	Measures		2018/19 Results	2019/20 Results	2020/21 Results (to update)	3-Year Average[1]
COST EFFECTIVENESS								
The gas supply plans will be cost-effective. Cost-effectiveness is achieved by appropriately balancing the principles and in executing the supply plan in an economically efficient manner.	Policies and Procedures	Demonstrates EGI's consideration of timely pricing information and the utility's ability to transact according to internal policies for managing counterparty risk	Procurement plan reviewed and approved as outlined in the policy		C	C	C	n/a
			Transacting counterparties have met appropriate credit requirements		C	C	C	n/a
	Weather Variance[2]	Illustrates weather risk in EGI's Plan correlated with price variances (e.g. Positive HDD variances tends to lead to higher prices)	HDD Variance - EGD CDA		6%	1%	-10%	-1%
			HDD Variance - EGD EDA		9%	2%	-10%	0%
			HDD Variance - EGD Niagara		6%	0%	-10%	-1%
			HDD Variance - Union North West		10%	5%	-6%	3%
			HDD Variance - Union North East		3%	-2%	-12%	-4%
			HDD Variance - Union South		3%	-1%	-10%	-3%
	Price Effectiveness	Demonstrates the diversity of supply terms within EGI's procurement plan through a layered approach to contracting	Distribution of procurement supply terms:					
			Less than one month		14%	3%	2%	6%
			Monthly		28%	27%	24%	26%
			Seasonal		25%	36%	37%	33%
			Annual or longer		32%	34%	37%	34%
		Illustrates price stability and consistency in EGI's Plan	Reference Price[3]		PLease see EB-2022-0072, Appendix I, page 3.	PLease see EB-2022-0072, Appendix I, page 4.	PLease see EB-2022-0072, Appendix I, page 5.	N/A
RELIABILITY AND SECURITY OF SUPPLY								
The gas supply plans will ensure the reliable and secure supply of gas. Reliability and security of supply is achieved by ensuring gas supply to various receipt points to meet planned peak day and seasonal gas delivery requirements.	Design Day	Demonstrates the extent to which EGI is able to procure assets required to meet design day demand, indicating the reliability of the plan	Acquired assets to meet design day requirements, as identified by the plan		100%	100%	100%	100%
	Storage	Demonstrates EGI's execution of its storage inventory strategy	Percentage of actual storage target at November 1 compared to the plan		98%	98%	96%	97%
			Percentage of actual storage target at February 28 compared to the plan		100%	100%	83%	94%
			Percentage of actual storage target at March 31 compared to the plan		95%	100%	100%	98%
	Communication	Ensure ongoing communication and understanding between planning and operations teams	Meet once a month at a minimum to discuss inventory position relative to targets and what action is required		C	C	C	C
			Instances when QRAM expected bill impacts exceed +/- 25%		0	2	3	2
			Communicated to ratepayers when bill impacts exceed +25%		C	C	C	C
	Diversity		Supply basin diversity[4] (TO BE Changed back into table format	Ontario/Dawn	36%	33%	29%	33%
				WCSB	19%	23%	25%	22%
				Appalachia	18%	15%	17%	17%
				Niagara Region	14%	16%	16%	15%
				Chicago	10%	9%	9%	9%
				U.S. Mid-Continent	2%	4%	4%	3%
				Ojibway	1%	0%	0%	0%
			Percentage of contracts with remaining terms of:					
			1-5 years		23%	15%	43%	27%
			6-10 years		33%	44%	32%	37%
			> 10 years		44%	40%	25%	36%
			Total number of unique counterparties		56	58	56	57
			Total number of receipt points		27	29	29	28
			Number of days of force majeure on upstream pipelines that reduced capacity		0	0	0	0
			Number of days of force majeure on upstream pipelines impacting customers' security of supply		0	0	0	0

2020/21 PERFORMANCE METRICS Enbridge Gas Inc.

OEB Guiding Principle	Performance Categories	Intent of Measures	Measures		2018/19 Results	2019/20 Results	2020/21 Results (to update)	3-Year Average[1]
	Reliability	Reports EGI's experience with pipeline and supply disruptions demonstrating the reliability of the portfolio	Number of days of failed delivery of supply		61	74	82	72
			Number of days of failed delivery of supply impacting customers security of supply		0	0	0	0
			Number of days of forced majeures on storage assets		0	0	0	0
PUBLIC POLICY								
The gas supply plan will be developed to ensure that it supports and is aligned with public policy where appropriate.	Supporting Policy	Reports public policy considered in EGI's Plan	Community expansion addressed in the plan		C	C	C	n/a
			DSM savings addressed in the plan		C	C	C	n/a
			Federal Carbon Pricing Program addressed in the plan		C	C	C	n/a
			Volume of RNG in portfolio		0%	0%	0%	0%

Footnotes:

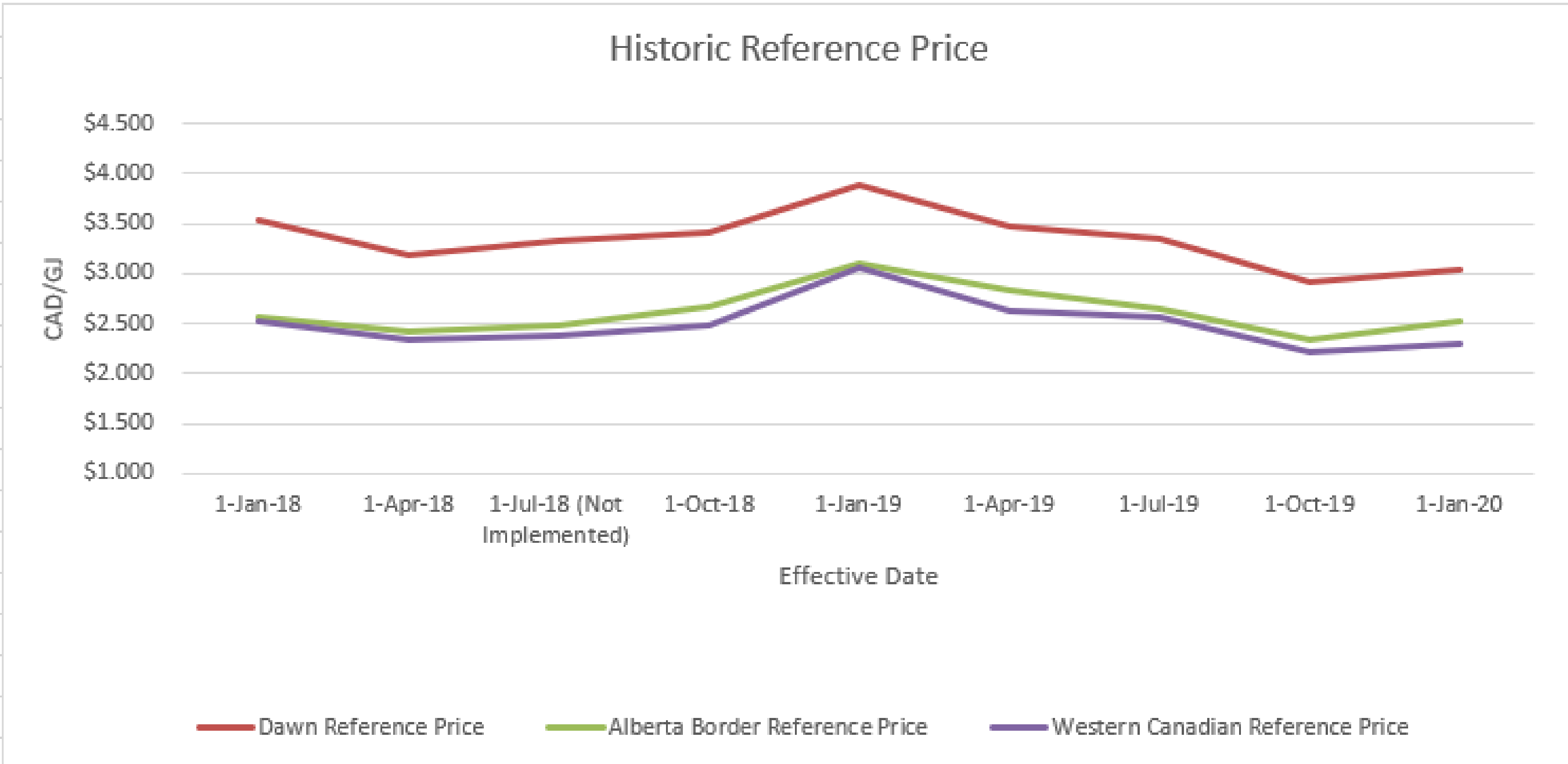
C - Compliant, NI - Needs Improvement

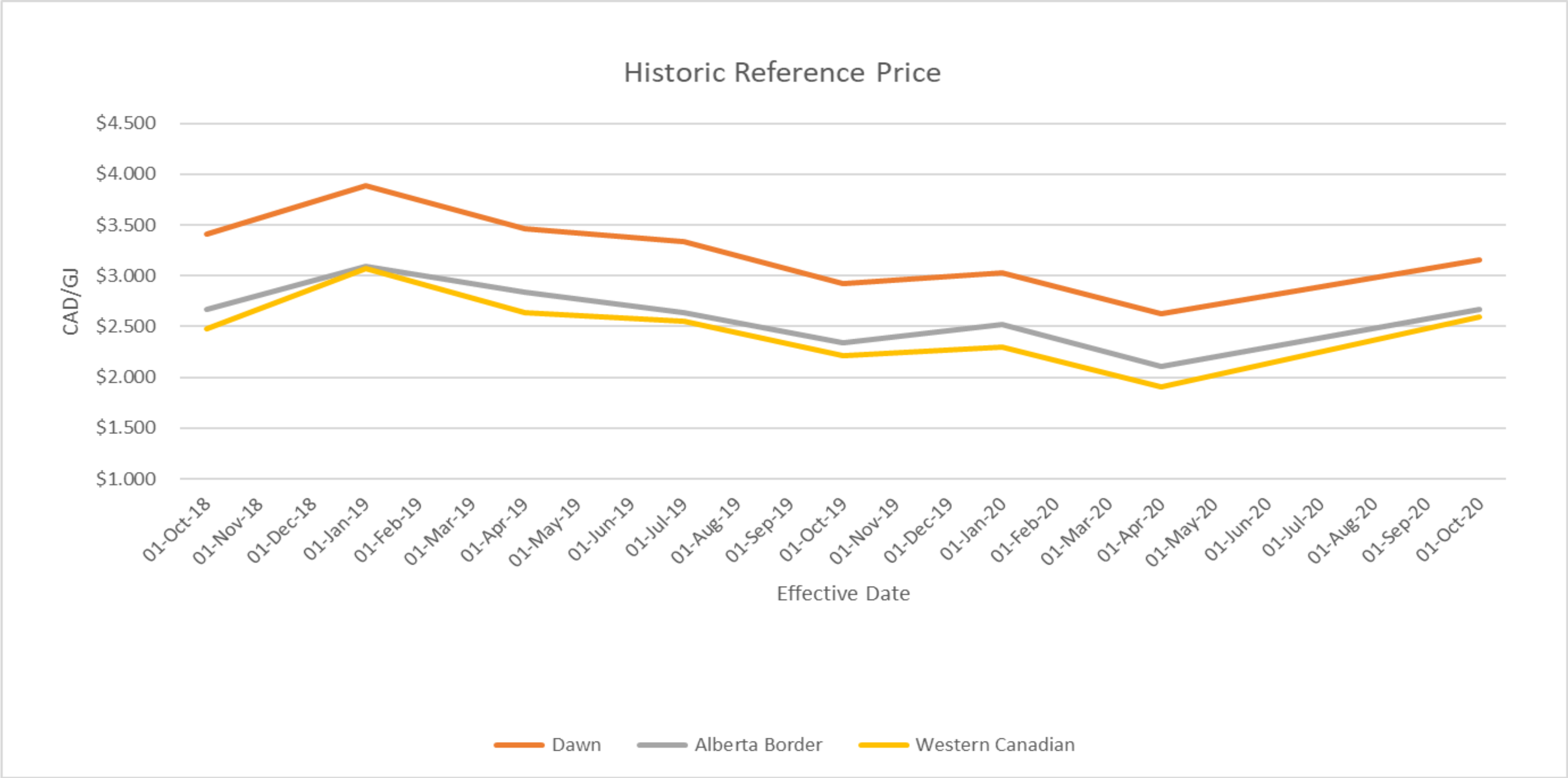
1 - 3-year rolling average for benchmarking purposes

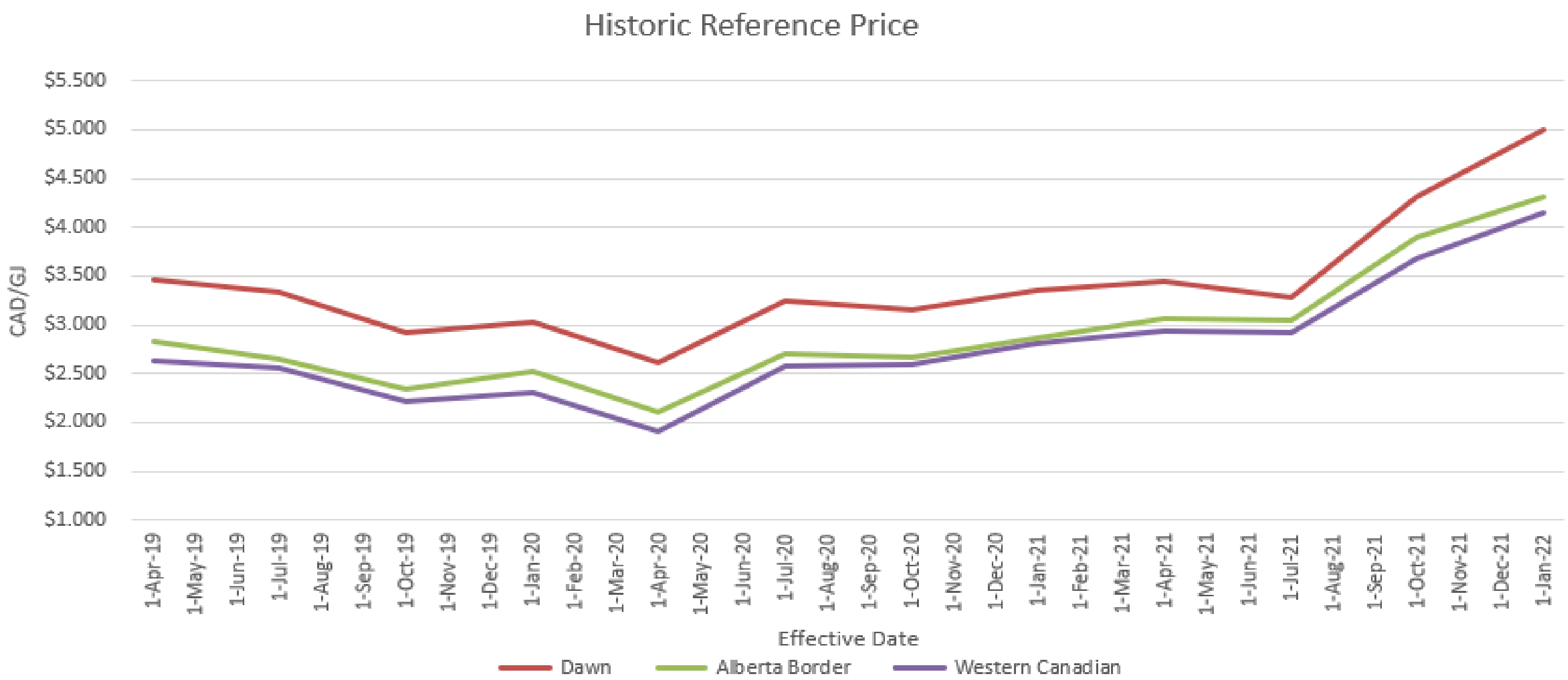
2 - Positive variance indicates colder than planned weather. Negative variance indicates warmer than planned weather.

3 - As filed in QRAM proceeding

4 - For data see Section 5.3


Historic Reference Price
CAD/GJ
$4.500
$4.000
$3.500
$3.000
$2.500
$2.000
$1.500
$1.000
1-Jan-18
1-Apr-18
1-Jul-18 (Not Implemented)
1-Oct-18
1-Jan-19
1-Apr-19
1-Jul-19
1-Oct-19
1-Jan-20
Effective Date
Dawn Reference Price
Alberta Border Reference Price
Western Canadian Reference Price


Historic Reference Price
$4.500
$4.000
$3.500
$3.000
$2.500
$2.000
$1.500
$1.000
CAD/GJ
01-Oct-18
01-Nov-18
01-Dec-18
01-Jan-19
01-Feb-19
01-Mar-19
01-Apr-19
01-May-19
01-Jun-19
01-Jul-19
01-Aug-19
01-Sep-19
01-Oct-19
01-Nov-19
01-Dec-19
01-Jan-20
01-Feb-20
01-Mar-20
01-Apr-20
01-May-20
01-Jun-20
01-Jul-20
01-Aug-20
01-Sep-20
01-Oct-20
Effective Date
Dawn
Alberta Border
Western Canadian


Historic Reference Price
$5.500
$5.000
$4.500
$4.000
$3.500
$3.000
$2.500
$2.000
$1.500
$1.000
CAD/GJ
1-Apr-19
1-May-19
1-Jun-19
1-Jul-19
1-Aug-19
1-Sep-19
1-Oct-19
1-Nov-19
1-Dec-19
1-Jan-20
1-Feb-20
1-Mar-20
1-Apr-20
1-May-20
1-Jun-20
1-Jul-20
1-Aug-20
1-Sep-20
1-Oct-20
1-Nov-20
1-Dec-20
1-Jan-21
1-Feb-21
1-Mar-21
1-Apr-21
1-May-21
1-Jun-21
1-Jul-21
1-Aug-21
1-Sep-21
1-Oct-21
1-Nov-21
1-Dec-21
1-Jan-22
Effective Date
Dawn
Alberta Border
Western Canadian