ENBRIDGE

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VIA RESS, EMAIL and COURIER

September 20, 2019

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: EB-2019-0137 – Enbridge Gas Inc. – 5 Year Gas Supply Plan

Enbridge Gas Inc. ("Enbridge Gas") has become aware of three non-material errors in its 5 Year Gas Supply Plan ("the Plan") filed May 1, 2019. Please find attached pages which correct the errors identified. A summary of the errors, including their location within the Plan and a basic description, has been provided below.

Location in Plan	Description
Table 8 – Enbridge CDA Design Day Supply / Demand Balance. p.46	Line 12 in the column titled "2020" reads 2.9%. This value should read 1.7%. All other values in the table, including those used to derive the figure in question, are correct.
Paragraph 3, p.70	The figure in sub-bullet 3 reads 0.03%. This value should read 0.3%.
Appendix B	Lines 3-5 in the column titled "Contract Termination Date" the dates shown read 31-Oct-2022. These dates should read 31-Oct-2024.

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

Sincerely,

(Original Signed)

Brandon Ott
Technical Manager, Regulatory Applications

Cc:
David Stevens, Aird & Berlis LLP
All Interested Parties EB-2019-0137, EB-2017-0129 & EB-2015-0238

5 Year Gas Supply Plan

EB-2019-0137

Enbridge Gas Inc.
May 1, 2019

Table of Contents

1. Administrative Information

1.1 Introduction

On October 25, 2018 the Ontario Energy Board ("Board") 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 in January 2019. In a letter dated November 20, 2018, Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union") requested the Board extend its deadline for the submission of five year gas supply plans until May 2019, to allow the gas utilities to prepare more complete submissions and maximize regulatory efficiency. On December 20, 2018 the Board issued a letter in response to EGD and Union extending the filing date for five year gas supply plans to May 1, 2019. Effective January 1, 2019, EGD and Union amalgamated to form Enbridge Gas Inc. ("EGI").

This document is a comprehensive review EGI's gas supply plan ("Plan"). Relevant to the EGD rate zone, the review of the Plan covers the five year period of January 1, 2020 to December 31, 2024. Relevant to the Union rate zones[2], the review of the Plan covers the five year period of November 1, 2019 to October 31, 2024.

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") customer annual, seasonal and design day natural gas delivery requirements while adhering to a set of gas supply planning guiding principles as outlined in the Framework.

Guiding Principles for the Assessment of Gas Supply Plans

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.
2. **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.
3. **Public policy** – The gas supply plan will be developed to ensure that it supports and is aligned with public policy where appropriate.

[1] EB-2017-0129
[2] Collectively, the Union North West, Union North East and Union South rate zones are referred to as "Union rate zones". Union North West and Union North East are collectively referred to as "Union North".

As this Plan demonstrates, EGI adheres to these principles by holding a diverse portfolio with respect to supply basins, gas supply producers and marketers, contract terms, and transportation service providers, in addition to owning and contracting for storage capacity. This approach allows EGI to effectively manage costs while maintaining the flexibility to adjust to changing market conditions and weather fluctuations. Balanced consideration of these principles ensures EGI customers have access to secure and reliable natural gas at a prudently incurred cost.

Amalgamation and the Plan

As outlined in EB-2018-0305, Exhibit E1, Tab 1, Schedule 1, EGI's 2019 Rate Application, the EGD and Union rate zones have existing differences between their gas supply planning processes, rate zones, methodologies, recovery mechanisms and regulatory constructs. Further, the EGD and Union rate zones will be maintained separately throughout the five year deferred rebasing period. As such, this document is organized in a manner that keeps the EGD rate zone and Union rate zones' portfolio decisions and strategies distinct from one another. Where possible, EGI has merged common sections.

EGI stated in the 2019 Rate Application that "[EGI] is committed to undertaking a thorough review of gas supply planning during the deferred rebasing period…While bringing the plans together, any residual differences in processes and procedures, and regulatory approach will be resolved over time."[3] While this commitment remains, EGI's top priority is to ensure it continues to provide safe, reliable, and cost-effective delivery of natural gas to customers in all of its rate zones. In light of the requirement to provide five year Plans four months after the amalgamation of EGD and Union, EGI has not integrated the processes and methodologies of its legacy gas supply functions. Throughout the five year term of the Plan as the analysis required to inform the integration of the gas supply function is completed, EGI expects the Annual Updates and other regulatory processes identified in Section 20 will provide opportunity to report on progress in this area.

Subject to the outcomes of a detailed integration analysis, EGI is hopeful that the transition toward a more integrated gas supply function can be completed prior to or concurrent with the submission of its next five year Plan for the 2025 to 2029 period. In any event, EGI hopes to identify any synergy opportunities in the execution of its Plan for both the EGD and Union rate zones, ideally leveraging EGI's combined assets to optimize the portfolio for all customers.

Monitoring the Framework in Meeting the Board's Objectives

As noted on page 16 of the Framework "The [Board] expects that over time, experience and lessons learned will provide insight into aspects of the Framework that can be further enhanced and strengthened."

As further outlined in Sections 8.1 and 15.1**,** EGI purchases commodity from a variety of basins, utilizing diverse terms including annual, monthly, weekly, daily or spot purchases. These are on-the-

[3] EB-2018-0305 Exhibit E1, Tab 1, Schedule 1, page 1

ground operational decisions made throughout the year based on the latest market conditions, weather forecasts and operational data available. Although commodity procurement decisions are carried out in real time market conditions, the basis for these decisions are strategic in nature and pre-empted by the transportation and storage portfolio decisions discussed in this Plan. This document will focus on the strategic transportation and storage decisions that underpin the commodity purchases.

The second point EGI wishes to highlight for the Board is the iterative nature of gas supply planning and the impact this has on the timing of portfolio decisions. The transportation and storage portfolios have been developed over a long period of time, and as a result, changes to the portfolio are limited to changes in demand requirements, contract expiries, and new opportunities as they become available in the market. This is a function of EGI having a diverse set of contracts, parameters and terms. The Plan will never undergo transformational change within the EGD and Union rate zones' portfolios within any given year. The five year Plan includes future supply option analyses providing the Board insight into EGI's gas supply planning.

EGI has endeavored to present upcoming decisions in this Plan in a manner which maximizes transparency and allows for meaningful consideration by the Board. As the Board pointed out in the Framework, "The responsibility for delivering reliable supply to customers in a prudent manner remains with the distributors. Distributors manage and execute their plans and adjust their activities to address changes to demand and supply conditions."[4] EGI is aware of this responsibility, and understands the Board's clarification in the Framework that "the assessment of gas supply plans will not result in a decision on the costs or cost recovery. That would be the subject of related applications."[5] Based on the above, EGI understands the Board's assessment of the Plan will not be an assessment of prudency, or an assessment of the appropriateness of the cost consequences of the Plan.

1.2 Significant Changes

This document is the first five year Plan filed by EGI. Future five year Plans and Annual Updates will contain a discussion of significant changes.

1.3 Process, Resources, and Governance

Gas supply planning is a complex process. The common starting point in developing EGI's Plan for either the EGD or Union rate zones is the creation of a demand forecast; an in-depth analysis that focuses on key factors impacting demand including customer growth, normalized weather, design day requirements, customer consumption patterns and economic outlooks. Sections 4 and 11 contain further detail regarding the demand forecasts for the EGD and Union rate zones respectively.

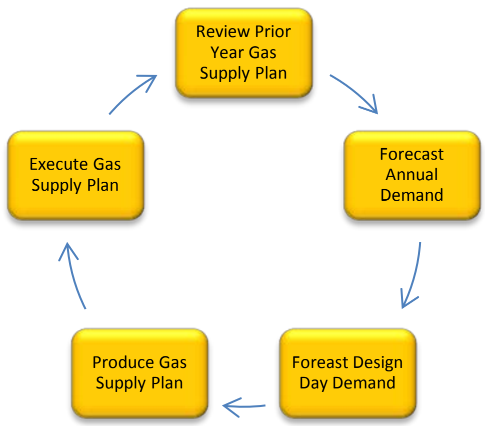
[4] Framework, page 1
[5] Ibid.

Subsequently, the planners must consider the appropriate quantity of upstream transportation contracts, along with storage assets, required to provide an integrated solution for all sales service and bundled DP customers to meet annual, seasonal and design day demand. The Plan does not include any excess assets; only those necessary to meet firm customer requirements.

In the final step of developing its Plan, EGI uses SENDOUT to optimize existing storage and transportation assets to determine the optimal mix of commodity purchases and storage utilization in order to meet its forecasted demand requirements. SENDOUT is a gas supply planning tool that is used by a number of local distribution companies in North America.

Figure 1 summarizes this planning process at a very high level.

Figure 1 – Annual Gas Supply Planning Process



Each year, the Plans are finalized and receive executive approval in the third quarter. The annual gas supply planning process flowcharts specific to the EGD and Union rate zones respectively are provided in Appendix A.

The results of each Plan are communicated to key stakeholders throughout EGI and support ongoing operations. One key step alluded to above is the evaluation of transportation, supply, and storage options. Such evaluations must by necessity have a long term strategic focus taking into consideration EGI's future growth and asset requirements, and analyzing each decision as part of a balanced portfolio which adheres to the guiding principles. Once the required assets are acquired, EGI will execute on its Plan for each rate zone; implementing a layered approach to procuring supply at various points in the year. Supply purchase decisions are made regularly throughout the year in order to allow EGI to continuously update its supply purchase plan to account for changes in customer requirements.

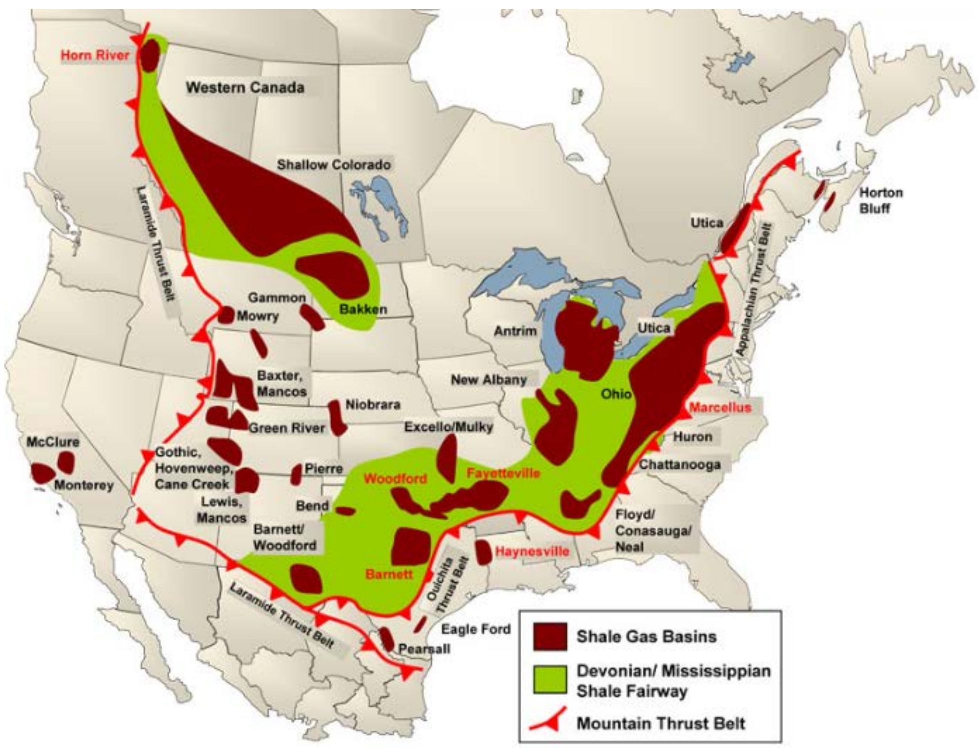
2. Market Overview

2.1 Description of Gas Supply and Asset Options

Gas Supply Options

The following sub-sections outline viable gas supply sources considered by EGI when evaluating supply options. Figure 2 illustrates the shale plays in North America at a summary level.

Figure 2 – North American Shale Plays



Source: ZIFF Energy Group, 2011

Western Canadian Supplies

Historically, the dominant source of natural gas supply for EGI has been the Western Canadian Sedimentary Basin ("WCSB"), which spans most of Alberta as well as parts of British Columbia and Saskatchewan. EGI typically refers to WCSB sources as supplies received at Empress, NOVA Inventory Transfer ("NIT"), also commonly referred to as the Alberta Energy Company ("AECO"), or Alliance Trading Pool location ("ATP").

The Empress trading point of the TransCanada PipeLines Limited ("TCPL") Canadian Mainline ("TCPL Mainline") is near the border of Alberta and Saskatchewan. Gas purchased at, or delivered to, Empress can be transported on TCPL Mainline to every EGI delivery area. A further description of TCPL Mainline is provided in the Transportation Options section.

AECO/NIT is a point notionally located in the center of the NOVA Gas Transmission Ltd. ("NGTL") system in Alberta. AECO/NIT purchases can be transported on the NGTL system to Empress, and onwards to EGI's delivery areas via TCPL Mainline.

ATP supply presents an alternative to Empress and AECO/NIT for procuring WCSB natural gas. This supply can be transported on the Alliance Pipeline to the Chicago market hub where it meets the Vector Pipeline. EGI does not currently procure supplies at the ATP.

Chicago Supplies

The central location of the Chicago market hub allows connection to several major gas production regions including Alberta, Appalachia, the Bakken, the Gulf of Mexico, the U.S. midcontinent, and the U.S Rockies, making it a liquid natural gas hub for EGI to access. Gas procured at the Chicago market hub can be transported to Dawn on the Vector Pipeline, where it can be stored and/or continue its flow to the EGI franchise areas on paths described in the Transportation Options section.

Dawn Supplies

Dawn is the largest integrated underground storage facility in Canada and is one of North America's most liquid natural gas trading hubs. Its proximity to Ontario customers as well as its direct access to natural gas supply basins makes it an integral part of the Plan for both the EGD and Union rate zones. Gas procured at Dawn can be transported to EGI's distribution system on transmission pipelines owned and operated by EGI and TCPL.

Appalachia Supplies

Shale gas basins are spread across the continent, with some of the largest and most prolific deposits located in the U.S. Northeast, such as the Marcellus and Utica. The development of infrastructure connecting these emerging plays to Ontario is ongoing. However, most relevant to EGI is the recent in-service of the NEXUS Gas Transmission ("NEXUS") Project which received FERC approval on October 10, 2018. This natural gas transmission pipeline can transport up to 1.5 Bcf/d of supply to northern Ohio, southeastern Michigan, Chicago and Dawn. Notwithstanding, Appalachian supplies are a relatively new option to consider in the Plans. Although the Marcellus and Utica basins are enormous in size, the market in this region is somewhat still developing.

South Central U.S. Supplies

Several prolific shale plays located in Kansas, Oklahoma, and Texas can be accessed via the Panhandle Eastern Pipeline ("Panhandle Eastern") System. Panhandle Eastern's field zone includes deliveries to any point west of the Haven, Kansas compressor station.

Niagara Supplies

The Niagara and Chippawa delivery points are located at the U.S.–Canada border and primarily import natural gas from shale plays such as the Marcellus and Utica within the Appalachian basin.

Gas procured at Niagara can be transported to EGI's franchise areas and/or storage facilities using transmission pipelines owned and operated by TCPL and EGI. However, since there are a limited number of counterparties delivering supply to the Niagara point, it is relatively illiquid and requires term supply contracts (e.g. seasonal, annual or monthly).

MichCon Supplies

EGI can procure gas supply at a point referred to as "MichCon Generic", which is part of the DTE Energy system in and around Detroit, Michigan. Gas delivered to MichCon Generic can be transported on the Vector, St. Clair and Link pipelines to Dawn and EGI's storage facilities or on the Great Lakes Gas Transmission ("GLGT") System to TCPL Mainline to Union North West.

Delivered Service

Delivered Service refers to term contracts with third-party providers typically contracted for the winter season to balance increased seasonal demand and diversify purchases. Depending on the arrangement made with the supplier, supplies are delivered to Dawn or directly to EGI's distribution system.

Peaking Supplies

Peaking supply arrangements source gas from third-party suppliers for firm delivery directly to EGI's franchise areas during the winter season. Since supplies are only required a few days per year (contracts are typically for a maximum of 10 days per winter season), they are traded at a premium to conventional supplies over a longer period. The agreed upon supply must be available to EGI on the days determined by EGI.

Ontario Production

Gas produced locally within Ontario is minimal, and presently does not provide a reasonable alternative for managing demand requirements within the Plan.

Transportation Asset Options

The following sub-sections outline the viable transportation providers considered by EGI when evaluating transportation options.

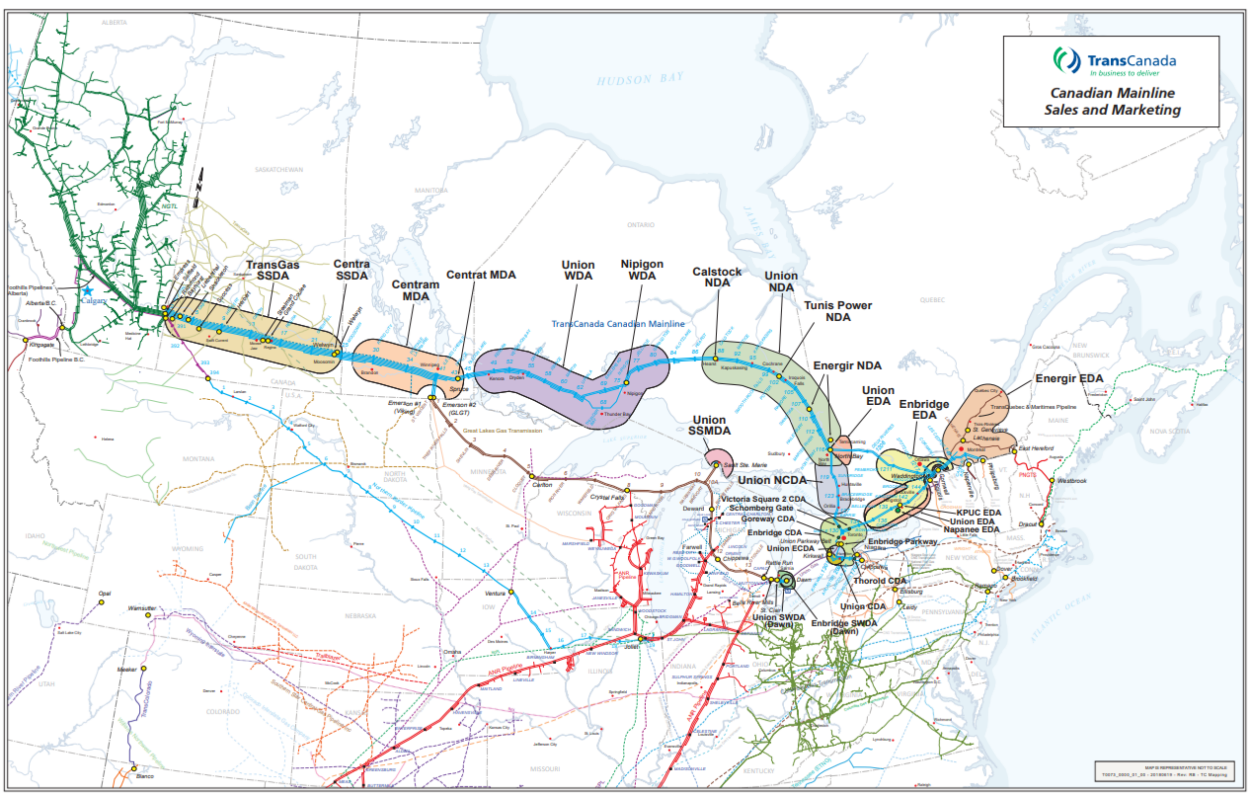
TCPL Mainline

The 14,101 km TCPL Mainline transports natural gas from Empress, through the Prairies, north of the Great Lakes, and branches off into two lines which form two sides of what is known as the "Eastern Triangle". One branch is directed south towards the Greater Toronto Area; the other branch continues east towards the Ottawa region, the U.S. border at Iroquois, and into Québec. The remaining side of the triangle connects to TCPL Mainline near the Greater Toronto Area in the west to the Ottawa region in the east.

TCPL Mainline also has multiple Transmissions by Others ("TBO") agreements which allow it to provide services to a variety of points not directly part of TCPL Mainline. One such TBO agreement is along the GLGT System – a pipeline that connects with TCPL Mainline near Emerson, Manitoba in the west and St. Clair, Ontario, near Dawn, in the east. Other TBO agreements TCPL has include capacity on EGI's Dawn Parkway System and on EGI's Albion Pipeline. TCPL Mainline is a reliable pipeline that provides diversity of path and service, as well as flexibility through a variety of different transportation services, and the ability to procure supply from the liquid Empress trading point.

TCPL Mainline and GLGT are displayed as blue and brown lines respectively in Figure 3, with TCPL Mainline running north of the Great Lakes and GLGT running south of the Great Lakes.

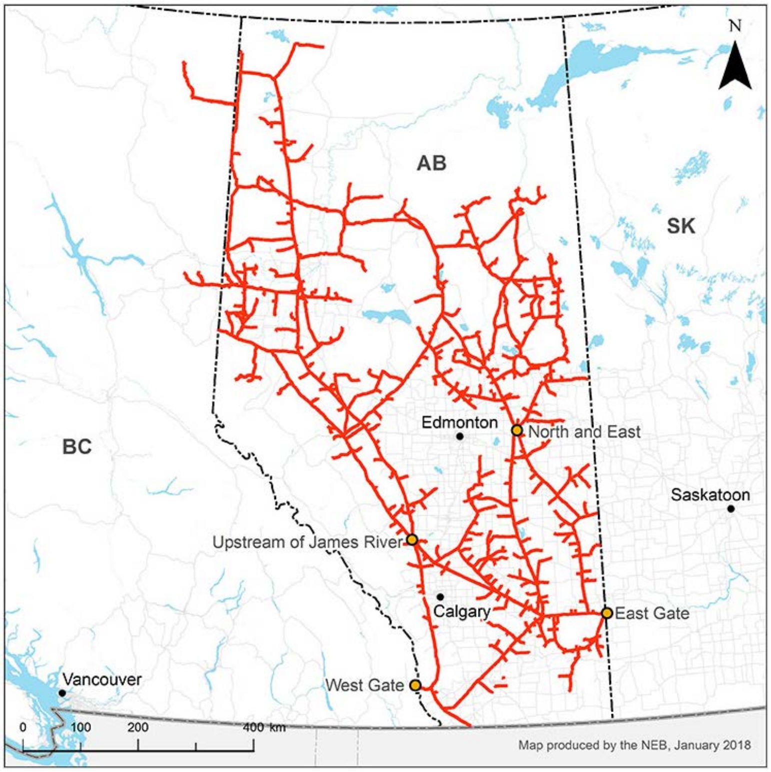
Figure 3 – TCPL Mainline



NOVA Gas Transmission Ltd. System

The 24,500 km NGTL system gathers and transports natural gas in Alberta and northeastern British Columbia. NGTL has over 1,100 receipt points and 300 delivery points. Of those delivery points, East Gate, otherwise known as Empress, is where NGTL meets TCPL Mainline. Figure 4 shows the NGTL system including key points on the system.

Figure 4 – NGTL System Map

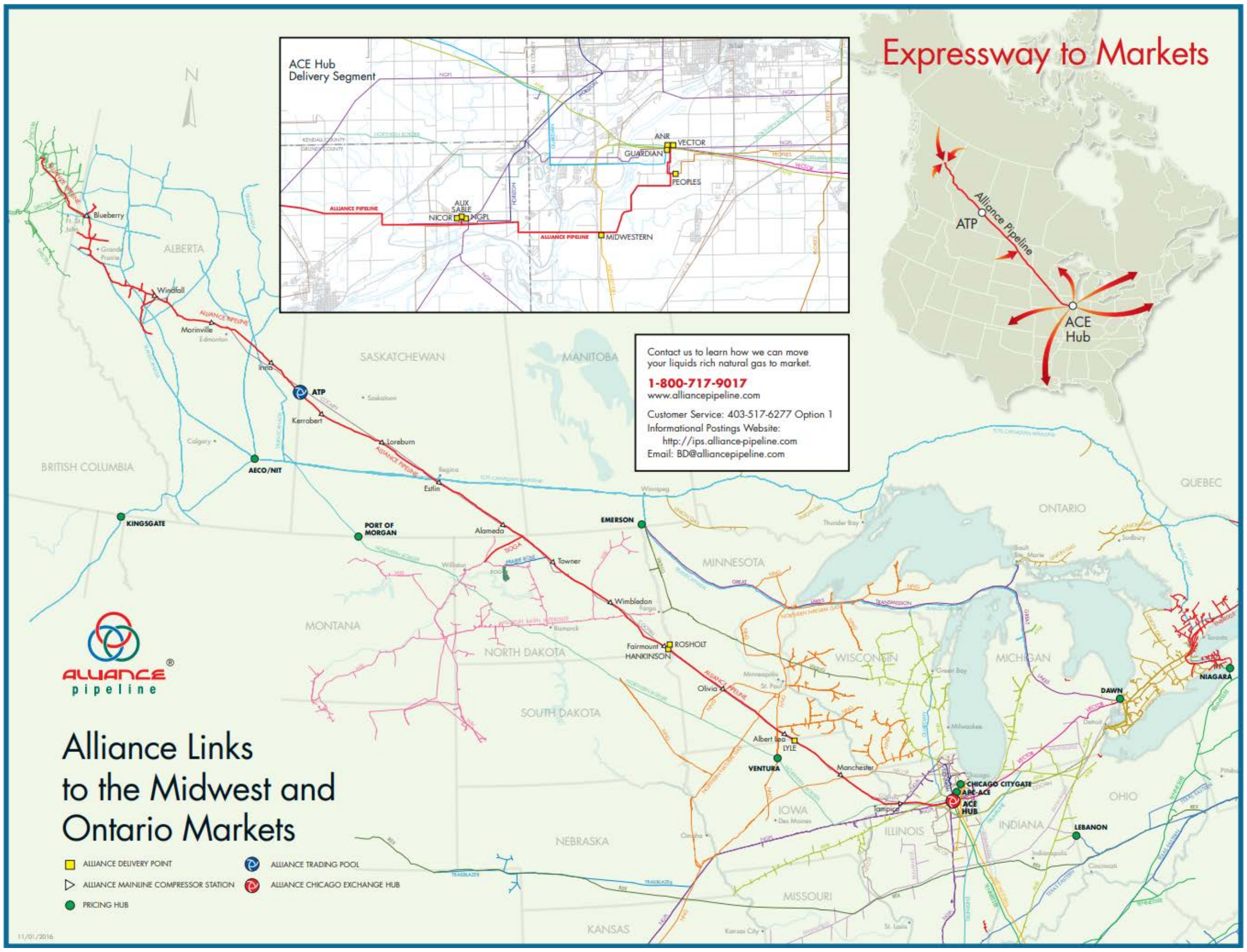


EGI's main procurement point on the NGTL system is the generic NGTL system point known as AECO/NIT. Supply procured at AECO/NIT is transported to Empress via the NGTL system. Procuring supply off of the NGTL system provides diversity and reliability for purchases made in Western Canada, as it allows the ability to move upstream of the Empress delivery point to the vast supply available within the NGTL system.

Alliance Pipeline

The 3,848 km Alliance Pipeline ("Alliance") system originates in northeastern British Columbia and transports WCSB natural gas southeast to Chicago. Alliance is a unique natural gas pipeline because natural gas liquids may remain in the natural gas stream. Alliance transports liquids-rich natural gas to Chicago. Extraction of the natural gas liquids occurs at the Aux Sable facility located near Chicago. Figure 5 shows the Alliance pipeline in red. Alliance can provide another system whereby Western Canadian supplies can be diversified.

Figure 5 – Alliance Transportation System



Vector Pipeline

The Vector Pipeline is a 348 mile pipeline that links Chicago to Dawn, and interconnects with the Alliance Pipeline in Illinois, Bluewater Storage in Michigan, DTE Gas Transportation and NEXUS Gas Transmission at Milford Junction and Belle River in Michigan, Rover Pipeline at Handy in Michigan, and Dawn in Ontario. Figure 5 above depicts the Vector pipeline in pink.

The Vector Pipeline offers the opportunity to diversify supply requirements into the Midwestern U.S. market and provides a liquid trading point which allows for the flexibility to manage purchase decisions on a short-term basis and with multiple counterparties to transact with, resulting in competitively priced supply and services.

Great Lakes Gas Transmission System

At 3,404 km in length, GLGT provides a link between natural gas supply in the WCSB and major markets in the US Midwest and central Canada. GLGT transports over 2.2 Bcf/d of natural gas through a high-pressure pipeline system. GLGT connects to TCPL Mainline at the Manitoba-North

Dakota border and continues throughout Michigan before linking to Great Lakes Canada Pipeline ("GLC") and further to Dawn. GLGT and GLC are reliable pipelines that provide diversity of path and service, as well as flexibility through a variety of different transportation services, and the ability to procure supply from the trading points such as Emerson and MichCon. Figure 6 below depicts the GLGT system in red.

Figure 6 – Great Lakes Gas Transmission System

Link Pipeline ("Link")

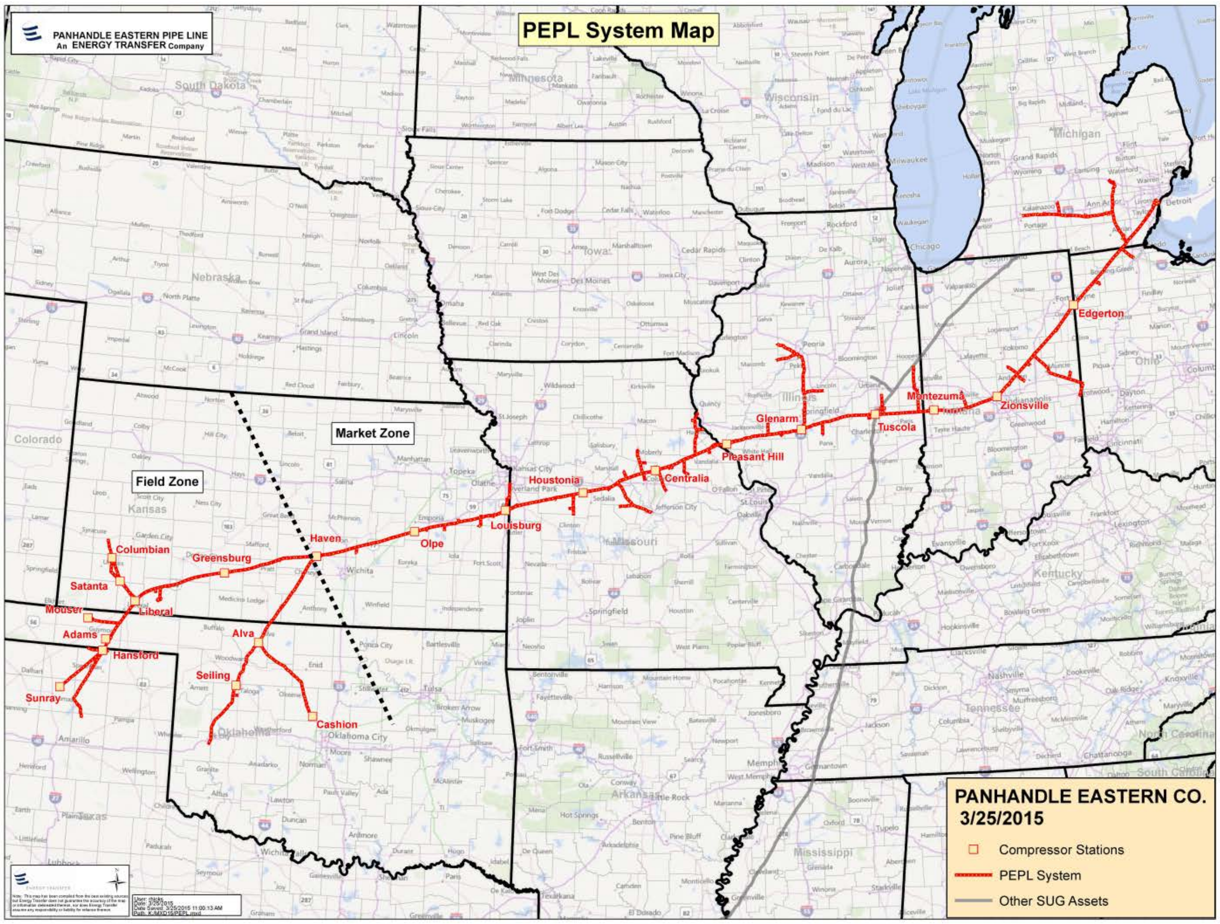
The Link extends from a point on the U.S.–Canada border under the St. Clair River to EGI storage assets near Sarnia. The Link provides EGI the opportunity to diversify its supply requirements with MichCon Generic-based pricing.

Panhandle Eastern Pipeline

Panhandle Eastern's transmission system consists of four large diameter pipelines extending approximately 1,300 miles from producing areas in the Anadarko Basin of Texas, Oklahoma and Kansas through Missouri, Illinois, Indiana, Ohio and into Michigan. It has a capacity of approximately 2.8 Bcf/d. Panhandle Eastern interconnects with EGI at the Ojibway point, located near Windsor, Ontario.

Figure 7 below shows the Panhandle Eastern system. Panhandle Eastern provides opportunities to access diversified supplies from prolific shale and conventional basins in the South-Central U.S.

Figure 7 – Panhandle Eastern System

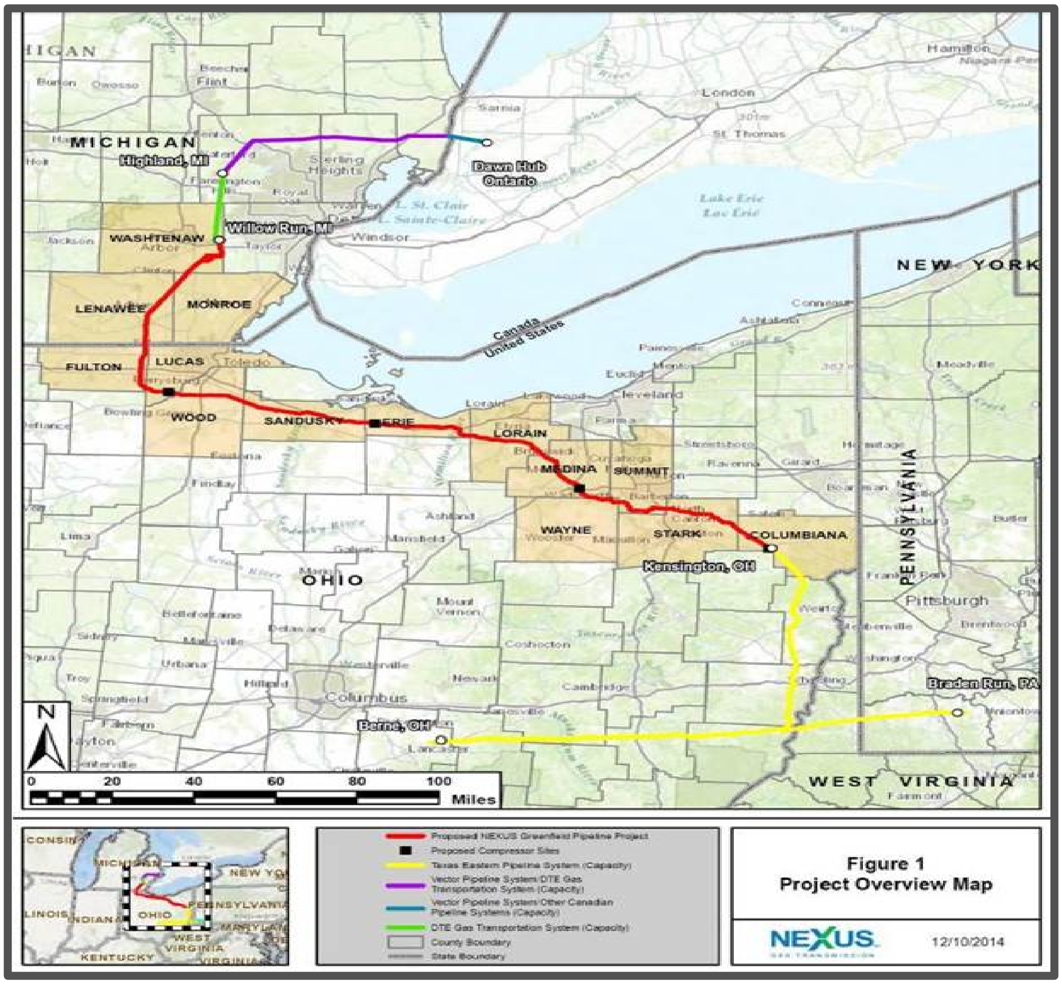


NEXUS Gas Transmission

NEXUS is a 256-mile interstate pipeline system delivering natural gas from Kensington, OH connecting upstream pipelines in the heart of the Appalachia supply basin to markets in the U.S. Midwest and Dawn in Ontario. Figure 8 below provides a map of the NEXUS project, with the greenfield portion of the project identified in red.

NEXUS provides the opportunity to diversify supply requirements by leveraging supply available in the emerging Appalachia supply basin and the flexibility to procure supply from various points within that region, including the point of Clarington which is accessed through NEXUS' Texas Eastern Appalachian Lease ("TEAL") project, described below.

Figure 8 – NEXUS Gas Transmission



Texas Eastern Transmission ("Texas Eastern")

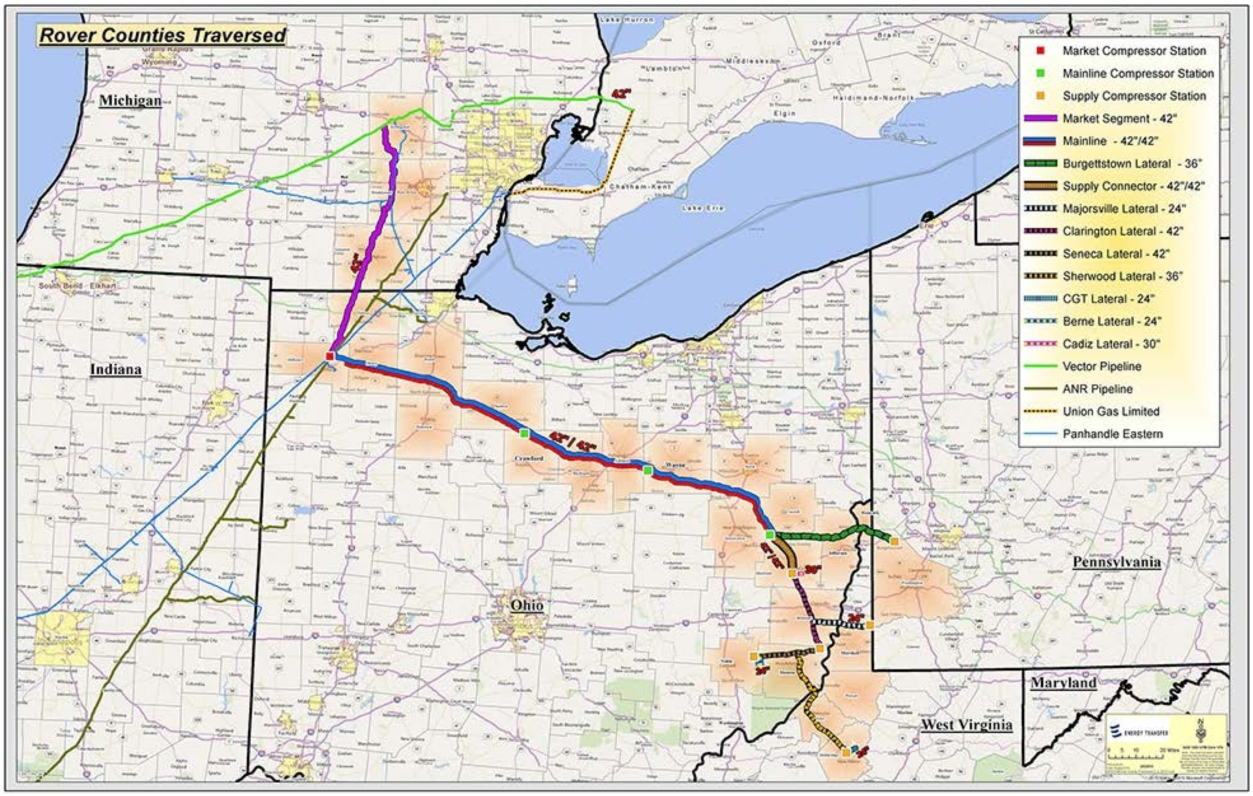
With 9,029 miles of pipeline, Texas Eastern connects Texas and the Gulf Coast with high demand markets in the northeastern U.S. Texas Eastern can transport 11.71 Bcf/d and offers approximately 74 Bcf of gas storage. Texas Eastern also connects to the east through Tennessee Natural Gas and Algonquin Gas Transmission. Texas Eastern is a major pipeline in the U.S. and connects NEXUS to Marcellus supply through the TEAL Project. Texas Eastern's connection to NEXUS is depicted in yellow in Figure 8 above. Texas Eastern provides access to a diversified set of secure and reliable supply options for EGI's NEXUS capacity.

Rover Pipeline

The Rover Pipeline ("Rover") is a 713-mile natural gas pipeline designed to transport 3.25 Bcf/d of natural gas from the Appalachian production basin, to markets across the U.S. as well as into Dawn. The project was fully operational in November 2018.

Rover transports natural gas from processing plants in West Virginia, Eastern Ohio and Western Pennsylvania for delivery to pipeline interconnects in West Virginia and Eastern Ohio as well Defiance, Ohio, where more than half of the gas is delivered for distribution to markets across the U.S. Rover provides the opportunity to diversify supply requirements by leveraging supply available in the emerging Appalachia supply basin and the flexibility to procure supply from various points within that region. Figure 9 below depicts the Rover pipeline.

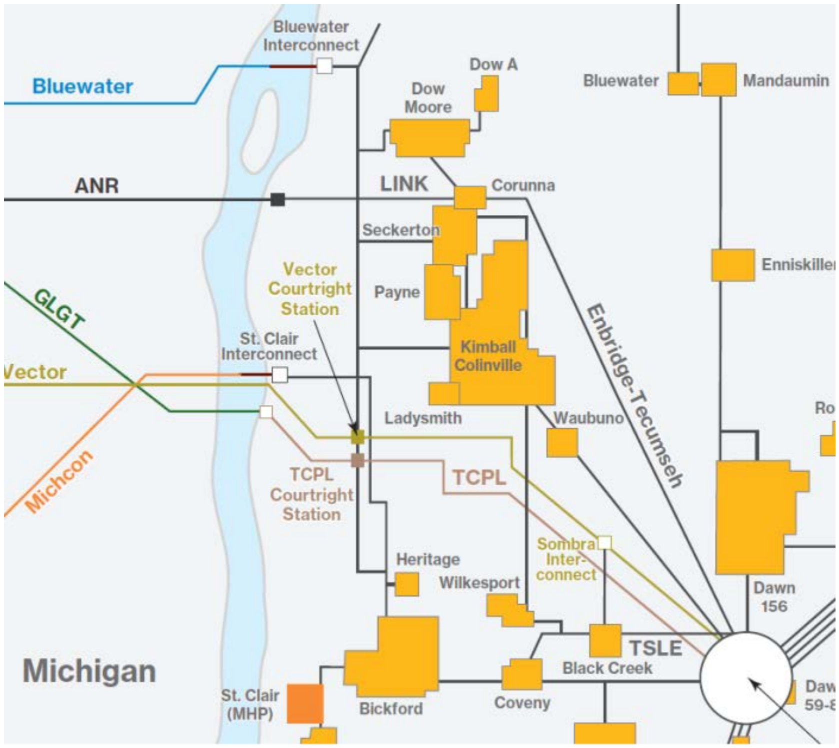
Figure 9 – Rover Pipeline



St. Clair Pipeline

The St. Clair Pipeline begins at St. Clair County Michigan, runs under the St. Clair River and terminates in Lambton County, Ontario, providing an important link between MichCon storage and increased access to gas supply options. The pipeline connects MichCon into EGI's system as shown by the maroon line terminating at the St. Clair Interconnect in Figure 10. The St. Clair Pipeline provides transportation of natural gas from the Canada-U.S. international border to valve sites near Sarnia, Ontario, and is strategically connected to Dawn through the integrated storage and transportation system of EGI.

Figure 10 – Storage Interconnectivity



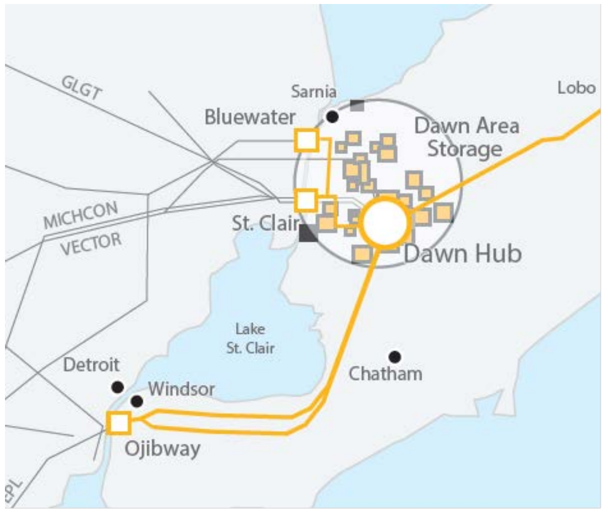
Bluewater Pipeline

The Bluewater Pipeline has an eastern segment that begins at the U.S.–Canada border, and ends at the interconnection with EGI's pipeline system on the Sarnia Industrial Line. Shippers utilize this bi-directional interconnect contract for storage in Michigan to move gas through Dawn to eastern markets. The ability to import and export gas is limited by demand in the Sarnia area. The Bluewater Pipeline is the maroon line connecting Bluewater to the Bluewater Interconnect in Figure 10. The Bluewater Pipeline provides transportation of natural gas from the Canada-United States international border to valve sites near Sarnia, Ontario, and is strategically connected to Dawn through the integrated storage and transportation system of EGI.

Panhandle Pipeline

The Panhandle Pipeline, owned by EGI, is a bi-directional pipeline system that connects upstream with Panhandle Eastern at the middle of the Detroit River and traverses 118 km to Dawn serving EGI's residential, commercial and industrial in-franchise markets along the way. Gas imported across the international border from Panhandle Eastern is received at he Ojibway Valve Site before being transported to markets in southwestern Ontario. The Panhandle Pipeline serves in-franchise markets and also provides a path for Panhandle Eastern deliveries to access Dawn. Depending on the time of the year and the demand level of in-franchise markets served by the Panhandle Pipeline, gas may either be received at Dawn on low market days or delivered from Dawn on high market days. Panhandle is shown as the yellow pipelines in the bottom of Figure 11 connecting Ojibway into Dawn.

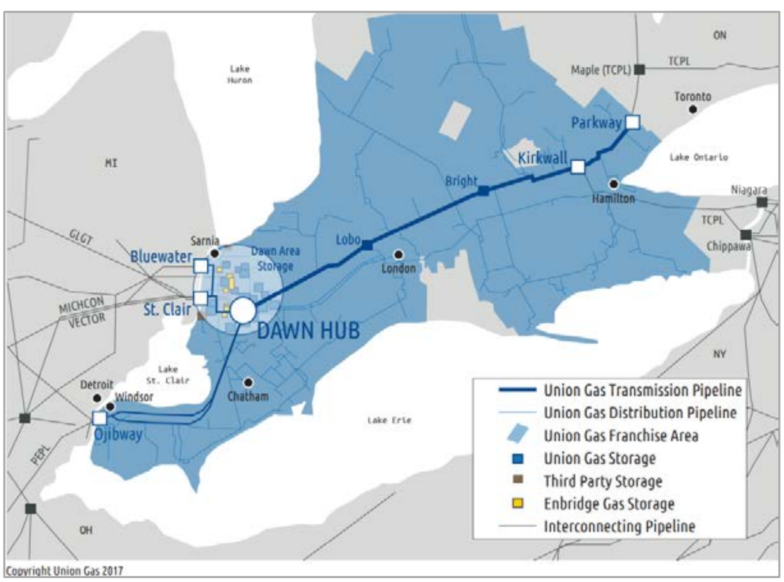
Figure 11 – Panhandle Pipeline



Dawn Parkway System

The Dawn Parkway System is a 229 km pipeline that provides bi-directional transportation services connecting Dawn to delivery points at Parkway, and Kirkwall, including a direct connection to the Enbridge Central Delivery Area ("CDA") at Parkway and Lisgar. Gas flowing on the Dawn Parkway System also connects to various EGI delivery areas through services offered on TCPL Mainline such as Firm Transportation Short Haul ("FT-SH"), and Storage Transportation Service ("STS"). Figure 12 below shows the Dawn Parkway System.

Figure 12 – Dawn Parkway System



The Dawn Parkway System offers the opportunity to diversify supply requirements into the Ontario market at Dawn, which is one of the most liquid trading hubs in North America. Dawn is connected to multiple upstream pipelines and is the largest integrated storage facility in North America.

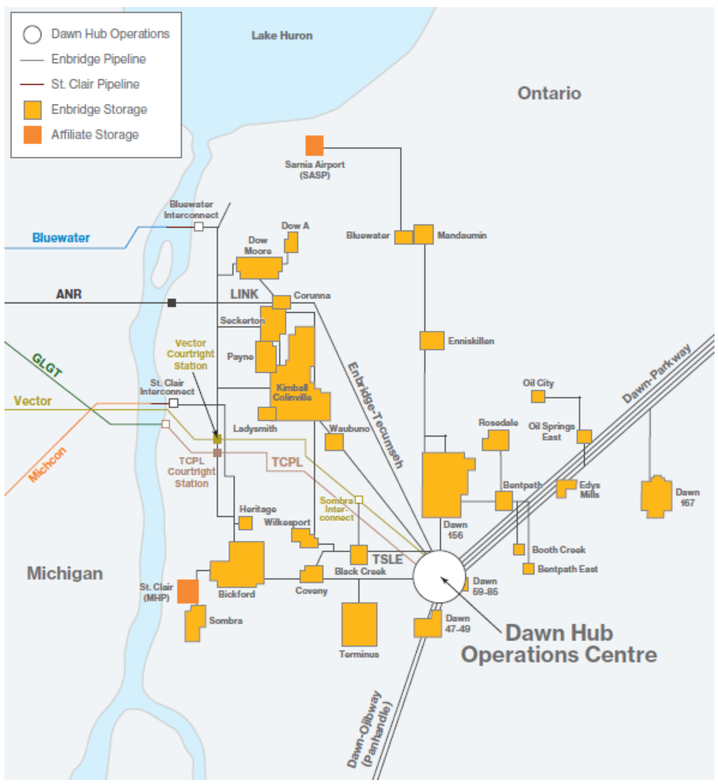
Storage Asset Options

The following sub-sections outline the viable storage sources considered by EGI when evaluating storage options.

Ontario Storage Pools

Ontario has 35 storage reservoirs which collectively have 280 Bcf of working capacity. These storage pools include Dawn and Tecumseh which are owned and operated by EGI. Figure 13 provides a map of storage pools that connect into Dawn.

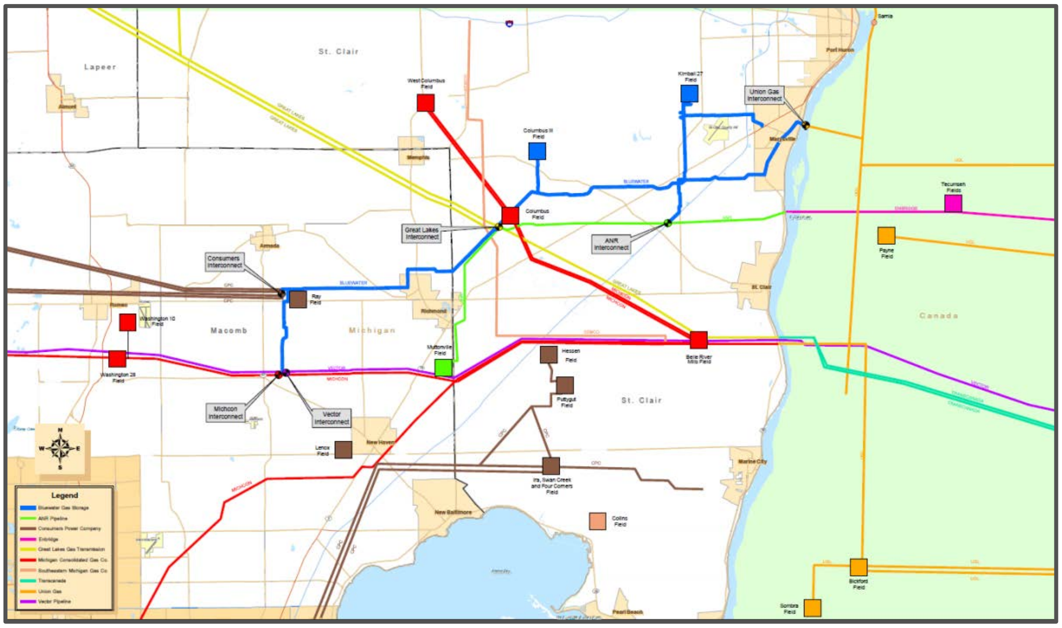
Figure 13 – EGI Storage



Michigan Storage Pools

Michigan has 52 storage reservoirs which collectively have over 680 Bcf of working capacity. The pools include, but are not limited to, Washington 10 and Belle River Mills. Figure 14 provides a map of Michigan storage pools closely located to the EGI distribution system.

Figure 14 – South Michigan Storage



2.2 Market Outlook

Emerging Supply Sources in North America

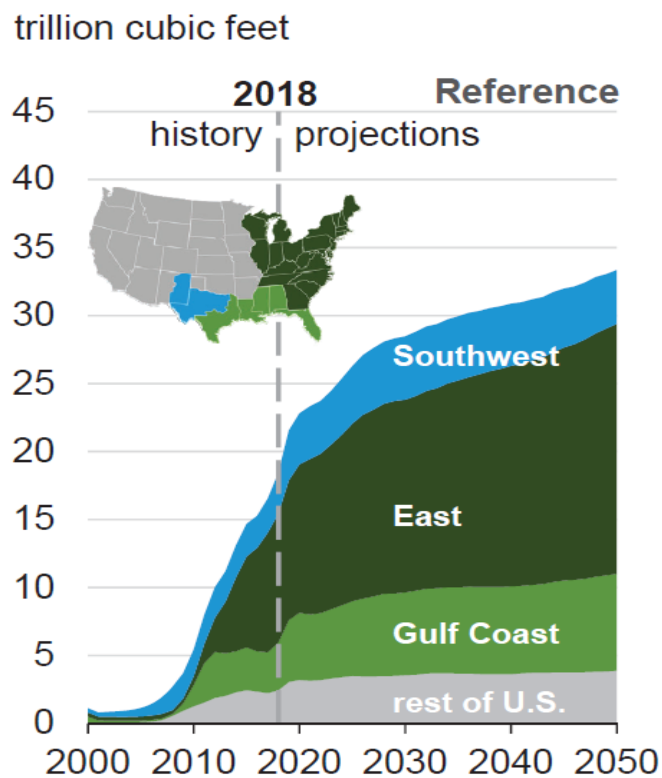
North American natural gas markets continue to experience significant change as production from shale gas formations in Appalachia, the Gulf region and Western Canada continue to exceed expectations. As a result, the flow of natural gas on the Canadian and U.S. pipeline grid continues to change with the addition of new pipeline infrastructure and different utilization of existing assets. Gas has traditionally flowed west to east and south to north. As new shale plays are developed, existing pipelines have and are continuing to reverse flows while new pipelines are also being built to allow gas to flow east to west and north to south. In addition, market area shippers have shifted from long haul transportation to short haul transportation as liquid market hubs continue to grow and supply basins emerge that are located closer to consuming markets.

The Energy Information Administration's ("EIA") Annual Energy Outlook 2019 states that in the U.S., dry natural gas production continues to increase as a result of the development of shale gas and tight oil plays both in share of production and absolute volume because of the sheer size of the associated resources which extend over nearly 500,000 square miles[6]. The growth in U.S. production of natural gas from shale resources is driven by continued development of the Marcellus and Utica shale plays in the east as shown in Figure 15 below. Shale gas production will account for more than 90% of natural gas production by 2050. In addition, continued technological advancements and

[6] EIA Annual Energy Outlook 2019 with projections to 2050 January 24, 2019, https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf

improvements in industry practices are expected to lower costs and increase the volume of oil and natural gas recovery per well.

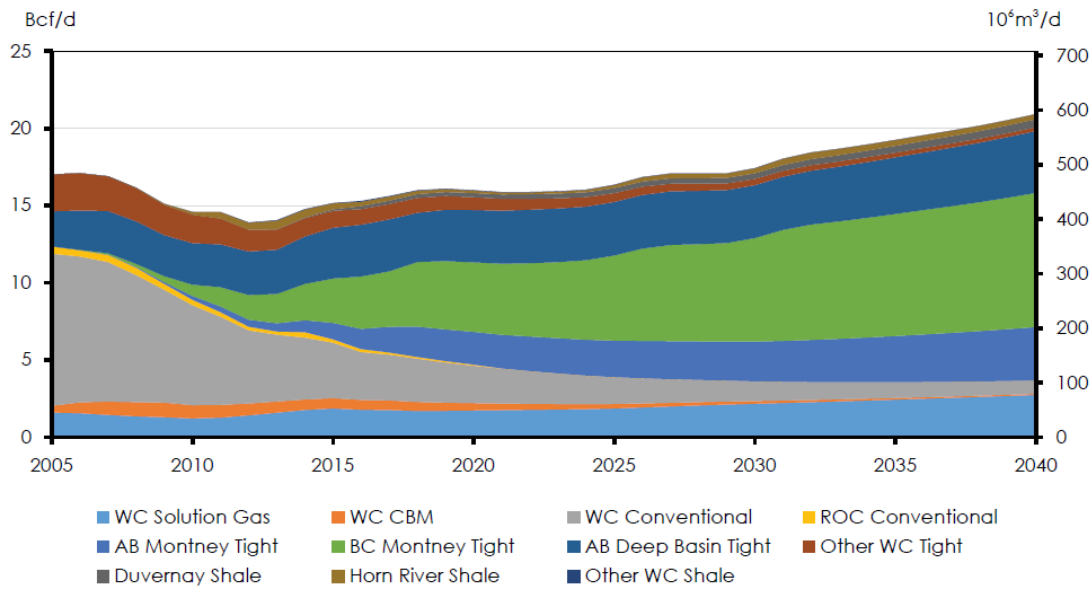
Figure 15 – Dry Shale Gas Production by Region



Production from the Montney Formation, a large gas resource extending from northeast British Columbia into northwestern Alberta, has grown significantly over the past several years increasing from no production prior to 2006 to almost 5.3 Bcf/d or 34% of total Canadian natural gas production in 2017[7]. The majority of Canadian production growth comes from the Montney, with its production expected to reach 12.1 Bcf/d by 2040. The Duvernay and Horn River shale gas plays currently produce small amounts of natural gas with modest production growth projected by 2040. In total, natural gas production in Canada is increasing as gradually higher prices and positive developments associated with proposed Liquefied Natural Gas ("LNG") facilities encourage production. LNG export facilities support a long term increase in drilling and capital spending; this coupled with increased well efficiency is projected to lead to WCSB production growing to 20.9 Bcf/d by 2040.

[7] National Energy Board, "Canada's Energy Future 2018: Energy Supply and Demand Projections to 2040," October 2018, http://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2018/index-eng.html

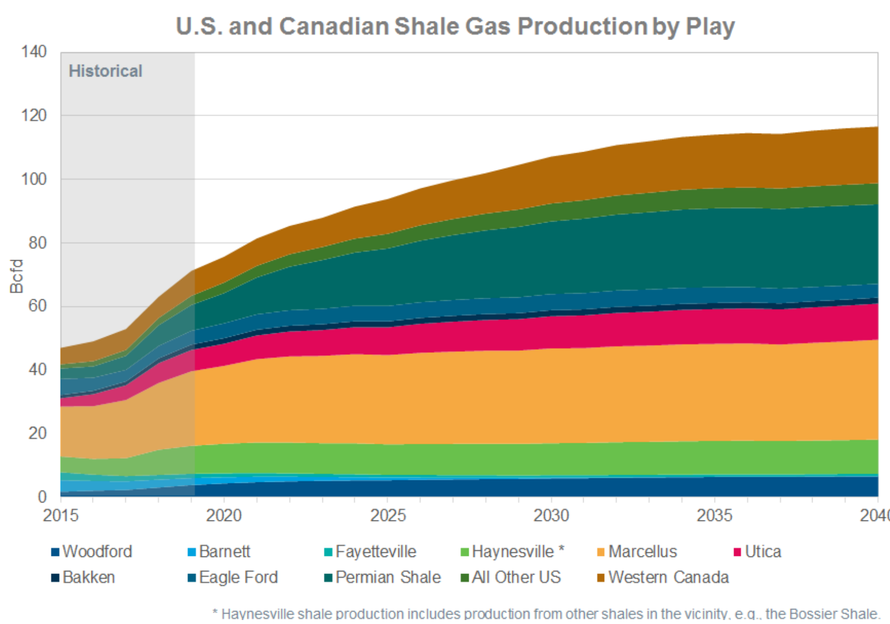
Figure 16 – Canadian Natural Gas Production by Type



Source: NEB 2018 Canada Energy Future

As shown below in Figure 17, ICF International Inc. ("ICF") is also projecting total U.S. and Canada shale gas production to almost double from 62.9 Bcf/d in 2018 to 111.2 Bcf/d in 2040. The Marcellus and Utica account for approximately 30% of the incremental production growth from shale formations, while production from tight oil plays in the Permian Basin is projected to more than triple by 2040 to reach about 19.7 Bcf/d.

Figure 17 – Shale Gas Production by Play



Source: ICF Forecast: Natural Gas – Strategic, Q1 2019 Outlook. Used with permission

The development of abundant and competitively priced natural gas presents Ontario consumers, including residential, commercial, industrial and power, with an opportunity to diversify their natural gas supply portfolio. Accessing this new supply will be essential to providing diversity of supply and long term affordable energy prices to fuel Ontario's economic competitiveness. By utilizing both new and existing infrastructure, access to abundant sources of supply can increase the reliability and security of Ontario's natural gas supply and provide increased liquidity at Dawn.

While the future of Canadian LNG exports has been uncertain, globally, LNG trade is expected to increase as the demand for natural gas rises by over 45% in the next 25 years. The forecasted demand increase could prove to be an opportunity for Canadian LNG export volumes, with several projects proposed to export LNG from Canada's west coast to access overseas natural gas markets. Further, as of the end of 2018, three LNG export facilities were operational in the Continental U.S. with additional LNG export facilities and expansions currently under construction. LNG export projects proposed on the east and west coasts of Canada to export LNG to Asian, European and South American markets, as well as LNG exports from the U.S., could result in additional competition for North American supply in the WCSB and Appalachia supply basins.

Natural Gas Price Signals

The continued growth of shale gas production and a rebound in drilling activity will lead to overall continued production growth and increases in per-well production.

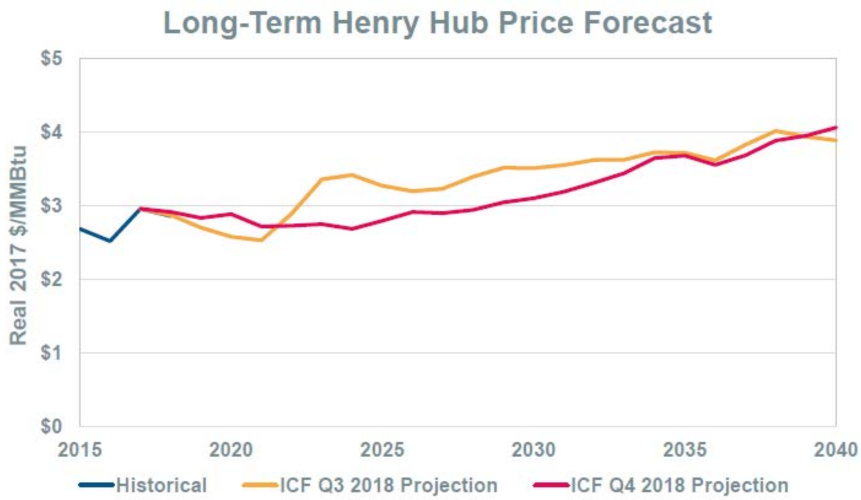
Natural gas prices set at Henry Hub are generally seen to be the primary price set for the North American natural gas market with locational basis differentials based off of the New York Mercantile Exchange ("NYMEX").

The EIA has noted that growing demand in domestic and export markets will lead to increasing natural gas spot prices at Henry Hub despite continued technological advances supporting increased production which would otherwise indicate lower market prices[8]. Natural gas prices are forecasted to remain lower than $4/MMBtu through 2035 and lower than $5/MMBtu through 2050 due to an increase in lower-cost resources; primarily tight oil plays in the Permian Basin.

ICF's forecast indicates that Henry Hub prices will remain in the $3-4 USD/MMBtu range in the long term through to 2040 as shown in Figure 18.

[8] EIA Annual Energy Outlook 2019 with projections to 2050 January 24, 2019 - https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf

Figure 18 – Henry Hub Price Forecast



Source: ICF Forecast: Natural Gas – Strategic, Q4 2018 Outlook. Used with permission

Ontario Gas Supply Market

New pipelines and services that provide new sources of supply and greater access to Dawn continue to emerge.

During the 2018/2019 winter, EGI experienced average daily third-party pipeline supply deliveries to the Dawn Parkway System, including at Dawn that were more than 0.6 PJ/d higher than the previous winter. The largest driver behind this increase was the placement of Rover and NEXUS into service. The Rover and NEXUS pipelines became fully operational in 2018, further enhancing liquidity at Dawn and providing the opportunity to transact with additional counterparties.

Access to Dawn

In the second half of 2018, EGI and TCPL each held 2021 new capacity open seasons for transportation services. EGI offered service from Dawn to Parkway while TCPL offered service from Parkway to downstream locations serving both the EGD and Union North East rate zones. Expansion facilities resulting from the open seasons are projected to be in-service as early as November 1, 2021.

New Sources of Supply to Ontario

National Fuel Gas Company ("National Fuel") is developing two projects in the U.S. Northeast which will deliver an incremental 660 MMcf/d (719 TJ/d) of supply to the Chippawa receipt point, which could increase market depth at Chippawa and could result in increased deliveries of gas to Dawn via TCPL Mainline and Dawn Parkway System facilities.

The first of these two project is the Northern Access project which will add 490 MMcf/d (535 TJ/d) of capacity to the Chippawa receipt point. The project has been forced to revise its in-service date multiple times and is not expected to be in service until at least 2022[9].

National Fuel's second project is the recently approved Empire North Project which will provide an incremental 170 MMcf/d (184 TJ/d) of delivery to the Chippawa receipt point. This project has a target in-service date of November 1, 2019[10].

[9] National Fuel, "Investor Presentation: Q1 Fiscal 2019 Update," January 31, 2019, https://s2.q4cdn.com/766046337/files/doc_presentations/2019/03/20190131-NFG-Q1-2019-Investor-Presentation-FINAL-(2).pdf

[10] Natural Fuel, "Empire North Project: Project Overview," CP18-89-000, https://pipelineandstorage.natfuel.com/current-projects/empire-north-project

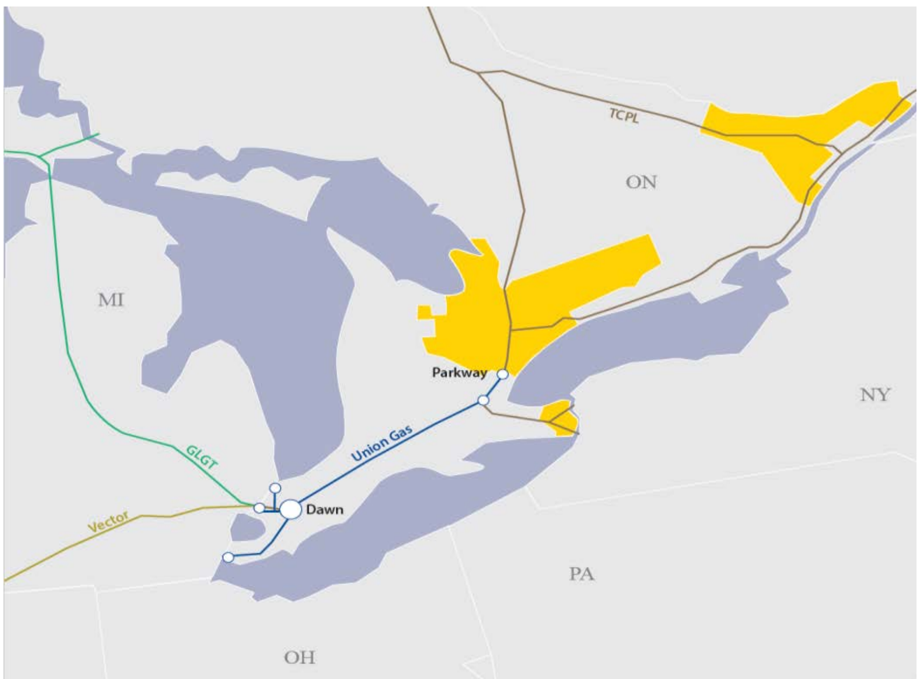
3. Enbridge Gas Distribution Rate Zone

The following Sections 3 through 9 are specific to the Plan for the EGD rate zone covering the period of January 1, 2020 to December 31, 2024.

3.1 Description of EGD Rate Zone

Within the EGD rate zone, EGI provides natural gas distribution services to over 2.2 million residential, commercial and industrial customers spread across the Greater Toronto Area ("GTA"), the Niagara Peninsula, Barrie, Midland, Peterborough, Brockville, Ottawa, Gatineau (via Gazifère Inc.), and other Ontario communities (collectively the "EGD rate zone"). See Figure 19 below for a depiction of the EGD rate zone, outlined in yellow.

Figure 19 – EGD Rate Zone Map



The EGD rate zone is divided into two distinct regions for gas supply planning purposes:

1. **Eastern Delivery Area ("Enbridge EDA"):** Containing Brockville, Ottawa, Gatineau and the surrounding area
2. **Central Delivery Area ("Enbridge CDA"):** Containing the GTA, the Niagara Peninsula, Barrie, Midland, Peterborough, and the surrounding area

The geographic location of the EGD rate zone has a significant impact on the Plan for a variety of reasons, including: climate and weather seasonality; population and customer makeup; and access to natural gas production basins, storage facilities and supply hubs.

Climate and Customer Makeup

The Enbridge CDA and Enbridge EDA regions are two of the most densely populated areas in Canada, and the vast majority of residential homes in both regions use natural gas for space and water heating. This reality is evident in EGI's customer makeup, as over 90% of the more than 2.2 million customers in the EGD rate zone are in the residential sector. While residential customers tend to use gas consistently throughout the year for water heating, the bulk of their usage relates to space heating in the winter. The seasonal consumption profile of residential customers is amplified by the particularly seasonal weather patterns experienced in the EGD rate zone (i.e. cold winters and hot summers). Pairing this largely residential customer base with seasonal weather patterns has a dramatic impact on gas consumption. On the day of peak consumption, EGD rate zone customers consume approximately nine times the volume of gas consumed on a day of low (i.e. baseload) consumption.

The above noted climate and customer makeup characteristics emphasize why gas supply planning is a complex process.

Service Types

EGD rate zone customers have the option to choose between multiple service types with varying degrees of sophistication. Distribution services, including the receipt of gas at the EGD rate zone and delivery to a customer's terminal location are provided to all customers. However, customers may elect to procure their own natural gas supply and/or transportation to the EGD rate zone. The following six types of services are offered to EGD rate zone customers:

- **Sales Service:** The utility provides gas supply, transportation, and load balancing services to customers;
- **Western Transportation Service ("WTS"):** Customers deliver gas supply to the utility at the Empress hub in Alberta and the utility provides transportation and load balancing services to the EGD rate zone;
- **Ontario Transportation Service ("OTS"):** Customers deliver gas supply to the utility at the EGD rate zone and the utility provides load balancing services within the EGD rate zone;
- **Dawn Transportation Service ("DTS"):** Customers deliver gas supply to the utility at Dawn in southwestern Ontario and the utility provides transportation and load balancing services to the EGD rate zone;
- **Unbundled Service:** Customers do not require gas supply, transportation, or load balancing services from EGI, and are not considered within the Plan; and,
- **Interruptible Service:** At the utility's discretion, EGI can request the customer to curtail their consumption.

Customers that elect to purchase their natural gas requirements directly from an entity other than the utility or who are brokers or agents for an end-user are referred to as DP customers, and subscribe to one of the WTS, OTS, or DTS services described above. DP customers are obligated to deliver natural gas each day to the utility, at a specified delivery point and at a Mean Daily Volume ("MDV"). Fluctuations in the demand for gas at the customer's terminal location are balanced by the utility. Therefore, it is important for EGI to consider what additional storage and transportation assets may be required. For example, a DP customer with a low load factor, such as a residential customer, would be required to deliver the same MDV to EGI every day of the year, despite the fact that their consumption profile will vary dramatically depending on weather. EGI needs to acquire additional capacity to serve this type of customer in the winter, when demand exceeds MDV.

Customers that elect interruptible service are an important component of the Plan as they provide the ability for EGI to meet firm distribution system requirements, without requiring EGI to hold additional capacity.

Access to Natural Gas Supply

Another result of the geographic location of the EGD rate zone is its access to natural gas production basins. The EGD rate zone does not have access to any significant local natural gas production within its franchise area, with less than 1% of its annual gas supply requirement locally produced within Ontario. In order to provide safe, reliable, and cost effective distribution of natural gas to its customers, EGI procures supply from basins and liquid hubs across North America. These supplies are transported to the markets served by the EGD rate zone through contracted capacity on several upstream natural gas transmission systems that ultimately connect to the EGD rate zone and natural gas storage facilities.

4. EGD Rate Zone: Demand Forecast Analysis

4.1 Annual Demand

The EGD rate zone demand forecast includes estimates for both the number of billed customers and the normalized average use per customer/consumption. These estimates are divided into two customer segments: general service market and contract market. The forecast process described below is consistent with the methodologies used in previous EGD rate applications as approved by the Board in RP-2000-0040 and EB-2014-0276.

General Service Market

The general service market in the EGD rate zone includes approximately 2.2 million customers billed in Rate 1 and Rate 6. EGI has used its existing Board approved methodology to forecast the average consumption for Rate 1 and Rate 6 customers in the Plan for the period of 2020-2024. The methodology relies on regression equations to estimate the underlying historical trend of average use per customer. Major variables in the models are heating degree days, vintage variable[11], natural gas prices and economic variables.

The general service demand forecast is prepared using the following estimation steps:

1. *Forecast the annual average number of billed customers for each rate class and sector for 2020-2024. The annual average number of customers forecast is a combination of historical number of customers and forecasted customer additions.* Residential, apartment, commercial and industrial customer additions are comprised of the new construction and replacement markets. The residential sector accounts for over 90% of the EGD rate zone forecast customer additions.

2. *Forecast the normalized average consumption ("NAC") for each revenue/rate class and sector.*

3. *Multiply the forecasted number of customers by their respective NAC forecasts to obtain the total general service throughput volume forecast.*

4. *Remove the forecasted volume savings resulting from natural conservation and DSM programs from the total general service throughput forecast.* DSM volumes are forecasted based on the 2015-2020 DSM plan approved by the Board in EB-2015-0049, historical actual achievement and best-available verification results.

General Service Market Risk Analysis

The risks associated with the general service demand forecast reside mostly in the assumptions used for each driver variable, such as weather, gas price and economic indicators. If actual demand drivers occur differently than assumed in the forecast, consumption will be affected by the corresponding sensitivities. These sensitivities which are determined through the impact analysis are described below:

- The primary risk to the general service annual demand forecast is the underlying heating degree days ("HDD" [12]) forecast. Based on the impact analysis results, the demand forecast generated by regression models for Rate 1 and Rate 6 would have been 8.1% and 7.7% higher/lower respectively by assuming a 10% colder/warmer weather than if 10% higher/lower degree days were used in the models. During the last 5 years, weather patterns have shown a wide range of variance relative to the Board approved heating degree days as shown in Table 1. The actual annual heating degree days for Central weather

[11] The vintage variable is a ratio that is employed as a proxy measure of gas space heating and gas water heating efficiency gains and residential thermal efficiency. This ratio captures the increasing market share of high-efficiency furnaces at the expense of the declining market share of conventional furnaces over time.
[12] HDD is a measure of temperature that identifies the need for heating and occurs when the average daily temperature falls below 18 degrees Celsius. For example, an average daily temperature of zero degrees Celsius equals 18 HDD.

zone has fluctuated between 5.7% (warmer) to 15.0% (colder) relative to the Board approved heating degree days[13].

Table 1 - Historical HDD Variance

Central region Heating Degree Days	Actual	Board Approved	Weather Variance
2014	4,044	3,517	15.0%
2015	3,710	3,536	4.9%
2016	3,412	3,617	-5.7%
2017	3,499	3,639	-3.9%
2018	3,728	3,642	2.4%

- Impact analysis also provides consumption sensitivities for the other general service demand drivers:
  - 2,000 more/less number of customers forecast would impact total volumes by about 0.1%;
  - 10% higher/lower gas prices would impact residential volumes by about 0.2%; and,
  - 10% higher/lower employment would impact total volumes by about 1.0%.

- There is also a risk that factors outside of the models (for example, customer behavior changes/thermostat settings, natural disasters, etc.) will affect consumption and cause a variance to the forecast. Because these outside factors are not included in the models, it is very difficult to estimate related consumption impacts.

Contract Market

The contract market in the EGD rate zone includes approximately 400 billed customers. The volume forecast in the Plan for these customers was generated using EGI's established grassroots approach, as well as a probability-weighted forecast approach to account for potential new large-volume contract customers.

EGI's traditional grassroots approach forecasts volumes at an individual customer level in consultation with customers during the forecasting process. At any given point in time EGI's sales representatives are in conversation with new and existing contract customers to evaluate their gas service requirements. Specifically, the sales representatives review the contract attributes of each contract to ensure that customers can meet the contracted rate class minimum volume and load factor requirements specified for their rate class. Current economic and industry conditions, as well as Board-approved degree days and anticipated DSM volumes, are also factored into the contract market demand forecast. The contract market DSM volume savings are forecasted based on the 2015-2020 DSM plan approved by the Board in EB-2015-0049, historical actual achievement and best-available verification results.

[13] HDD forecasts are generated according to the Board approved methodologies for each weather zone within the franchise area: Central, Eastern and Niagara zones.

Contract Market Risk Analysis

- Contract market volumes are primarily driven by economic factors. As a result significant changes in economic conditions relative to expectations (e.g. recession) can lead to higher variances.

- The impacts of expected growth (e.g. capital projects, government programs), changes to customer operations, volume reductions relating to DSM and customer facility closures are all included in the EGD rate zone contract market demand forecast. There are risks associated with each of these items, both related to their timing and the likelihood of materialization.

- Contract renewals for most customers are conducted annually. Contract renewal discussions can include customers switching between delivery service options, which in turn can lead to forecast variances.

Annual Demand Forecast

The Plan is based on the weather normalized demand forecast for general service customers and contract market rate classes as prepared by EGI's Demand Forecasting & Analysis department.

Table 2 below illustrates the annual demand forecast for the EGD rate zone. EGD rate zone volumes are expected to be almost flat over the projection period of 2020-2024. Customer growth partially offsets the continued decline in average use for the residential sector while Rate 6 and contract market volumes are expected to remain stable. Energy efficiency and the expectation of higher gas prices mainly driven by the federal carbon tax[14] continue to play a role in reducing both general service and contract market demand growth.

Table 2 – EGD Rate Zone Annual Demand Forecast

Line No.	Particulars (TJ)	2020	2021	2022	2023	2024
1	General Service	384,494	384,233	384,182	384,703	385,403
2	Contract Market	73,664	73,227	72,789	72,353	71,917
3	Total EGD Demand Forecast	458,159	457,460	456,971	457,055	457,319

[14] The forecast assumes $20 per tonne for 2019, increasing by $10 per tonne annually until it reaches $50 per tonne in 2022.

4.2 Design Day Demand

Daily Demand Profile

In order to develop the EGD rate zone demand profile, design criteria approved by the Board are used to distribute forecast annual demand across a daily demand profile. Much of the information below appears in the pre-filed evidence and Settlement Agreement of EB-2011-0354, in which the current design criteria were presented to the Board and approved.

For a natural gas utility, design criteria refer to one or more statistical or probabilistic conditions and assumptions about weather – usually in the form of HDDs. Design criteria are used to develop Plans to meet forecast utility demand and account for the risk of an extreme weather event or multiple extreme weather events. For gas utilities in cold climates with weather-sensitive loads, such as the EGD rate zone, developing Plans to meet expected winter demand on design day, or the day of highest demand, is of critical importance.

Design day demand is derived using the HDDs assumed within the design criteria. Failing to assume an appropriate level of demand on design day poses the risk of needing to procure high priced peaking services on short notice, or not being able to meet demand as a result of not contracting for sufficient transportation capacity or ensuring appropriate levels of gas in storage. An inability to meet design day demand can result in low distribution system pressure or, in extreme cases, system outages and the accompanying economic and safety implications of not having natural gas available to customers.

Design criteria can be applied to more than a single day using a method referred to as multi-peak design criteria. In addition to considering the crucial single design day weather criteria, this method incorporates statistical conditions regarding weather on other high-consumption days in the winter season. The statistical conditions associated with design criteria can range from a predetermined recurrence interval, to the coldest day on record for the service area or areas in which a utility operates.

A recurrence interval is defined as the average frequency, in years, in which an actual weather event or HDD level is expected to occur. For example, a 1 in 10 recurrence interval would mean that the HDD level assumed on design day is expected to be experienced once every ten years, on average. Another way to express this statement is that there is a 10% probability that the specified design day HDD value would be achieved in any given year. All else equal, the longer the recurrence interval, the higher the design day HDD assumption in a given year, and the more conservative the Plan.

If the coldest day method is utilized, 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.

In addition to temperature or HDD values, utilities may include other weather variables in their design criteria such as wind speed, humidity, sunlight intensity, and cloud coverage. In evidence filed in EB-2011-0354, Navigant Consulting, Inc. (on behalf of EGD) identified two weather parameters that affect load: temperature and wind speed. Other variables were not found to have significant influence.

EGI's current design criteria for the EGD rate zone utilizes a 1-in-5 recurrence interval and 18 multi-peaks representing the coldest temperatures that are expected to occur over the winter season of the planning period, covering January through to the end of March. Multi-peaks are developed for each of the Central, Eastern and Niagara weather zones.

When daily historical temperatures and wind speeds are plotted on a graph, they fit a bell curve distribution. From a statistical perspective, there are a number of bell curve distributions that have different characteristics. With respect to the multi-peak weather conditions, the curve that most closely represents the temperature data is a lognormal distribution. The 18 multi-peaks in the current design criteria correspond to a recurrence interval of 1-in-5 years and are derived assuming a lognormal distribution of degree days.

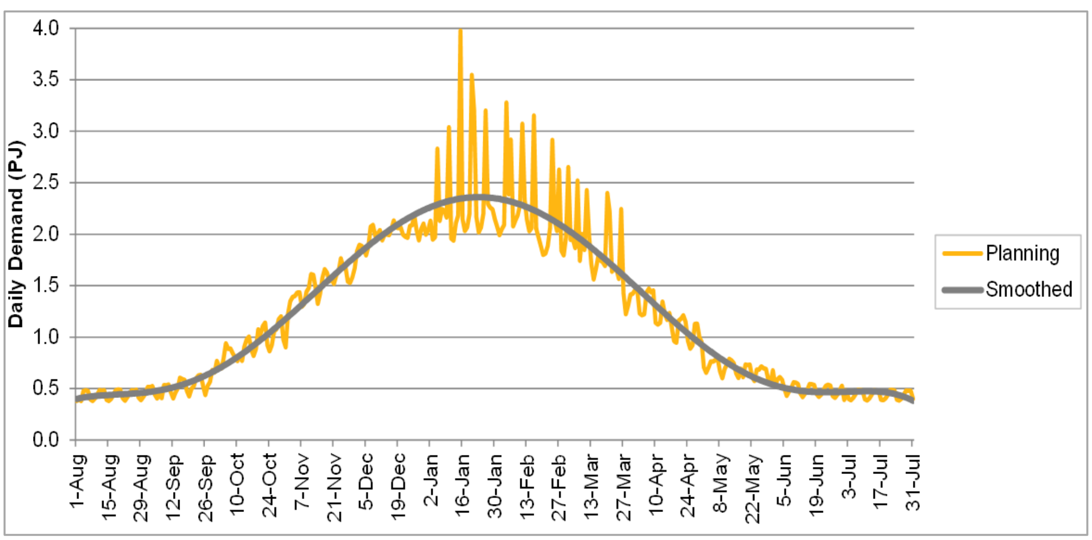
Table 3 below shows the peak day HDD values used in the current design criteria for each weather zone.

Table 3 – EGD Rate Zone: Design Day HDD Value for Each Weather Zone using Existing Design Criteria

Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone
41.4	48.2	38.8

Figure 20 illustrates the resulting daily demand profile used in developing the Plan.

Figure 20 – EGD Rate Zone Illustrative Daily Demand Profile



The demand profile in Figure 20 represents natural gas demand for the entire EGD rate zone. It is a consolidation of demand from residential customers, commercial businesses, institutions, and large and small industrial facilities. Every customer has their own profile, and they vary dramatically across customer classes. As noted, a residential customer profile is typically the "peakiest", with demand in winter most impacted by weather. Alternatively, an industrial customer using natural gas as part of its day-to-day operations may not see impacts from weather, resulting in a largely flat profile throughout the year. While load factors and demand profiles of various customer classes are important to understand, the Plan is ultimately designed for the system as a whole, as demonstrated within the single consolidated demand profile illustrated in Figure 20.

Design Day Demand Forecast

When developing the demand profile, the most critical component is a forecast of design day demand (or peak day demand normalized to design conditions)[15].

The forecast of design day demand for the EGD rate zone is established by evaluating the underlying market demand for natural gas to estimate a regression model. Subsequently, the regression model is combined with the design criteria for weather and a projection of customer growth to forecast design day demand.

Regression Modeling

Before EGI can forecast design day demand for the EGD rate zone, EGI first estimates the response of customer consumption behavior to extreme cold weather events. This process is completed by estimating time-series multi-variate regression models for each weather zone within the EGD rate zone (i.e. Central, Eastern, and Niagara weather zones).

To generate the regression models, EGI uses the statistical software package EViews[16] which estimates consumption behavior during extreme cold weather events in each weather zone based on the general form equation which best describes consumption behaviour. The regression models for each weather zone take the general form:

$$\boxed{\ln(PDD_t) = C + \ln(DD_t) + \ln(DD(Lag)_t) + \ln(WS_t) + \ln(TREND_t) + WKD_{1,0}}$$

Where:

ln	=	*Natural Logarithm*
t	=	*Year*
PDD	=	*Peak Day Demand*
C	=	*Constant*
DD	=	*Degree Days on Peak Day Demand*

[15] Design day demand is the estimated level of demand that would result from assuming the design criteria. Peak day demand is the actual highest day of demand for a given year.
[16] http://www.eviews.com/

DD(Lag)	=	*Degree Days the day before Peak Day Demand*
WS	=	*Wind Speed on Peak Day Demand*
TREND	=	*Time trend or Unlocks, depending on best fit*
WKD	=	*Variable where: 1 = Weekday (M-TR), 0 = Other Days*

Using the historical data for each weather zone (i.e. 1997-2018), design day demand regression models are used to estimate the propensity to consume natural gas during extreme weather conditions in each weather zone.

Design Day Demand Forecast

To forecast design day demand, the coefficients estimated from the regression equations are multiplied by design day weather conditions and projected customer growth.

Combining the EViews equations with the planned values yields the forecast of design day demand in Table 4, which underpins the Plan[17].

Table 4 – EGD Rate Zone Design Day Demand Forecast by Delivery Area

Line No.	Particulars (TJ)	2020	2021	2022	2023	2024
1	CDA	3,414	3,426	3,439	3,451	3,463
2	EDA	723	730	738	745	752
3	EGD Rate Zone	4,137	4,157	4,176	4,196	4,215

It is important to note that design day demand is not expected to occur every year in the Plan. However, since it is not possible to know when a design day event will occur and EGI is responsible for acting as the supplier of last resort, the Plan must and does assume design day demand will occur each year. By normalizing annual peak day demand to design conditions in the Plan, EGI is able to mitigate the risk of undersupplying the market when design conditions are met or exceeded.

Risk Analysis

The statistical condition of a 1-in-5 recurrence interval sets the weather conditions assumed in order to estimate the highest day of demand in each year of the Plan, which subsequently indicates the transportation assets required to deliver gas to the EGD rate zone under such conditions. In other words, design day demand has been risk-adjusted to assume a high level of demand which leads to the design of a portfolio which limits the utility's risk of not being able to meet customers demand requirements. Notwithstanding the above, should design conditions be exceeded and customer

[17] Since the Central and Niagara weather zones are served through the same upstream pipeline systems these two weather zone make up the CDA.

demand exceed the level forecasted for design day demand, EGI will not have procured enough transportation assets to meet that demand and is at risk of outages in the downstream distribution system.

5. EGD Rate Zone: Current Portfolios

5.1 Commodity Portfolio

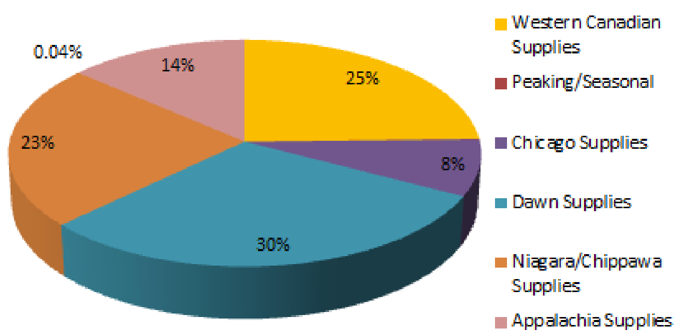
In order to serve the EGD rate zone, EGI holds firm transportation contracts on multiple upstream pipelines providing access to supplies in Western Canada, Chicago, Niagara, Dawn and Appalachia. In addition, the EGD rate zone can receive supply from delivered services, such as peaking services. The EGD rate zone also relies on deliveries from DP customers to balance system demand each day.

Table 5 provides the sources of supply assumed in EGI's plan for the EGD rate zone for sales service customers with an illustration in Figure 20.

Table 5 – EGD Rate Zone Sources of Supply

Line No.	Particulars (TJ)	2020	2021	2022	2023	2024
1	Western Canadian Supplies	76,718	76,701	76,807	76,472	77,141
2	Peaking/Seasonal	111	131	26	45	64
3	Chicago Supplies	25,062	24,994	24,994	24,994	25,062
4	Dawn Supplies	92,680	90,593	90,905	91,170	91,179
5	Niagara/Chippawa Supplies	73,179	72,979	72,979	72,979	73,179
6	Appalachia Supplies	42,477	42,361	42,361	42,361	42,477
7	Total EGD Supply Forecast	310,227	307,758	308,071	308,021	309,102

Figure 20 – EGD Rate Zone 2020 Sources of Supply



5.2 RNG Portfolio

RNG is an alternative to conventional gas supply and can be stored, transmitted and distributed when connected to existing natural gas infrastructure. RNG is produced by capturing methane that results from the decay of organic matter. Some examples of RNG sources include landfills and waste water treatment plant gas.

The Provincial Government's recent Made-in-Ontario Environment Plan ("MOEP") includes a requirement for natural gas utilities to offer voluntary RNG to customers. EGI is currently in the process of developing a voluntary RNG program in response to this policy.

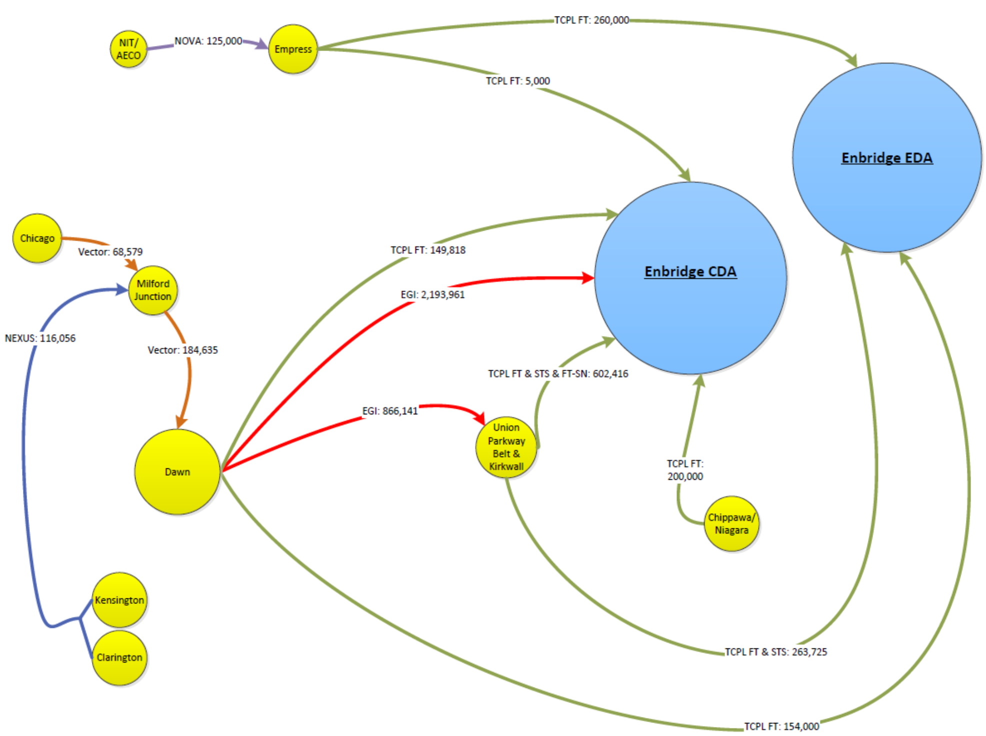
At this time, EGI does not hold any RNG supply in its Plan. However, EGI remains committed to working with the provincial and federal governments, as well as other organizations, to offer services that will support government policies and objectives.

5.3 Transportation Portfolio

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

Figure 21 below provides a visual representation of all contracted transportation services as of January 1, 2020. A complete listing of all signed contracts is provided in Appendix B.

Figure 21 – EGD Rate Zone Transportation Portfolio in GJ/d



Transportation Portfolio Changes

The following section addresses all transportation portfolio changes for the EGD rate zone since the time the Plan was developed in the second half of 2018. The format of this section is consistent with the transportation contracting analysis previously filed as part of Union's annual deferral disposition.

Transportation Contracting Analysis

For the period of January 1, 2020 to December 31, 2024 EGI has the following portfolio changes specific to the EGD rate zone:

1. The North Bay Junction Long Term Fixed Price ("NBJ LTFP") Service, a related Iroquois delivery point amendment to Enbridge EDA, and an amending agreement to swap capacity between the Enbridge CDA and Enbridge EDA;
    a. Effective November 1, 2019, EGI will swap 70,000 GJ/d of long haul Empress to Enbridge CDA capacity to be delivered to the Enbridge EDA instead. Simultaneously EGI will also swap 70,000 GJ/d of short haul Parkway to Enbridge EDA capacity to be delivered to the Enbridge CDA;
    b. Effective January 1, 2021, amending the delivery point of the Empress to Iroquois capacity of 26,956 GJ/d to a delivery point of Enbridge EDA; and,
    c. Effective January 1, 2021 to December 31, 2030, EGI has converted 265,000 GJ/d of long haul firm transportation capacity to a combination of NBJ LTFP service from Empress to North Bay Junction, and 5,000 GJ/d of short haul firm transportation capacity from North Bay Junction to the Enbridge CDA and 260,000 GJ/d of short haul firm transportation capacity from North Bay Junction to the Enbridge EDA.

2. TCPL Mainline and Dawn Parkway System 2021 New Capacity Open Season ("NCOS")
    a. Effective as early as November 1, 2021, EGI has contracted for 125,000 GJ/d of new capacity from Dawn to Parkway to serve the EGD rate zone; and,
    b. Effective as early as November 1, 2021, EGI has contracted for 100,000 GJ/d of new capacity from Parkway to Enbridge CDA and 25,000 GJ/d of capacity from Parkway to Enbridge EDA to serve the EGD rate zone.

A comparison of landed costs for the NBJ LTFP and 2021 NCOS relative to the viable alternatives considered can be found in Appendix C and Appendix D respectively.

Rationale for NBJ LTFP Service and related Iroquois Delivery Point Amendment and Capacity Swap

The current EGI long haul capacity of 265,000 GJ/d serving the EGD rate zone provides the portfolio with access to a low cost and reliable supply source in Western Canada, diversity of path, annual renewal rights, and flexible service attributes such as diversions. Further, long haul firm transportation is delivered directly to the EGD rate zone, making it a delivery source for design day purposes. However, the fixed costs associated with long haul firm transportation capacity on TCPL Mainline are much higher than other alternatives, such as short haul firm transportation, largely due to the distance that the supply needs to travel.

TCPL's new NBJ LTFP service offers a fixed toll of \$0.93/GJ/d[18] to North Bay Junction. Taking into account the associated short haul firm transportation required to connect the service to the EGD rate zone, the fixed costs associated with shipping supply from Alberta are \$0.60/GJ/d lower than TCPL's traditional long haul firm transportation service. Furthermore, converting the Iroquois delivery point to the Enbridge EDA also reduces the fixed costs associated with 26,956 GJ/d by another \$0.01/GJ/d. The overall estimated benefit of the NBJ LTFP service and Iroquois amendment relative to the use of long haul firm transportation capacity is \$593M over 10 years.

In addition to the benefits of the NBJ LTFP service outlined above, EGI also agreed to swap 70,000 GJ/d of long haul Empress to Enbridge CDA capacity to be delivered to the Enbridge EDA with a matching swap of 70,000 GJ/d of short haul Parkway to Enbridge EDA capacity to be delivered to the Enbridge CDA. In doing so, EGD rate zone can reduce the fixed costs associated with its short haul capacity. The overall estimated benefit of the capacity swap compared to not executing the swap is \$9.3M/yr

The benefits of this service and the associated amendments are:

i. Lands supply in the EGD rate zone to support the system on design day;

ii. Landed cost of gas flowing to the EGD rate zone is \$0.60/GJ/d less than traditional long haul, with supply in the Enbridge CDA at roughly the same cost as short haul firm transportation and supply in the Enbridge EDA at a cost \$0.27/GJ/d lower than short haul firm transportation;

iii. Supports the acquisition of secure supply from the WCSB, and maintains supply diversity of contract terms and supply basins; and,

iv. Provides both receipt and delivery flexibility within the short haul path from North Bay Junction.

Rationale for NCOS 2021

If the EGD rate zone has a forecasted design day asset shortfall of less than 2%, EGI will plan to balance design day demand with short-term market based solutions, such as peaking supply. These solutions are cost-effective and do not require long-term commitments, but are less reliable and lack the diversity and flexibility of service attributes associated with firm transportation. In the event the forecasted design day shortfall grows to an amount that is in excess of 2% of design day demand requirements, EGI will seek out firm transportation assets to address the forecasted shortfall.[19]

As shown in Table 8 and Table 11 below, the design day shortfalls for the Enbridge CDA and Enbridge EDA are forecast to reach 3% in 2021. Since design day demand is forecast to continue to increase over time, without acquiring capacity in the above noted NCOS 2021, the 3% shortfall to

[18] Inclusive of abandonment charges
[19] See Section 6 for the rationale underpinning the 2% threshold.

the EGD rate zone would continue to increase each year. In order to reduce this growing design day asset shortfall to less than 2%, EGI submitted the aforementioned bids for firm transportation service. These bids provide a service that is the highly reliable, sources supply from Dawn, offers flexible service attributes, includes renewal rights, and is the lowest cost firm transportation path[20] available that connects to a liquid trading hub. Notwithstanding the above, the NCOS 2021 capacity does require 15-year term commitments. However EGI does have transportation contracts serving the EGD rate zone that have annual renewal rights which can be de-contracted should design day demand growth decrease in the future.

The benefits of the NCOS 2021 bids are:

i. Increases the reliability of the EGD rate zone design day plan by reducing reliance on market based solutions to less than 2%;

ii. Is the lowest cost firm transportation path available that connects to a liquid trading hub;

iii. Provides flexibility of service attributes associated with firm transportation that are not available with market-based services such as peaking supply; and,

iv. Allows for supply to be sourced from a liquid trading hub.

5.4 Storage Portfolio

In accordance with the Natural Gas Electricity Interface Review ("NGEIR") Decision[21] and confirmed in the Board's Decision and Order regarding the amalgamation of EGD and Union and the associated rate-setting mechanism ("MAADs decision")[22], the amount of cost-based storage reserved for EGD rate zone customers at EGI's facility near Sarnia in southwestern Ontario is 99.4 PJ. The allocation of storage to natural gas distribution customers is based upon methodologies approved by the Board as part of the Natural Gas Storage Allocation Policies Decision[23] and the quantity was confirmed in the MAADs decision. EGD rate zone customers also benefit from ownership and use of a small (0.3 PJ) underground storage facility embedded in EGI's distribution system near Welland in the Niagara Region.

In addition to the cost-based storage available to customers in the EGD rate zone, EGI holds 11 service agreements equaling 26.4 PJ of storage capacity with third parties at market based rates. The size and term of each service agreement varies. Every year EGI conducts a blind request for proposal ("RFP") process to replace expiring capacity. **Error! Reference source not found.** outlines the EGD rate zone storage requirement and Table 7 provides the portfolio of storage service agreements held to serve the EGD rate zone.

[20] Forecast NCOS 2021 service costs are $14.4M/yr more costly than peaking supply.
[21] EB-2005-0551, Decision with Reasons, November 7, 2006
[22] EB-2017-0306/0307, Decision and Order, August 30, 2018
[23] EB-2007-0724/0725, Decision with Reasons, April 29, 2008

Table 6 – EGD Rate Zone Storage Requirement

	Capacity (PJ)
Cost of Service Storage - Sarnia	99.4
Cost of Service Storage - Welland	0.3
Market Based Storage	26.4
Total Storage Requirement	**126.1**

Table 7 - EGD Rate Zone Storage Service Agreements

Line No.	Capacity (GJ)	Effective Date	Expiration Date
1	3,000,000	01-Apr-15	31-Mar-20
2	3,000,000	01-Apr-15	31-Mar-20
3	1,055,056	01-May-17	30-Apr-20
4	2,110,112	01-May-18	30-Apr-20
5	1,500,000	01-Apr-16	31-Mar-21
6	1,055,056	01-Apr-19	31-Mar-21
7	1,582,584	01-Apr-19	31-Mar-21
8	5,000,000	01-Apr-17	31-Mar-22
9	2,110,112	01-Apr-19	31-Mar-22
10	3,000,000	01-Apr-18	31-Mar-23
11	3,000,000	01-Apr-19	31-Mar-24
Total	**26,412,920**		

The inclusion of storage assets in the Plan provides a cost effective, reliable and secure alternative to purchasing commodity when required by customers, which is consistent with the Board's guiding principles. Storage provides the Plan further operational flexibility and aligns with the target to fill storage at November 1, maintain sufficient inventory at February 28 to provide required deliverability from all storage assets, and maintain inventory at March 31 to provide sufficient deliverability to meet peak day demand in March.

5.5 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 divert long haul transportation at no or limited incremental cost because the diversions would be generally in path.

6. EGD Rate Zone: Supply Option Analysis

EGI's gas supply, storage, and transportation portfolios have been developed over time 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 2.2. 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 options 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 Board's guiding principles for assessment of the Plan.

Evaluating the reliability and flexibility of a potential supply option includes the assessment of a number of 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 option, gate station connectivity; and,
- The level of discretionary services (e.g. peaking) held within the portfolio. EGI aims to limit the level of discretionary services in the EGD rate zone portfolio to 2% of total deliveries. EGI uses 2% because the utility has the ability to over-deliver on its firm transportation contracts up to 2% before incurring penalties, so in the event that all discretionary services failed to deliver, the utility would be able to manage the supply shortfall within the parameters of its firm transportation contracts[24].

Some elements of flexibility that EGI may consider in its evaluation may include:

- Contracting lead time, transportation contract term, supply contract term, availability of discretionary services, number of nomination windows, and renewal rights.

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

When evaluating a supply option's impact on diversity, EGI assesses a supply option's ability to provide transportation capacity through multiple paths and the impact that supply option has on overall supply diversity. Transportation path diversity and supply diversity are typically evaluated on a quantitative basis.

EGI's consideration of diversity of transportation path and supply supports the Board'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 Board's guiding principle of cost-effectiveness.

[24] Applies to EGD rate zone only

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 as listed in Section 2.1 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 an analysis as part of the Plan or its Annual Updates.

Once a decision has been made, the decision analysis will be filed in the appropriate section within the next available Annual Update or five year plan.

6.1 Design Day Analysis

Enbridge CDA

Each year EGI conducts a design day supply/demand balance analysis for the Enbridge CDA (Table 8) in which projected design day demand is compared against existing contracted assets serving the Enbridge CDA. This analysis determines whether additional assets are required to ensure continued safe and reliable delivery services for customers. Provided EGI holds enough capacity to serve its design day demand then it also holds enough capacity to meet all other days.

Design Day Supply/Demand Balance

As Table 8 shows on line 11, for each year during the five year period of this Plan the Enbridge CDA has a shortfall of gas supply assets relative to projected design day demand. The identification of a shortfall triggers a requirement for EGI to evaluate supply and asset option alternatives to meet design day demand.

Table 8 – Enbridge CDA Design Day Supply/Demand Balance

Line No.	Particulars (TJ)	2020	2021	2022	2023	2024
	CDA Design Day Demand					
1	Gross Design Day Demand	3,414	3,426	3,439	3,451	3,463
2	Curtaliment	(79)	(79)	(79)	(79)	(79)
3	Net CDA Design Day Demand	3,335	3,347	3,360	3,372	3,384
	CDA Design Day Supply Assets					
4	In-Franchise Supply	88	88	88	88	88
5	Third-Party Services	40	-	-	-	-
6	TCPL Long Haul	5	5	5	5	5
7	TCPL Short Haul	668	668	768	768	768
8	TCPL STS	284	284	284	284	284
9	EGI D-P	2,194	2,194	2,194	2,194	2,194
10	CDA Design Day Supply Assets	3,279	3,239	3,339	3,339	3,339
11	**CDA Design Day Supply Assets Surplus/(Shortfall)**	**(56)**	**(108)**	**(21)**	**(33)**	**(45)**
12	*Shortfall % of Net Design Day Demand*	*1.7%*	*3.2%*	*0.6%*	*1.0%*	*1.3%*

Supply Options

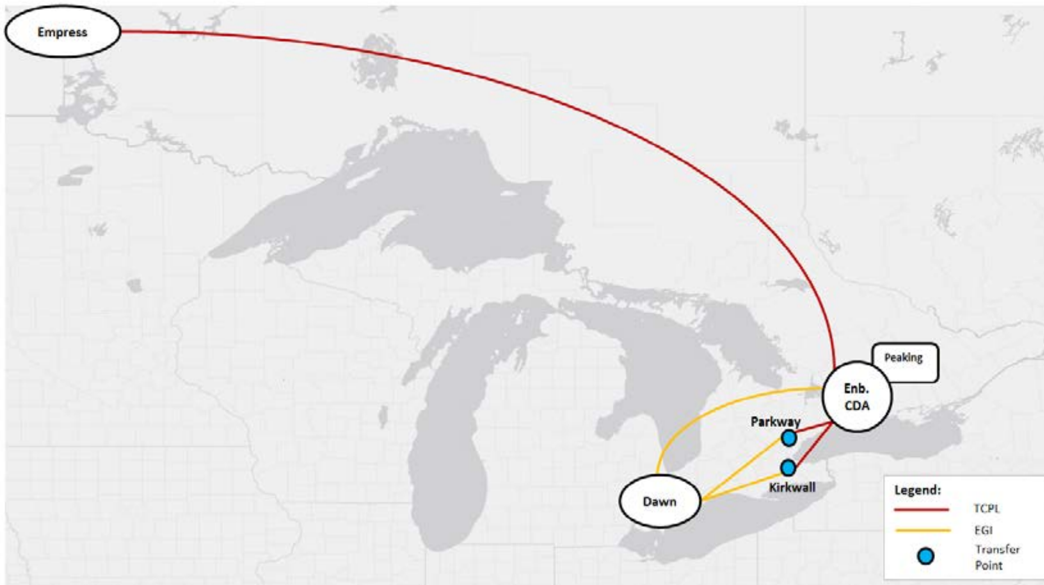
Table 9 below lists service and asset options which are expected to be available to EGI[25], at various times during the five years, to meet the Enbridge CDA design day gas supply asset shortfalls projected. Figure 22 provides a representative map of the paths described in the options.

Table 9 – Enbridge CDA Design Day Asset Shortfall Supply Options

Option	Option Details				
	Provider(s)	**Service**	**Receipt Point**	**Transfer Point**	**Delivery Point**
Peaking	Market Participants	Peaking	Enb. CDA	-	Enb. CDA
Long Haul	TCPL	FT-LH	Empress	-	Enb. CDA
Dawn Parkway	EGI	D-P	Dawn	-	Enb. CDA
Short Haul-Parkway	EGI + TCPL	D-P + FT-SH	Dawn	Parkway	Enb. CDA
Short Haul-Kirkwall	EGI + TCPL	D-P + FT-SH	Dawn	Kirkwall	Enb. CDA

25 The list of options in Table 9 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 temporary phenomenon. One example of an option not listed is FT from Niagara. This option is not included in the analysis because a design day event is short-term and temporary and Niagara supply is procured with a minimum term of one month (i.e. poor flexibility). In the future should FT from Niagara become more flexible then it will be included.

Figure 22 - Enbridge CDA Design Day Asset Shortfall Supply Options Map



Evaluation Matrix

Each of the options outlined in Table 9 above were evaluated for their reliability, flexibility, diversity and annual costs, as described at the beginning of Section 6. Table 10 below summarizes the analysis.

Table 10 – Enbridge CDA Design Day Asset Shortfall Options: Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($M/yr)	Average Cost/Customer Impact[26]
Peaking	→	↓	↑	1.7	< 1%
Long Haul	↑	↑	→	34.5	1-2%
Dawn Parkway	↑	→	→	2.8	< 1%
Short Haul-Parkway	↑	→	→	6.0	< 1%
Short Haul-Kirkwall	↑	→	→	6.0	< 1%

For reference, the symbols in Table 10 describe whether or not 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.

[26]Average cost per customer impact is for typical residential sales service customers consuming 2,400 m^3 annually. Estimated costs are derived based on sales service volumes for the EGD rate zone for the respective period. The impact for T-Service customers varies from sales service customers as they procure their own supply.

Preferred Planning Strategy

EGI's preferred planning strategy to eliminate the design day asset shortfall is to procure a peaking service for each year over the five year period.

In terms of costs, peaking is the lowest cost option at a total expected average annual cost of $1.7M, which is $1.1M/year less than the next lowest cost option. As such selection of peaking supports the Board's guiding principle of cost-effectiveness.

Peaking is a somewhat reliable option, albeit not the most reliable available. However, EGI's RFP process for procuring peaking stipulates the need to demonstrate that the service is underpinned by firm transportation, which limits reliability risks. Furthermore, there is no recent history of contracted peaking supplies failing to be delivered to the distribution system. Should peaking supply fail to be delivered, EGI's risk mitigation strategy is to utilize the parameters of its existing firm transportation contracts; namely limited balancing agreement. This approach, inclusive of a risk mitigation strategy, is consistent with the Board's guiding principle of ensuring reliability and security of supply.

In considering the flexibility of peaking supply there are positives and negatives. On the one hand, peaking supply is readily available in the market, does not require construction of new facilities, can be called on with short notice and can be adjusted on a daily basis. On the other hand, peaking supply does not have discretionary service attributes (e.g. interruptible diversion rights). This restraint is of limited concern in this instance given the peaking supply is only being procured for use in the Enbridge CDA during a design day. Peaking supply also only has one nomination window, meaning that it cannot be used to balance intra-day demand changes. However this too is of limited concern since EGI holds sufficient transportation assets to balance daily fluctuations. Finally, the peaking supply lacks renewal rights. Having renewal rights is desirable since it guarantees the utility the option to re-contract for an asset.

The use of peaking supply has marginal implications for the Plan's diversity and can provide additional diversity in terms of counterparties, term of the service, and pricing.

Overall, peaking supply is the lowest cost option, has limited reliability concerns for the design day plan, is readily available in the market on short notice, and has some marginal benefits to overall portfolio diversity. EGI's preferred planning strategy to eliminate design day asset shortfall will be to procure peaking supply in the Enbridge CDA for each year of the five year period. This approach appropriately balances the Board's guiding principles, ensuring cost-effective, reliable and secure supply for EGD rate zone customers.

Enbridge EDA

As it does for the Enbridge CDA, each year EGI conducts a design day supply/demand balance analysis for the Enbridge EDA (Table 11) where projected design day demand is compared against contracted assets serving the Enbridge EDA.

Design Day Supply/Demand Balance

As Table 11 shows on line 9, for each year during the five year period, the Enbridge EDA has a shortfall of gas supply assets relative to projected design day demand, triggering EGI to evaluate supply option alternatives to meet design day demand.

Table 11 – Enbridge EDA Design Day Supply/Demand Balance

LineNo.	Particulars (TJ)	2020	2021	2022	2023	2024
	EDA Design Day Demand					
1	Gross Design Day Demand	723	730	738	745	752
2	Curtailment	(30)	(30)	(30)	(30)	(30)
3	Net EDA Design Day Demand	693	700	707	715	722
	EDA Design Day Supply Assets					
4	In-Franchise Supply	0	0	0	0	0
5	TCPL Long Haul	260	260	260	260	260
6	TCPL Short Haul	337	337	362	362	362
7	TCPL STS	81	81	81	81	81
8	EDA Design Day Supply Assets	678	678	703	703	703
9	**EDA Design Day Supply Assets Surplus/(Shortfall)**	**(15)**	**(22)**	**(5)**	**(12)**	**(19)**
10	Shortfall % of Net Design Day Demand	*2.1%*	*3.2%*	*0.6%*	*1.7%*	*2.6%*

Supply Options

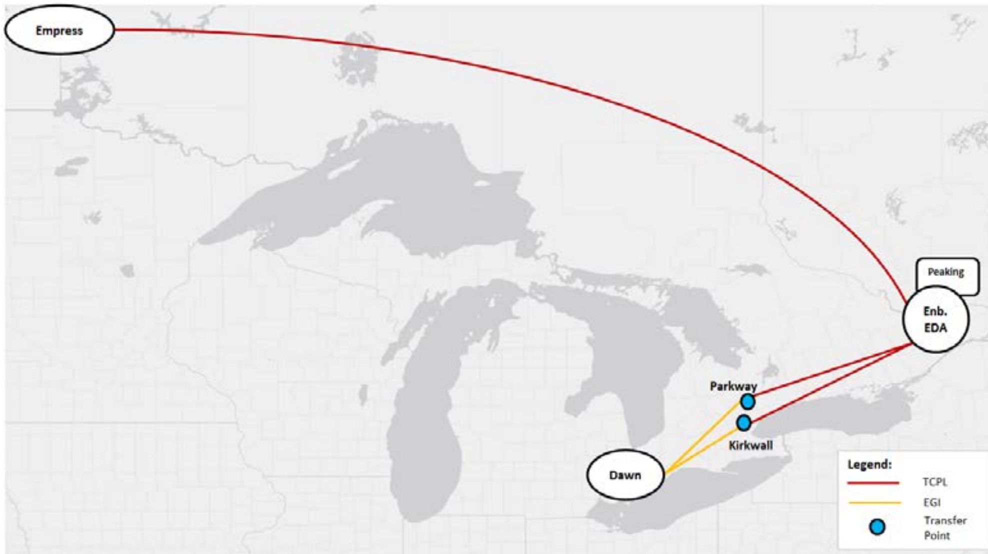
Table 12 below provides a list of options which are expected to be available to EGI[27], at various times over the five year period, to meet the projected Enbridge EDA design day gas supply asset shortfalls. Figure 23 provides a representative map of the paths described in the supply options.

Table 12 – Enbridge EDA Design Day Asset Shortfall Supply Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Peaking	Market Participants	Peaking	Enb. EDA	-	Enb. EDA
Long Haul	TCPL	FT-LH	Empress	-	Enb. EDA
Short Haul-Parkway	EGI + TCPL	D-P + FT-SH	Dawn	Parkway	Enb. EDA
Short Haul-Kirkwall	EGI + TCPL	D-P + FT-SH	Dawn	Kirkwall	Enb. EDA

[27] 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 temporary phenomenon. One example of an option not listed is FT from Niagara. This option is not included in the analysis because a design day event is short-term and temporary and Niagara supply is procured with a minimum term of one month (i.e. poor flexibility). In the future should FT from Niagara become more flexible then it will be included.

Figure 23 – Enbridge EDA Design Day Asset Shortfall 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 6. Table 13 below summarizes the analysis.

Table 13 – Enbridge EDA Design Day Asset Shortfall Options: Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($M/yr)	Average Cost/Customer Impact[28]
Peaking	→	↓	↑	0.5	< 1%
Long Haul	↑	↑	→	10.8	1-2%
Short Haul-Parkway	↑	→	→	3.3	< 1%
Short Haul-Kirkwall	↑	→	→	3.3	< 1%

For reference, the symbols in Table 13 describe whether or not 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

Taking into consideration the analysis above, EGI's preferred planning strategy to eliminate the design day asset shortfall projected in the Enbridge EDA is the same as was recommended for the Enbridge CDA; procuring peaking service for each year over the five year period.

[28] Average cost per customer impact is for typical residential sales service customers consuming 2,400 m^3 annually. Estimated costs are derived based on sales service volumes for the EGD rate zone for the respective period. The impact for T-Service customers varies from sales service customers as they procure their own supply.

The rationale for preferring peaking service to eliminate the Enbridge EDA shortfall follows the same logic outlined in the preferred planning strategy for the Enbridge CDA, which demonstrated that peaking is the lowest cost option, has limited reliability concerns for the design day plan, is readily available in the market on short notice, and has some marginal benefits to overall portfolio diversity. Again this approach appropriately balances the Board's guiding principles.

6.2 Average Day Requirement

The next consideration in developing the EGD rate zone portion of the Plan is to address changes in average day demand. Since the preferred planning strategy borne out of the design day analysis above provides the EGD rate zone Plan with sufficient capacity to reliably serve demand on all individual days of the year, 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 4.1, Table 14 below shows both the annual and average day demand growth expected over the five year period of the Plan for sales service customers.

Table 14 – EGD Rate Zone Average Day Demand Analysis for Sales Service Customers

Line No.	Particulars (TJ)	2020	2021	2022	2023	2024	Growth 2020→2024
1	Annual Demand	310,661	310,365	309,876	309,960	309,821	(839)
2	Daily Demand	849	850	849	849	847	(2)

As Table 14 shows, EGD rate zone annual demand is expected to decrease by roughly 839 TJ over the five years, or roughly 2 TJ/d of average day demand. In percentage terms, the forecasted decrease in demand is 0.2%, or effectively flat. As a result, EGI does not plan to procure additional gas supply assets to serve annual demand changes. However, a supply option analysis for average day requirements will be presented below.

Supply Options

The EGD rate zone Plan assumes the following transportation capacities are utilized at a 100% load factor:

- TCPL Long Haul = 265,000 GJ/d (including NIT capacity = 125,000 GJ/d)
- Niagara Short Haul = 200,000 GJ/d
- Vector = 65,000 Dth/d (or 68,576 GJ/d)
- NEXUS = 110,000 Dth/d (or 116,056 GJ/d)

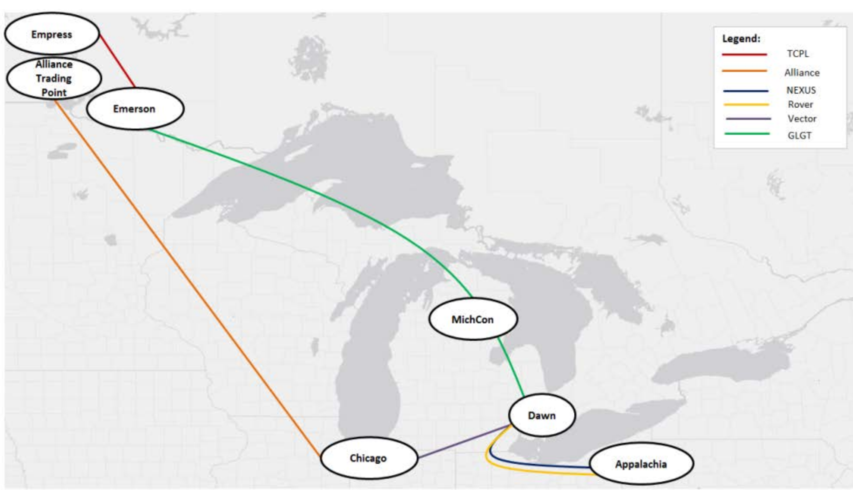
With each of the above transportation capacities planned to be 100% utilized moving supply to the distribution system and/or into storage, existing transportation capacity that is connected directly to Dawn and EGD rate zone storage assets, such as capacity on the Dawn Parkway System and short haul capacity on TCPL Mainline, is sufficient to meet growth in average day demand. Therefore managing average day demand changes by purchasing the commodity at Dawn is possible within the capacity of existing transportation assets. However, it is important to investigate if contracting for additional transportation assets upstream of Dawn will provide the EGD rate zone with additional reliability, flexibility, diversity and cost effectiveness.

Table 15 below provides a list of options which are expected to be available to EGI[29], at various times over the five year period. Figure 24 provides a representative map for the paths of the supply options.

Table 15 – EGD Rate Zone Average Day Growth Supply Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Dawn Spot	N/A	N/A	Dawn	-	Dawn
TCPL & GLGT	TCPL + GLGT	FT-LH + FT	Empress	Emerson	Dawn
GLGT	GLGT	FT	MichCon	-	Dawn
Alliance & Vector	Alliance + Vector	FFPS + FT-1	Alliance Trading Point	Chicago	Dawn
Vector	Vector	FT-1	Chicago	-	Dawn
NEXUS	NEXUS	FT	Dominion	-	Dawn
Rover	Rover	FT	Dominion	-	Dawn

Figure 24 – EGD Rate Zone Average Day Growth Supply Options Map



[29] The list of options in Table 15 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 average day demand growth. One example of an option not listed is procurement of supply from Texas' Permian Basin. This option is not included in the analysis because supply from the Permian Basin would result in significant transportation costs (i.e. poor cost-effectiveness). In the future should Permian Basin supply become more cost-effective then it will be included.

Evaluation Matrix

Each of the options outlined in Table 15 above were evaluated for their: reliability, flexibility, diversity and landed costs, as described at the beginning of Section 6. Table 16 summarizes the analysis.

Table 16 – EGD Rate Zone Average Day Growth Supply Options: Evaluation Matrix

Option	Relative to Status Quo			Costs ($/GJ)	Average Cost/Customer Impact – Relative to Status Quo [30]
	Reliability	Flexibility	Diversity		
Dawn Spot	↑	↑	→	3.27	-
TCPL & GLGT	↑	→	→	3.25	> -1%
GLGT	↑	→	↑	3.36	< 1%
Alliance & Vector	→	↓	↑	3.33	< 1%
Vector	↑	→	→	3.54	< 1%
NEXUS	↑	→	→	3.80	< 1%
Rover	↑	→	↑	3.81	< 1%

For reference, the symbols in Table 16 describe whether or not 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

Since the EGD rate zone is forecasted to have relatively flat demand growth over the Plan period, EGI's preferred planning strategy is to continue to manage changes in average day demand through purchases at Dawn, and not change the current portfolio composition. Managing changes in average day demand through purchases at Dawn is consistent with the Board's guiding principles, as Dawn provides a cost-effective alternative and offers reliability as it is one of the most liquid trading hubs in North America. Furthermore, Dawn purchases provide flexibility since no term transportation contracts would be required, as well as offering the ability for EGI to enter into supply agreements for multiple terms with multiple counterparties. This approach appropriately balances the Board's guiding principles, ensuring cost-effective, reliable and secure supply for EGD rate zone customers.

6.3 Contract Renewals: Delivering to the Distribution System

As has been the case for many years, EGI is faced with the decision to renew firm transportation contracts on an annual basis. During the five years covered by the Plan these same decisions will need to be made.

[30] Average cost per customer impact is for typical residential sales service customers consuming 2,400 m^3 annually. Estimated costs are derived based on sales service volumes for the EGD rate zone for the respective period. The impact for T-Service customers varies from sales service customers as they procure their own supply.

A variety of the firm transportation contracts that underpin EGI's Plan to serve the Enbridge CDA and Enbridge EDA on design day are approaching renewal deadlines. It is EGI's discretion to determine whether these contracts should be renewed. Table 17 below provides a listing of these contracts.

Table 17 – EGD Rate Zone Expiring Contracts Supporting Design Day Plan

Service Provider	Service Type	Receipt	Delivery	Capacity (GJ/d)	Effective Date	Expiration Date
TCPL	FT	Dawn	CDA	149,818	01-Nov-03	31-Oct-22
TCPL	FT	Dawn	EDA	114,000	01-Nov-03	31-Oct-22
TCPL	FT	Dawn	Iroquois	40,000	01-Sep-10	31-Oct-22
TCPL	FT	Pkwy	CDA	572	01-Nov-10	31-Oct-22
TCPL	FT-SN	Pkwy	CDA	85,000	12-Jan-09	31-Oct-22
TCPL	STS	Pkwy	CDA	283,892	01-Nov-02	31-Oct-22
TCPL	STS	Pkwy	EDA	9,716	01-Nov-03	31-Oct-22
TCPL	STS	Pkwy/Kwl	EDA	70,895	01-Nov-99	31-Oct-22

Each of the contracts in Table 17 are included within the design day supply/demand balance analyses previously presented for the Enbridge CDA and Enbridge EDA, and as the effective dates of the firm contracts demonstrate, these assets have been required to serve the EGD rate zone on design day for many years.

Given that EGI's design day plans for the Enbridge CDA and Enbridge EDA, as shown above, already contain adequate levels of third-party services (e.g. peaking), EGI is not contemplating replacing firm contracts with third-party services. As of today, the viable alternatives available to replace the expiring contracts listed in Table 17 are restricted to the firm transportation options found in Table 8 and Table 11 for the Enbridge CDA and Enbridge EDA, respectively.

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 Board's guiding principles by ensuring security of supply and the reliability of the Plan. EGI will retain significant flexibility to respond to changing design day demand requirements and, should a need arise to reduce the amount of firm transportation capacity to the distribution system, diversity of path and service will remain intact and the portfolio costs will not be impacted.

The above being said, EGI's decision to renew expiring contracts will also be informed by current market conditions at the time a decision is made. In 2018 TCPL formed a Post-2020 Working Group, which includes TCPL and a subset of TransCanada Tolls Task Force ("TTF") members. The purpose of the Post-2020 Working Group is to discuss and collaborate on the preparation of a regulatory construct for the National Energy Board's consideration that will govern TCPL Mainline post-2020 (the current tolling framework of the Mainline Settlement Agreement expires on December 31, 2020[31]). It is generally anticipated that the toll structure and regulatory framework for TCPL Mainline will be different than the structure in place for the 2015 to 2020 period. The post-2020 TCPL Mainline regulatory construct may result in changes to services, tolls, delivery areas and cost allocation, creating risks for EGI including the potential for less flexibility and higher costs. It is possible that such changes bring about the requirement for a revised Plan relative to what is planned today. However, at this time EGI cannot estimate what the impacts may be. The contracts mentioned above will be considered as part of the overall post-2020 contract negotiations, and the decision to retain these contracts may be made in conjunction with all other potential TCPL contract changes included within broader negotiations.

6.4 Contract Renewals: Delivering Upstream of the Distribution System

Of the EGD rate zone contracts that EGI plans to utilize at a 100% load factor during the five year period of the Plan, Table 18 below provides a list of contracts that will require a capacity renewal decision.

Table 18 – EGD Rate Zone Expiring Contracts Supporting Average Day Demand

Service Provider	Service Type	Receipt	Delivery	Capacity (GJ/d)	Effective Date	Expiration Date
NGTL	FT-D	AECO/NIT	Empress	50,000	1-Nov-14	31-Oct-20
NGTL	FT-D	AECO/NIT	Empress	75,000	1-Jan-18	31-Dec-20
Vector	FT-1	Chicago	St. Clair	68,579	1-Jun-16	31-Oct-21
Vector	FT-1	St. Clair	Dawn	68,579	1-Jun-16	31-Oct-21

NGTL Capacity

EGI's NGTL capacity of 125,000 GJ/d delivers supply to Empress where long haul transportation of 265,000 GJ/d begins. There are two primary ways to take receipt of supply at Empress; purchasing upstream off the NGTL system and delivering to Empress or directly sourcing supply at the Empress trading point.

EGI holds NGTL capacity for the EGD rate zone as a means to diversify its Alberta purchases through access to the AECO/NIT trading hub, instead of solely making purchases at Empress. AECO/NIT is located in the heart of the WCSB and is one of North America's largest and most liquid supply hubs. Procuring supply at AECO/NIT allows EGI to make supply arrangements with multiple counterparties across multiple points, which in turn helps to limit risk of pricing disparities in Alberta. For example, from time-to-time the NGTL system will experience planned and unplanned outages between AECO/NIT and Empress. During these events, the cost of gas supply between AECO/NIT and Empress can vary significantly, such that having the ability to procure upstream of Empress limits the risk of Alberta purchases being exposed to temporary pricing disparities within Alberta.

[31] RH-001-2014, Reasons for Decision, December 18, 2014

Vector Capacity

EGI's Vector capacity, which delivers supply from the Chicago market to Dawn, provides the portfolio with diversity, a reliable source of supply from a liquid hub, and a flexible transportation contract provided that the contract is on an annual renewal. Table 15 above identifies the various options evaluated by EGI to deliver supply to Dawn as an alternative to Vector capacity. As shown in Table 19 below, Chicago supplies shipped through Vector land at a cost of $0.27/GJ incremental to what the supply would have cost if bought directly at Dawn. Table 19 below provides an evaluation matrix assessing holding Vector capacity on an annual renewal compared to the options outlined below.

Table 19 – EGD Rate Zone Average Day Contract Renewals for Vector: Evaluation Matrix

Option	Relative to Status Quo			Costs ($/GJ)	Average Cost/Customer Impact – Relative to Status Quo[32]
	Reliability	Flexibility	Diversity		
Dawn Spot	↑	↑	↓	3.27	> -1%
TCPL & GLGT	↑	→	↓	3.25	> -1%
GLGT	↑	→	↑	3.36	> -1%
Alliance & Vector	→	↓	→	3.33	> -1%
Vector	↑	↑	→	3.54	-
NEXUS	↑	↑	↓	3.80	< 1%
Rover	↑	→	↑	3.81	< 1%

For reference, the symbols in Table 19 describe whether or not a particular option has a: positive ↑, neutral →, or negative ↓ impact on the ability of the option to satisfy average day requirements as compared to the current portfolio.

Preferred Planning Strategy

EGI's preferred planning strategy with respect to its NGTL capacity is to continue to renew the contracts on an annual basis. This will continue to provide diversity for EGI Alberta purchases, allowing for procurement from a reliable supply point that has flexible contract terms and cost effective pricing. This decision is consistent with the Board's guiding principles of cost-effectiveness and reliable, secure supply.

EGI's preferred planning strategy for its expiring Vector capacity is to continue to renew these contracts on an annual basis. This capacity allows for a reliable source of supply, the flexibility that comes with annual renewal terms, and at the same time will provide overall diversity to the EGD rate zone supply portfolio. Similar to EGI's preference to renew NGTL contracts this approach

[32] Average cost per customer impact is for typical residential sales service customers consuming 2,400 m^3 annually. Estimated costs are derived based on sales service volumes for the EGD rate zone for the respective period. The impact for T-Service customers varies from sales service customers as they procure their own supply.

appropriately balances the Board's guiding principles, ensuring cost-effective, reliable and secure supply for EGD rate zone customers.

6.5 Storage Renewals

As shown in Section 5.4, within each of the five years of the Plan EGI intends to issue a RFP to the market to replace storage service agreements that are expiring.

EGI holds 26.4 PJ of market storage capacity for use in the EGD rate zone, as approved by the Board most recently in EB-2017-0086. This storage capacity is held across 11 different 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 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. Storage is located close to EGD rate zone increasing reliability and security of supply. 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 RFPs to the market each year to replace any capacity that is expiring.

6.6 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 the EGD rate zone EGI, utilizes capacity on multiple upstream pipelines to access several supply basins and market hubs. These pipelines provide access to supplies in Western Canada, Chicago, Dawn, Niagara and Appalachia.

As part of its ongoing process, EGI will continue to evaluate the EGD rate zone portfolio to ensure it meets the needs identified in the Plan, balancing the guiding principles set forth by the Board 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 for the EGD rate zone includes:

- Design day
    - Enbridge CDA – acquire peaking services to manage design day shortfalls

    - Enbridge EDA – acquire peaking services to manage design day shortfalls
- Average day
    - Purchase supply at Dawn to manage average day growth
- Transportation contracts renewals
    - Renew existing transportation contracts on an annual basis
- Storage Service Agreement Renewals
    - Renew existing storage service agreements on an annual basis for varying terms

7. EGD Rate Zone: Risk Mitigation Analysis

The EGD rate zone portion of the Plan is developed using forecasts that are underpinned by assumptions based on the best available information at a moment in time. Since forecasts in the Plan will be different from the actual experience, there are inherent forecast risks in the Plan in addition to the risk of unforeseen events.

These risks include:

1. Variation to planned assumptions
    - Weather variation
    - Demand forecast variation
    - Price variation
2. Supply interruption
3. Transportation interruption

7.1 Variation to Planned Assumptions

Weather Variation Risk

EGI assumes normal weather when developing annual demand forecasts for the Plans. However, normal weather is an expectation based on a trend, and it is expected that weather will vary from that trend each year. Temperatures can be colder which generally drives higher demand and market prices, or it can be warmer which generally drives lower demand and market prices.

Demand Forecast Variation Risk

Annual Demand Variation

As further described in Section 4.1, there are risks associated with generating the annual demand forecast relating to weather normal HDD forecast, average use, contract market growth, and number of customers.

Design Day Demand Variation

As further described in Section 4.2, the EGD rate zone uses design conditions that conform to a 1-in-5 recurrence interval to determine the potential for design day weather, as approved by the Board in EB-2011-0354. This statistical condition sets the weather conditions that will yield the highest day of demand in each year of a Plan as well as the estimated coefficients from the regressing equations. Notwithstanding this level of demand and estimated coefficients, should design conditions and/or customer use exceed the levels assumed in the design day demand forecast models, the utility will not have procured enough transportation assets and is at risk of outages to the downstream distribution system. See Section 8 for a description of how EGI executes its Plan when demand activity deviates from the Plan.

Pricing Variation Risk

Market prices are driven by both local market conditions, such as weather, and the operation of the broader North American natural gas market. EGI is a price-taker, and its procurement of supply is subject to prevailing market conditions which can vary significantly from location-to-location on a daily basis.

Given the risk of price changes, EGI's Plan maintains diversity and flexibility in its commodity purchase plan. This is achieved by making purchases at multiple locations (e.g. AECO, Empress, Niagara, Chicago, Dawn, Appalachia), for a variety terms (e.g. annual, seasonal, monthly, weekly, daily) executed at different times throughout the year.

Scenario Analysis

In order to illustrate the potential for weather volatility and its impact on demands, pricing, and portfolio costs, EGI engaged ICF to conduct an analysis to provide some insight into possible weather variation outcomes.

ICF conducted an analysis that used the weather patterns from its 84-year history of weather conditions to simulate natural gas demand for North America for the period of April 2019 to March 2022, and subsequently assessed the resulting price responses experienced in the North American natural gas market. ICF conducted sensitivity analyses which allowed for natural gas prices to increase and decrease based on the weather experiences in North America over an 84-year period, ultimately providing EGI with "high" and "low" price scenarios. Based on ICF's analysis the high price scenario corresponds with the weather pattern experienced from 1977 to 1980, whereas the low price scenario corresponds with the weather pattern experienced during the 2010 to 2013 period. Please see Appendix E for a copy of the report ICF has prepared.

Using ICF's high price and low price scenario time periods as a basis, EGI used its own weather zone experiences for the scenario years identified and simulated the EGD rate zone demand for the 2020 to 2022 period. With simulated demand and forecasted prices, EGI substituted these values into SENDOUT to generate a possible range of potential costs to the upstream portfolio. ICF provided three years of commodity prices and EGI analyzed the SENDOUT results for all three years. Summarized below are the most significant one-year deviations in cost relative to the Plan.

	Rate Zone	Demand (% Change in Vol)	Portfolio Cost (% Change in Portfolio Cost)
High Price	EGD	+9%	+77%
Low Price	EGD	-7%	-17%

Every year the Plan will be faced with demand and price volatility which is why EGI employs a strategy of procuring supply from multiple supply basins and price hubs, staggering the terms and timing of supply deals, in order to cost-effectively and reliably manage supply procurement. Specifically, when executing the Plan for the EGD rate zone, EGI routinely reviews and analyses the prevailing weather conditions and demand patterns, and performs in-season forecasts of demand that take into consideration up-to-date weather forecasts. These in-season demand forecasts provide EGI with updated short-term expectations of demand that help to inform whether or not EGI may need to make changes to its short-term gas supply procurement strategy. See Section 8.1 for more details on the execution of the Plan within EGD rate zone.

Beyond diversifying procurement across multiple points and using multiple terms, storage capacity manages weather volatility by allowing EGI to inject excess gas supply if demands are low when commodity prices tend to be lower and less volatile, and withdraw the stored supply when demands increase and prices tend to be higher and more volatile.

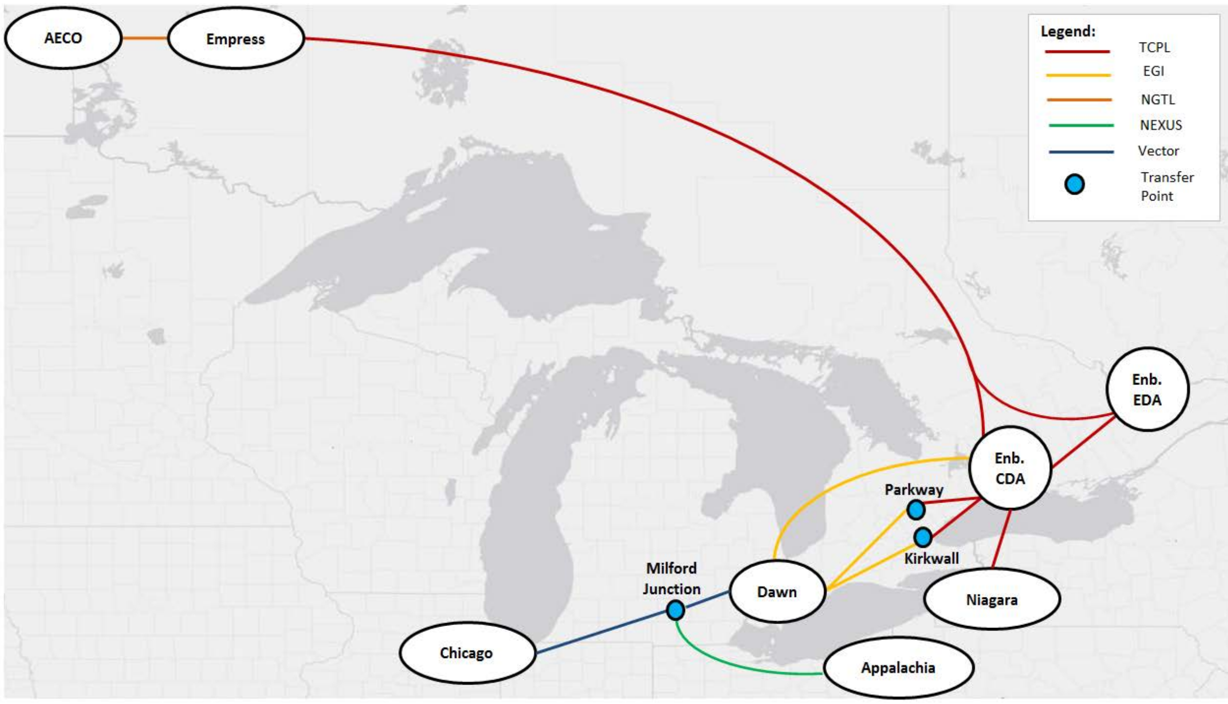
7.2 Supply Interruption Risk

The strategy EGI utilizes to limit the risk of supply being interrupted is to contract for supply with creditworthy counterparties and to procure supply at liquid supply points which have numerous counterparties. These practices are consistent with EGI's procurement policy referenced in Section 8.1.

7.3 Transportation Interruption Risk

EGI mitigates the risks associated with transportation service interruptions in multiple ways. One practice is to contract and procure transportation capacity with regulated upstream service providers, such as TCPL, Vector, and NEXUS, which themselves have numerous risk mitigation policies underpinning their operations. Another practice is to contract for firm transportation services with upstream service providers instead of interruptible or non-firm services. In doing so, the firm services guarantee the ability to schedule supply, as only during a force majeure would service be interrupted. Further, EGI's portfolio of upstream transportation contracts includes a diverse mix of transportation providers, so if one transportation provider were to experience a force majeure event EGI has the flexibility to change the utilization of the unaffected transportation contracts in order to mitigate the downstream impacts. Also, by holding capacity with multiple upstream service providers which are connected to liquid supply hubs, such as Alberta and Dawn, EGI retains the flexibility to contract for short-term services such as interruptible transportation and short term firm transportation, if the need arises. See Figure 25 below for a map depicting the EGD rate zone transportation contracting diversity.

Figure 25 – EGD Rate Zone Transportation Path Diversity

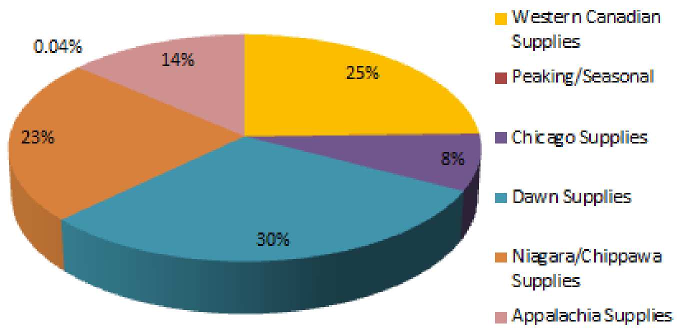


7.4 Summary

EGI manages risk by holding a portfolio that supports basin diversity, efficient supply procurement policy, and a variety of transportation contracts with differing parameters to assist EGI with changing market conditions.

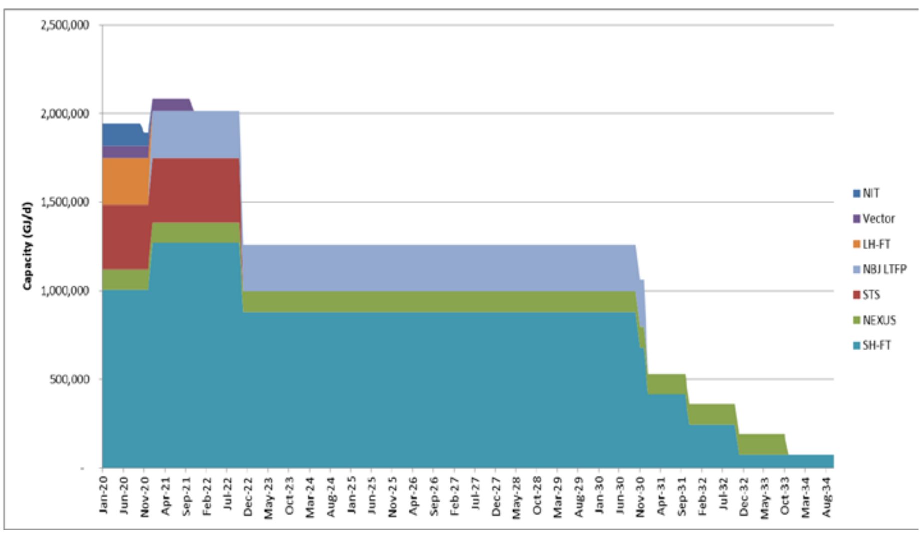
Figure 26 below is the projected 2020 system supply portfolio for the EGD rate zone which helps illustrate diversity through supply basins and trading points. The current gas supply and transportation portfolio supports two primary production basins in the WCSB and Appalachia, with further diversity and flexibility from three market hubs: Chicago, Niagara, and Dawn.

Figure 26 – EGD Rate Zone Current Sources of Supply Visual



Depicted in Figure 27 below are the transportation contracts included in the EGD rate zone portfolio. This figure illustrates that EGI's contracted terms continue have staggered expiry dates. In order to secure supply and ensure EGI has assets available to serve demands, certain contracts require long-term commitments (e.g. 10 years or 15 years).

Figure 27 – EGD Rate Zone Transportation Contract Term Diversity



8. EGD Rate Zone: Gas Supply Plan Execution

Once the Plan for the EGD rate zone has been established, the execution phase takes place. EGI executes the Plan balancing reliability, diversity and flexibility, while still achieving a cost-effective solution for ratepayers, in accordance with the Board's guiding principles.

To manage risk, EGI procures supply regularly throughout the year from credit worthy counterparties at multiple trading points using a layered approach with consideration to diversity of delivery term. 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 deviations in demand. These deviations may be a result of weather, usage patterns or other factors that contribute to increases or decreases in customer consumption.

Within each season, EGI frequently monitors actual and forecast customer activity. Decisions related to the continued execution of the Plan are made regularly during operational planning meetings. These meetings are held throughout the year and the frequency will increase based on the season, weather and market or operational conditions. A diverse, cross-functional team operates with oversight from the Director of Gas Supply to make purchase decisions related to the execution of the Plan through gas supply procurement and transportation capacity utilization decisions.

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.

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.

It is expected that the current execution for the EGD rate zone portion of the Plan will evolve over time as EGI begins to realize any synergy benefits of combining the EGD rate zone Plan with the Union rate zones' Plan as discussed in Section 19.

8.1 Procurement Process and Policy

EGI purchases natural gas for the EGD rate zone gas supply portfolio. The Gas Procurement Policy and Procedures ("Policy") is filed with the Energy Returns Officer and any updates are provided to the Board as they are made. The Policy addresses the process of securing natural gas supplies for system gas customers.

In the months prior to a given planning year, EGI's Gas Supply department develops a monthly procurement plan. While the monthly procurement plan identifies the expected commodity transactions to be executed, EGI still maintains the flexibility to make decisions within the planning year to make purchases for various terms, such as annual, seasonal, monthly or daily, or leave transportation capacity empty.

Within the planning year execution of the procurement plan is carried out under the direction and authorization of the Director of Gas Supply. The EGD rate zone procurement plan layers in annual, seasonal, monthly and daily purchases each month. Procuring supply throughout the year achieves market representative pricing, while not being unduly influenced by pricing and market dynamics at a specific point in time.

On a planned basis, gas supply for the EGD rate zone is currently purchased:

- Through a RFP process (written and verbal);
- Primarily based on index price contracts;
- Primarily in the forward market;
- For contract terms on a monthly, seasonal, and annual (or multi-year) basis; and
- For contract terms shorter than one month.

As per the Policy, EGI is authorized to use the following transaction pricing instruments either through the RFP process (written and verbal), electronic gas trading platforms or a brokerage house, or directly with a counterparty:

- Fixed price contracts specify purchase of natural gas at a fixed price for a specific term; and
- Index price contracts specify purchase of natural gas at a price to be determined in the future for a specific term.

EGI purchases gas for the EGD rate zone from suppliers under a North American Energy Standards Board ("NAESB") contract or a Gas Electronic Data Interchange ("gasEDI") contract. Existing NAESB and gasEDI contracts provide EGI the option to transact with over 100 suppliers. EGI's gas commodity purchases are influenced by the characteristics and traits of the specific supply points or basins where EGI purchases supplies. Each of these purchase points have different liquidity and supply characteristics.

As system operator, EGI also manages many operational factors for the EGD rate zone including:

- Actual and forecast consumption relative to planned consumption for its sales service customers;
- Seasonal balancing requirements for sales service customers;
- Weather variances for all sales customers;
- Changes in supply and balancing requirements as customers move between sales service and DP;
- Unaccounted for gas and compressor fuel variances; and
- Supply or pipeline disruptions – planned or unplanned.

9. EGD Rate Zone: 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.

9.1 Heating Degree Days

		2015			2016			2017		
Line No.	Particulars	Actual	Budget	Variance	Actual	Budget	Variance	Actual	Budget	Variance
1	Central Weather Zone	3,710	3,536	5%	3,412	3,617	-6%	3,499	3,639	-4%
2	Eastern Weather Zone	4,397	4,267	3%	4,231	4,323	-2%	4,334	4,341	0%
3	Niagara Weather Zone	3,548	3,376	5%	3,233	3,408	-5%	3,293	3,405	-3%

As shown in the analysis above:

- 2015 degree days were higher than budget across all weather zones due to colder than expected temperatures
- 2016 degree days were lower than budget across all weather zones due to warmer than expected temperatures
- 2017 degree days were lower than budget across all weather zones due to warmer than expected temperatures

9.2 Demand

The purpose of this section is to provide a brief review of the prior three years, comparing the demand forecast underlying each Plan to the actual throughput volume.

Line		2015			2016			2017		
No.	Particulars (TJ)	Actual	Budget	Variance	Actual	Budget	Variance	Actual	Budget	Variance
1	EGD Rate Zone	471,934	434,448	37,486	449,640	449,735	(94)	453,305	456,548	(3,243)

9.3 Supply

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

Line		2015			2016			2017		
No.	Particulars (TJ)	Actual	Budget	Variance	Actual	Budget	Variance	Actual	Budget	Variance
1	Western Canadian Supplies	196,238	178,508	17,730	150,129	130,745	19,384	62,857	67,303	(4,446)
2	Peaking/Seasonal	423	299	125	273	83	190	50	162	(111)
3	Ontario Production	3	28	(25)	1	14	(13)	-	14	(14)
4	Chicago Supplies	55,686	71,037	(15,351)	44,688	69,086	(24,398)	68,697	64,842	3,855
5	Dawn Supplies	43,853	26,988	16,865	17,382	40,546	(23,165)	92,512	85,913	6,599
6	Niagara Supplies	-	12,472	(12,472)	70,845	74,831	(3,987)	72,552	74,627	(2,075)
7	Link Supplies	-	-	-	2,579	-	2,579	12,816	12,431	385
8	Dominion Supplies	-	-	-	-	-	-	-	7,237	(7,237)
9	Direct Purchase Delivery	179,528	147,311	32,217	161,140	139,916	21,224	147,659	143,399	4,260
10	Storage (Injection)/Withdrawal	(3,797)	(2,194)	(1,604)	2,605	(5,487)	8,092	(3,838)	620	(4,458)

As shown in the analysis above:

- In 2015, colder than expected temperatures increased demand and gas supply deliveries above budget
- In 2016, warmer than expected temperatures decreased demand and gas supply deliveries below budget
- In 2017, warmer than expected temperatures decreased demand and gas supply deliveries below budget

9.4 Unutilized Capacity

EGD's 2015 Rate Application EB-2014-0276 (Exhibit D1, Tab 2, Schedule 1, page 6 of 11) committed to providing monthly reporting of UDC. Monthly reports have been filed with the Board outlining planned and actual UDC for the years of 2015 and 2016. Since 2016, no UDC has been planned or incurred by EGI within the EGD rate zone.

10. Union Rate Zones

The following Sections 10 to 16 of the Plan are specific to the Union rate zones and address the period from November 1, 2019 to October 31, 2024.

10.1 Description of Union Rate Zones

The Union rate zones provide natural gas distribution services to over 1.5 million of EGI's total of 3.7 million residential, commercial and industrial customers located throughout Ontario. The Union rate zones include Union North West and Union North East (together referred to as "Union North"), and Union South as shown in Figure 28. The delivery areas embedded within the Union rate zones are described below:

Union North West:

- **Manitoba Delivery Area ("MDA"):** Containing Fort Frances and surrounding areas
- **Western Delivery Area ("WDA"):** Stretches from Longlac to Kenora containing Thunder Bay, Dryden and surrounding areas
- **Sault Ste. Marie Delivery Area ("SSMDA"):** Containing Sault Ste. Marie and surrounding areas

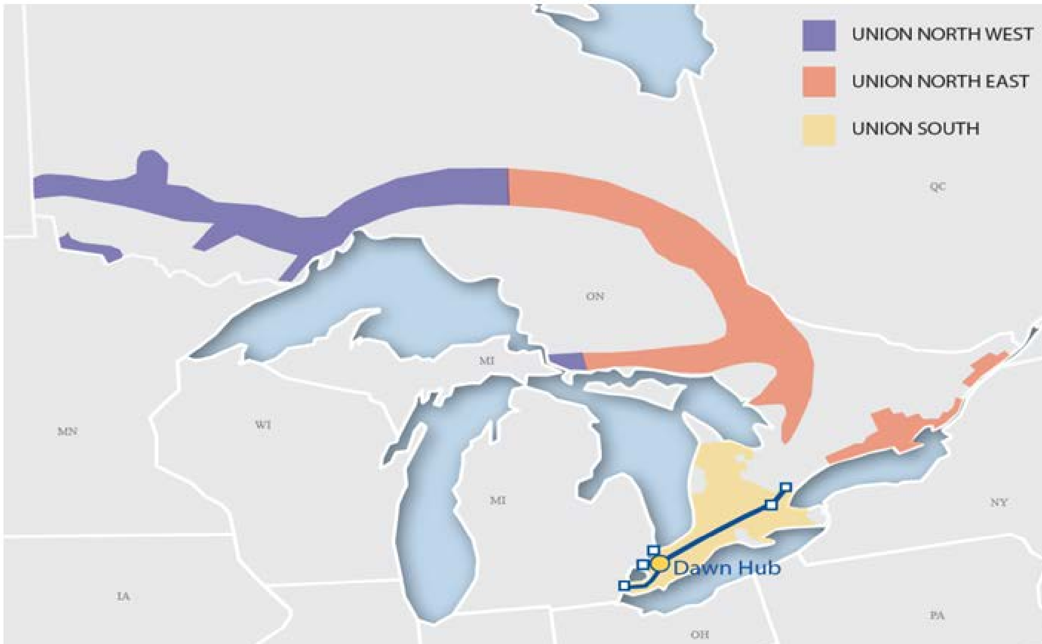
Union North East:

- **North Delivery Area ("NDA"):** Stretches from North Bay to Calstock containing North Bay, Sudbury, Timmins and surrounding areas
- **North Central Delivery Area ("NCDA"):** Stretches from Orillia to North Bay containing Parry Sound, Huntsville and surrounding areas
- **Eastern Delivery Area ("EDA"):** Stretches from Coburg to Cornwall containing Belleville, Kingston, Brockville and surrounding areas

Union South:

- **Union South:** Stretches from Windsor to Owen Sound to Oakville containing Sarnia, London, Goderich, Waterloo, Kitchener, Cambridge, Guelph, Burlington, Milton, Brantford, Hamilton and surrounding areas

Figure 28 – Union Rate Zones Map



EGI provides distribution services to all Union rate zones' in-franchise customers, however customers continue to have the option to purchase their supply from EGI or arrange supply through a DP arrangement. Union rate zones' in-franchise customers fall into three distinct categories:

- **Sales Service:** EGI acquires supply and transportation capacity for these customers and their demand is included in the Plan;
- **Bundled DP:** These customers acquire their own supply. In Union North, EGI holds transportation capacity on their behalf while in Union South these customers acquire their own transportation capacity. The needs of these customers are included in the Plan; and,
- **Transportation Service ("T-Service") DP:** These customers acquire their own supply and transportation and are not considered within the Plan with the exception of the allocation of in-franchise storage space.

Of the 1.5 million customers that EGI serves in the Union rate zones approximately 1.4 million are sales service customers that rely on EGI to provide their gas supply. Sales service customers are primarily residential and small commercial customers. Customers that do not receive sales service rely on DP arrangements with marketers and alternate suppliers to meet their gas supply needs. Residential customers use gas consistently throughout the year for water heating, with the bulk of their usage attributable to space heating in the winter. Industrial customers use gas more consistently throughout the year, having a lower proportion of a weather-sensitive load.

The Union rate zones are spread across Ontario and encompass different customer bases and weather patterns.

11. Union Rate Zones: Demand Forecast Analysis

11.1 Annual Demand

The Union rate zones' demand forecast includes estimates for both the number of billed customers and the total annual throughput volumes. These estimates are divided into two customer segments: general service market and contract market. The forecast process described below is consistent with the Board-approved methodology employed in EB-2011-0210, Union's 2013 Cost of Service proceeding.

General Service Market

The general service market for the Union rate zones is comprised of approximately 1.5 million customers billed in Rate M1, Rate M2, Rate 01 and Rate 10. The general service demand forecasting methodology uses multiple regression analyses based on a historic database containing monthly actual data from January 1993 to December 2017.

The general service demand forecast process is comprised of four separate estimation steps:

1. *Forecast the total number of billed customers for each rate class and service class*. The customer forecast is a combination of historical customer counts and forecasted attachments. There are four focal categories of attachments: new housing starts, residential conversions, commercial customer additions, and small industrial customer additions.

2. *Forecast the normalized average consumption ("NAC") for each rate class and service class*. The NAC forecast for residential customers incorporates several explanatory variables including: weather normal, energy efficiency, and price signals. The USD/CAD foreign exchange rate is incorporated into the non-residential NAC forecast.

3. *Multiply the customer forecasts and NAC forecasts for each rate class and service class to obtain the total general service throughput volume forecast*.

4. *Remove the forecasted volume savings related to DSM programs from the total general service throughput forecast.* These DSM volume impacts correspond to the 2016-2020 DSM plan approved by the Board in EB-2015-0029.

General Service Market Risk Analysis

The risks associated with the general service forecast reside mostly in the assumptions used for each explanatory variable, such as weather and economic indicators. If actual demand drivers occur differently than assumed in the forecast, consumption will be affected by the corresponding sensitivities. These sensitivities are described below:

- The primary risk to the general service annual demand forecast is the underlying weather normal heating degree day ("HDD") forecast. Approximately 77% of the Union rate zones' general service volume is driven by weather. Regression analysis indicates that a 10% deviation from the weather normal assumption underlying the forecast results in almost an 8% change to demand. During the last five years (2014-2018), weather patterns have shown a wide range of variance relative to the Board approved weather normal. The actual annual heating degree days have fluctuated between -6.8% (warmer) to +14.7% (colder) relative to normal. Table 20 below provides the actual and normal HDD for the past 5 years.

Table 20 – Historical HDD Variance

Union Gas Heating Degree Days	Actual	Board Approved	Weather % Variance
2014	4,506	3,929	14.7%
2015	4,104	3,969	3.4%
2016	3,789	4,068	-6.8%
2017	3,879	4,066	-4.6%
2018	4,147	4,064	2.0%

- Regression analysis also provides consumption sensitivities for the other demand drivers in the general service models:
  - Variance of 2,000 in the customer forecast impacts total volumes by about 0.1%;
  - 10% change to the CAD/USD exchange rate impacts total volume by about 0.6%;
  - 10% change to the total bill amount (price) impacts total volumes by about 0.3%;
  - and,
  - 1% change to the efficiency index[33] impacts total volumes by about 0.5%.

- There is also a risk that factors outside of the models (customer behavior changes/thermostat settings, natural disasters, etc.) will affect consumption and cause a variance to the forecast. Because these outside factors are not included in the models, it is very difficult to estimate related consumption impacts.

Contract Market

EGI's contract market forecast for the Union rate zones is segmented into several sectors, including natural gas-fired power generation, steel, refinery and petrochemical, greenhouse, wholesale, and broad-based large commercial and industrials ("LCI"). The forecast for these contract market customers is developed using two methodologies. For the small- to mid-size customers, represented

[33] The efficiency index is based on historical customer survey data from EGI's market research department, and is meant to represent natural efficiency and conservation saving trends for residential customers.

by the LCI and greenhouse market sectors, an econometric linear regression methodology is applied using historical weather-normalized consumption data. The resulting forecast is reviewed and adjusted for known changes to customer and market conditions that are expected to impact consumption. Key demand drivers impacting the forecast for small- to mid-size contract customers include number of customers, the USD/CAD foreign exchange rate, seasonal load differences, and greenhouse acreage.

For the remainder of the contract market (power generation, steel, refinery and petrochemical), a bottom-up forecast methodology is applied. This involves a combination of historical consumption data, consultation with customers, and knowledge of specific customers' production plans and expectations.

The forecasted DSM consumption savings are then removed from the total contract market volume estimations. The DSM volume savings correspond to the 2016-2020 DSM plan approved by the Board in EB-2015-0029.

Contract Market Risk Analysis

- Contract market volumes are primarily driven by economic factors. As a result, significant changes in economic conditions relative to expectations (e.g. recession) can lead to higher variances.

- The impacts of expected growth (e.g. capital projects, government programs), changes to customer operations, volume reductions relating to DSM and customer facility closures are all included in the Union rate zones' contract market demand forecast. There are risks associated with each of these items, both related to their timing and the likelihood of materialization.

- Contract renewals for most customers are conducted annually. Contract renewal discussions can include customers switching between delivery service options, which in turn can lead to forecast variances.

- Colder weather will lead to higher consumption. Extreme weather in Union North can also drive higher Rate 25 consumption due to favorable pricing of system gas relative to the market. A customer's contract may allow for the consumption of Rate 25 system gas in addition to another delivery service option. Under such circumstances it is at the customer's discretion as to how they elect to source their consumption.

- Periodically, EGI will offer Rate 25 system gas to customers at discounted prices, often resulting in customers electing to consume larger quantities of system gas.

Annual Demand Forecast

The Plan is based on the weather normalized demand forecast for general service customers and contract rate classes as prepared by EGI's Demand Forecasting & Analysis department.

Table 21 below illustrates the annual demand forecast for the Union rate zones. These volumes are expected to be relatively flat over the projection period of 2020-2024. Increased consumption from customer growth in all sectors is offset by continued declining NAC for the general service customers.

Table 21 – Union Rate Zones Annual Forecast

Line No.	Particulars (TJ)	2019/20	2020/21	2021/22	2022/23	2023/24
	Union North West					
1	General Service	14,022	13,886	13,814	13,742	13,741
2	Contract	1,338	1,330	1,372	1,363	1,355
3	Total Union North West	15,360	15,216	15,185	15,105	15,095
	Union North East					
4	General Service	36,339	35,967	35,765	35,558	35,533
5	Contract	3,644	3,683	3,955	5,198	5,305
6	Total Union North East	39,983	39,650	39,720	40,756	40,838
	Union South					
7	General Service	164,963	163,321	162,482	161,632	161,595
8	Contract	51,379	51,720	52,144	52,436	52,659
9	Total Union South	216,342	215,041	214,626	214,068	214,254
10	Total Union Forecast Demand	271,685	269,907	269,531	269,929	270,188

11.2 Design Day Demand

Similar to its practice in the EGD rate zone, within the Union rate zones EGI ensures assets are available to provide firm service to customers on an extreme cold weather day referred to as a design day, which is measured in HDDs. The main information required to develop a plan to serve design day demand includes weather, number of customers, firm customer demand, forecast demand growth and firm assets.

The design day planning methodologies outlined below are consistent with the Supply Planning Review report prepared for Union by Sussex Economic Advisors (the "Sussex Report")[34,35].

Weather

The Union rate zones use the coldest observed HDD method to determine the design day HDD for each delivery area.

[34] EB-2013-0109, Exhibit C, Tab 2 and Tab 3

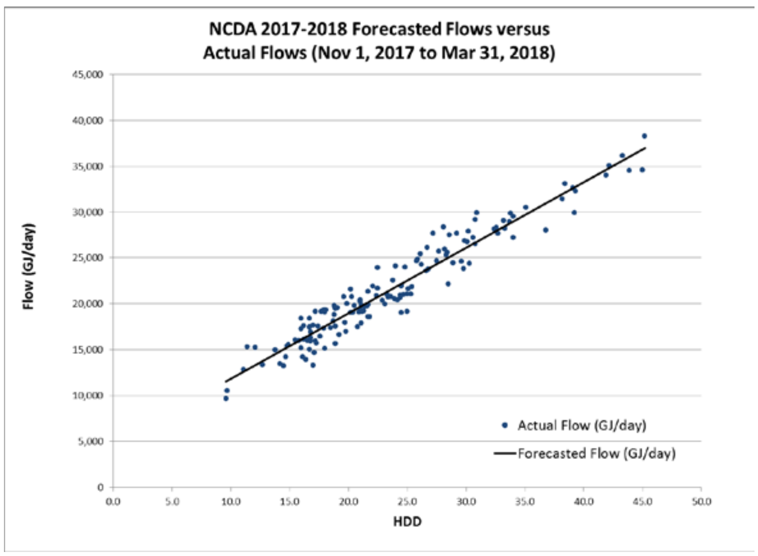
[35] The Sussex Report applies to sales service and bundled DP customers in Union North and sales service customers in Union South.

Firm Customer Demand

EGI's firm customer design day demand in the Union rate zones is forecasted first by multiplying the firm use per degree day described below with the coldest observed heating degree day.

For the Union rate zones, EGI develops a linear regression using the daily firm customer consumption from the prior winter and corresponding daily heating degree day data. EGI extrapolates the resulting regression line to the coldest observed heating degree day for each delivery area, ultimately establishing an estimated design day demand for each delivery area. An illustrative example of the actual demand and HDD data and the regression line calculation for the NCDA is provided in Figure 29.

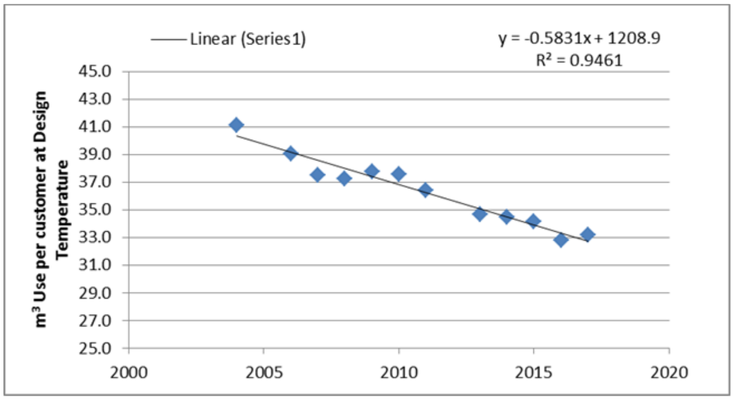
Figure 29 – Example of Actual Demand vs. HDD



The firm customer design day demand is then multiplied by the use per customer factor[36] which dampens year to year demand variability due to weather differences and measurement tolerances. When available, a rolling 20 years of use per customer data is regressed as seen in Figure 30. The use per customer factor is the ratio of the current year's use per customer divided by the use per customer calculated from the rolling 20 year regression line.

[36] The use per customer is the estimated general service design day demand divided by the number of customers

Figure 30 – Historical m^3 per Customer at Design Temperature



Forecast Demand Growth

The design day demand described above is adjusted by the winter season growth trend to provide a forecast design day demand for each delivery area for general service customers. The winter season growth trend is the line of best fit using the historical design day demands including the most current winter. The contract customer demand, including growth, is added to the general service demand to provide the total forecast design day demand for each delivery area.

Firm Assets

Once determined, the design day demand requirements of the Union rate zones are met by holding a combination of firm storage and transportation capacity. Though design day weather conditions do not occur every day, the assets must be available should a design day occur given EGI's role as the system operator and supplier of last resort for sales service and bundled DP customers.

Design Day Demand Forecast

To meet the design day demand requirements, EGI must have a sufficient volume of gas in storage and sufficient transportation assets to move the upstream supply and gas out of storage and into the transmission pipeline systems.

Union North Design Day

Union North design day demand is the total firm requirement of the in-franchise sales service and bundled DP customers in each of Union North's delivery areas.

As noted above, design day weather conditions are based on the coldest observed HDD experienced in each of the delivery areas. The design degree day for each Union North delivery area is as follows:

WDA	51.6	Thunder Bay
MDA	54.7	Fort Frances
SSMDA	48.2	Sault Ste Marie
NCDA	49.3	Muskoka / Gravenhurst

NDA	51.9	Sudbury
EDA	47.1	Kingston

Union North delivery areas are connected to TCPL Mainline and are physically separated from EGI's Dawn storage and transmission pipeline assets. Therefore, EGI requires firm transportation services on TCPL Mainline to connect each of the six Union North delivery areas to a supply source. Further, since there is no physical storage in Union North, EGI is required to purchase transportation services to move the firm design day demand from Parkway, Dawn or Empress to the delivery areas where the gas is consumed.

EGI uses a portfolio of firm services and assets including TCPL FT, TCPL firm STS and other firm TCPL services such as enhanced market balancing, to meet the Union North design day demand requirement. Since EGI is required to contract for transportation services to meet design day demand, and the full suite of assets is only used in each delivery area when a design day occurs, there are days when the pipe is not fully utilized. The process to address unutilized transportation capacity is discussed further in Section 12.5.

Table 22 illustrates Union North design day demand by rate zone.

Table 22 – Union North Design Day Demand

Line No.	Particulars (TJ/day)	North West 2019/20	2020/21	2021/22	2022/23	2023/24	North East 2019/20	2020/21	2021/22	2022/23	2023/24
	Demand										
1	Union North*	130	129	129	128	128	403	400	408	408	411

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

Over the term of the Plan, design day demand in Union North West remains relatively consistent each year, while Union North East experiences some growth in 2021/22 in the Union EDA.

Union South Design Day

Union South design day demand is the total firm requirement of in-franchise sales service, bundled DP, and T-Service customers.

The design day weather condition for Union South is based on the coldest observed degree day of 43.1 as measured in London.

Table 23 illustrates Union South design day demand.

Table 23 – Union South Design Day Demand

Line No.	Particulars (TJ/day)	2019/20	2020/21	2021/22	2022/23	2023/24
	Demand					
1	Union South*	3,108	3,139	3,265	3,314	3,344

* includes Sales Service, Bundled DP, T-Service

Design day demands in Union South are increasing as a result of growth.

Risk Analysis

EGI uses the coldest observed day method to determine the potential for design day demand in the Union rate zones and this methodology mitigates the risk of not meeting projected customers' demands on design day. EGI only procures firm assets for the Union rate zones further reducing the risk of under delivery on design day.

12. Union Rate Zones: Current Portfolios

12.1 Commodity Portfolio

To serve Union North West, EGI holds firm transportation contracts connecting to supplies in Western Canada via TCPL Mainline; the only pipeline available to directly supply these areas of EGI's franchise.

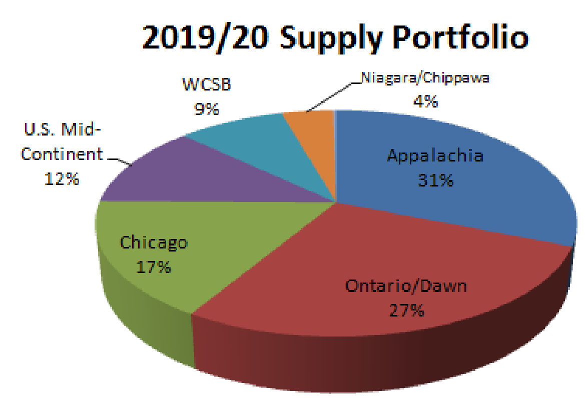
For Union North East, EGI holds firm transportation contracts on multiple upstream pipelines providing access to supplies in Western Canada and Appalachia. The Plan also includes Dawn purchases within the Union North East supply portfolio.

Similarly, EGI holds firm transportation contracts on multiple upstream pipelines to serve Union South, providing access to supplies in Western Canada, Chicago, the U.S. Mid-Continent and Appalachia. The Plan also includes Dawn purchases as part of the Union South supply portfolio. Table 24 provides the sources of supply underpinned by EGI's transportation portfolio for sales service customers, as illustrated in Figure 31.

Table 24 – Union Rate Zones Supply Forecast

Line No.	Particulars (TJ)	2019/20	2020/21	2021/22	2022/23	2023/24
	Union North West					
1	WCSB	13,461	13,038	12,348	11,089	11,291
	Union North East					
2	Appalachia	19,308	19,255	19,255	19,255	19,308
3	Ontario/Dawn	8,677	9,152	9,788	10,551	10,246
4	WCSB	1,368	1,364	1,364	1,364	1,368
5	Total North East Supply	29,353	29,771	30,408	31,170	30,922
	Union South					
6	Appalachia	38,615	38,510	38,510	38,510	38,615
7	Chicago	30,892	30,807	30,807	30,807	30,892
8	Local Producers	453	452	452	452	453
9	Niagara	7,723	7,702	7,702	7,702	7,723
10	Ontario/Dawn	42,437	42,852	42,170	42,386	41,148
11	U.S. Mid-Continent	22,011	21,950	21,950	21,950	22,011
12	WCSB	1,098	1,095	1,095	1,095	1,098
13	Total South Supply	143,229	143,368	142,686	142,902	141,940
14	Total Union Supply Forecast	186,042	186,177	185,442	185,161	184,152

Figure 31 – Union Rate Zones' 2019/20 Supply Forecast Chart



12.2 RNG Portfolio

Please refer to Section 5.2 regarding EGI's RNG portfolio.

12.3 Transportation Portfolio

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

Figure 32 and Figure 33 below depict the current transportation contracts that EGI holds for its Union North and Union South rate zones respectively. A complete listing of the transportation and storage service capacity currently contracted for Union North and Union South is provided in Appendix F and Appendix G, respectively.

Figure 32 – Union North Transportation Portfolio

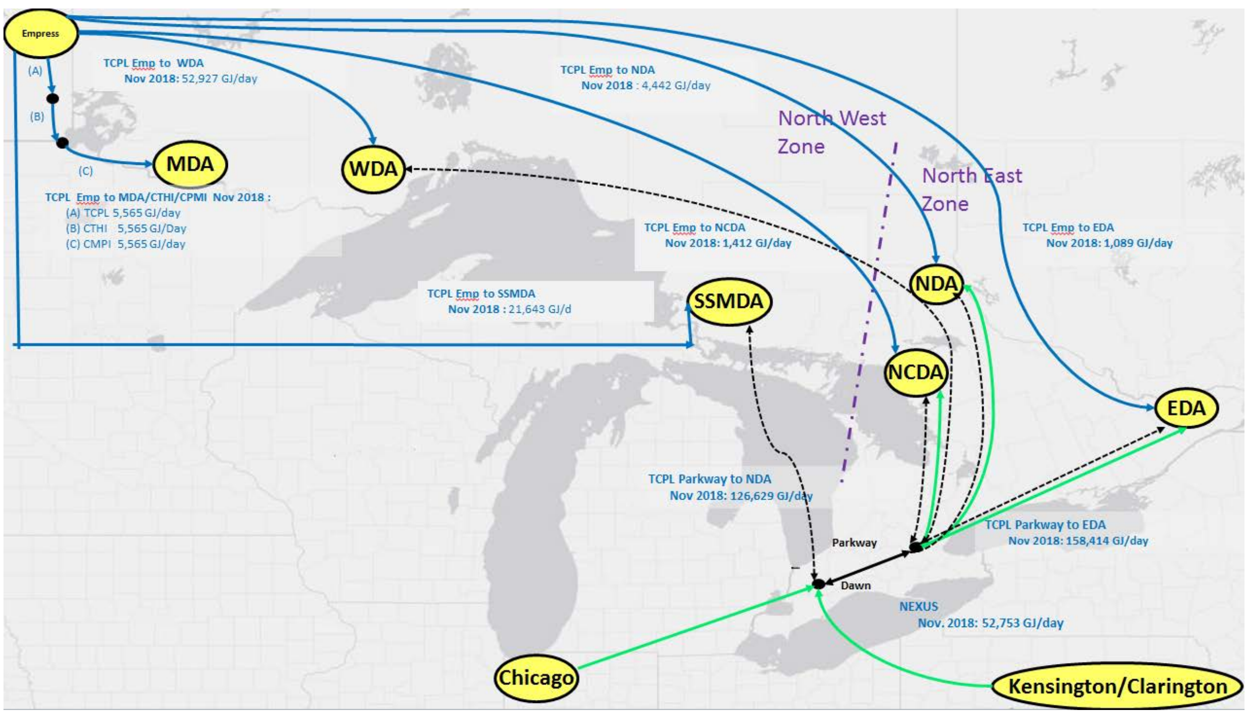


Figure 33 – Union South Transportation Portfolio

Transportation Portfolio Changes

The following section addresses all transportation portfolio changes for the Union rate zones since the time the Plan was developed in Q3 2018. The format of this section is consistent with the transportation contracting analysis, previously filed as part of Union's annual deferral disposition.

Transportation Contracting Analysis

For the period of November 1, 2019 to October 31, 2024 Union South has the following portfolio changes:

1. Panhandle Eastern Transportation Contract Renewals;
    a. Increase the existing Panhandle Eastern contract from 10,000 Dth/d (10,551 GJ/d) to 22,000 Dth/d (23,211 GJ/d) for the renewal period of November 1, 2019 to October 31, 2027
    b. Increase the existing Panhandle Eastern contract from 25,000 Dth/d (26,376 GJ/d) to 35,000 Dth/d (36,927 GJ/d) November 1, 2019 to October 31, 2025

2. Dawn Parkway System 2021 NCOS
    a. Effective as early as November 1, 2021, 40,000 GJ/d of capacity from Dawn to Parkway is required for Union South in-franchise growth

A comparison of landed costs for the Panhandle Eastern and Dawn Parkway System NCOS relative to the viable alternatives considered can be found in Appendix H and Appendix I, respectively.

Rationale for Panhandle Eastern Capacity

A minimum of 60,000 GJ/d of supply delivered at Ojibway is required to meet long term design day demand along EGI's Panhandle Transmission System. The 8-year and 10-year contract terms were negotiated with Panhandle Eastern to secure long term capacity into Ojibway. This capacity can also be renewed through a Right of First Refusal.

Union discussed this in detail in EB-2016-0186 and EB-2017-0087[37].

The benefits of this capacity include:

i. Lands gas at Ojibway to support the Panhandle Transmission System on design day;

ii. Landed cost of gas flowing to EGI along this route is competitively priced;

iii. Supports the acquisition of secure supply from basins located in the South Central U.S., maintaining diversity of contract terms and supply basins;

iv. Provides both receipt and delivery flexibility within the path; and,

v. Contract has renewal provisions (right of first refusal) which provide contractual rights to retain access to this capacity in future years if required.

Rationale for Dawn Parkway System Capacity

A requirement for an additional 40,000 GJ/d of capacity was identified to support distribution system growth east of Dawn. In the latter half of 2018, Union bid into the Dawn to Parkway Open Season for 40,000 GJ/d of capacity with an in-service date in 2021.

The benefits of this capacity include:

i. Moves gas from Dawn to Parkway to meet Union South in-franchise requirements;

ii. Landed cost of gas flowing to EGI along this route is competitively priced;

iii. Supports the acquisition of supply from upstream markets, maintaining diversity of contract terms and supply basins; and,

iv. Direct access to Dawn providing flexibility and ability to transact with multiple counterparties from a liquid trading point.

12.4 Storage Portfolio

In order to meet the design day demand for Union South and Union North, EGI uses a combination of contracted upstream transportation capacity, storage, transmission and distribution assets. The inclusion of storage assets in the Plan provides a cost effective, reliable and secure alternative to

[37] EB-2017-0087. Exhibit B.TCPL.2

contracting for upstream firm transportation assets, consistent with the Board's guiding principles. Storage provides the Plan further operational flexibility and aligns with EGI's target to fill storage at November 1 and maintain sufficient inventory at February 28 to meet the design day storage withdrawal requirement.

In accordance with the Board's NGEIR Decision[38], the allotment of storage space to in-franchise customers in the Union rate zones is 100 PJ. The allocation of storage to Union rate zones' customers is based upon methodologies approved by the Board as part of the Natural Gas Storage Allocation Policies Decision[39].

The storage space available to sales service and bundled DP customers is determined using the aggregate excess methodology. 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.

Aggregate Excess = Forecasted Winter Consumption – [(Total Annual Consumption x 151/365)]

Union South T-Service customers select from the following four methodologies to calculate their contracted storage space:

1. Aggregate excess;
2. 15 x Obligated daily contract quantity ("DCQ");
3. Peak hourly consumption x 24 x 4 days; or,
4. Contract demand x 10.

Table 25 illustrates the in-franchise storage requirement specific to the Union rate zones.

Table 25 – Union Storage Requirement Forecast

Line No.	Particulars (PJ)	2019/20	2020/21	2021/22	2022/23	2023/24
1	Space Allocated for Infranchise Use	100.0	100.0	100.0	100.0	100.0
2	Contingency	9.5	9.5	9.5	9.5	9.5
3	General Service	63.4	62.1	62.0	61.7	61.9
4	Contract	5.8	5.6	5.7	5.8	5.5
5	T-Service/Unbundled	14.1	15.6	15.6	15.6	15.6
6	Infranchise Storage Requirement	92.7	92.7	92.8	92.6	92.5
7	Excess Utility Space Available for Sale	7.3	7.3	7.2	7.4	7.5

[38] EB-2005-0551, Decision with Reasons, November 7, 2006
[39] EB-2007-0724/0725, Decision with Reasons, April 29, 2008

Since Union North is not physically connected to EGI's Dawn storage facilities, EGI is required to manage storage through services purchased from TCPL, including by:

- Using TCPL STS injections, which allow EGI to transport excess supply away from Union North to Parkway to be injected into Dawn storage in the summer;
- Using TCPL STS withdrawals and the Enhanced Market Balancing service in the winter months to serve weather-driven demands. Gas is withdrawn from Dawn storage throughout the winter and is transported to Union North; and,
- Using contractual STS pooling rights to aggregate all of the Union rate zones' STS rights to serve the Union North delivery areas collectively. This provides EGI with the flexibility to serve certain delivery areas in Union North with gas service in excess of the STS rights specific to individual delivery areas.

12.5 Unutilized Capacity

In Union North, 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 Union South, upstream pipeline capacity flows 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 26 illustrates the total planned UDC by rate zone.

Table 26 – Union Planned UDC

Line No.	Particulars (PJ)	2019/20	2020/21	2021/22	2022/23	2023/24
1	North West	12.0	12.4	13.1	14.4	14.3
2	North East	6.5	6.1	5.3	3.4	3.7
3	South	-	-	-	-	-
4	Total Planned UDC	18.6	18.5	18.4	17.8	18.0

13. Union Rate Zones: Supply Option Analysis

Please refer to Section 6 for a detailed description of the criteria used to evaluate supply options for the Union rate zones.

13.1 Design Day Analysis

A design day shortfall occurs when there is more demand than supply 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 in question and assesses all viable alternatives. If there are no constraints in the delivery area or risk to the future availability of capacity, transportation will be acquired on a short term basis. Contracting for one year 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).

Union North

The Union North demand and supply balance which identifies EGI's design day position is outlined in Table 27. The forecast shows a 1 TJ/d shortfall every year in the North West, which is specific to the Union WDA. Transportation is acquired on a short term basis through TCPL's existing capacity open season process. EGI has a 3 TJ/d shortfall in the Union North East rate zone starting in 2021/22 specific to the Union EDA which is forecast to grow to 5 TJ/d by 2023/24. This shortfall results from growth in the Union EDA market and requires the procurement of firm transportation.

Table 27 – Union North Design Day Excess/Shortfall

Line No.	Particulars (TJ/day)	North West 2019/20	2020/21	2021/22	2022/23	2023/24	North East 2019/20	2020/21	2021/22	2022/23	2023/24
	Demand										
1	Union North*	130	129	129	128	128	403	400	408	408	411
	Supply										
2	Empress	78	78	78	78	78	4	4	4	4	4
3	Dawn	-	-	-	-	-	67	67	67	67	67
4	Nexus	-	-	-	-	-	53	53	53	53	53
5	North Dawn T-Service	-	-	-	-	-	33	33	33	33	33
6	Redelivery from Storage										
7	*From Parkway*										
8	STS Withdrawals	31	31	31	31	31	81	82	88	88	88
9	STS Pooled Withdrawals	-	-	-	-	-	21	17	16	15	17
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	18	18	18	-	-	-	-	-
14	Total Supply	128	128	128	127	127	403	400	406	405	406
15	Excess(Shortfall)	-1	-1	-1	-1	-1	0	0	-3	-4	-5

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

Union WDA

Supply Options

The supply options to serve the WDA are limited to TCPL Mainline as it is the only pipeline to serve this delivery area as illustrated in Figure 34. The volumes delivered are not material enough to support the construction of new infrastructure to encourage new sources of supply to the WDA.

Figure 34 – Supply Option to Serve WDA

Preferred Planning Strategy

EGI's preferred planning strategy is to continue to procure firm long-haul transportation from TCPL through existing capacity open seasons on a short term basis. Contracting for one year at a time gives EGI the flexibility to adjust the contracted pipe as planned requirements may change when updating the annual design day forecast. EGI evaluates the risk in contracting for existing capacity annually and if the availability of existing capacity is at risk, EGI will evaluate alternative options (e.g. requesting multi-year transportation contract terms with renewal rights).

Union EDA

As noted above, Union North East is forecast to be in a shortfall position starting in 2021/22 as a result of growth in the Union EDA. The Union EDA is currently constrained downstream of Parkway and EGI is evaluating options to meet long term design day demands. The sustained nature of forecast growth in the Union EDA, coupled with the constrained nature of the area, may require EGI to enter into a contract with a longer term in order to meet future demand.

Supply Options

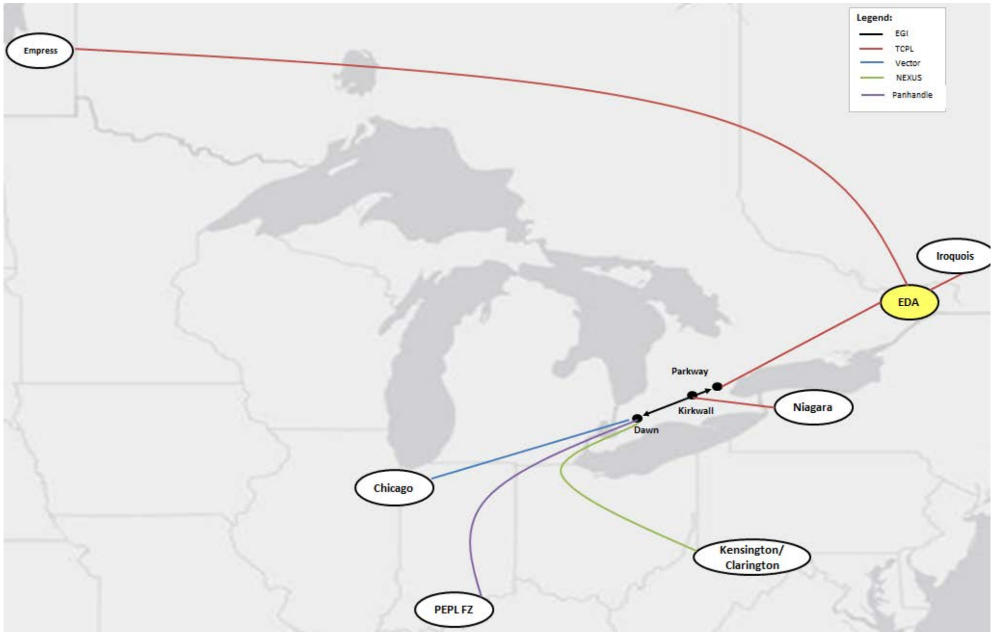
Table 28 below provides a list of options which are expected to be available to EGI[40] at various times over the next five years. Figure 35 provides a representative map for the paths of the supply options.

Table 28 – Union EDA Supply Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Short-haul-Dawn	EGI + TCPL	D-P + FT-SH	Dawn	Parkway	Union EDA
Short-haul-Niagara	TCPL	FT-SH	Kirkwall	-	Union EDA
Long-haul	TCPL	FT-LH	Empress	-	Union EDA
Short-haul-Iroquois	TCPL	FT-SH	Iroquois	-	Union EDA

[40] The list of options in Table 28 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 temporary phenomenon.

Figure 35 – Union EDA Supply Options Map



Evaluation Matrix

Each of the options outlined in Table 28 above were evaluated for their reliability, flexibility, diversity and landed costs, as described at the beginning of Section 6. Table 29 summarizes the analysis.

Table 29 – Union EDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($/GJ)	Average Cost/Customer Impact[41]
Short-haul-Dawn	↑	→	→	$5.96	< 1%
Short-haul-Niagara	↓	→	↑	$4.78	< 1%
Long-haul	↑	→	↑	$6.31	< 1%
Short-haul-Iroquois	↑	→	↑	$6.47	< 1%

For reference, the symbols in Table 29 describe whether or not 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.

At this time, it is unknown what transportation option will be available to the Union EDA beginning in 2021 as all incremental transportation options could require a facilities build. Transportation contracts supporting a facility build would require a term of 15 years in addition to the 3 to 4 years of lead time to allow for construction, limiting contracting flexibility.

[41] Average cost per customer impact is for typical sales service customers consuming 2,200 m^3 annually. Estimated costs are derived based on sales service volumes for each Union rate zone for the respective period. The impact for bundled DP customers varies from sales service customers as they procure their own supply.

All of the transportation options noted above would increase reliability by providing additional firm transportation into the Union EDA. TCPL long-haul transportation would source gas at Empress providing diversity. Short-haul transportation from Dawn increases diversity because Dawn gas is sourced from a variety of different basins (e.g. Chicago, Appalachia and U.S. midcontinent) with multiple counterparties to transact with. Transportation from Niagara would increase supply diversity, however EGI has noted a lack of liquidity in the Niagara market with negative impacts for reliability in procuring supply. Transportation from Iroquois would increase diversity as this would be a new supply point. The Iroquois trading point has been identified as having neutral impact to flexibility because it is volatile and not a major trading hub. EGI intends to further explore the impact of transacting at this point.

Preferred Planning Strategy

EGI is in the early stages of evaluating transportation options to the Union EDA to meet this shortfall. Given that the growth in the EDA is not forecast to result in a shortfall until 2021/22, options will be evaluated within the context of the post-2020 TCPL Mainline toll negotiations and a decision will be made in conjunction with any other TCPL contract changes contemplated as part of broader negotiations.

Union South

EGI's Union South rate zone design day demand to supply position is outlined below in Table 30. EGI currently forecasts no excess or shortfall in the Union South rate zone over the term of the Plan.

Table 30 – Union South Design Day Position

Line No.	Particulars (TJ/day)	2019/20	2020/21	2021/22	2022/23	2023/24
	Demand					
1	Union South*	3,108	3,139	3,265	3,314	3,344
	Supply					
2	Empress	3	3	3	3	3
3	Nexus	106	106	106	106	106
4	Non-obligated (e.g. Power Plants)	270	270	270	270	270
5	Ontario Dawn	548	549	641	643	645
6	Ontario Parkway	225	225	222	220	226
7	Panhandle	60	60	60	60	60
8	TCPL Niagara	21	21	21	21	21
9	Vector	84	84	84	84	84
10	Redelivery from Storage	1,790	1,821	1,858	1,907	1,928
11	Total Supply	3,108	3,139	3,265	3,314	3,344
12	Excess(Shortfall)	-	-	-	-	-

* includes Sales Service, Bundled DP, T-Service

13.2 Average Day Requirement

Beyond forecasting design day it is also important for EGI to understand the average day demand requirements within the Union rate zones, as this can help to inform EGI's approach to procuring supply throughout the year. EGI has the opportunity to purchase supply at Dawn or upstream of Dawn and transport it into the Union rate zones.

Consistent with the annual demand forecast developed by EGI found in Section 11.1, Table 31 below shows both the annual and average day demand growth expected over the five year period of the Plan.

Table 31 – Union Rate Zones Average Day Demand Analysis for Sales Service Customers

Line No.	Particulars (TJ)	2019/20	2020/21	2021/22	2022/23	2023/24	Growth 2020 → 2024
1	Annual Demand	180,093	178,656	178,204	177,725	178,292	(1,801)
2	Daily Demand	493	489	488	487	488	(5)

As Table 31 shows, the Union rate zones' demand is expected to fall 1,801 TJ over the five years, or roughly 5 TJ/d of average day demand. As a result, EGI does not plan to procure additional gas supply assets to serve annual demand changes. However, a supply option analysis for average day requirements will be presented below.

Supply Options

The Union rate zones' Plan assumes the following transportation capacities are utilized at a 100% load factor:

- Niagara Short Haul = 21,101 GJ/d
- Vector = 80,000 Dth/d (or 84,405 GJ/d)
- Panhandle = 57,000 Dth/d (or 60,138 GJ/d)
- NEXUS = 150,000 Dth/d (or 158,259 GJ/d)

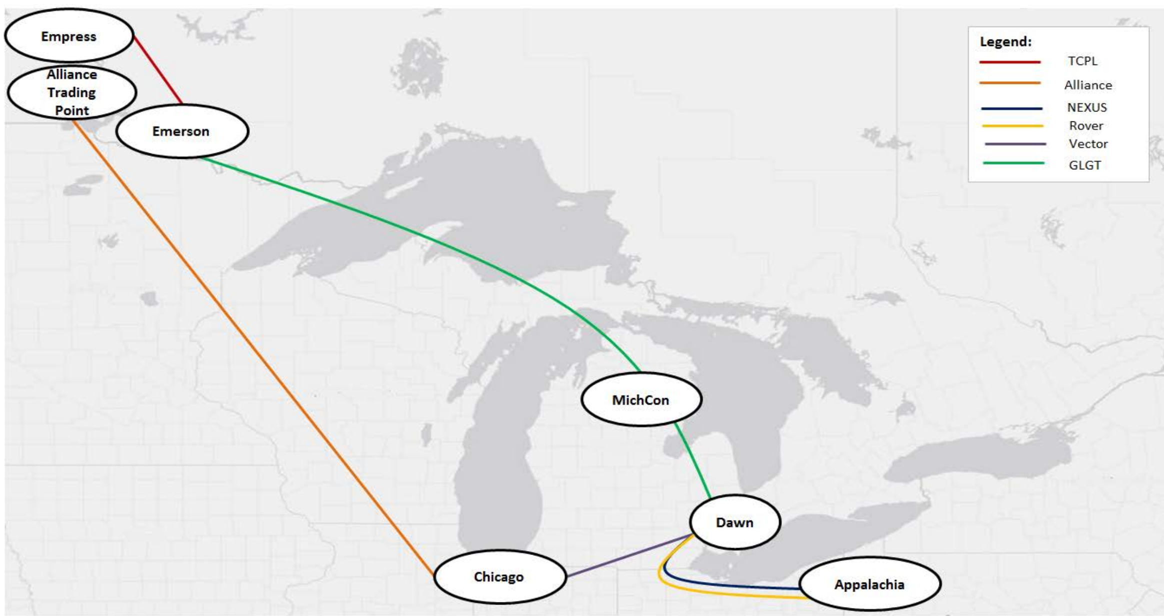
With each of the above transportation capacities planned to be 100% utilized moving supply to the distribution system or into storage, existing transportation capacity that is connected directly to Dawn and EGI storage assets, such as capacity on the Dawn Parkway System and short haul capacity on TCPL Mainline, is sufficient to meet growth in average day demand. Therefore, managing average day demand changes by purchasing the commodity at Dawn is possible without the acquisition of additional transportation assets because of the sufficient capacity that exists on all days that are not design day. However, it is important to investigate if contracting for additional transportation assets upstream of Dawn will provide the Union rate zones with additional reliability, flexibility, diversity and cost effectiveness.

Table 32 below provides a list of options which are expected to be available to EGI[42], at various times over the five year period. Figure 36 provides a representative map for the paths of the supply options.

Table 32 – Union Rate Zones Average Day Growth Supply Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Dawn Spot	N/A	N/A	Dawn	-	Dawn
TCPL & GLGT	TCPL + GLGT	FT-LH + FT	Empress	Emerson	Dawn
GLGT	GLGT	FT	MichCon	-	Dawn
Alliance & Vector	Alliance + Vector	FFPS + FT-1	Alliance Trading Point	Chicago	Dawn
Vector	Vector	FT-1	Chicago	-	Dawn
NEXUS	NEXUS	FT	Dominion	-	Dawn
Rover	Rover	FT	Dominion	-	Dawn

Figure 36 – Union Rate Zones Average Day Growth Supply Options Map



Evaluation Matrix

Each of the options outlined in Table 32 above were evaluated for their: reliability, flexibility, diversity and landed costs, as described at the beginning of Section 6. Table 33 summarizes the analysis.

[42] The list of options in Table 32 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 average day demand growth. One example of an option not listed is procurement of supply from Texas' Permian Basin. This option is not included in the analysis because supply from the Permian Basin would result in significant transportation costs (i.e. poor cost-effectiveness). In the future should Permian Basin supply become more cost-effective then it will be included.

Table 33 – Union Rate Zones Average Day Growth Supply Options: Evaluation Matrix

Option	Relative to Status Quo			Costs ($/GJ)	Average Cost/Customer Impact – Relative to Status Quo [43]
	Reliability	Flexibility	Diversity		
Dawn Spot	↑	↑	→	3.36	-
TCPL & GLGT	↑	→	→	3.25	< 1%
GLGT	↑	→	↑	3.36	< 1%
Alliance & Vector	→	↓	↑	3.33	< 1%
Vector	↑	→	→	3.54	< 1%
NEXUS	↑	→	→	3.80	< 1%
Rover	↑	→	↑	3.81	< 1%

For reference, the symbols in Table 33 describe whether or not 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

Taking into consideration the discussion above, EGI's preferred planning strategy to manage average day demand growth is through Dawn purchases for each year over the term of the Plan, evaluating alternatives on an ongoing basis.

In terms of reliability, Dawn purchases are among the most reliable options for commodity supply given that purchases are made directly at Dawn, one of the most liquid supply hubs in North America, can be used to serve Union South, can be nominated to Union North East via TCPL Mainline at Parkway, and/or can be injected into storage.

Purchasing at Dawn is also flexible as it provides pipeline quality gas, is available every trading day of the year, allows for multiple terms, and no long term contract is required.

In considering diversity, Dawn is the largest integrated underground storage facility in Canada and is one of North America's most liquid natural gas trading hubs with access to multiple supply basins.

EGI recognizes that a balance must be struck between Dawn purchases and the principle of having diversity of supply. Given that Dawn purchases are readily available and do not require the procurement of additional assets, EGI's preferred planning strategy is to consider incremental Dawn purchases while evaluating alternatives each year.

[43] Average cost per customer impact is for typical sales service customers consuming 2,200 m^3 annually. Estimated costs are derived based on sales service volumes for each Union rate zone for the respective period. There is no impact for bundled DP customers as they procure their own supply and transportation to Dawn.

13.3 Expiring Contracts

The following table outlines EGI's contracts specific to the Union rate zones that are expiring within the term of the Plan. These contracts have been organized into categories for the purpose of the analysis that follows.

Category	Path	Pipeline	Contract Quantity		Expiry Date
Sarnia Integrity	Chicago to US/Cdn Border	Vector	80,000	DTH	31-Oct-22
Sarnia Integrity	US/Cdn Border to Dawn	Vector	84,404	GJ	31-Oct-22
Sarnia Integrity	Bluewater/Intl Border to Bluewater/Intl Border	St.Clair Pipelines L.P. (Bluewater Pipeline)	127,000	GJ	31-Oct-23
Sarnia Integrity	St.Clair/Intl Border to St.Clair/Intl Border	St.Clair Pipelines L.P. (St.Clair Pipeline)	214,000	GJ	31-Oct-23
TCPL	Dawn to Union ECDA	TCPL	8,000	GJ	31-Oct-21
TCPL	Empress to Centrat MDA	TCPL	4,522	GJ	31-Oct-21
TCPL	Empress to Centrat MDA	TCPL	1,043	GJ	31-Oct-21
TCPL	Empress to Union ECDA	TCPL	3,000	GJ	31-Oct-21
TCPL	Empress to Union NCDA	TCPL	1,412	GJ	31-Oct-21
TCPL	Empress to Union NDA	TCPL	4,442	GJ	31-Oct-21
TCPL	Empress to Union SSMDA	TCPL	2,700	GJ	31-Oct-21
TCPL	Empress to Union SSMDA	TCPL	6,143	GJ	31-Oct-21
TCPL	Empress to Union SSMDA	TCPL	12,800	GJ	31-Oct-21
TCPL	Empress to Union WDA	TCPL	39,880	GJ	31-Oct-21
TCPL	Empress to Union WDA	TCPL	11,527	GJ	31-Oct-21
TCPL	Empress to Union EDA	TCPL	1,089	GJ	31-Oct-22
TCPL	Niagara to Kirkwall	TCPL	21,101	GJ	31-Oct-22
TCPL	Dawn to Union SSMDA	TCPL	35,022	GJ	31-Oct-24
TCPL	Parkway to Union EDA	TCPL	30,000	GJ	31-Oct-24
TCPL	Parkway to Union EDA	TCPL	5,000	GJ	31-Oct-24
TCPL	Parkway to Union EDA	TCPL	26,351	GJ	31-Oct-24
TCPL	Parkway to Union NCDA	TCPL	13,704	GJ	31-Oct-24
TCPL	Parkway to Union NDA	TCPL	48,375	GJ	31-Oct-24
TCPL	Parkway to Union WDA	TCPL	31,420	GJ	31-Oct-24
TCPL	Union EDA to Parkway	TCPL	1,000	GJ	31-Oct-24
TCPL	Union NDA to Parkway	TCPL	49,100	GJ	31-Oct-24
TCPL	Union WDA to Parkway	TCPL	3,150	GJ	31-Oct-24

Sarnia Integrity

The Sarnia in-franchise market is one of the largest petrochemical and refined petroleum manufacturing areas in North America and requires substantial and increasing natural gas flow all year round. The market also serves two large combined cycle natural gas fired power generation plants: TransAlta Sarnia and St. Clair Sarnia. These plants have the ability to quickly fluctuate market demand on short notice based on gas generators' ability to quickly ramp up electricity production.

The Sarnia Industrial Line system connects directly to one of EGI's storage pools, GLGT and Vector, and MichCon and Bluewater via St. Clair Pipeline interconnects. EGI holds transportation contracts on St. Clair Pipeline to facilitate moving gas from MichCon and Bluewater to EGI.

EGI currently flows gas supplies along the Vector and MichCon pipelines. These supplies are not sufficient to meet the Sarnia market's design day in the winter. EGI relies on storage withdrawals and third party gas flowing on Vector and GLGT to supply this substantial market.

In the summer, in addition to the MichCon and Vector supplies, EGI also has the option to feed Sarnia via the Sarnia Expansion Project which connects EGI's Payne pool to the Sarnia system. The Sarnia Expansion Project (EB-2014-0333) was purpose-built to provide security of supply for the current Sarnia market. In the winter, EGI has a limited number of days available to backstop the Sarnia market with this connection based on the length of the time required to empty the Payne pool.

Supply Options

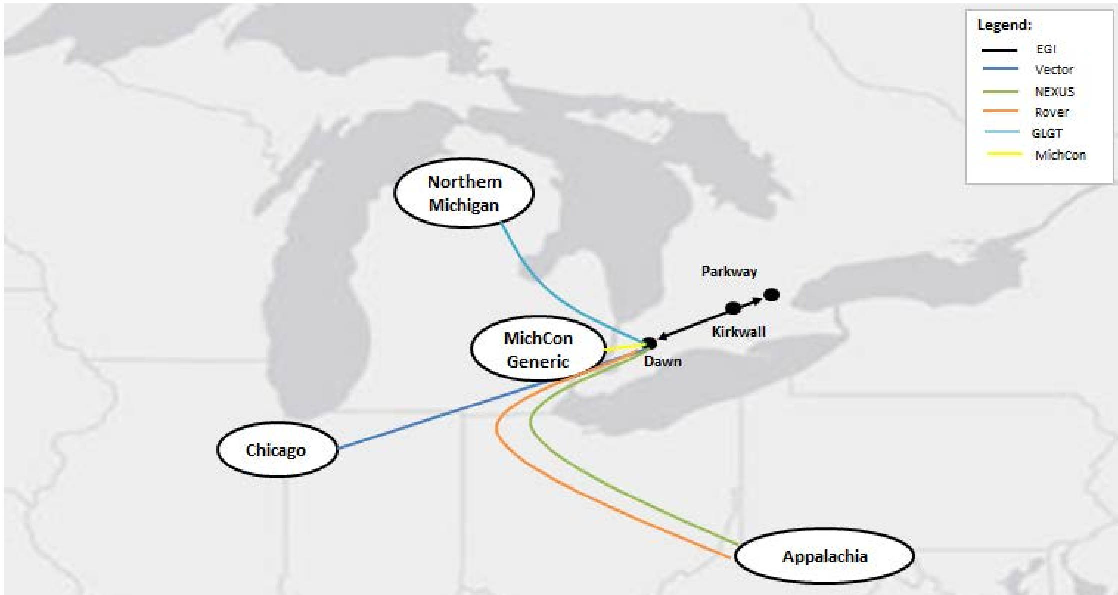
Table 34 below provides a list of options which are expected to be available to EGI[44], at various times over the next five years. Figure 37 provides a representative map of the paths relevant to the supply options listed in Table 34.

Table 34 – Union South Supply Options for Sarnia Customers

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Vector	Vector	FT	Chicago	Courtright	Union South
NEXUS	NEXUS	FT	Dominion	Courtright	Union South
Rover	Rover	FT	Dominion	Courtright	Union South
MichCon	St. Clair Pipelines	FT	MichCon	St. Clair Line Station	Union South
GLGT	Great Lakes	FT	Northern Michigan	GLC Sarnia	Union South

[44] The list of options in Table 34 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. Supply options that do not intersect the Sarnia Industrial Line, including Dawn, Panhandle Eastern, TCPL long-haul and Niagara are not practical due to system constraints.

Figure 37 – Union South Supply Options for Sarnia Customers Map



Evaluation Matrix

Each of the options outlined in Table 34 above were evaluated for their reliability, flexibility, diversity and landed costs, as described at the beginning of Section 6. Table 35 summarizes the analysis.

Table 35 – Union South Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($/GJ)	Average Cost/Customer Impact – Relative to Status Quo [45]
Vector	positive	positive	neutral	4.73	-
NEXUS	positive	positive	negative	4.01	< -1%
Rover	positive	neutral	neutral	4.19	< -1%
MichCon	neutral	neutral	neutral	4.63	> -1%
GLGT	positive	neutral	neutral	4.74	-

For reference, the symbols in Table 35 describe whether or not a particular option has a: positive, neutral, or negative impact on the ability of the option to renew Sarnia contracts as compared to the current portfolio.

Vector Pipeline

EGI's Vector contracts specific to the Union rate zones expire on October 31, 2022 and can be extended for three years with 1 year's notice. These are firm transportation contracts, consistent

[45]Average cost per customer impact is for typical sales service customers consuming 2,200 m^3 annually. Estimated costs are derived based on sales service volumes for each Union rate zone for the respective period. There is no impact to bundled DP customers as they procure their own supply and transportation to Dawn.

with the Board's guiding principle of ensuring secure and reliable gas supply to EGI's service territory. Vector provides EGI delivery optionality within the path, including the Sarnia Industrial Line, and sources supply from Chicago. Chicago is a liquid market hub that receives competing gas supplies from the WCSB, the U.S. Midwest, Appalachia, Gulf and the U.S. Rockies basins. As such procuring supply at Chicago supports EGI's objective of diversity of supply basins, which in turn can assist EGI in adhering to the Board's guiding principles of both cost-effectiveness and security and reliability of supply.

Vector Replacement Options

Alternatives to Vector Pipeline capacity include NEXUS, Rover, GLGT, Michcon/St.Clair River Crossing and the Bluewater River Crossing. All options, except for the Bluewater River Crossing could offer firm transportation service consistent with the Board's guiding principles of ensuring secure and reliable gas supply to EGI's service territory at a reasonable cost. Both the NEXUS and Rover pipelines have made contractual arrangements to bring supply to Dawn on the Vector pipeline. As a result, transportation contracts on NEXUS and Rover that utilize Vector effectively provide the same benefit to the Sarnia market as Vector transportation.

NEXUS and Rover receive gas supplies from Appalachia which supports EGI's objective of diversity of supply basins. MichCon is also a liquid market hub that receives gas supplies from the WCSB, the U.S. Midwest, Appalachia, Gulf and the U.S. Rockies basin which supports EGI's objective of diversity of supply basins. GLGT provides flexibility to access supply points including Emerson, Farwell and Crystal Falls. Capacity on this path could also be utilized to serve requirements in the Union SSMDA and to access storage in Michigan. GLGT has an ongoing open season for capacity from Emerson to St. Clair interconnect.

Other Transportation Supporting Sarnia Market

The Bluewater and St. Clair River Crossings are used by EGI to provide a benefit to the Sarnia system. The Bluewater River Crossing interconnects upstream with Bluewater Gas Storage, and the St. Clair River Crossing interconnects with the MichCon system and provides a path for NEXUS supply to enter the EGI system from Michigan. EGI utilizes both the Bluewater River Crossing and the St. Clair River Crossing capacity, not utilized by NEXUS supply, in conjunction with other assets to market transportation services which help offset costs. Both paths serve to improve security of supply in the event of an emergency and enhances competition at Dawn.

Preferred Planning Strategy

The associated options to replace or renew Vector contracts will be reviewed again closer to the expiry date as options can change depending on the market conditions at that point in time. At this time, EGI's preferred planning strategy is to exercise the right to renew capacity on Vector, St. Clair, and Bluewater.

TCPL

As noted in Section 6 above, in 2018 TCPL formed the Post-2020 Working Group, which includes TCPL and a subset of TTF members, with the purpose of discussing and collaborating on the regulatory construct of the Mainline for post-2020 (the current tolling framework of the Mainline Settlement Agreement expires on December 31, 2020[46]). It is generally anticipated that the toll structure and regulatory framework for the Mainline will be different than it has been for the 2015 to 2020 period. The post-2020 Mainline regulatory framework may result in changes to services, tolls, delivery areas and cost allocation resulting in a number of risks for EGI including less flexibility, higher costs and the requirement for a revised gas supply plan compared to what is planned today. However, at this time EGI cannot estimate what the impacts may be. The contracts mentioned above will be considered as part of the overall post-2020 contract negotiations. The decision to retain these contracts will be made in conjunction with all other TCPL contract changes as part of the broader negotiations.

Preferred Planning Strategy

EGI is planning to exercise its right to renew all existing TCPL contracts in the Plan as no further information is available at this time. As the deadline to renew gets closer, a complete supply option analysis will be completed in order to make the most appropriate decision for ratepayers.

13.4 Summary of Supply Option Analysis

As is the case in the EGD rate zone, EGI's approach to diversifying the Union rate zones' 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 the Union rate zones, EGI utilizes capacity on multiple upstream pipelines to access several supply basins or market hubs. These pipelines provide access to supplies in Western Canada, Chicago, Dawn, Niagara and Appalachia.

As part of its ongoing process, EGI will continue to evaluate the portfolio for the Union rate zones to ensure it meets the needs identified in the Plan, balancing the guiding principles set forth by the Board 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 for the Union rate zones include:

- Design day
  - Union WDA – continue to acquire TCPL long-haul capacity
  - Union EDA – evaluate options as part of the TCPL post-2020 negotiations
- Average day

[46] RH-001-2014, Reasons for Decision, December 18, 2014

    - Purchase supply at Dawn to manage average day growth
- Transportation contracts renewals
    - Renew existing transportation contracts on an annual basis

14. Union Rate Zones: Risk Mitigation Analysis

The Union rate zones' portion of the Plan is developed using forecasts that are underpinned by assumptions based on the best available information at that time. Since forecasts in the Plan will be different from the actual experience, there are inherent risks in the Plan in addition to the risk of unforeseen events.

These risks include:

1. Variation to planned assumptions
    - Weather variation
    - Demand forecast variation
    - Price variation
2. Supply interruption
3. Transportation interruption

14.1 Variation to Planned Assumptions

Weather Variation Risk

EGI assumes normal weather when developing annual demand forecasts for the Plans. However, normal weather is an expectation based on a trend, and it is expected that weather will vary from that trend each year. Temperatures can be colder which generally drives higher demand and market prices, or it can be warmer which generally drives lower demand and market prices.

Demand Forecast Variation Risk

Annual Demand Variation

As mentioned in Section 11.1, there are risks associated with generating the annual demand forecast relating to weather normal HDD forecast, average use, contract market growth, and number of customers.

Design Day Demand Variation

As mentioned in Section 11.2, EGI bases design day demand on the coldest observed day in each delivery area and procure firm assets to meet those demands for the Union rate zones. This statistical condition sets the weather conditions that will yield the highest day of demand in each year of the plan. In order to manage the risks around weather volatility and its impact on demand, EGI contracts for sufficient transportation capacity to meet its design day demand forecast. This results in all days of the year when design demand is not achieved; sufficient assets exist to deliver supply to the distribution system. See Section 15 for a description of how EGI executes its Plan when demand activity deviates from the plan.

Pricing Variation Risk

Market prices are driven by both local market conditions, such as weather, and the operation of the broader North American natural gas market. EGI is a price-taker and its procurement of supply is subject to prevailing market conditions which can vary significantly from location-to-location on a daily basis.

Given the risk of price changes, EGI's Plan maintains diversity and flexibility in its commodity purchase plan. This is achieved by making purchases at multiple locations (e.g. AECO, Empress, Niagara, Chicago, Dawn, Appalachia), for a variety terms (e.g. annual, seasonal, monthly, weekly, daily) executed at different times throughout the year.

Scenario Analysis

In order to illustrate the potential for weather volatility and its impact on demands, pricing, and portfolio costs, EGI engaged ICF to conduct an analysis to provide some insight into possible weather variation outcomes.

ICF conducted an analysis that used the weather patterns from its 84-year history of weather conditions to simulate natural gas demand for North America for the period of April 2019 to March 2022, and subsequently assessed the resulting price responses experienced in the North American natural gas market. ICF conducted sensitivity analyses which allowed for natural gas prices to increase and decrease based on the weather experiences in North America over an 84-year period, ultimately providing EGI with "high" and "low" price scenarios. Based on ICF's analysis the high price scenario corresponds with the weather pattern experienced from 1977 to 1980, whereas the low price scenario corresponds with the weather pattern experienced during the 2010 to 2013 period. Please see Appendix E for a copy of the report ICF has prepared.

Using ICF's high price and low price scenario time periods as a basis, EGI used its own weather zone experiences for the scenario years identified and simulated the Union rate zones' demand for the 2020 to 2022 period. With simulated demand and forecasted prices, EGI substituted these values into SENDOUT to generate a possible range of potential costs to the upstream portfolio. ICF provided three years of commodity prices and EGI analyzed the SENDOUT results for all three years. Summarized below are the most significant one-year deviations in cost relative to the Plan.

	Rate Zone	Demand (% Change in Vol)	Portfolio Cost (% Change in Portfolio Cost)
High Price	Union North West	+14%	+35%
	Union North East	-	+39%
	Union South	+7%	+46%
Low Price	Union North West	-5%	-31%
	Union North East	-15%	-11%
	Union South	-10%	-33%

Every year the Plan will be faced with demand and price volatility which is why EGI employs a strategy of procuring supply from multiple supply basins and price hubs, staggering the terms and timing of supply deals, in order to cost-effectively and reliably manage supply procurement. Specifically, when executing the Plan for the Union rate zones, EGI routinely reviews and analyses the prevailing weather conditions and demand patterns, and performs in-season forecasts of demand that take into consideration up-to-date weather forecasts. These in-season demand forecasts provide EGI with updated short-term expectations of demand that help to inform whether or not EGI may need to make changes to its short-term gas supply procurement strategy. See Section 15.1 for more details on the execution of the Plan within the Union rate zones.

Beyond diversifying procurement across multiple points and using multiple terms, storage capacity manages weather volatility by allowing EGI to inject excess gas supply if demands are low when commodity prices tend to be lower and less volatile, and withdraw the stored supply when demands increase and prices tend to be higher and more volatile.

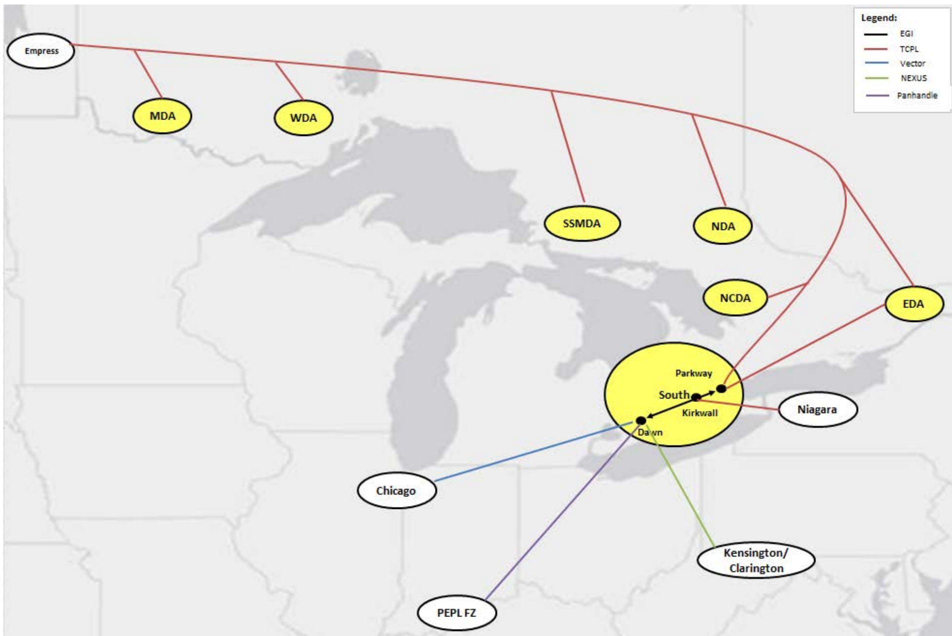
14.2 Supply Interruption Risk

The strategy EGI utilizes to limit the risk of supply being interrupted is to contract for supply with creditworthy counterparties and to procure supply at liquid supply points which have numerous counterparties. These practices are consistent with EGI's procurement policy referenced in Section 15.1.

14.3 Transportation Interruption Risk

EGI mitigates the risks associated with transportation service interruptions in multiple ways. One practice is to contract and procure transportation capacity with regulated upstream service providers, such as TCPL, Vector, and NEXUS, which themselves have numerous risk mitigation policies underpinning their operations. Another practice is to contract for firm transportation services with the upstream service providers instead of interruptible or non-firm services. In doing so, the firm services guarantee the ability to schedule supply, as only during a force majeure would service be interrupted. Further, EGI's portfolio of upstream transportation contracts includes a diverse mix of transportation providers, so if one transportation provider was to experience a force majeure event, EGI has the flexibility to change the utilization of the unaffected transportation contracts in order to mitigate the downstream impacts. Also, by holding capacity with multiple upstream service providers which are connected to liquid supply hubs, such as Alberta and Dawn, EGI retains the flexibility to contract for short-term services such as interruptible transportation and short term firm transportation, if the need arises. See Figure 38 below for a map depicting the EGI's transportation contracting diversity for the Union rate zones.

Figure 38 - Union Rate Zones' Transportation Path Diversity

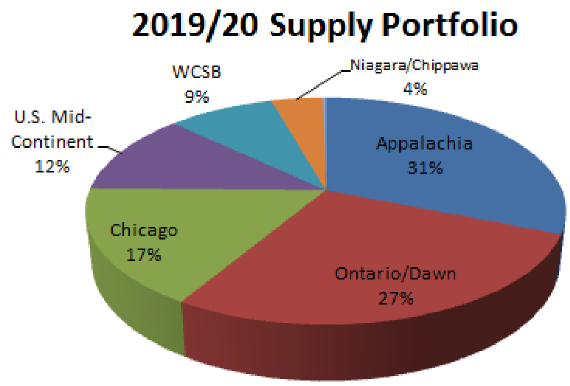


14.4 Summary

EGI manages risk for the Union rate zones by holding a portfolio that supports basin diversity, efficient supply procurement policy, and a variety of transportation contracts with differing parameters to assist EGI in managing market conditions.

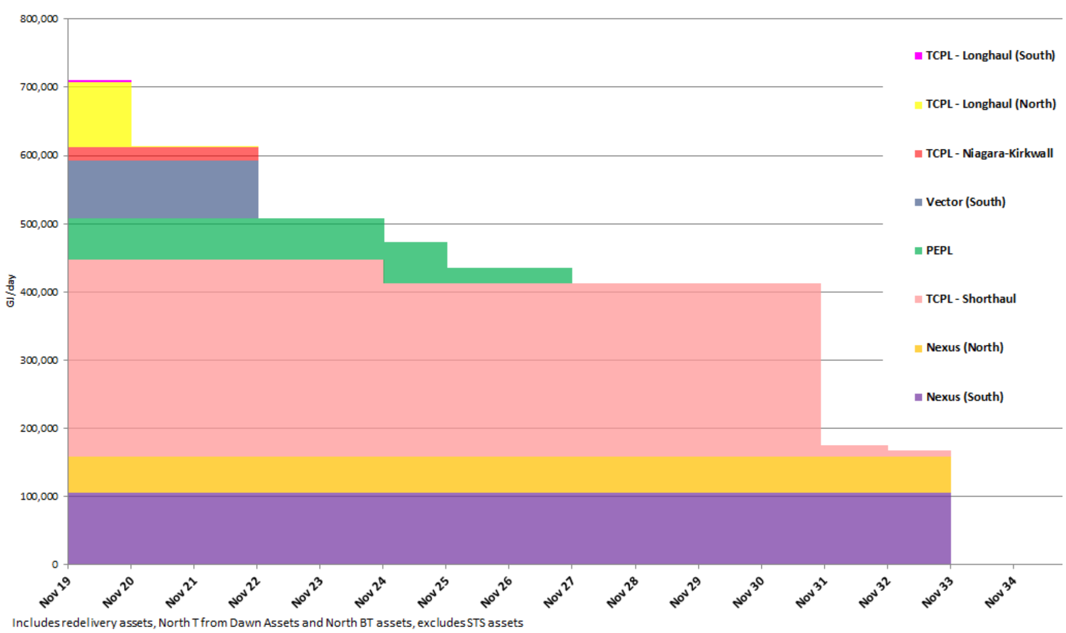
Figure 39 below is the current system supply portfolio which illustrates diversity through supply basins. The current gas supply and transportation portfolios supports three primary production basins: WCSB, Appalachia, U.S. mid-continent, and provides diversity and flexibility from two liquid market hubs: Chicago and Dawn.

Figure 39 – Union Rate Zones' System Supply Portfolio



Depicted in Figure 40 are the transportation contracts to serve the Union rate zones and the corresponding expiry dates, which illustrates that more than 50% of the transportation portfolio is contracted beyond 2030. In order to secure supply and ensure EGI has the assets available to serve demands, certain contracts required a 15 year commitment. EGI is exiting a period of change across the portfolio. Over the past few years EGI has further increased diversity and reliability of its portfolio by shifting from predominantly sourcing supplies in the WCSB and contracting for long-haul transportation on TCPL Mainline to sourcing supply at Dawn and converting to short-haul transportation. In addition, EGI has further diversified its portfolio by contracting for NEXUS capacity sourcing supply in the Appalachian basin. With these changes complete, EGI is now entering a period of increased stability.

Figure 40 – Union Rate Zones' Transportation Expiry Profile



15. Union Rate Zones: Gas Supply Plan Execution

Once the Plan for the Union rate zones has been established, the execution phase takes place. EGI executes the Plan balancing reliability, diversity and flexibility while still achieving a cost-effective solution for ratepayers.

To manage risk, EGI procures supply regularly throughout the year from credit worthy counterparties at multiple trading points using a layered approach with consideration to diversity of delivery term. 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 deviations in demand. These deviations may be a result of weather, usage patterns or other factors that contribute to increases or decreases in customer consumption.

Within each season, EGI frequently monitors actual and forecast customer activity. Decisions related to the continued execution of the Plan are made regularly, during operational planning meetings. These meetings are held throughout the year and the frequency will increase based on the season, weather and market or operational conditions. A diverse, cross-functional team operates with oversight from the Director of Gas Supply to make purchase decisions related to continuing to execute the Plan through gas supply procurement and transportation capacity utilization decisions.

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.

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.

It is expected that the current execution of the Plan for the Union rate zones will evolve over time as EGI begins to realize any synergy benefits of combining the EGD rate zone Plan with the Union rate zones Plan as explained in Section 19.

15.1 Procurement Process and Policy

EGI purchases natural gas for system operations and the regulated system gas supply portfolio for the Union rate zones. The Gas Procurement Policy and Procedures (the “Policy” updated as of August, 2016) was last filed in EB-2016-0296 and addresses the process of securing natural gas supplies for Union rate zones system gas customers.

The Gas Supply department develops the monthly procurement plan. The monthly procurement plan identifies the specific volumes and dates for the transactions to be executed.

EGI's Director of Gas Supply signs 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. Procuring supply throughout the year achieves market representative pricing, while not being unduly influenced by pricing and market dynamics at a specific point in time.

On a planned basis, gas supply is purchased:

- Through a RFP process (written and verbal);
- Primarily based on index price contracts;
- Primarily in the forward market; and
- Primarily on a monthly, seasonal, and annual (or multi-year) basis.

As per the Policy, EGI is authorized to use the following transaction pricing instruments either through the RFP process (written and verbal), electronic gas trading platforms or a brokerage house:

- Fixed price contracts specify purchase of natural gas at a fixed price for a specific term.
- Index price contracts specify purchase of natural gas at a price to be determined in the future for a specific term.
- Price trigger contracts are a hybrid of fixed and index contracts. Initially, the contract is index and EGI has the right to fix the price over the contract term.

EGI purchases gas for Union rate zones from suppliers under a North American Energy Standards Board ("NAESB") contract. EGI has NAESB contracts with over 100 suppliers to be used for Union rate zones' procurement. EGI's gas commodity purchases are influenced by the characteristics and traits of the specific supply points or basins where EGI purchases supplies. Each of these purchase points have different liquidity and supply characteristics.

The Union rate zones' current upstream transportation portfolio and related supply is diversified with respect to supply basin, gas supply producers and marketers, contract term and transportation service provider. EGI's approach to diversifying the portfolio of firm assets is analogous to a prudent investment portfolio where diversity of funds, risk and term are critical to a successful portfolio. In Union South and Union North East, EGI utilizes capacity on multiple upstream pipelines to access several supply basins or market hubs. These pipelines provide access to supplies in Western Canada, the Gulf of Mexico, Chicago, the U.S. mid-continent and Appalachia through Niagara and Dawn. The Plan also includes Dawn purchases as part of the supply portfolio.

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

- Actual and forecast consumption relative to planned consumption for its sales service customers (95% of all 1.5 million customers);
- Seasonal balancing requirements for sales service customers at key control points;
- Weather variances outside of checkpoint balancing for bundled DP customers;

- Changes in supply and balancing requirements as customers move between sales service and bundled DP;
- Unaccounted for gas and compressor fuel variances; and
- Supply or pipeline disruptions – planned or unplanned.

16. Union Rate Zones: 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.

16.1 Heating Degree Days

Line No.	Particulars (HDD)	2015/16 Actual	2015/16 Plan	2015/16 Variance	2016/17 Actual	2016/17 Plan	2016/17 Variance	2017/18 Actual	2017/18 Plan	2017/18 Variance
1	Union North West	4,392	4,930	-11%	4,535	4,425	2%	5,064	4,918	3%
2	Union North East	4,612	4,930	-6%	4,794	4,918	-3%	5,479	4,918	11%
3	Union South	3,321	3,780	-12%	3,386	3,782	-10%	3,921	3,779	4%

The above table outlines the weather activity in Union rate zones over the past 3 years. The Plan HDDs are based on normal weather. Gas years 2015/16 and 2016/17 were warmer than normal and 2017/18 was slightly colder than normal.

16.2 Demand Forecast

The purpose of this section is to provide a brief review of the prior three years, comparing the demand forecast underlying each Plan to the actual throughput volume.

Line No.	Particulars (TJ)	2015/16 Actual	2015/16 Plan	2015/16 Variance	2016/17 Actual	2016/17 Plan	2016/17 Variance	2017/18 Actual	2017/18 Plan	2017/18 Variance
	Union North West									
1	General Service	12,433	14,684	(2,251)	13,124	13,993	(869)	14,765	13,420	1,345
2	Contract	1,851	3,004	(1,152)	1,943	3,160	(1,217)	2,861	2,022	839
3	Total Union North West	14,284	17,688	(3,404)	15,067	17,154	(2,086)	17,626	15,442	2,184
	Union North East									
4	General Service	33,312	37,060	(3,748)	34,595	36,933	(2,338)	38,849	36,834	2,015
5	Contract	3,581	3,821	(240)	3,741	4,038	(297)	4,019	3,879	140
6	Total Union North East	36,893	40,881	(3,988)	38,337	40,971	(2,635)	42,868	40,713	2,155
	Union South									
7	General Service	146,702	164,076	(17,374)	152,298	164,897	(12,599)	176,087	161,379	14,708
8	Contract	45,285	49,777	- 4,491	48,155	45,426	2,730	51,808	49,350	2,458
9	Total Union South	191,988	213,853	(21,865)	200,454	210,323	(9,869)	227,895	210,729	17,166
10	Total Union Forecast Demand	243,165	272,421	(29,256)	253,858	268,448	(14,590)	288,389	266,883	21,506

2015/16 – Warmer than normal weather decreased demand below budget

2016/17 – Warmer than normal weather decreased demand below budget

2017/18 – Colder than normal weather increased demand above budget

16.3 Commodity Portfolio

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

Line No.	Particulars (TJ)	2015/16 Actual	2015/16 Plan	2015/16 Variance	2016/17 Actual	2016/17 Plan	2016/17 Variance	2017/18 Actual	2017/18 Plan	2017/18 Variance
	Union North West									
1	WCSB	42,077	44,432	(2,355)	13,272	12,678	595	15,487	11,343	4,144
2	Ontario/Dawn			-			-	3,293		3,293
3	Total North West Supply	42,077	44,432	(2,355)	13,272	12,678	595	18,780	11,343	7,437
	Union North East									
4	Appalachia			-			-	-	3,218	(3,218)
5	Chicago			-	17,894	19,255	(1,361)	8,016	16,037	(8,021)
6	Ontario/Dawn			-	6,484	8,013	(1,528)	20,936	7,326	13,610
7	WCSB			-	7,074	4,383	2,691	4,545	4,781	(236)
8	Total North East Supply	-	-	-	31,452	31,651	(199)	33,497	31,362	2,135
	Union South									
9	Appalachia	7,723	7,723	0	-	-	-	-	6,436	(6,436)
10	Chicago	38,220	40,568	(2,348)	40,087	40,689	(602)	32,365	24,329	8,036
11	Local Production	318	533	(215)	367	465	(98)	638	465	173
12	Niagara	6,431	7,723	(1,292)	7,702	7,702	0	7,553	7,702	(149)
13	Ojibway	-	-	-	7,702	7,702	0	7,702	7,702	0
14	Ontario/Dawn	5,528	8,972	(3,444)	19,397	30,570	(11,173)	48,139	47,070	1,069
15	U.S. Mid-Continent	38,127	47,142	(9,015)	44,633	45,056	(423)	48,030	42,345	5,685
16	WCSB	21,164	20,636	528	6,002	4,585	1,417	1,095	1,095	-
17	Total South Supply	117,511	133,297	(15,786)	125,890	136,769	(10,879)	145,522	137,144	8,378
18	Total Union Supply Forecast	159,588	177,729	(18,141)	170,615	181,097	(10,483)	197,799	179,850	17,949

* Union North was split into North West and North East in 2016. For simplicity 2015/16 is listed all as Union North West, but encompasses North West and North East

2015/16 – Warmer than normal weather decreased demand and gas supply deliveries below budget.

2016/17 – Warmer than normal weather decreased demand and gas supply deliveries below budget. This is the first year for which North purchases were split between North East and North West zones.

2017/18 – Colder than normal weather increased demand and gas supply deliveries above budget. In the North East zone, Dawn deliveries began to offset Western Canadian supply.

16.4 Unutilized Capacity

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

		2015/16			2016/17			2017/18		
Line No.	Particulars (PJ)	Actual	Plan	Variance	Actual	Plan	Variance	Actual	Plan	Variance
1	North West	17.1	15.5	1.6	14.3	12.3	2.0	6.7	14.3	(7.6)
2	North East				5.3	1.2	4.1	0.6	2.7	(2.1)
3	South	14.4	0.0	14.4	6.8	0.0	6.8	-	-	-
4	Total UDC	31.5	15.5	16.0	26.4	13.5	12.9	7.3	17.0	(9.7)

* Union North was split into North West and North East in 2016. For simplicity 2015/16 is listed all as Union North West, but encompasses North West and North East

2015/16 – The actual UDC incurred was 16 PJ higher than planned due to warmer than normal weather that resulted in lower transportation throughput.

2016/17 – The actual UDC incurred was 10.8 PJ higher than planned due to warmer than normal weather.

2017/18 – The actual UDC incurred was 9.7 PJ lower than planned due to colder than normal weather.

17. Achieving Public Policy

EGI has and will continue to be responsive to public policy; including in the execution of the gas supply function in accordance with the guiding principles set forth by the Board in the Framework. The following are three examples of EGI's commitment to adhere to public policy goals by helping the government to i) increase the presence of RNG in Ontario, ii) expand natural gas access in rural and northern community areas and iii) compliance with the Federal Carbon Pricing Program.

17.1 Renewable Natural Gas

The EGD and Union 2018 Cap-and-Trade Compliance Plans[47] made clear their intention to include the purchase of RNG as an abatement activity subject to the receipt of government funding. In February 2018, EGD and Union issued RFPs for RNG commodity that were predicated on government funding.

Subsequently on July 25, 2018, the newly formed Ontario government introduced Bill 4, the *Cap and Trade Cancellation Act, 2018* which repeals the *Climate Change Mitigation and Low-carbon Economy Act, 2016*. As a result of this change to Ontario's environmental regulations, EGD and Union closed their respective RNG RFPs without accepting any bids in September 2018.

On November 29, 2018, the Ontario government released the new MOEP, which outlines a requirement for natural gas utilities to implement a voluntary renewable natural gas option for customers. The Ontario government will also consult on the appropriateness of clean content requirements[48]. EGI recognizes the importance of GHG abatement across the province, as well as the important role that EGI plays in supporting the achievement of GHG emission reduction targets. At this time, EGI does not hold any RNG supply in its Plan. However, EGI remains committed to working with the provincial and federal governments and other organizations to offer services that will support government policies and objectives.

17.2 Community Expansion

EGI has been actively working with all levels of government in order to bring secure, reliable and affordable natural gas to unserved communities within Ontario through community expansion proceedings and government funding programs. Several community expansion projects have been filed and approved by the Board toward this end.

On December 6, 2018, Bill 32, *An Act to Amend the Ontario Energy Board Act, 1998*, received Royal Assent, providing rate protection for customers with respect to costs incurred by a gas distributor in making a qualifying investment for the purpose of providing access to a natural gas distribution

[47] EB-2017-0224 and EB-2017-0255
[48] Ontario Ministry of the Environment, Conservation and Parks, "Preserving and Protecting our Environment for Future Generations: A Made-in-Ontario Environment Plan", page 33.

system to those customers[49]. This will allow expansion of natural gas for up to 78 communities serving approximately 33,000 customers.

17.3 Federal Carbon Pricing Program

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

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

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

As part of EGI's compliance with the FCPP, EGI filed its 2019 FCPP application (EB-2018-0187) with the Board on January 11, 2019.

18. Performance Measurement

EGI has developed performance metrics that reflect the criteria the Board has established as a way to monitor effectiveness of the Plan and how the guiding principles have been achieved, and as a means to drive continuous improvements. EGI's performance metrics can be found in Appendix J with a brief explanation of each measure's intent. Since gas supply costs are treated as a direct pass-through to customers and there is no opportunity for EGI to earn revenue on its gas supply activities, EGI does not expect that performance measurement will be applied in any way that may financially reward or penalize EGI for its gas supply activities.

Since this is the initial year of filing such detail, there is no history to form a basis to discuss actual metric results. The metric results will be recorded and filed each year as part of the Annual Update.

19. Continuous Improvement Strategies

EGI continues to enhance its gas supply planning processes and practices over time. EGI will continue to evaluate and act on opportunities to improve as they arise in accordance with the guiding principles. As discussed in the Amalgamation and the Plan portion of Section 1.1, the EGD and Union rate zones have existing differences between their gas supply planning processes, internal rate zones, methodologies, recovery mechanisms and regulatory constructs. The EGD and Union rate zones will be maintained separately throughout the five year deferred rebasing period, however it is expected that a detailed

[49] Explanatory note to Bill 32, Access to Natural Gas Act, 2018

integration strategy will be developed over the upcoming year. This strategy will include a full analysis and comparison of each the EGD and Union rate zones' gas supply plans, processes and methodologies. This is a significant undertaking and EGI does expect there will be opportunities for the existing processes to evolve as EGI realizes any synergistic benefits of combining existing methodologies. These processes include, but are not limited to:

- Design day methodologies;
- Gas supply plan execution; and,
- Procurement process and policy.

As EGI evolves its planning processes and realizes future integration opportunities, they will be discussed in future iterations of Section 1.2 regarding Significant Changes to the Plan.

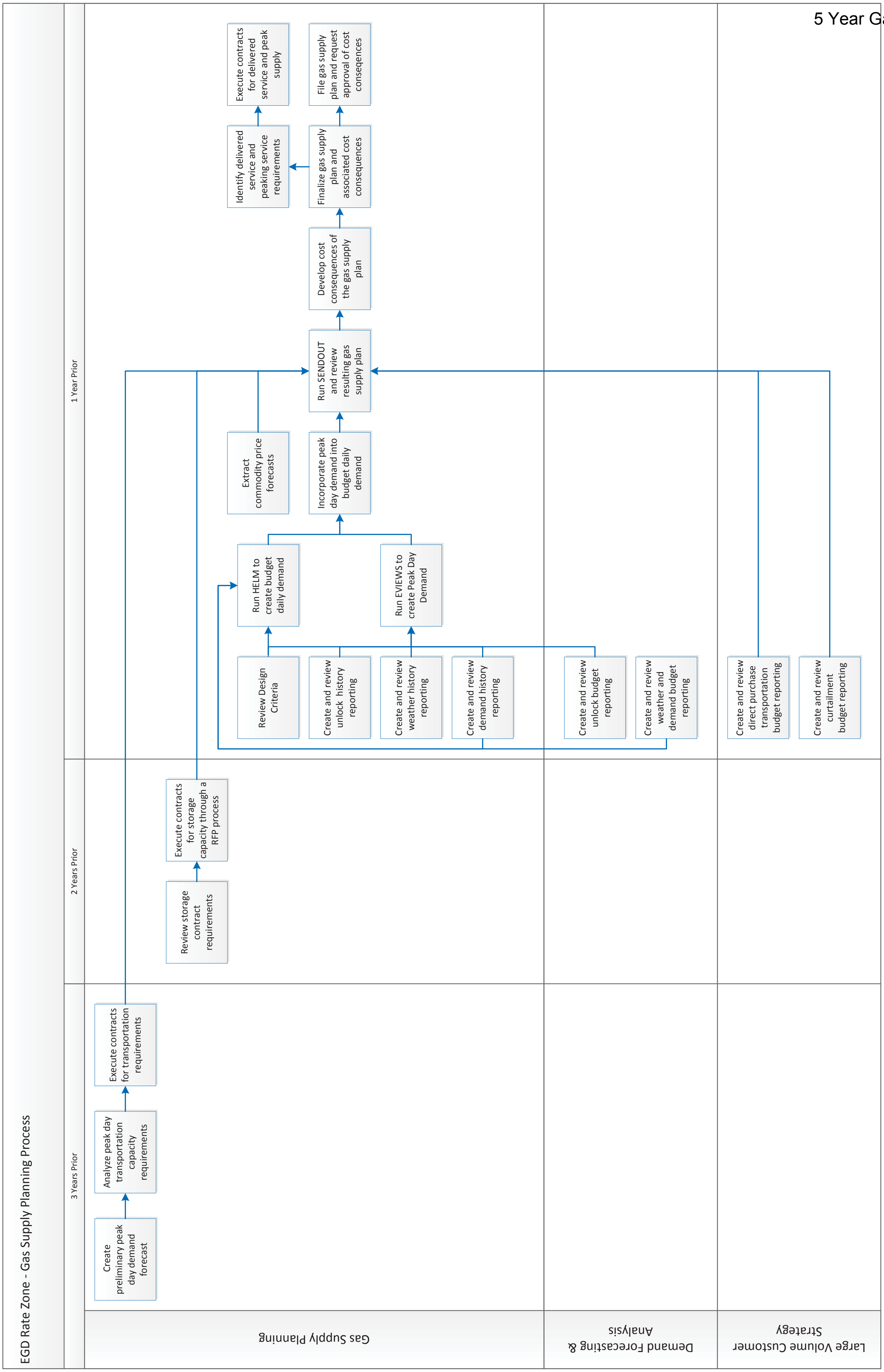
20. Link to Other Applications

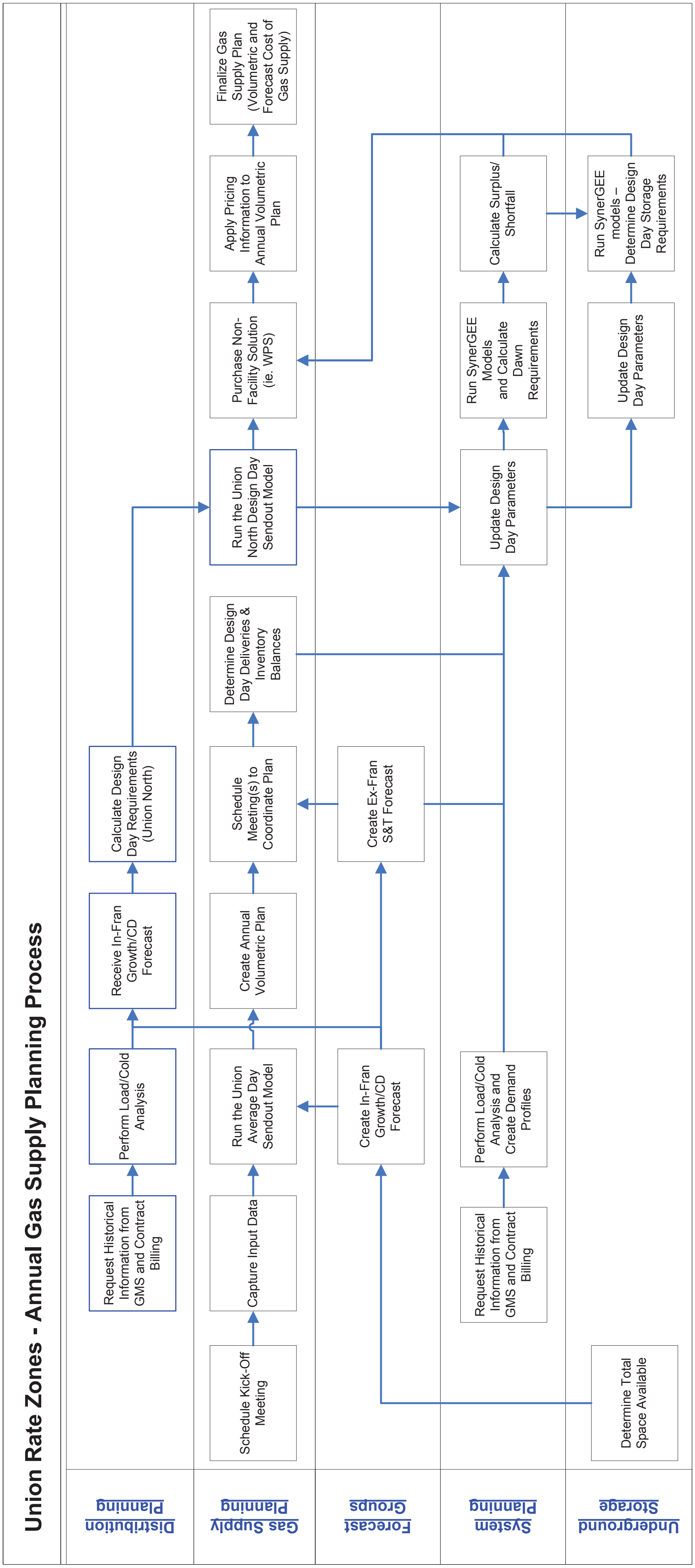
Table 36 below outlines at a high-level how EGI expects the Plan to inform other gas supply related applications, as well as how those applications may in turn inform the Plan through updates. EGI notes the table below may require updating in the future depending upon the outcome of EB-2017-0257, the Board's Consultation on Moving to a Single Annual Natural Gas Rate Application.

Table 36 – Links to Other Applications

Related Application	How the Plan Informs Related Applications	How Related Applications Inform the Plan	Implications for Rates
QRAM	Execution of the Plan will result in ongoing changes to pass-through gas supply costs which are largely recovered through QRAM applications	QRAM applications include data and information which will help to inform Annual Updates and next iteration of the five year Plan	QRAM applications are the mechanism through which the majority of gas supply costs are passed through to customers in rates
Annual Rate Applications	The most recent iteration of the EGD rate zone portion of the Plan will be reflected in Annual Rate applications. Gas Supply memoranda will no longer appear in Annual Rate applications, having been replaced by the Plan	Annual Rate applications are not anticipated to significantly inform or influence the Plan	Within the EGD rate zone, some gas supply cost changes resulting from the most recent composition of the gas supply portfolio for that year are passed through to customers in rates through Annual Rate applications[50]
Leave to Construct Applications	The most recent iteration of the Plan provides the foundation for related Leave to Construct applications which enable sustained or improved execution of the Plan in accordance with the Board's guiding principles	Upon approval of related Leave to Construct applications any resulting new assets or gas supply options will be reflected in Annual Updates and the next iteration of the five year Plan	Capital expenditures resulting from related Leave to Construct applications will be adjudicated in the appropriate proceeding. Any resulting changes to gas supply costs will be reflected in QRAM and/or Annual Rate applications as appropriate
Long-Term Contract Applications	The most recent iteration of the Plan provides the foundation for Long-Term Contract applications which enable sustained or improved execution of the Plan in accordance with the Board's guiding principles	Upon approval of related Long-Term Contract applications any resulting new assets or gas supply options will be reflected in Annual Updates and the next iteration of the five year Plan	Any changes to gas supply costs resulting from Long-Term Contract applications will be reflected in QRAM and/or Annual Rate applications as appropriate

[50] For further explanation please see EGI's Response to Decision and Procedural Order No. 2 in EB-2018-0305, dated April 11, 2019.


EGD Rate Zone - Gas Supply Planning Process
Gas Supply Planning
Demand Forecasting & Analysis
Large Volume Customer Strategy
3 Years Prior
2 Years Prior
1 Year Prior
Create preliminary peak day demand forecast
Analyze peak day transportation capacity requirements
Execute contracts for transportation requirements
Review storage contract requirements
Execute contracts for storage capacity through a RFP process
Review Design Criteria
Create and review unlock history reporting
Create and review weather history reporting
Create and review demand history reporting
Create and review unlock budget reporting
Create and review weather and demand budget reporting
Create and review direct purchase transportation budget reporting
Create and review curtailment budget reporting
Run HELM to create budget daily demand
Run EVIEWS to create Peak Day Demand
Extract commodity price forecasts
Incorporate peak day demand into budget daily demand
Run SENDOUT and review resulting gas supply plan
Develop cost consequences of the gas supply plan
Finalize gas supply plan and associated cost consequences
Identify delivered service and peaking service requirements
Execute contracts for delivered service and peak supply
File gas supply plan and request approval of cost consegences


Union Rate Zones - Annual Gas Supply Planning Process
Distribution Planning
Gas Supply Planning
Forecast Groups
System Planning
Underground Storage
Request Historical Information from GMS and Contract Billing
Perform Load/Cold Analysis
Receive In-Fran Growth/CD Forecast
Calculate Design Day Requirements (Union North)
Schedule Kick-Off Meeting
Capture Input Data
Run the Union Average Day Sendout Model
Create Annual Volumetric Plan
Schedule Meeting(s) to Coordinate Plan
Determine Design Day Deliveries & Inventory Balances
Run the Union North Design Day Sendout Model
Purchase Non-Facility Solution (ie. WPS)
Apply Pricing Information to Annual Volumetric Plan
Finalize Gas Supply Plan (Volumetric and Forecast Cost of Gas Supply)
Create In-Fran Growth/CD Forecast
Create Ex-Fran S&T Forecast
Request Historical Information from GMS and Contract Billing
Perform Load/Cold Analysis and Create Demand Profiles
Update Design Day Parameters
Run SynerGEE Models and Calculate Dawn Requirements
Calculate Surplus/ Shortfall
Determine Total Space Available
Update Design Day Parameters
Run SynerGEE models – Determine Design Day Storage Requirements

Summary of January 1, 2020 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 CDA FT	Empress	CDA	5,000	GJ	10/31/2020[1]
2	Empress to EDA FT	Empress	EDA	260,000	GJ	10/31/2022[1]
3	Dawn to CDA FT	Dawn	CDA	149,818	GJ	31-Oct-2024
4	Dawn to EDA FT	Dawn	EDA	114,000	GJ	31-Oct-2024
5	Dawn to Iroquois FT	Dawn	Iroquois	40,000	GJ	31-Oct-2024
6	Parkway to EDA FT	Parkway	EDA	13,114	GJ	31-Oct-2032
7	Parkway to CDA FT	Parkway	CDA	572	GJ	31-Oct-2022
8	Parkway to CDA FT	Parkway	CDA	157,952	GJ	31-Oct-2032
9	Parkway to CDA FT[2]	Parkway	CDA	75,000	GJ	31-Oct-2034
10	Parkway to CDA FT-SN	Parkway	Victoria Square #2 CDA	85,000	GJ	31-Oct-2022
11	Parkway to EDA FT	Parkway	EDA	170,000	GJ	31-Oct-2031
12	Niagara Falls to CDA	Niagara Falls	Parkway CDA	76,559	GJ	31-Oct-2030
13	Chippawa to CDA	Chippawa	Parkway CDA	123,441	GJ	31-Oct-2030
14	TCPL FT - Total			1,270,456	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
15	CDA	Parkway	CDA	283,892	GJ	31-Oct-2024
16	EDA	Parkway/Kirkwall	EDA	70,895	GJ	31-Oct-2024
17	EDA	Parkway	EDA	9,716	GJ	31-Oct-2024
18	TCPL Firm STS Withdrawal - Total			364,503	GJ	
	TransCanada Storage Transportation Service Firm Injection					
19	CDA	Parkway	CDA	283,892	GJ	31-Oct-2024
20	EDA	Parkway/Kirkwall	EDA	70,895	GJ	31-Oct-2024
21	EDA	Parkway	EDA	9,716	GJ	31-Oct-2024
22	TCPL Firm STS Injection - Total			364,503	GJ	
	NOVA Transmission					
23	AECO to Empress	AECO	Empress	50,000	GJ	31-Oct-2020
24	AECO to Empress	AECO	Empress	75,000	GJ	31-Dec-2020
25	Nova Transmission - Total			125,000	GJ	
	Vector Pipeline					
26	Vector US FT1	Milford Junction	Cdn/US Interconnect	110,000	DTH	31-Oct-2033
27	Vector Canada FT1	Cdn/US Interconnect	Dawn	116,056	GJ	31-Oct-2033
28	Vector US FT1	Chicago	Cdn/US Interconnect	65,000	DTH	31-Oct-2021
29	Vector Canada FT1	Cdn/US Interconnect	Dawn	68,579	GJ	31-Oct-2021
30	Vector - Total			184,635	GJ	
	NEXUS					
31	NEXUS - FT	Kensington	Milford Junction	55,000	DTH	31-Oct-33
32	NEXUS - FT	Clarington	Milford Junction	55,000	DTH	31-Oct-33
33	NEXUS - Total			116,056	GJ	

Conversion Factor 1.055056

Note:
(1) Implied end date of Dec 31, 2020. To be replaced by NBJ LTFP effective Jan 1, 2021
(2) Effective November 1, 2019

North Bay Junction Landed Cost Analysis

Summary of Landed Cost Analysis ($C/GJ)

Pipeline/Service	Path	Pricing Point	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Average
	Delivered to Enbridge CDA												
Alliance/FFPS & Vector/FT-1 Union/M12 & TCPL/FT-SH	Alliance Trading-to-Border-to-Chicago-to-Dawn-to-Parkway-to-Enbridge CDA	Alliance Trading	3.68	3.75	3.89	3.93	3.97	4.02	4.07	4.14	4.19	4.25	3.99
TCPL/FT-SH & GLGT/FT & GLPC/FT & Union/M12 & TCPL/FT-SH	Empress-to-Emerson 2-to-St.Clair-to-Dawn-to Parkway-to-Enbridge CDA	Empress	3.57	3.50	3.59	3.63	3.68	3.73	3.79	3.86	3.90	3.97	3.72
TCPL/FT-LH	Empress-to-Enbridge CDA	Empress	3.82	3.89	4.03	4.07	4.11	4.16	4.21	4.28	4.32	4.38	4.13
TCPL/LT-FP & TCPL/FT-SH	Empress-to-North Bay Junction-to-Enbridge CDA	Empress	3.21	3.27	3.41	3.45	3.50	3.54	3.60	3.66	3.71	3.77	3.51
TCPL/FT-SH	Chippawa-to-Enbridge Parkway CDA	Niagara	2.77	2.79	2.86	2.92	2.98	3.04	3.12	3.20	3.27	3.35	3.03
TCPL/FT-SH	Niagara-to-Enbridge Parkway CDA	Niagara	2.77	2.79	2.86	2.92	2.98	3.04	3.12	3.20	3.27	3.35	3.03
Union/M12	Dawn-to-Parkway/EGT	Dawn	3.07	3.08	3.15	3.21	3.29	3.35	3.44	3.54	3.62	3.71	3.35
Union/M12 & TCPL/FT-SH	Dawn-to-Union Parkway Belt-to-Enbridge CDA	Dawn	3.25	3.26	3.33	3.40	3.47	3.54	3.63	3.73	3.80	3.90	3.53
Union/M12 & TCPL/FT-SH	Dawn-to-Kirkwall-to-Enbridge CDA	Dawn	3.25	3.26	3.33	3.39	3.47	3.53	3.62	3.72	3.80	3.89	3.53
Vector/FT-1 & Union/M12 & TCPL/FT-SH	Chicago-to-Dawn-to-Parkway-to-Enbridge CDA	Chicago	3.57	3.59	3.68	3.74	3.81	3.88	3.97	4.07	4.15	4.24	3.87
Vector/FT-1 & Union/M12 & TCPL/FT-SH	Chicago-to-Dawn-to-Kirkwall-to-Enbridge CDA	Chicago	3.56	3.58	3.67	3.74	3.81	3.88	3.97	4.07	4.14	4.23	3.86
Vector/FT-1 & Union/M12X & TCPL/FT-SH	Chicago-to-Dawn-to-Parkway-to-Enbridge CDA	Chicago	3.60	3.62	3.70	3.77	3.84	3.91	4.00	4.10	4.18	4.27	3.90
Vector/FT-1 & Union/M12X & TCPL/FT-SH	Chicago-to-Dawn-to-Kirkwall-to-Enbridge CDA	Chicago	3.61	3.63	3.72	3.78	3.86	3.92	4.01	4.11	4.19	4.28	3.91
NEXUS & Union/M12 & TCPL/FT-SH (Base)	Dominion South-to-Milford Junction-to-Dawn-to-Parkway-to-Enbridge CDA	Dominion South	3.88	3.84	3.92	3.97	4.03	4.08	4.16	4.24	4.30	4.38	4.08
Rover & Union/M12 & TCPL/FT-SH	Dominion South-to-Dawn-to-Parkway-to-Enbridge CDA	Dominion South	3.80	3.76	3.84	3.89	3.95	4.00	4.08	4.16	4.22	4.30	4.00

Average Commodity Prices ($C/GJ)

Pricing Point	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Average
Alliance Trading	1.656	1.719	1.851	1.891	1.936	1.978	2.032	2.093	2.138	2.196	1.949
Chicago	2.902	2.922	3.010	3.076	3.148	3.216	3.304	3.403	3.478	3.571	3.203
Dawn	2.918	2.930	2.997	3.062	3.134	3.201	3.290	3.388	3.462	3.555	3.194
Dominion South	2.424	2.390	2.463	2.516	2.575	2.630	2.703	2.784	2.845	2.921	2.625
Empress	1.991	1.924	2.013	2.057	2.106	2.151	2.211	2.277	2.327	2.389	2.145
Niagara	2.550	2.563	2.635	2.692	2.755	2.815	2.892	2.979	3.044	3.126	2.805

Forward Prices updated after market close: August 21/2018

North Bay Junction Landed Cost Analysis

Summary of Landed Cost Analysis ($C/GJ)

Pipeline/Service	Path	Pricing Point	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Average
	Delivered to Enbridge EDA												
Alliance/FFPS & Vector/FT-1 & Union/M12 & TCPL/FT-SH	Alliance Trading-to-Border-to-Chicago-to-Dawn-to-Parkway-to-Enbridge EDA	Alliance Trading	3.985	4.051	4.191	4.233	4.279	4.322	4.380	4.445	4.493	4.554	4.29
TCPL/FT-SH & GLGT/FT & GLPC/FT & Union/M12 & TCPL/FT-SH	Empress-to-Emerson 2-to-St.Clair-to-Dawn-to Parkway-to-Enbridge EDA	Empress	3.870	3.800	3.890	3.936	3.984	4.031	4.091	4.160	4.210	4.274	4.02
TCPL/FT-LH	Empress-to-Enbridge EDA	Empress	3.885	3.950	4.088	4.130	4.176	4.219	4.276	4.340	4.387	4.446	4.19
TCPL/LT-FP & TCPL/FT-SH	Empress-to-North Bay Junction-to-Enbridge EDA	Empress	3.252	3.318	3.456	3.498	3.543	3.587	3.643	3.708	3.754	3.814	3.56
Union/M12 & TCPL/FT-SH	Dawn-to-Parkway-to-Enbridge EDA	Dawn	3.554	3.566	3.634	3.701	3.773	3.841	3.931	4.032	4.106	4.200	3.83
Union/M12 & TCPL/FT-SH	Dawn-to-Kirkwall-to-Enbridge EDA	Dawn	3.558	3.570	3.638	3.705	3.777	3.845	3.934	4.036	4.109	4.203	3.84
Union/M12X & TCPL/FT-SH	Dawn-to-Parkway-to-Enbridge EDA	Dawn	3.583	3.595	3.663	3.730	3.802	3.871	3.960	4.061	4.135	4.230	3.86
Union/M12X & TCPL/FT-SH	Dawn-to-Kirkwall-to-Enbridge EDA	Dawn	3.605	3.617	3.685	3.752	3.824	3.893	3.982	4.083	4.157	4.251	3.88
Vector/FT-1 & TCPL/FT-SH	Chicago-to-Dawn-to-Enbridge EDA	Chicago	3.897	3.917	4.006	4.072	4.144	4.212	4.302	4.403	4.477	4.571	4.20
Vector/FT-1 & Union/M12 & TCPL/FT-SH	Chicago-to-Dawn-to-Parkway-to-Enbridge EDA	Chicago	3.870	3.890	3.980	4.047	4.119	4.187	4.277	4.379	4.453	4.548	4.18
Vector/FT-1 & Union/M12 & TCPL/FT-SH	Chicago-to-Dawn-to-Kirkwall-to-Enbridge EDA	Chicago	3.874	3.894	3.983	4.050	4.122	4.190	4.280	4.382	4.456	4.550	4.18
Vector/FT-1 & Union/M12X & TCPL/FT-SH	Chicago-to-Dawn-to-Parkway-to-Enbridge EDA	Chicago	3.900	3.920	4.009	4.076	4.148	4.217	4.306	4.408	4.482	4.577	4.20
Vector/FT-1 & Union/M12X & TCPL/FT-SH	Chicago-to-Dawn-to-Kirkwall-to-Enbridge EDA	Chicago	3.922	3.941	4.030	4.098	4.169	4.238	4.327	4.429	4.503	4.598	4.23
NEXUS & Union/M12 & TCPL/FT-SH (Base)	Dominion South-to-Milford Junction-to-Dawn-to-Parkway-to-Enbridge EDA	Dominion South	4.187	4.149	4.221	4.276	4.334	4.390	4.464	4.548	4.609	4.687	4.39
Rover & Union/M12 & TCPL/FT-SH	Dominion South-to-Dawn-to-Parkway-to-Enbridge EDA	Dominion South	4.106	4.069	4.141	4.195	4.253	4.309	4.382	4.466	4.527	4.605	4.31

Average Commodity Prices ($C/GJ)

Pricing Point	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Average
Alliance Trading	1.656	1.719	1.851	1.891	1.936	1.978	2.032	2.093	2.138	2.196	1.949
Chicago	2.902	2.922	3.010	3.076	3.148	3.216	3.304	3.403	3.478	3.571	3.203
Dawn	2.918	2.930	2.997	3.062	3.134	3.201	3.290	3.388	3.462	3.555	3.194
Dominion South	2.424	2.390	2.463	2.516	2.575	2.630	2.703	2.784	2.845	2.921	2.625
Empress	1.991	1.924	2.013	2.057	2.106	2.151	2.211	2.277	2.327	2.389	2.145

Market close: August 21, 2018

2021 NCOS Landed Cost Analysis

Receipt	Delivery	Service Type	Peaking Service as Alternative for NCOS 2021							
			Start Date	End Date	Volume (GJ/d)	Fixed Costs ($/GJ/d)	Variable Costs ($/GJ/d)	Average Load Factor	Term Cost ($M)	Average Annual Cost ($M)
EDA	EDA	Peaking	1-Nov-21	31-Oct-36	25,000	0.1231	9.5878	30.0%	11.2	0.7
CDA	CDA	Peaking	1-Nov-21	31-Oct-36	100,000	0.5152	9.5878	30.0%	50.9	3.4
Total for Peaking Service Strategy					**125,000**				**62.1**	**4.1**

Receipt	Delivery	Service Type	SHFT as Alternative for NCOS 2021							
			Start Date	End Date	Volume (GJ/d)	Fixed Costs ($/GJ/d)	Variable Costs ($/GJ/d)	Average Load Factor	Term Cost ($M)	Average Annual Cost ($M)
Dawn	Parkway	M12	1-Nov-21	31-Oct-36	25,000	0.1282	4.9238	0.8%	23.1	1.5
Parkway	EDA	SHFT	1-Nov-21	31-Oct-36	25,000	0.4636	0.0292	0.8%	63.5	4.2
Subtotal					**25,000**				**86.6**	**5.8**
Dawn	Parkway	M12	1-Nov-21	31-Oct-36	100,000	0.1282	4.9238	0.8%	92.4	6.2
Parkway	CDA	SHFT	1-Nov-21	31-Oct-36	100,000	0.1794	0.0071	0.8%	98.3	6.6
Subtotal					**100,000**				**190.7**	**12.7**
Total for SHFT Strategy					**125,000**				**277.4**	**18.5**

Receipt	Delivery	Service Type	LHFT as Alternative for NCOS 2021							
			Start Date	End Date	Volume (GJ/d)	Fixed Costs ($/GJ/d)	Variable Costs ($/GJ/d)	Average Load Factor	Term Cost ($M)	Average Annual Cost ($M)
Empress	EDA	LHFT	1-Nov-21	31-Oct-31	25,000	1.9897	2.3704	83.3%	361.9	36.2
Parkway	Dawn	C1	1-Nov-21	31-Oct-36	25,000	0.0287	0.0071	0.8%	3.9	0.3
	Dawn	Purchases	1-Nov-21	31-Oct-31	25,000	-	3.2836	-82.5%	(247.2)	(24.7)
Subtotal					**25,000**				**118.6**	**11.7**
Empress	CDA	LHFT	1-Nov-21	31-Oct-31	100,000	1.9315	2.3678	83.3%	1,425.7	142.6
Parkway	Dawn	C1	1-Nov-21	31-Oct-36	100,000	0.0287	0.0071	0.8%	15.8	1.1
	Dawn	Purchases	1-Nov-21	31-Oct-31	100,000	-	3.2836	-82.5%	(989.0)	(98.9)
Subtotal					**100,000**				**452.4**	**44.7**
Total for LHFT Strategy					**125,000**				**571.0**	**56.4**

Assessing the Impact of Weather on Natural Gas Prices in the Enbridge Gas Supply Portfolio

April 15, 2019

Submitted to:
Enbridge Gas Inc.

Submitted by:
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9300 Lee Highway
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1 Introduction

1.1 Purpose

The Ontario Energy Board requested that Enbridge Gas Inc. (Enbridge or the Company) conduct a natural gas supply risk mitigation analysis to determine the value of supply diversity and reliability within the Utility's natural gas supply portfolio. According to the OEB:

> *"Distributors develop a gas supply plan that supports the needs of its customers as identified through the demand forecast, and in doing so also manages both the cost and reliability-related risks on behalf of their customers. Increased reliability typically costs more and distributors are expected to determine the appropriate balance. Distributors will articulate their approach by including a suite of scenarios that describe the envelope of plan forecasts based on worst, best and most likely cases, in addition to their selected option(s). This accompanied by commensurate price forecasts for customers can describe the range of realistic outcomes."*

ICF was engaged by Enbridge Gas Inc. (Enbridge or the Company) to assist in this analysis. While a diversified supply portfolio should be expected to reduce risk associated with a variety of potential market and infrastructure events, the most immediate benefit is generally the reduction in natural gas supply and price risk associated with weather uncertainty. Hence, ICF's analysis focuses on the risks associated with weather.

ICF evaluated the impact of weather on natural gas prices in different supply basins utilized by the Utility as part of the overall utility supply portfolio. The ICF analysis included both an assessment of the historical weather and price data to illustrate the impact of weather on the behavior of prices in different natural gas supply regions, as well as a forecast of natural prices at different locations under a range of historical weather patterns in order to establish. ICF also developed a set of natural gas price forecasts for different supply regions reflecting a range of realistic natural gas price outcomes. The price forecasts were then used to develop reasonable worst, best and most likely gas price scenarios based on weather uncertainty.

1.2 Overview of Approach

The analysis presented in this report consists of three major components:

1) An assessment of historical weather and natural gas market price relationships.
2) A forecast of natural gas markets under different weather conditions.
3) Development of three alternative gas price scenarios based on different weather patterns.

Historical Weather and Price Data

The historical weather and price analysis is based on monthly Heating Degree Day (HDD) data from NOAA and from StatsCanada, and average natural gas prices for different market centers from ICF's natural gas price data service. The HDD data and price data is averaged on a monthly basis to be consistent with the ICF forecasting approach described below. The monthly averaging has the impact of masking the magnitude of the day-to-day swings in natural gas prices, while capturing the primary impacts of weather on natural gas demand, and supply portfolio costs.

Forecasting the Impact of Weather on Future Prices

The ICF used its proprietary Gas Market Model (GMM®) and Gas Price Risk Service module to evaluate the impact of weather on natural gas prices. ICF's GMM is an internationally recognized modeling and market analysis system for the North American gas market. The GMM was developed in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions. Since then, the GMM has been used to complete strategic planning studies for governments, non-government associations, utilities, and private sector companies. The GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply, demand, and pipeline conditions. The Gas Price Risk Report is a separate module of the GMM that evaluates 85 weather scenarios based on actual historical weather patterns to create a distribution of prices and impacts from weather on current and projected gas markets. A more detailed review of the ICF GMM is included in Appendix A.

Development of Weather Scenarios

In order to assess the value of natural gas supply diversity for Enbridge under different weather scenarios, ICF used GMM to develop three alternative price scenarios[1] based on actual historical weather patterns applied to the 3-year period from April 2019 through March 2022. The three cases are:

- **Base Case:** This case uses a 20-year normal weather outlook.
- **Worst Case Weather Scenario**: This case includes the largest price increase at Dawn versus the base case during 2020-21 winter months.
- **Best Case Weather Scenario:** This case includes the largest price decrease at Dawn versus the base case during 2020-21 winter months.

Because weather patterns can differ widely in different regions, and because the impact of weather on prices depends to a significant degree on the timing of a weather event, and the market conditions prior to a weather event, a broad-based increase or decrease in heating degree days (HDDs) across the North American natural gas market does not provide a useful assessment of the likely impact of weather on natural gas prices in different regions of the country.

In addition, the timing and sequencing of weather events plays a significant role in determining the impact of weather on natural gas prices.

- **Timing of weather events within the winter season**: Early cold snaps have different price impacts from later cold snaps.

[1] ICF developed these three weather scenarios (Base, Cold, and Warm) independently and the weather scenarios should not be directly compared to any other Enbridge weather scenarios or future outlook.

- **Year to year changes**: Weather patterns that impact storage levels entering the winter season can have significant impacts on the market ability to adapt to cold weather events.
- **Regional differences:** The impact of weather on natural gas markets can differ widely depending on the regional spread of the changes in weather. For example, a cold snap in both the Midwest and the northeast will have a much larger impact on markets than a cold snap in the Midwest and on the west coast.

In order to address both the regional differences and the timing issues associated with different weather patterns, ICF used a series of actual 3-year weather patterns to assess the potential impacts of weather on natural gas prices at different market centers and supply regions.

ICF used historical weather patterns from 84 years of history to evaluate the impact of weather on natural gas markets. The GMM was run for each historical weather pattern over the indicated time period. This resulted in 85 unique forecasts based on different weather patterns based on actual historical weather conditions over the last 84 years. The results of the 84 three year weather scenarios are summarized in Appendix 2.

The 84 different three year weather scenarios were then used to select the three price scenarios requested by the OEB. The use of an actual 3-year historical weather pattern, instead of a one year "Colder than Normal" or "Warmer than Normal" weather pattern, or an average "Colder than Normal" or "Warmer than Normal" weather pattern enables the alternative scenarios to reflect the range of impacts that are likely to result from differences in regional impacts of weather and in the timing of weather events.

1.3 Structure of Report

This report documents the results of ICF's weather analysis, and provides an assessment of the impact of weather volatility on natural gas prices and basis at the natural gas market centers provided by Enbridge based on their gas supply portfolio. **Section 2** of this report evaluates the historical relationship between weather, natural gas demand and natural gas prices in Ontario and in other natural gas markets accessed as part of the Enbridge supply portfolio. **Section 3** of this report provides a summary of expected near term changes in the natural gas market outlook in Ontario, and more broadly in the U.S. and Canada that will influence natural gas prices in the Enbridge natural gas supply portfolio. **Section 4** of this report discusses the results of ICF's weather analysis and shows the prices for major supply basins for different cases. **Section 5** of this report derives the Worst Case, Base Case and Best Case Weather Scenarios provided to Enbridge by ICF.

2 Review of Historical Weather and Natural Gas Price Relationships

The North American gas market is highly seasonal, with higher demand occurring over the winter periods when there is an increase in demand for space heating, and reduced demand over the shoulder and summer months. Despite growth in natural gas use in the power sector, which has a different seasonal use profile than space heating load and can peak in the summer months, as well as rising industrial and gas exports, North American gas markets continue to have the highest demand over the winter season.

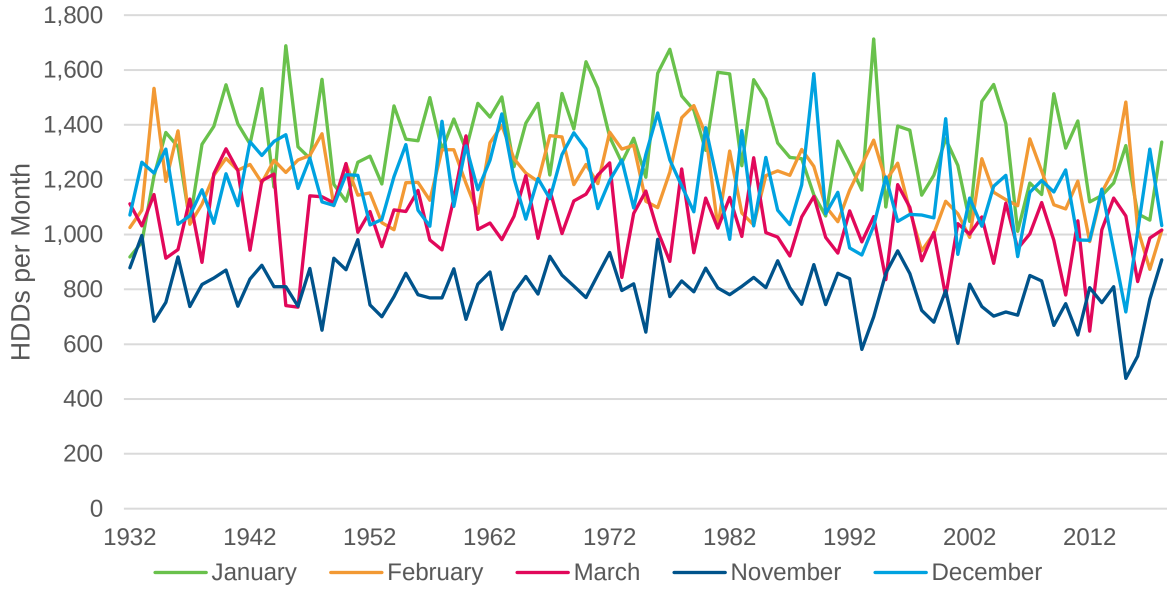
A key measure for assessing the variability in weather year-to-year, or even day-to-day or month-to-month is the use of Heating Degree Days (HDDs) and Cooling Degree Days (CDDs), which are measures used to represent the levels of heating of cooling demand based on daily temperatures.

There can be correlation in HDDs across months across a particular winter season. For instance, there can be abnormally warm or cold weather that stretches across the end of one month to the start of the following month. Or there can be broader regional or climate conditions that may have a longer-term impact to weather in Ontario, such as changes to ocean currents or jet streams.

Variability in Ontario, Canada Weather

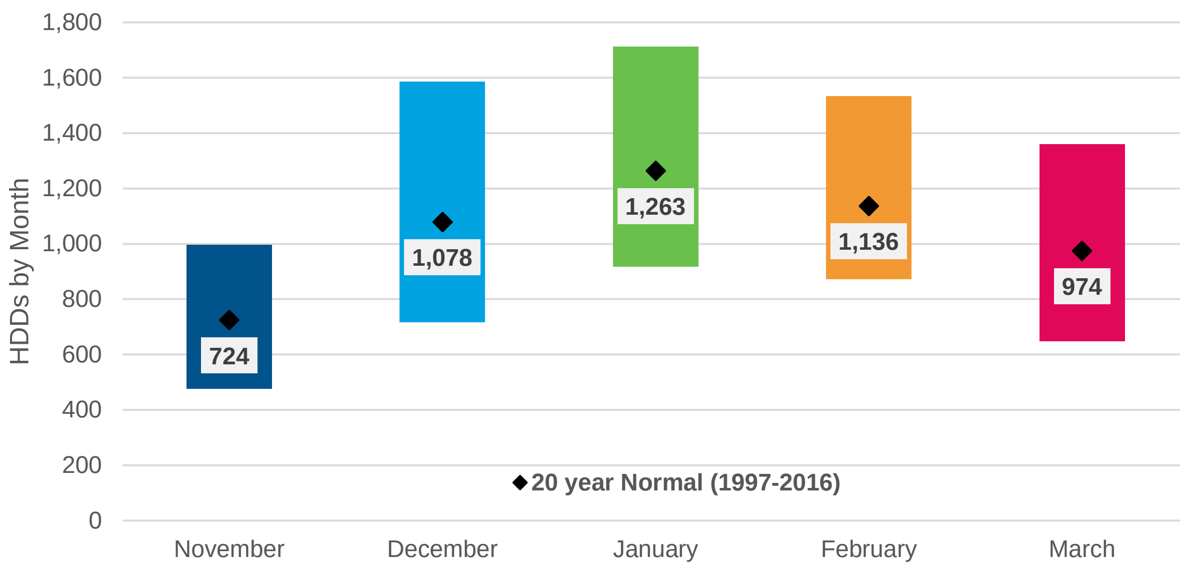
January is consistently the coldest month when measured by HDDs in Ontario, and also can exhibit large variation year-to-year in total HDDs, with a standard deviation in monthly HDD's of 13.5% from 1930 to 2018. February is the next coldest month, with a 20-year average HDD that is 10% lower (warmer) than January with a narrower range of weather, not experiencing the same kind of major cold-spells as January. The standard deviation in February HDD's between 1930 and 2018 was 11%. The month of December can be both very cold or conversely, warmer than normal and has the widest range between the coldest and warmest month. For instance, from 2008 to 2018 there were three years that December was colder than January, while at the same time there were also three years that December was warmer than March in that year. The standard deviation in December HDD's between 1930 and 2018 was 13.5%.

Figure 1. Historical Heating Degree Days for Winter Months in Ontario, Canada



Source: NOAA

Figure 2. Historical Range of Heating Degree Days for Winter Months in Ontario



Source: NOAA

One of the benefits of a diversified supply portfolio is the ability to purchase natural gas from different regions to take advantage of price diversity between different supply basins. The differences in regional prices are in part driven by differences in weather patterns. The table below shows the correlation coefficient of winter weather measured n HDD's in Ontario to U.S. Census Divisions and Alberta over the 20-year period from 1997 to 2016.

Table 1. Correlation Coefficient of Winter Season HDDs by U.S. Census Division and Alberta to Ontario
(Five Month Winter Average – Nov 1932 to Mar 2018)

Region	Correlation Coefficient
New England	0.85
Mid-Atlantic	0.86
East North Central	0.82
West North Central	0.67
South-Atlantic	0.68
East South Central	0.63
West South Central	0.51
Mountain	0.14
Pacific	(0.03)
Alberta	0.34

Source of HDD Data: NOA, Government of Canada. Analysis conducted by ICF.

The correlation coefficient shows the linear regression of Winter HDDs between Ontario and U.S Census regions. The higher the value, the more correlated the weather is between regions. Hence, weather patterns in the East North Central, Mid-Atlantic and New England are relatively similar to weather patterns in Ontario, while weather patterns in other regions tend to be more independent. Weather in the Pacific region is slightly negatively correlated with weather in the Ontario.

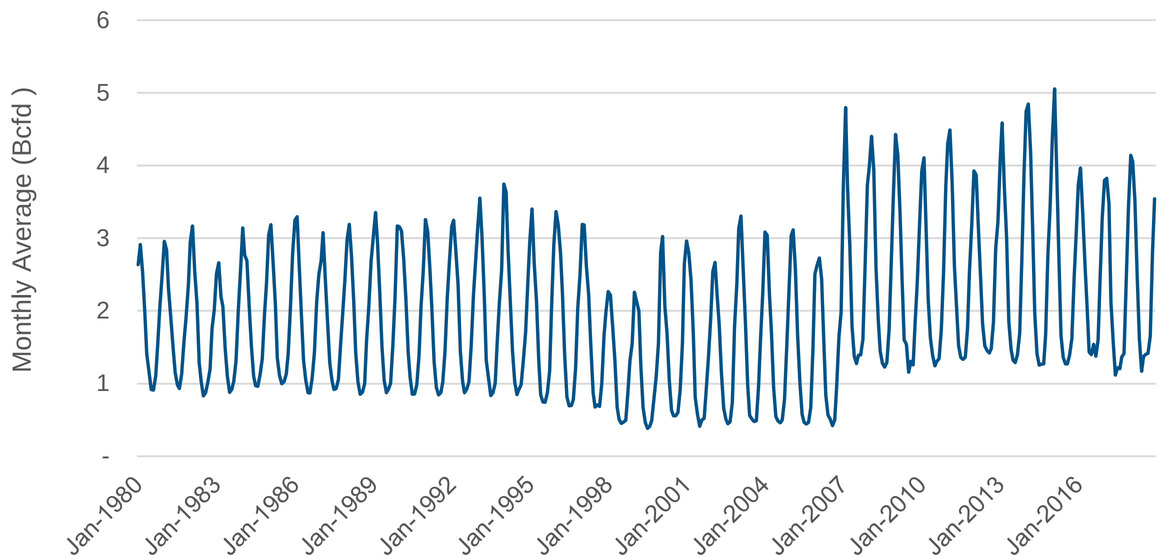
Regional proximity is a strong factor for weather correlations but not the only factor. Both the East North Central and the Middle Atlantic divisions neighbor Eastern Canada. Both these regions do exhibit strong relationships with the weather patterns in Ontario. The New England region has a higher correlation to Ontario weather than the East North Central, which includes Michigan, Ohio, and Illinois.

Impact of Weather on Ontario Gas Demand

Much of the gas price volatility associated with weather is driven by changes in natural gas demand associated with changes in weather. Natural gas demand in Ontario exhibits a high degree of seasonality, with demand peaking in the summer months and relatively low demand over the summer periods. From 1980 to 2018 there was an average difference of 2.6 Bcfd between the lowest monthly demand and highest monthly demand. This spread in monthly demand has expanded in recent years, averaging 3.07 Bcfd over the past 10-year, driven by a higher relative increase in winter demand levels when compared to summer demand.

The composition of Ontario demand changes significantly between the seasons, with a much higher level of power and industrial demand as a share of total demand for the province in the summer months when compared to winter months, when space heating demand rises with colder weather. It is this strong relationship between weather and demand that allows the use of weather scenarios and analysis to help understand and model the potential ranges of natural gas demand within Ontario under different weather scenarios.

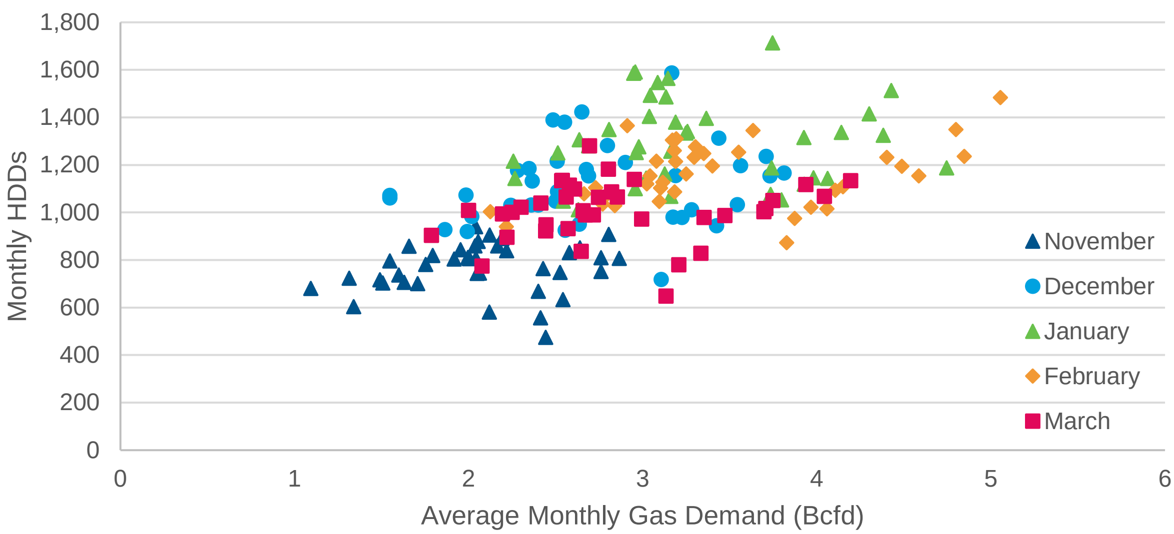
Figure 3. Historical Monthly Ontario Natural Gas Demand



Source: Government of Canada

There is a strong correlation in monthly demand to the levels of HDDs in a given month. While there are changes in underlying load growth, the main drive of annual variation in demand by month in Ontario is the changes in underlying weather. The Figure below show the average monthly natural gas demand in Ontario from 1980 to 2018 and the corresponding monthly HDD measure for the province. Each month exhibits a strong relationship between total demand and weather, even with changes in underlying market fundamentals over the past 40 years.

Figure 4. Historical Monthly Gas Demand and HDDs in Ontario (1980 to 2018)



Source: NOAA, StatCan

Regional Natural Gas Price Relationships

The relationship between natural gas prices in different regions is one of the factors that influences the value of supply diversity in a natural gas supply portfolio. Ideally, when prices spike for one source of supply, price changes for other sources of supply in different areas will be more moderate. Hence access to different sources of natural gas provides the gas purchaser with the ability to shift purchases away from the highest cost sources of supply.

The analysis of historical natural gas price data illustrates this benefit. Gas prices at some of the supply locations used by Enbridge are highly correlated with natural gas prices at Dawn, while other supply basins tend to move in a less correlated manner. The historic price data indicates a high degree of correlation between Dawn prices and prices in Chicago, MichCon, and deliveries from the Alliance pipeline, while prices at Dominion South, Henry Hub, and AECO tend to move in a more independent manner relative to Dawn prices.

The relationship also changes over time due to market changes, and differences in weather patterns. Table 2 illustrates these points, showing the correlation between gas prices at Dawn and gas prices at different market centers for two different historical time periods.

Table 2. Correlation Coefficient of Winter Season Natural Gas Prices at Different Supply Basins

Region	Correlation Coefficient 2013-2018	Correlation Coefficient 2016-2018
Texas Eastern, M-2 receipts	0.50	0.91
Iroquois, receipts	0.75	0.55
Dominion South Point	0.79	0.92
Alliance, into interstates	0.99	0.94
Chicago city-gates	0.97	0.93
Mich Con city-gate	1.00	0.99
Henry Hub	0.83	0.94
Panhandle, Tx.-Okla	0.92	0.96
AECO	0.74	0.10

Source: ICF analysis of historical data.

3 Natural Gas Market Overview

Natural gas markets in Ontario and in the broader North American market have evolved significantly over the last few years and will continue to evolve over the next few years. The Enbridge gas supply portfolio and gas supply planning process need to consider a forward looking assessment of natural gas markets as well as historical analysis.

Major factors driving shifts in the natural gas market include:

- Growth in natural gas supply, and changes in the location of natural gas supply
- Completion of new pipelines into and around Ontario, including completion of Rover and NEXUS from the Marcellus/Utica supply basins into the Midwest and Ontario
- Proposed changes in pipeline tariffs on TransCanada.
- Investments in new pipeline capacity in Ontario to serve demand at the eastern end of the TransCanada system, including expansion of capacity into Quebec and New England.
- Development of LNG export facilities, and associated pipeline capacity and natural gas supply in both the U.S. and Canada.

A brief review of these gas market drivers for North America and for Ontario are provided below.

3.1 North American Natural Gas Markets

The overall North American natural gas market has a significant impact on natural gas prices, and the impact of weather on natural gas prices in Ontario.

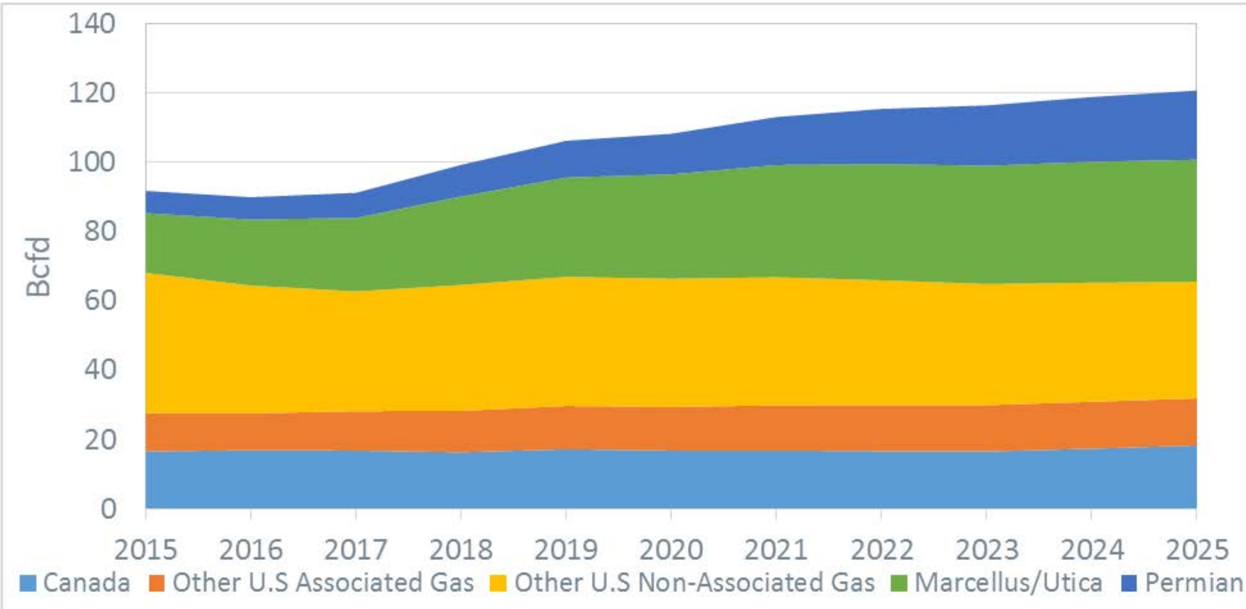
3.1.1 North American Supply Outlook

The North American natural gas market has changed dramatically in the past ten years due to the rapid penetration of natural gas production from shale gas resources based on horizontal drilling and hydraulic fracturing technologies. Prior to the rise of shale gas, U.S. and Canada consumption was increasing more quickly than production, resulting in relatively high and volatile gas prices. As gas prices increased, investments were made in new technologies to develop the natural gas reserves found in shale formations.

While it had been long known that there were large deposits of gas and oil in shale formations, it was not until the early 2000s that techniques were developed to economically tap these reserves. The new combination of directional drilling and hydraulic fracturing techniques were first applied in the Barnett Shale in north Texas, but quickly spread to other regions. The first successful shale well in the Marcellus Shale (which stretches from West Virginia through Northeastern Pennsylvania) was drilled in 2004, but Marcellus production did not reach significant levels until 2010. Shale gas development has also spread to the Utica Shale, an over-lapping play that extends into eastern Ohio, which has grown rapidly over the past six years. By 2025, dry gas production from Marcellus and Utica region is projected to rise to 35 Bcfd, about 38% higher than 2018 production levels.

Over the past three years, the rate of growth from Permian basin has rivaled that of Marcellus and Utica region, mainly due to the drilling technology and well productivity improvements that resulted in longer laterals, better well completion design and better formation targeting. By 2025, dry gas production from Permian region is projected to rise to 20 Bcfd, which is more than twice the 2018 production level. While dry gas production from other shale plays are also increasing, Marcellus/Utica and Permian regions account for a large majority of the projected production growth from 2019 through 2025. By 2025, dry gas production Marcellus, Utica and Permian plays are projected to account for about 46% of the overall U.S. and Canadian gas production.

Exhibit 3-1: U.S. and Canada Natural Gas Production



Source: ICF GMM® Q1 2019

The shifts in regional gas supply and demand have changed interregional pipeline flow patterns, and the changes are likely to continue in the future. Marcellus/Utica production growth has already resulted in dramatic changes to pipeline flow patterns, with the Northeast becoming a net exporting region. Prior to the development of Marcellus and Utica, the Mid-Atlantic and Northeast U.S. relied on gas supplies from the Gulf Coast and Western Canada.

As Marcellus/Utica production continues to grow and becomes an even larger source of gas supplies to other areas, flows along the traditional in-bound paths are increasingly reversed as gas flows out of the region to the South, to the Midwest, and to Eastern Canada. Most of the production growth from the Permian region will support the incremental LNG exports from the gulf coast, pipeline exports to Mexico and increase in power generation gas demand in the West South Central and South-Atlantic regions. Flows from Western Canada to the east remain low, as consumers in Eastern Canada increasingly rely on Marcellus/Utica supplies.

3.1.2 North American Demand Outlook

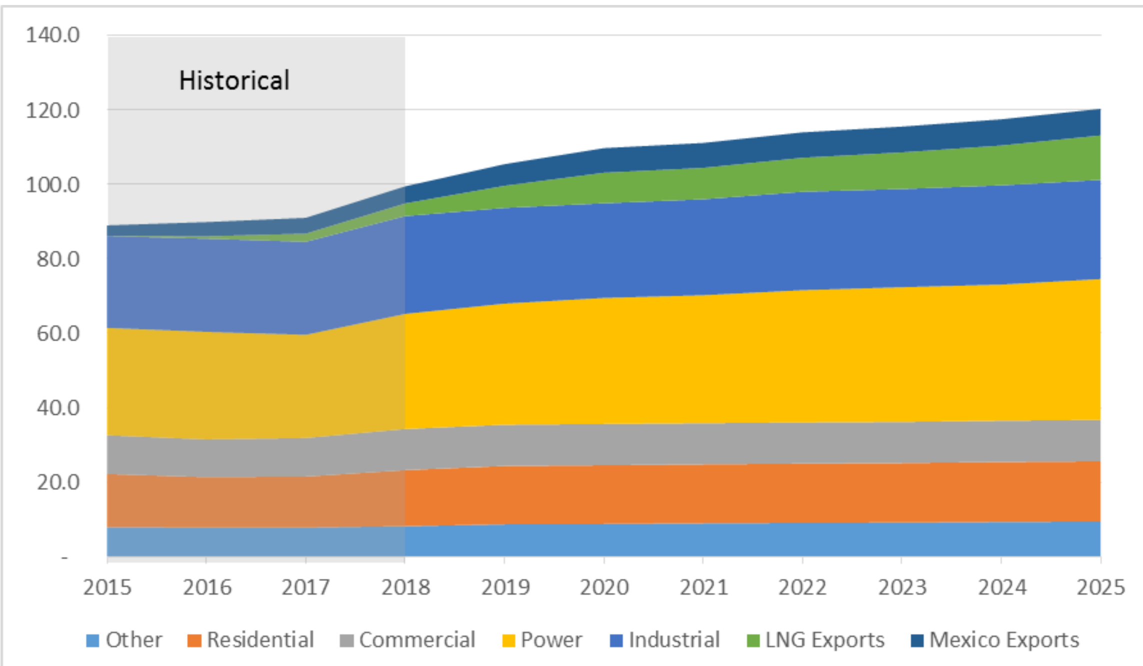
The rapid growth of shale gas production encourages continued growth in gas consumption and exports from North America. Through 2025, growth in North America demand is projected primarily from natural gas exports and from power generation. The majority of the expected exports are via LNG terminals and piped gas to Mexico.

The power generation sector has been the major driver of incremental gas consumption within North America. The growth in power sector gas consumption is driven by multiple factors, including the favorable economics of gas-fired generation, pre-existing environmental regulations (such as Mercury and Air Toxic Standards), and state and provincial regulations. By 2025, ICF projects that power sector gas demand will rise to 37.9 Bcfd, about 22% higher than 2018 power generation gas demand.

Gas demand from residential, commercial and industrial sectors are projected to grow modestly through 2025. Residential and commercial gas demands are expected to rise only slightly, as increased demand due to the addition of new gas customers is partially offset by reductions in per-customer consumption due to energy efficiency improvements.

Gas demand in Mexico is expected to increase sharply in order to meet growing power generation demand. By 2025, ICF projects that natural gas pipeline exports to Mexico will reach 7.2 Bcfd, about 56% higher than 2018 export volumes.

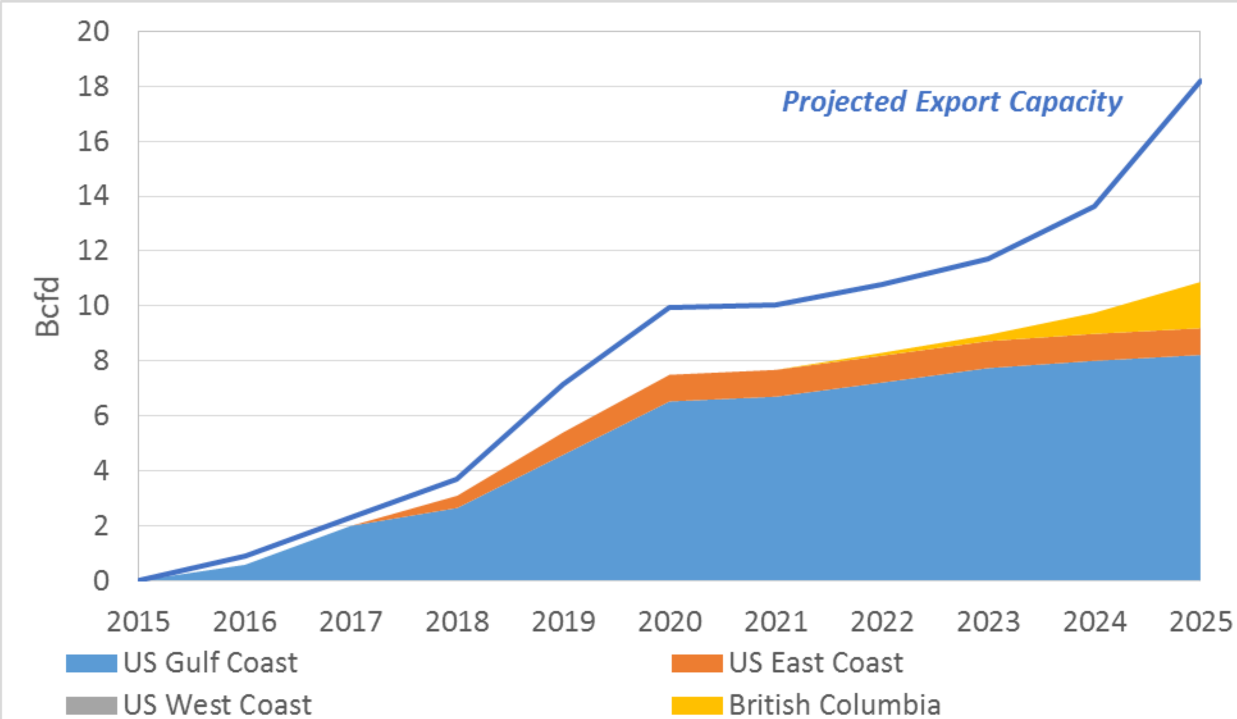
Exhibit 3-2: U.S. and Canada Natural Gas Demand by Sector



Source: ICF GMM® Q1 2019

LNG exports are projected to be a major driver of demand growth in the North American natural gas markets. ICF's current projection projects that the total North American LNG exports (excluding liquefaction losses) reach 10.9 Bcfd by 2025, more than three times the 2018 levels.

Exhibit 3-3: LNG Export Volume versus Capacity



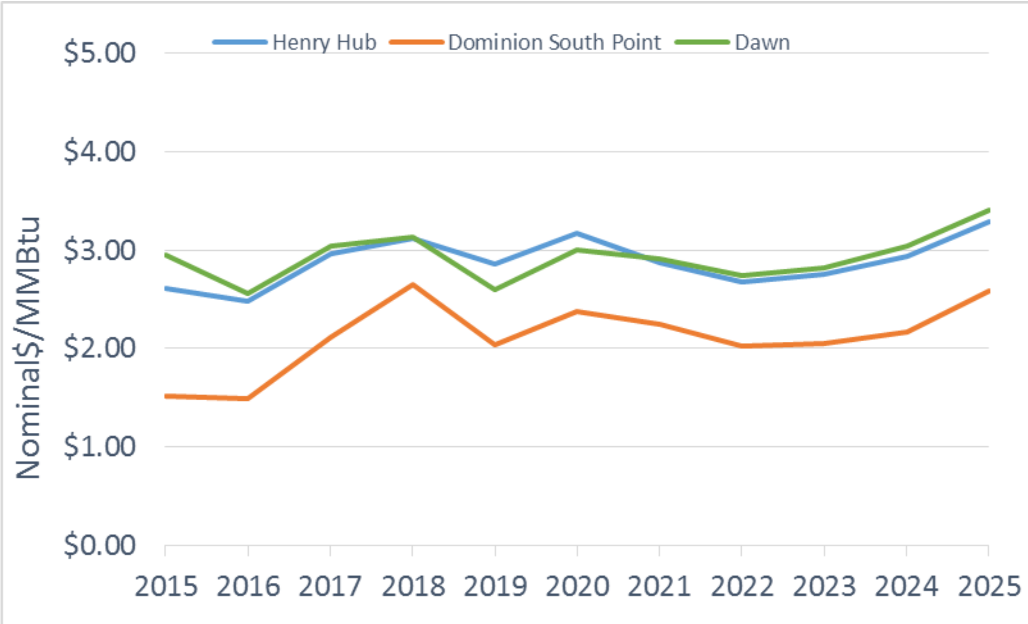
Source: ICF GMM® Q1 2019

3.1.3 North American Price Outlook

ICF expects natural gas prices across North America to stay relatively flat in real terms through 2025 despite growth in demand from LNG exports, pipeline exports to Mexico and power generation gas demand. Production is projected to continue to grow rapidly from shale and tight oil plays, especially from the Marcellus/Utica and Permian regions. Low gas production costs will prevent large price increases from occurring, as a supply response is expected due to increasing gas prices that make it economic to grow gas production in areas outside of the Permian region, Marcellus and Utica shale plays.

ICF is projecting Henry Hub natural gas prices to stay below US$3.30 per MMBtu through 2025. ICF projects that prices at Dawn will rise to US$3.41/MMBtu (in nominal terms) by 2025.

Exhibit 3-4: Natural Gas Prices (US$) at Henry Hub, Dominion South Point, and Dawn



Source: ICF GMM® Q1 2019

3.2 Ontario Natural Gas Markets

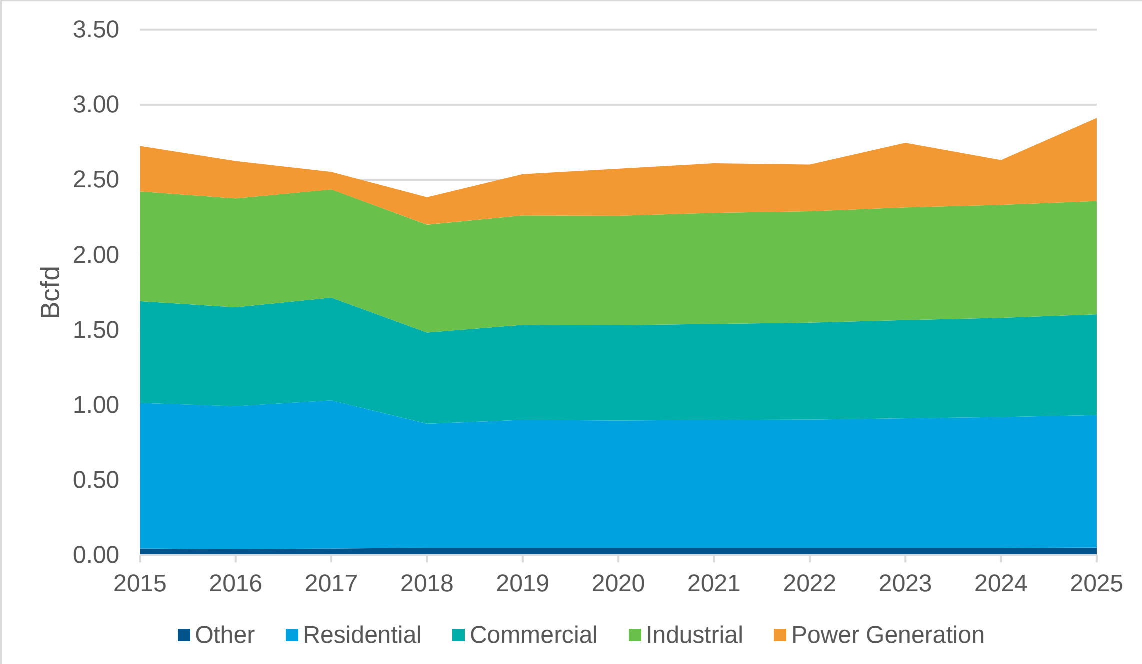
The Ontario gas market is also continuing to develop. Ontario's natural gas demand in 2018 was estimated to be about 2.4 Bcfd and accounted for approximately 21 percent of Canada's total natural gas demand. The demand in Ontario is expected to increase slightly to 2.5 Bcfd in 2019 and to 2.9 Bcfd by 2025.

ICF expects power generation gas demand to experience the most growth during the next seven years, increasing from 0.2 Bcfd in 2018 to 0.6 Bcfd in 2025. The power generation gas demand in 2017 was significantly lower than in 2016 mainly driven by lower demand, higher hydro generation and reduced net electricity exports from Ontario. The gas demand from power sector in 2018 rebounded from the 2017 lows, compensating for slightly lower nuclear output and higher demand compared to the prior year. As nuclear power plants retire and access to gas from the Western Canada and Marcellus/Utica supply region of the U.S. improves, natural gas-fired power generation is projected to increase significantly by 2025.[2]

Currently, the residential sector, which mainly relies on natural gas for space and water heating, has the largest demand for natural gas in Ontario and averages about 0.8 Bcfd annually. The residential and commercial sectors together comprise over half of Ontario's natural gas demand. These sectors are expected to remain relatively stable over the next few years.

[2] ICF's base case model includes a carbon price assumption reflecting accounts for Output Based Pricing System (OBPS) benchmark of 370 tons CO2e/GWh for carbon pricing in Ontario. The new OBPS benchmark contributed to lower gas demand from the power sector, especially in the near term, with carbon pricing rising between 2019 and 2022 before leveling out post-2022.

Exhibit xx: Ontario Natural Gas Demand



Source: ICF GMM® Q1 2019

3.3 Alberta Natural Gas Markets

The development of shale gas technologies has had significant impacts on Alberta natural gas markets. ICF is projecting overall natural gas production from Alberta to rise slowly over the next five years as growth in shale gas production in Western Alberta and Eastern British Columbia more than offsets declines in production from conventional natural gas resources in Eastern Alberta.

The shift in the location of production between Eastern Alberta and Western Alberta/British Columbia is resulting in the need for significant new pipeline construction from the new production plays into the AECO market center. Currently, AECO prices are suppressed relative to Empress prices and other North American gas markets due to the imbalance between production growth and pipeline capacity development. As pipeline capacity development catches up with production, the price spread between AECO and Empress is expected to return to historical levels.

In the longer term, LNG exports from British Columbia will also drive natural gas demand and prices in the WCSB. However, development of BC LNG export facilities are not expected to be completed during the time frame of this analysis.

3.4 Implications of Changes in North American Natural Gas Markets on the Enbridge Gas Supply Portfolio

Recent changes in North American gas markets are changing the both the optimal natural gas supply portfolio for Ontario, as well as the characteristics of the gas market that drive the cost and volatility of the natural gas supply portfolio. The largest market shift has been the rapid growth in natural gas supply, lowering overall natural gas prices, and increasing overall stability in the market.

The growth in supply has also resulted in fundamental changes in natural gas infrastructure, with additional implications on natural gas market behavior in Ontario. These changes include improved pipeline access to the Marcellus/Utica basin through the Rover and NEXUS pipelines.

- Rover and NEXUS provide additional gas supply into the U.S. Midwest and Ontario, reducing gas price volatility in the broader region.

The availability of these two new pipelines, plus additional contracted pipeline capacity from Western Canada via the TransCanada Dawn LTFP service has increased the natural gas supply diversity for Ontario natural gas consumers and appears to have reduced overall price volatility at Dawn.

The availability of the additional pipeline capacity into the US Midwest and into Ontario has both short- and long-term market impacts. In the near-term, excess pipeline capacity on NEXUS provides additional flexibility to the market during periods of high natural gas demand. The stability is provided by the direct link to gas prices in the Marcellus/Utica. As long as excess pipeline capacity is available, natural gas prices in the demand region will more closely reflect gas price behavior in the supply basin, which typically remain more stable than demand region prices during extreme weather events. Hence, the NEXUS Pipeline has helped stabilize natural gas prices in Ontario in the near term, even during extreme weather events.

However, NEXUS pipeline capacity is unlikely to remain underutilized in the longer term. As production continues to increase in the Marcellus/Utica, pipeline capacity utilization out of the basin will increase, reducing supply flexibility, and leading to a return in volatility in Ontario natural gas prices.

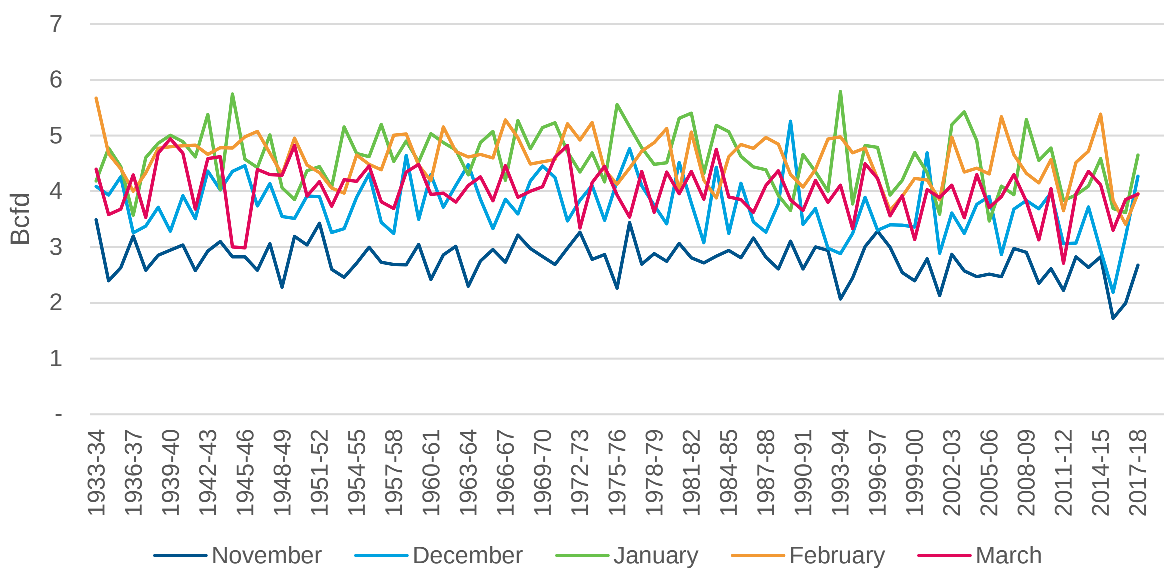
4 Projecting the Impact of Weather on Future Natural Gas Prices

As described in Section 1.2 of this report, ICF used the Gas Market Model (GMM) to produce monthly gas commodity price forecasts across supply basins contracted by Enbridge under a range of different weather conditions, in order to generate cold case, base case, and warm case scenarios, as well as an assessment of the variability around the scenarios. The commodity price forecasts were provided to Enbridge as inputs to the Enbridge Sendout © model, including prices for each supply basin where Enbridge contracts for natural gas.

4.1 Impact of Weather on Projected Ontario Natural Gas Demand

The figure below shows the monthly gas demand in Ontario for November 2020 to March 2021 across all 85 weather scenarios that are part of ICF's Gas Price Risk Report. This figure shows that across most weather scenarios that average daily demand for November is the lowest, followed by December. January and February are consistently the highest demand months across nearly all the weather scenarios.

Figure 5. Forecast of Ontario Monthly Demand for the 2020-21 Winter by Weather Scenario

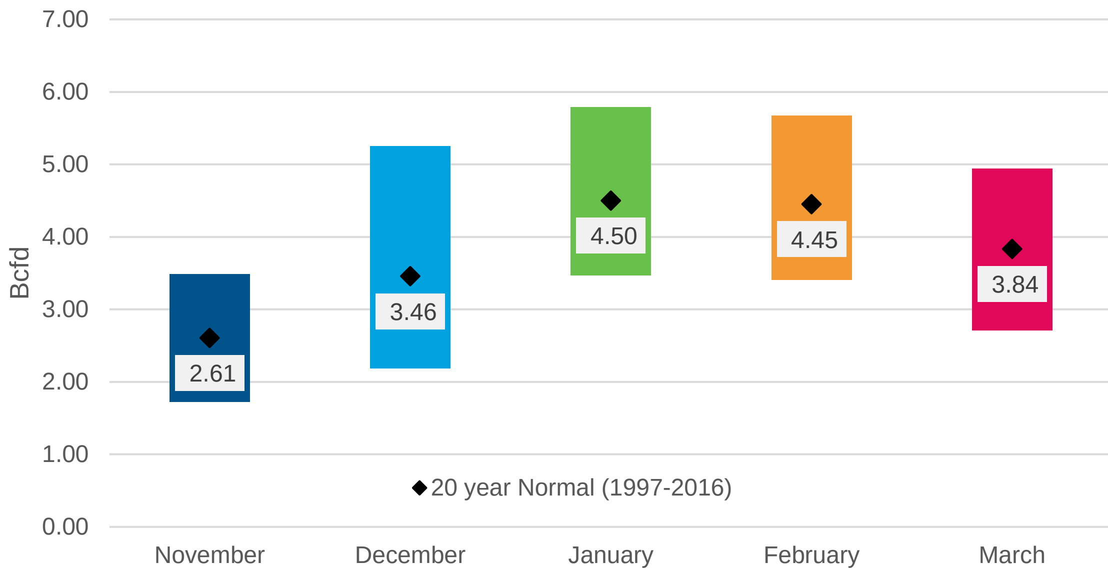


Source: ICF GMM® – Gas Price Risk Report

In Ontario, January is typically the highest demand month with an average monthly demand of 4.5 Bcfd, followed by February at 4.45 Bcfd. December and March are the third and fourth highest daily demand month with November demand typically being over 60% lower than levels in January.

December is the month with the widest ranges between maximum daily demand and minimum demand levels. These variations in demand are driven by the large swings in the monthly HDDs year-to-year that December can experience, particularly from lower than normal heating demand associated with a late start to winter similar to that experienced in December 2015, when HDDs were nearly 33% lower than the 20-year average.

Figure 6. Forecast of Monthly Demand Range of Ontario Gas Demand for the 2020-21 Winter Based on Weather

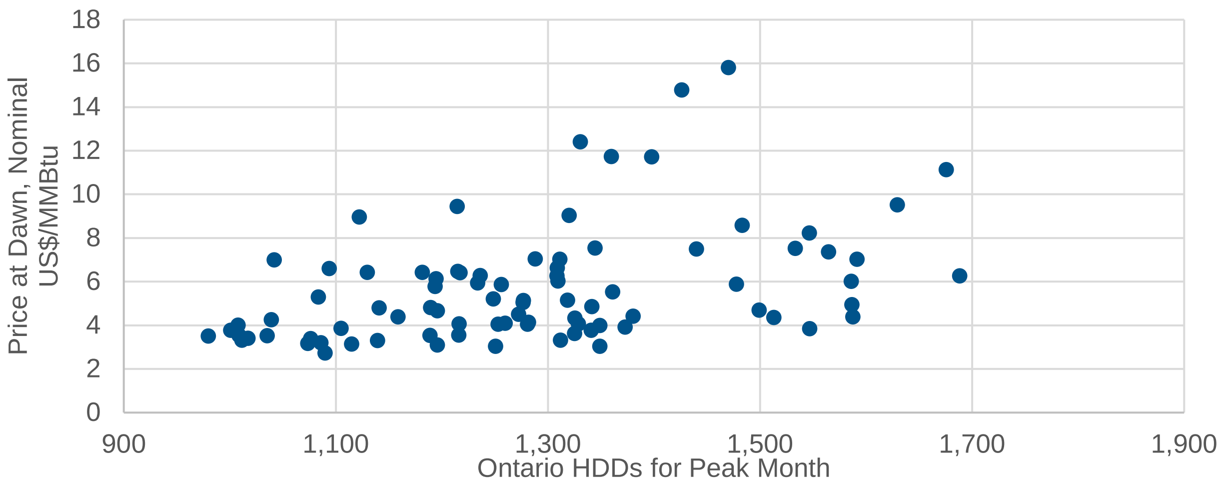


Source: ICF GMM® – Gas Price Risk Report

4.2 Outlook for Natural Gas Price at Dawn

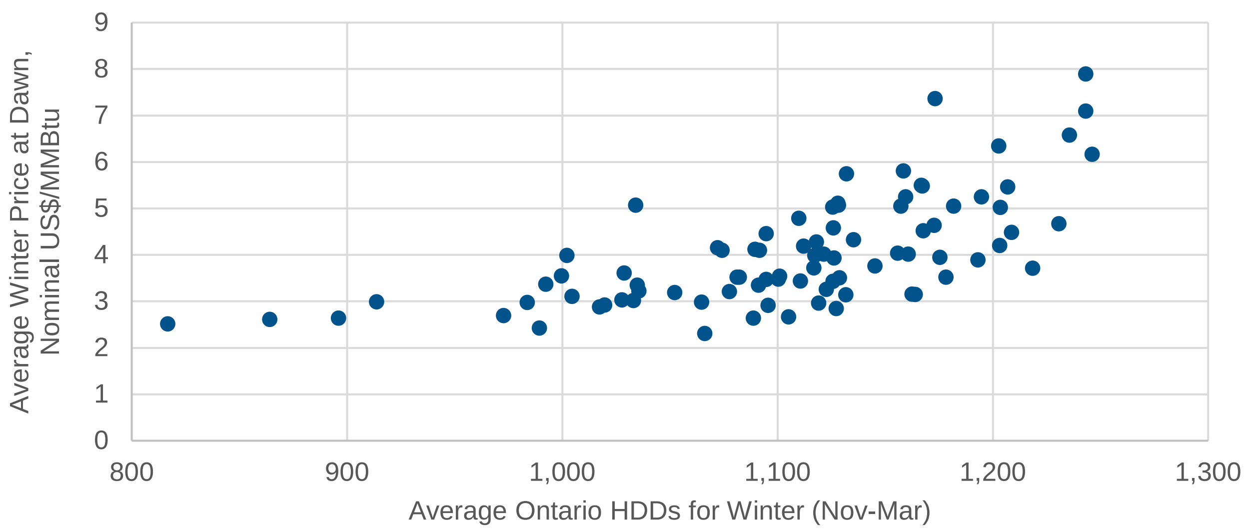
Figure 7 illustrates the price distribution at Dawn during peak winter month in Nov 2021 – March 2022 and the corresponding HDDs in Fahrenheit for each of the weather scenarios. The scatter plot shows that the price at Dawn is different for the same number of HDDs. Though the peak winter price at Dawn is dependent on HDDs, it also depends on several factors like the duration of the cold weather, storage inventory levels going into the peak month, weather in the U.S. Northeast and U.S. Midwest among various other factors. Figure 8 shows the same plot for average winter price at Dawn (Nov 2020 – Mar 2021) versus the average HDDs during the same period for each of the weather scenarios.

Figure 7: Peak Month Natural Gas Price at Dawn versus Peak month Ontario HDDs



Source: ICF GMM® – Gas Price Risk Report

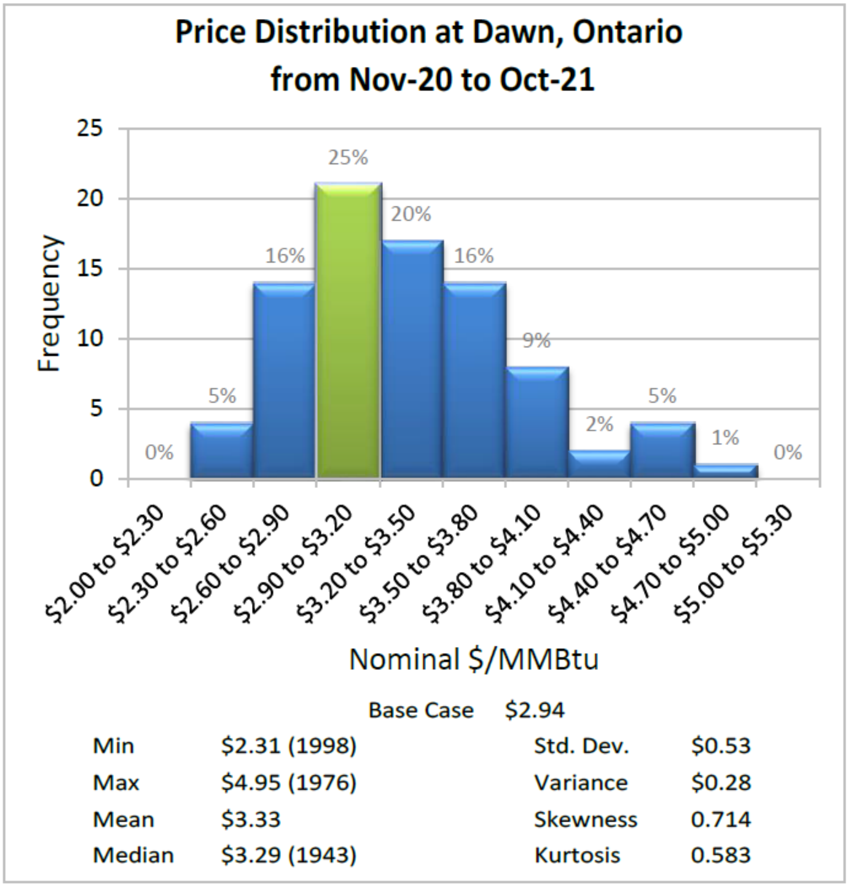
Figure 8: Average Winter Natural Gas Price at Dawn versus Ontario HDDs



Source: ICF GMM® – Gas Price Risk Report

Figure 9 shows the range of average gas prices at Dawn for 84 different weather cases for the next year based on an earlier ICF Base Case Analysis. As shown on this chart, the price risk associated with weather is on the high side, with the mean price of the 84 different weather scenarios at US$3.33 compared to the normal weather price of US$2.94 per MMBtu. The actual range of impacts is due to the range of positive and negative correlations between weather patterns in different regions of North America.

Figure 9: Price Distribution at Dawn



Source: ICF GMM® – Gas Price Risk Report

Appendix C provides the price distribution information for the market centers significant to Enbridge's gas supply portfolio.

5 Development of Base Case, Best Case, and Worst Case Natural Gas Price Scenarios Due to Weather

ICF uses the average weather patterns over the last twenty years to project a base case natural gas market forecast, including demand, transportation and natural gas prices. However, as discussed previously, differences in weather can have a significant impact on natural gas prices.

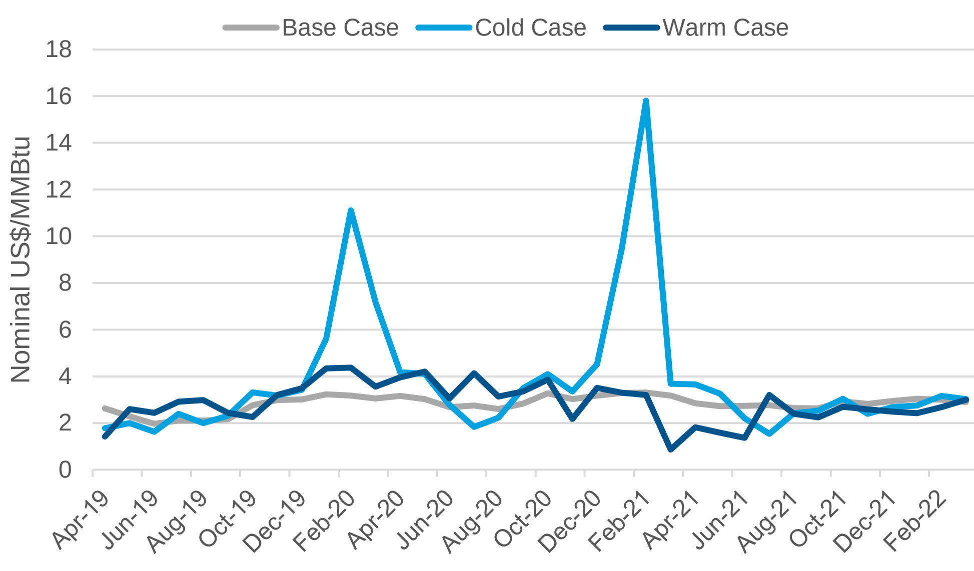
In order to create the best case and worst case gas price scenarios requested by the OEB, ICF used the GMM to forecast natural gas prices using historical weather patterns. The focus of the analysis was on the 12-month period from November 2020 through October 2021. However, the modeling was done for a three-year time period from April 2019 through March 2022 The use of the three-year time period enabled the projections to account for the impact of previous year weather on natural gas market conditions during the assessment year.

5.1 Impact of Weather on Natural Gas Prices at Dawn

The “Best” case and “Worst Case” weather patterns were selected based on the biggest one-month impact during the 12 month assessment period. Of note, the biggest impact does not necessarily occur during the coldest year or warmest year. In fact, in the largest price impact in the “Worst Case” scenario occurred in the second year of two consecutive years with colder than normal weather.

Figure 12 shows the price distribution at Dawn for three cases based on three-year weather runs. We can see that the prices at Dawn are projected to be significantly higher than the base case in the Worst Case weather scenario while the prices in the Best Case weather are generally lower than the base case during the winter of Nov 2020-Oct 2021 gas year.

Figure 10: Dawn Prices (US$) Under the Three ICF Weather Scenarios



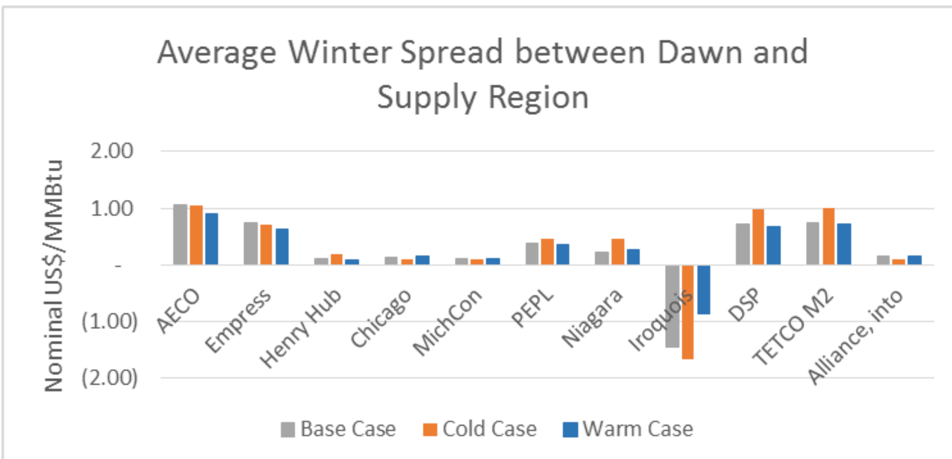
Source: ICF GMM® – Gas Price Risk Report

The monthly prices for each of the three scenarios are included in Appendix C.

5.2 Impact of Weather on Natural Gas Prices at Other Natural Gas Market Centers Relevant to Enbridge

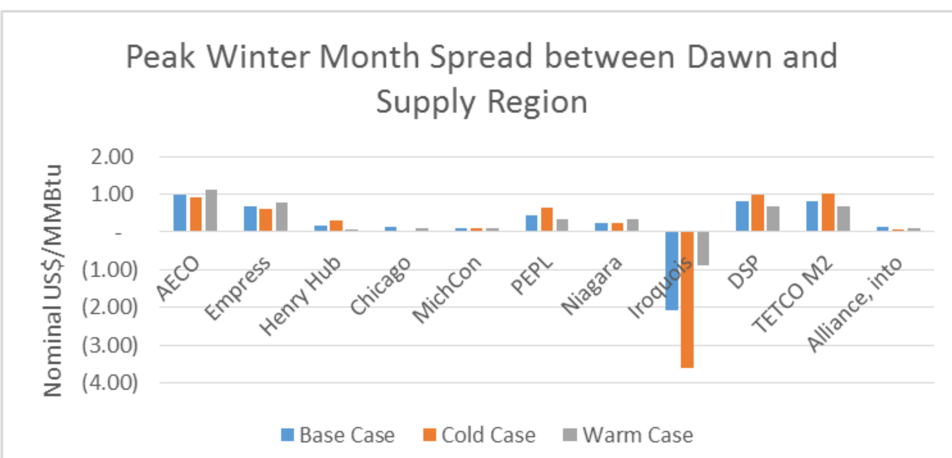
Most of the price impact in the Worst Case Weather Scenario is the result on tight supply conditions, and the price impact occurs across most major North American gas markets. However, there are regional differences in gas prices related to the differential impact of weather in different regions. Figures 11 and 12 illustrate the differential regional impacts of weather on gas prices for each of the three weather scenarios.

Figure 11: Average Winter Spread between Dawn and Supply Region



Source: ICF GMM® – Gas Price Risk Report

Figure 12: Peak Winter Month Spread between Dawn and Supply Region



Source: ICF GMM® – Gas Price Risk Report

The monthly forecast for each market center and scenario is included in Appendix C.

5.3 Base Case, Worse Case and Best Case Weather Scenarios

The average prices for the 12-month period from November 2020 through October 2021 for the three weather cases are shown in Table 3 for each of 12 market centers of significance to Enbridge. The average prices for the 5-month winter from November 2020 through March 2021 for the three weather cases are shown in Table 4. The average prices for the peak month (February) during the November 2020 through March 2021 winter are shown in Table 5.

Table 3. 12 Month Average Natural Gas Prices at Key Market Centers (2017 $/Dth)

	Average Price Nov 2020 - Oct 2021				Price Spread Relative to Dawn		
	Base Case Weather Scenario	Worst Case Weather Scenario	Best Case Weather Scenario		Base Case Weather Scenario	Worst Case Weather Scenario	Best Case Weather Scenario
AECO	$1.88	$3.54	$1.41		$1.06	$1.08	$0.95
Empress	$2.16	$3.81	$1.66		$0.77	$0.81	$0.70
Dawn	$2.94	$4.62	$2.36				
Henry Hub	$2.93	$4.51	$2.36		$0.01	$0.11	$0.00
Chicago	$2.78	$4.47	$2.21		$0.15	$0.15	$0.15
MichCon	$2.83	$4.52	$2.25		$0.11	$0.10	$0.11
PEPL	$2.58	$4.17	$2.04		$0.35	$0.45	$0.32
Niagara	$2.61	$4.03	$2.02		$0.32	$0.59	$0.34
Iroquois	$3.61	$5.42	$2.79		-$0.68	-$0.80	-$0.43
Dominion South	$2.28	$3.69	$1.72		$0.66	$0.93	$0.64
TETCO M2	$2.23	$3.64	$1.68		$0.70	$0.98	$0.68
Alliance Trading Point	$2.77	$4.46	$2.20		$0.16	$0.16	$0.16

Table 4. Average 5-Month Winter Natural Gas Prices at Key Market Centers (2017 $/Dth)

	Average Price Nov 2020 - Mar 2021				Price Spread Relative to Dawn		
	Base Case Weather Scenario	Worst Case Weather Scenario	Best Case Weather Scenario		Base Case Weather Scenario	Worst Case Weather Scenario	Best Case Weather Scenario
AECO	$2.14	$6.33	$1.70		$1.05	$1.04	$0.91
Empress	$2.46	$6.65	$1.98		$0.73	$0.72	$0.63
Dawn	$3.19	$7.36	$2.61		$0.00	$0.00	$0.00
Henry Hub	$3.10	$7.19	$2.53		$0.10	$0.18	$0.08
Chicago	$3.06	$7.27	$2.47		$0.13	$0.09	$0.14
MichCon	$3.08	$7.28	$2.50		$0.11	$0.09	$0.11
PEPL	$2.81	$6.91	$2.25		$0.38	$0.46	$0.36
Niagara	$2.97	$6.90	$2.33		$0.22	$0.46	$0.28
Iroquois	$4.64	$9.04	$3.47		-$1.45	-$1.68	-$0.86
Dominion South	$2.47	$6.39	$1.93		$0.72	$0.97	$0.68
TETCO M2	$2.44	$6.36	$1.90		$0.75	$1.00	$0.71
Alliance Trading Point	$3.05	$7.26	$2.46		$0.14	$0.10	$0.15

Table 5. Peak Month Winter Natural Gas Prices at Key Market Centers (2017 $/Dth)

	Average Price February 2021				Price Spread Relative to Dawn		
	Base Case Weather Scenario	Worst Case Weather Scenario	Best Case Weather Scenario		Base Case Weather Scenario	Worst Case Weather Scenario	Best Case Weather Scenario
AECO	$2.31	$14.88	$2.32		$0.99	$0.93	$0.88
Empress	$2.62	$15.19	$2.63		$0.68	$0.62	$0.57
Dawn	$3.30	$15.81	$3.21		$0.00	$0.00	$0.00
Henry Hub	$3.14	$15.50	$3.07		$0.16	$0.30	$0.14
Chicago	$3.17	$15.76	$3.07		$0.13	$0.05	$0.13
MichCon	$3.20	$15.70	$3.10		$0.11	$0.11	$0.11
PEPL	$2.86	$15.18	$2.80		$0.44	$0.63	$0.40
Niagara	$3.07	$15.58	$2.78		$0.23	$0.23	$0.43
Iroquois	$5.36	$19.42	$4.20		-$2.06	-$3.61	-$1.00
Dominion South	$2.49	$14.80	$2.29		$0.81	$1.00	$0.92
TETCO M2	$2.47	$14.78	$2.27		$0.83	$1.02	$0.94
Alliance Trading Point	$3.16	$15.75	$3.06		$0.14	$0.06	$0.14

These tables illustrate both the range in natural gas prices at the market centers of significance to Enbridge, as well as the differential impact of weather on market prices at different market centers. The impact of weather on prices is clearly asymmetrical, with price increases in the Worst Case Weather scenario much larger than the price decreases in the Best Case Weather Scenario. The monthly forecast for each scenario is included in Appendix C.

Appendix A: Description of ICF Gas Market Model (GMM)

ICF's Gas Market Model (GMM®) is an internationally recognized modeling and market analysis system for the North American gas market. The GMM was developed in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions. Since then, the GMM has been used to complete strategic planning studies for governments, non-government associations, utilities, and private sector companies. The different types of studies include:

- Analyses of pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by the user.

Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Figure 1). Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and curves. ICF does significant backcasting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

There are nine different components of ICF's model, as shown in Figure 2. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The gas consumption for the power sector is matched with the outputs from the IPM model (described below), and the two models (GMM and IPM) are run together until the gas prices and power sector gas consumption are converged.

The GMM model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Figure 3. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import levels. The supply component may be integrated with the GMM to solve for deliverability. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (*i.e.*, gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (*i.e.*, end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module.

Exhibit 5: Natural Gas Supply and Demand Curves in the GMM

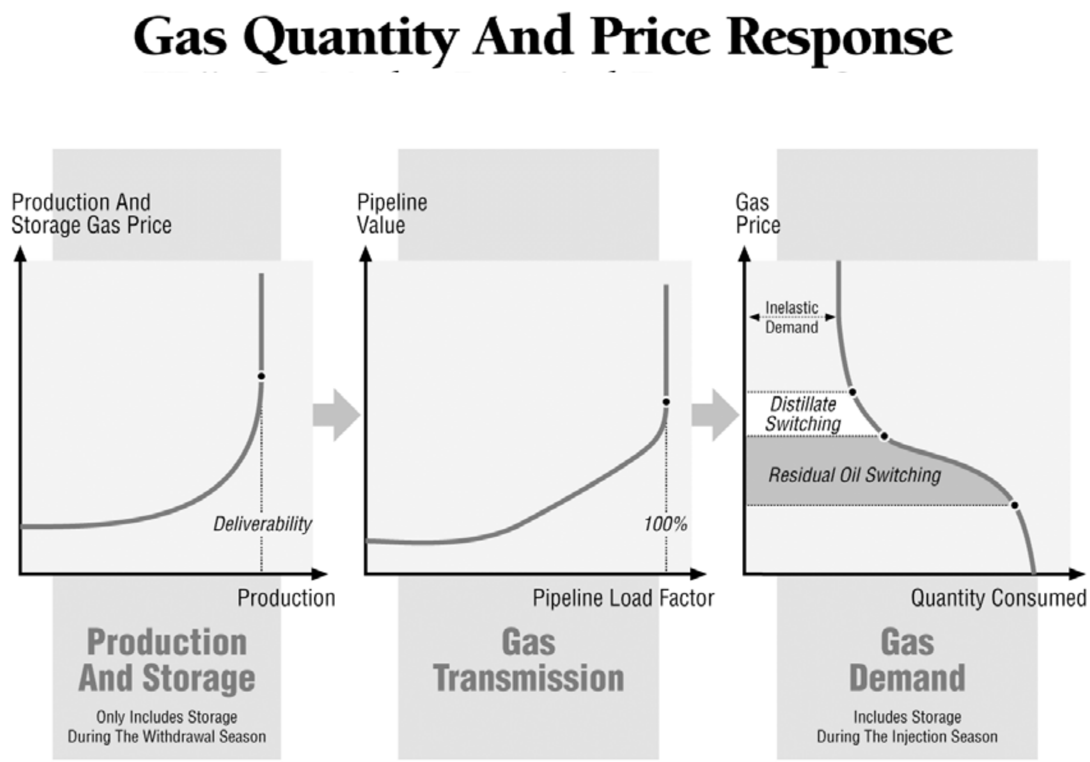


Exhibit 6: GMM Structure

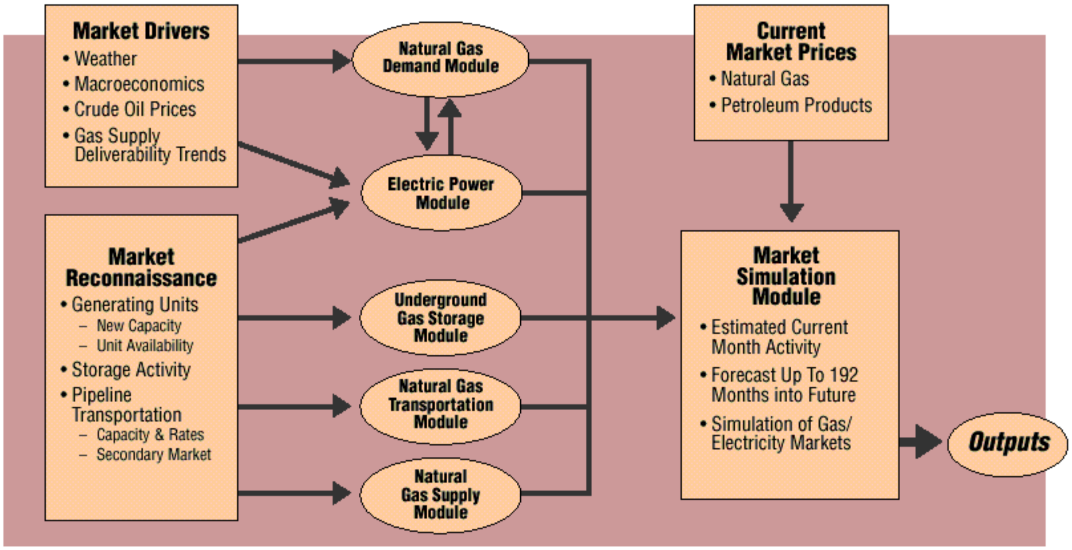
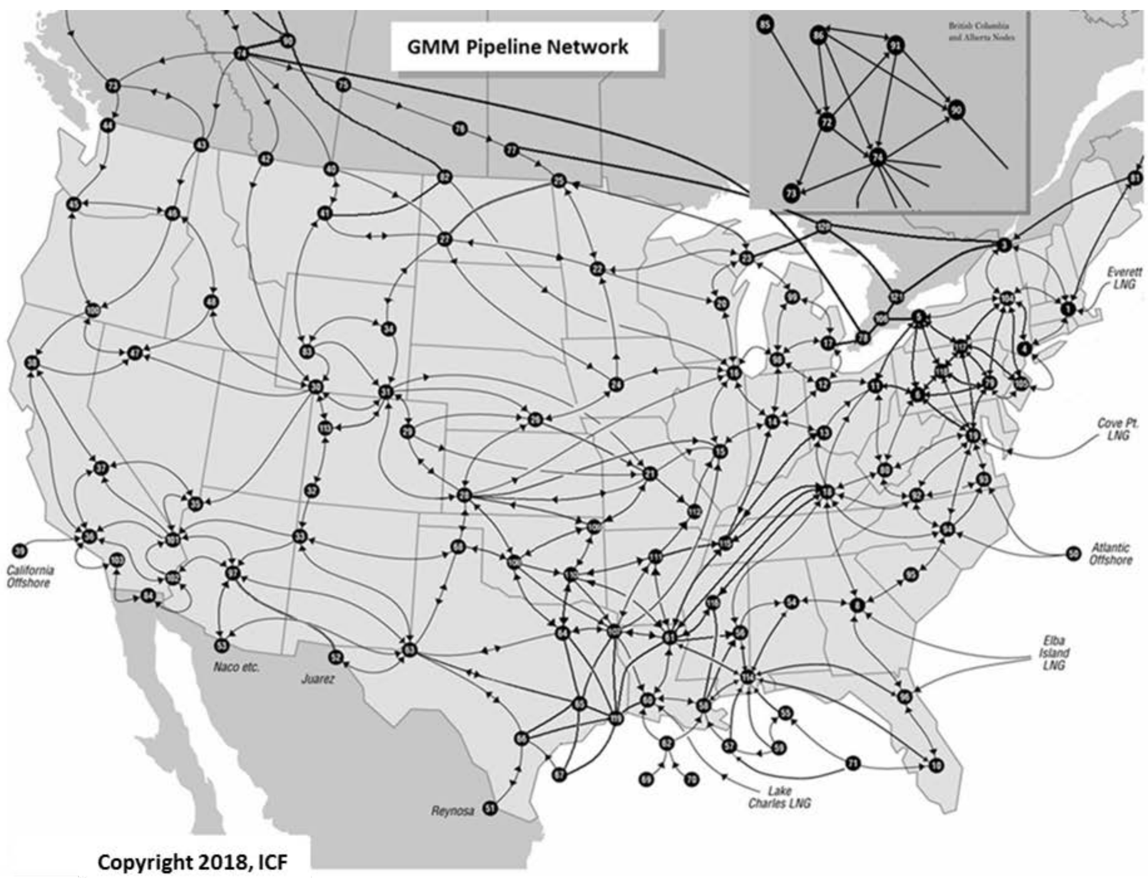


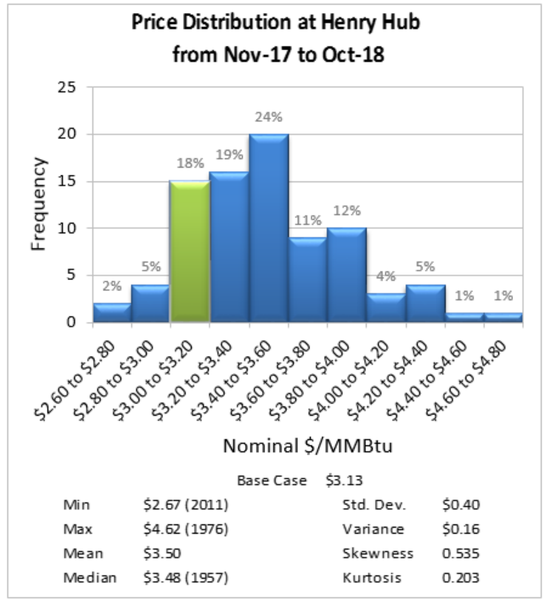
Exhibit 7: GMM Transmission Network



Appendix B: Natural Gas Price and Basis Distribution for Weather Runs at Different Hubs

ICF's Gas Price Risk Report

Providing Gas Price Distributions Based on Historic Weather



ICF's Gas Price Risk Report helps gas producers, midstream service providers, marketers, and gas consumers, including gas utilities and power providers, address gas price volatility due to the unpredictability of weather. Weather is a critical driver for near term gas prices. For ICF's Gas Price Risk Report, ICF does not try to predict weather, but instead uses 80 years of regional weather data to define distributions of gas prices at major price points throughout North America.

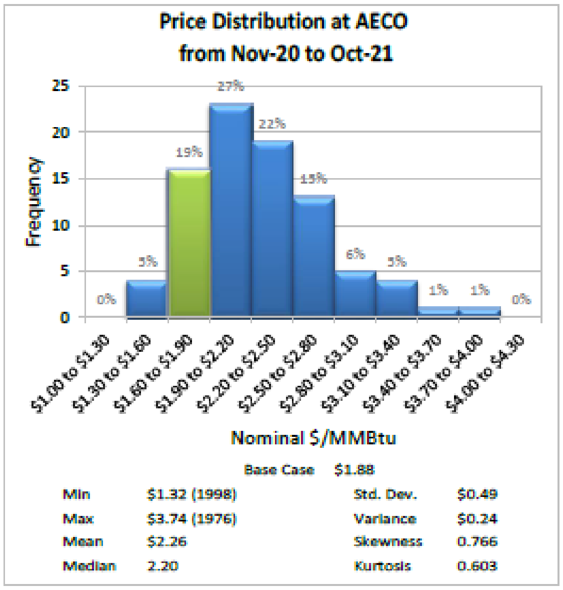
The Gas Price Risk Report is based on results from the Gas Market Model (GMM©), ICF's proprietary model of the North American gas market. To produce the report, ICF's model is run multiple times with actual weather data from the past 80 years, solving for gas prices under current market conditions with the changing weather conditions. The model output is then used to define price and regional price basis distributions. The distributions in the report can be used to advise financial and resource planning as well.

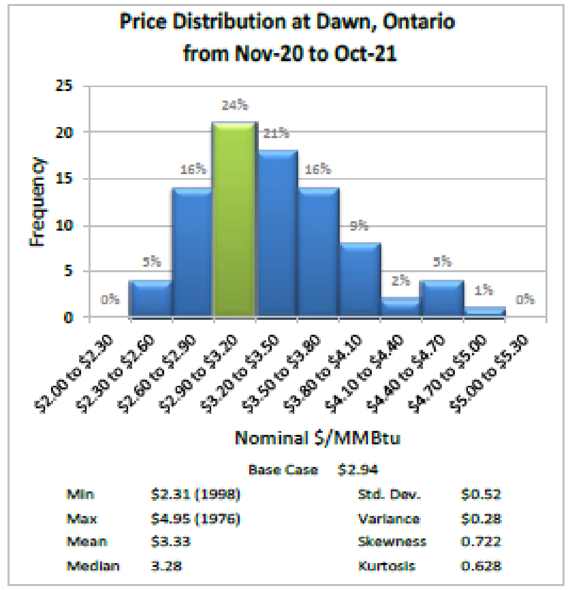
The Detailed Information Presented in the Gas Price Risk Report Includes:

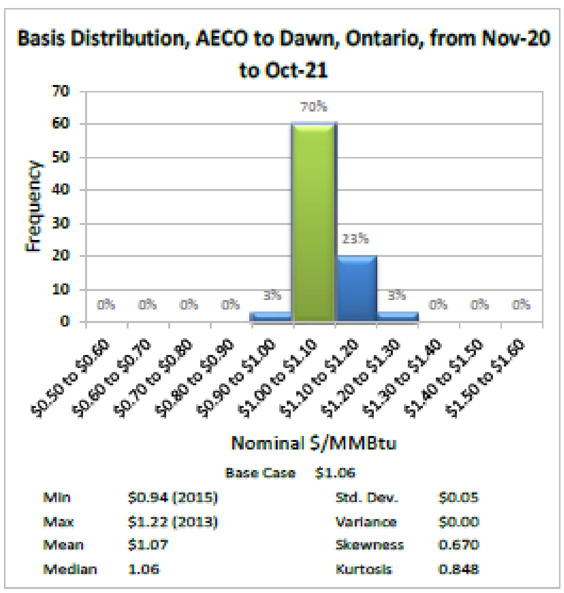
- **Price Charts** that provide price distributions for gas prices at major pricing points throughout North America.
- **Price Charts** that provide regional price basis distributions for basis between major pricing points across North America.
- **Statistical Measures**, including the mean, median, standard deviation, variance, and measures of skewness are provided for each price and regional price basis distribution.
- **Regional Charts** provide distributions for heating degree days (HDDs) and Cooling Degree Days (CDDs).
- **A Database**, including price results, HDDs, and CDDs from the multiple runs of ICF's GMM© is provided so that subscribers may develop their own charts and relationships for the information.

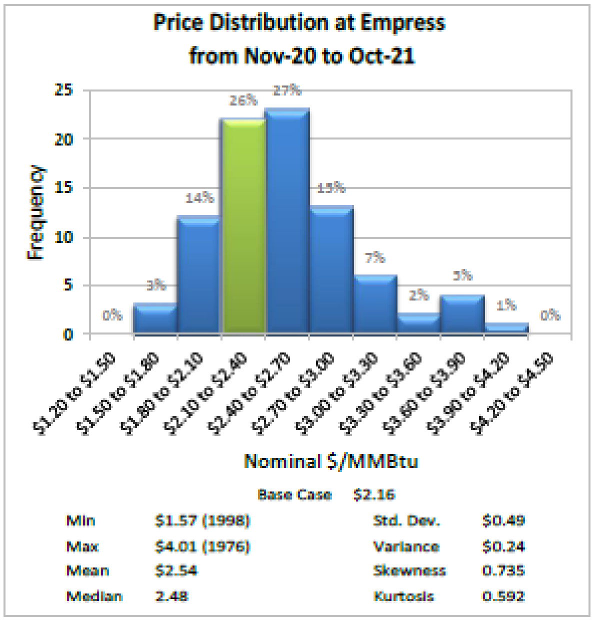
Exhibit 8: Dawn, Ontario and AECO Price Distributions from Nov-20 to Oct-21

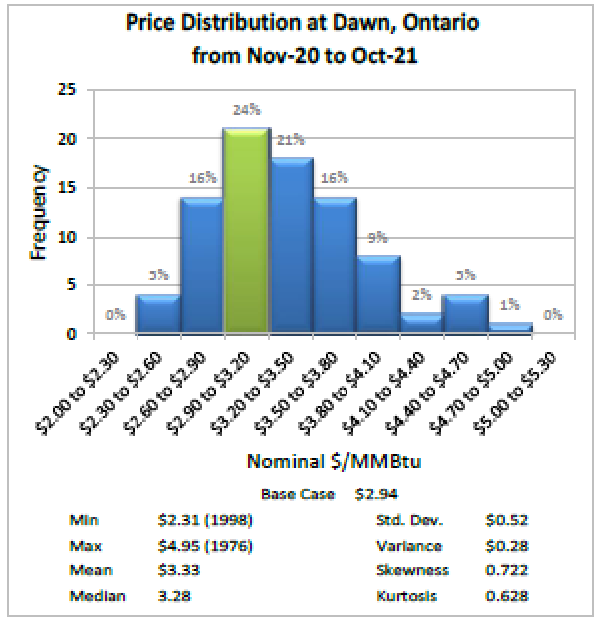
Source: ICF GMM® – Gas Price Risk Report











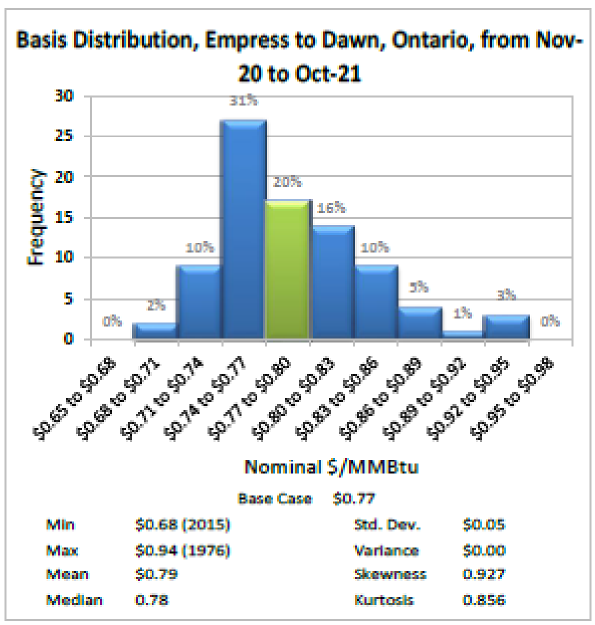
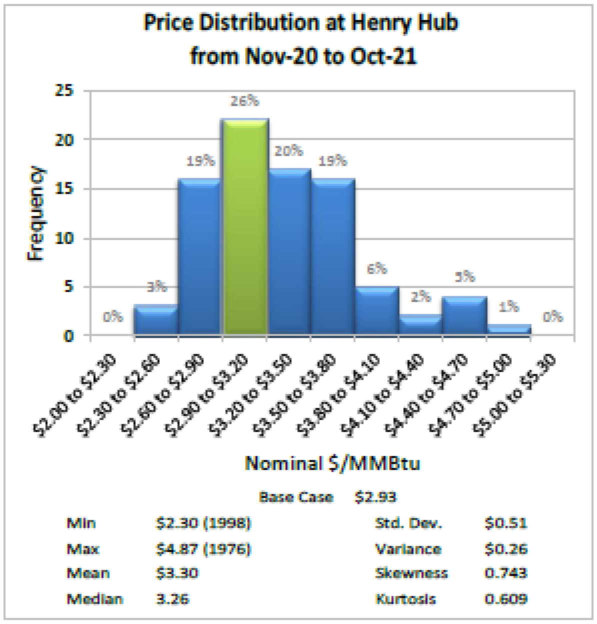
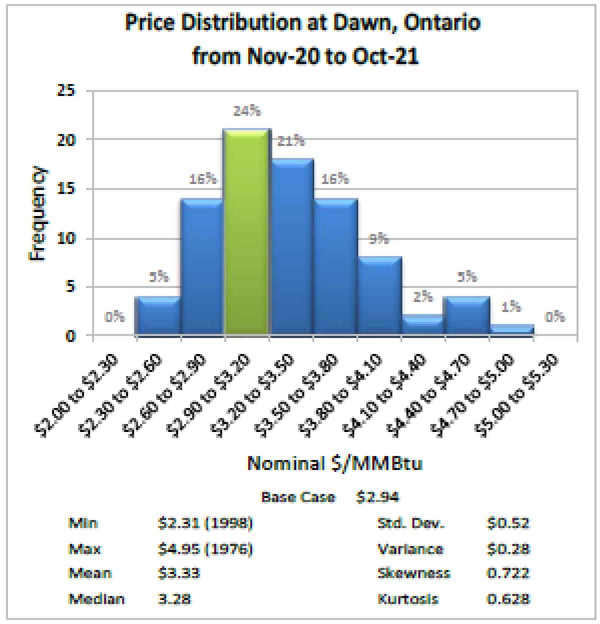


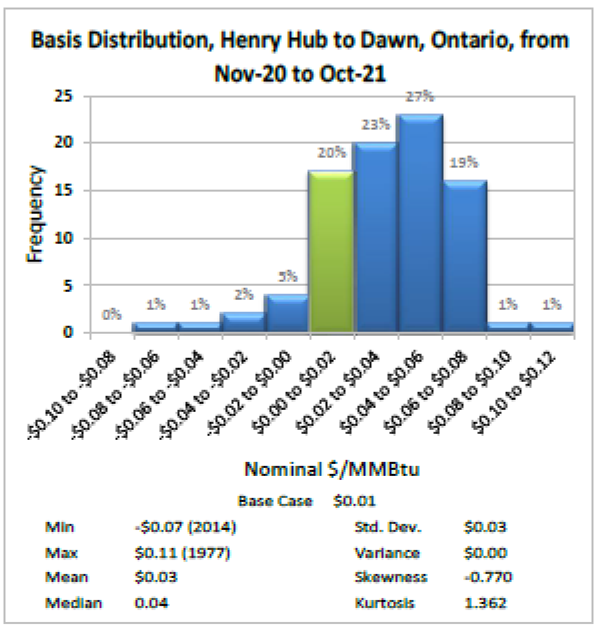
Exhibit 9: Dawn, Ontario and Empress Price Distributions from Nov-20 to Oct-21

Source: ICF GMM® – Gas Price Risk Report

Exhibit 10: Dawn, Ontario and Henry Hub Price Distributions from Nov-20 to Oct-21

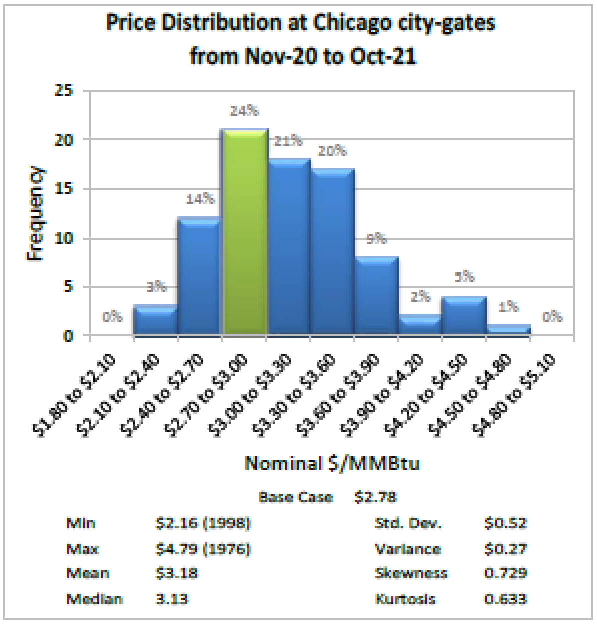


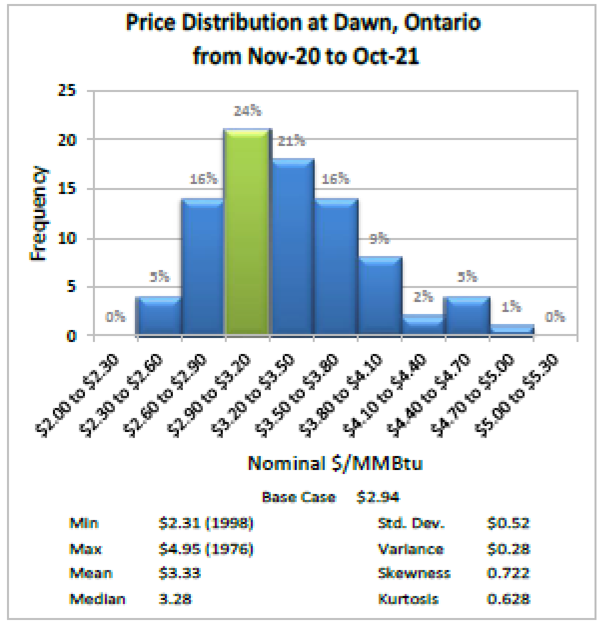


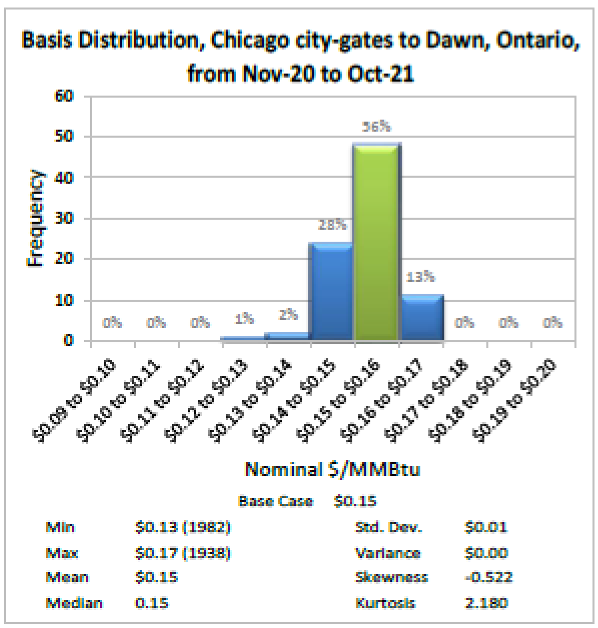


Source: ICF GMM® – Gas Price Risk Report

Exhibit 11: Dawn, Ontario and Chicago City-Gate Price Distributions from Nov-20 to Oct-21

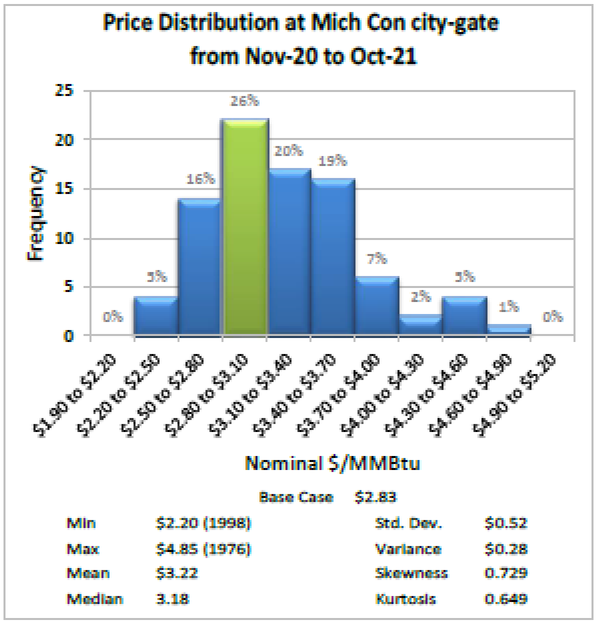


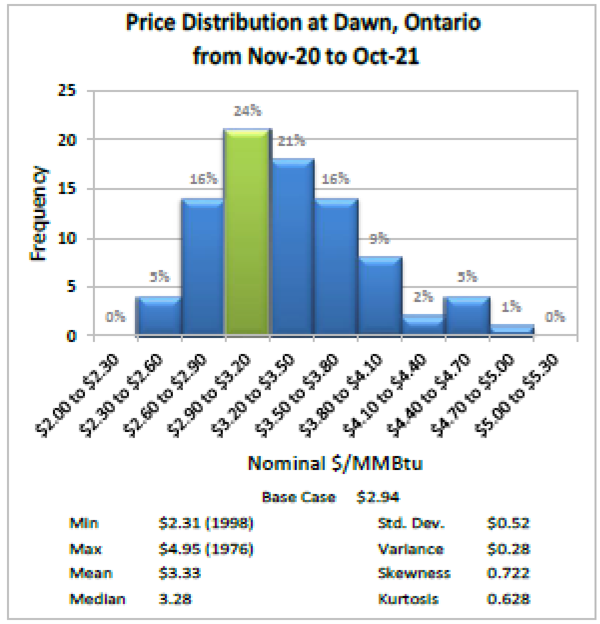


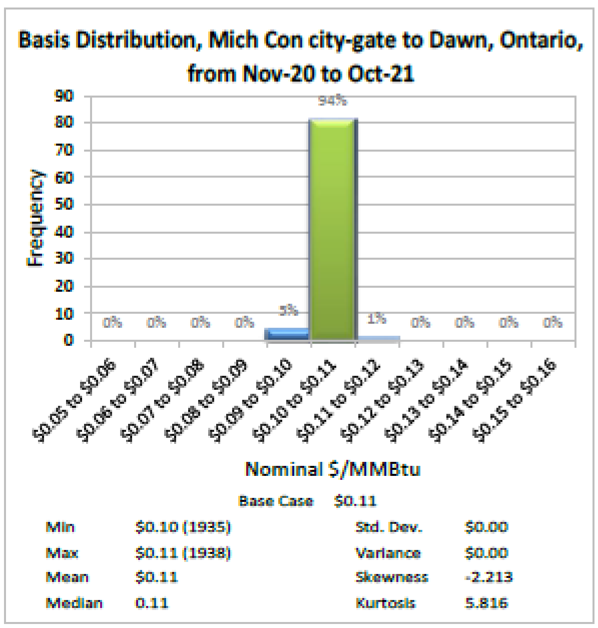


Source: ICF GMM® – Gas Price Risk Report

Exhibit 12: Dawn, Ontario and MichCon City-Gate Price Distributions from Nov-20 to Oct-21

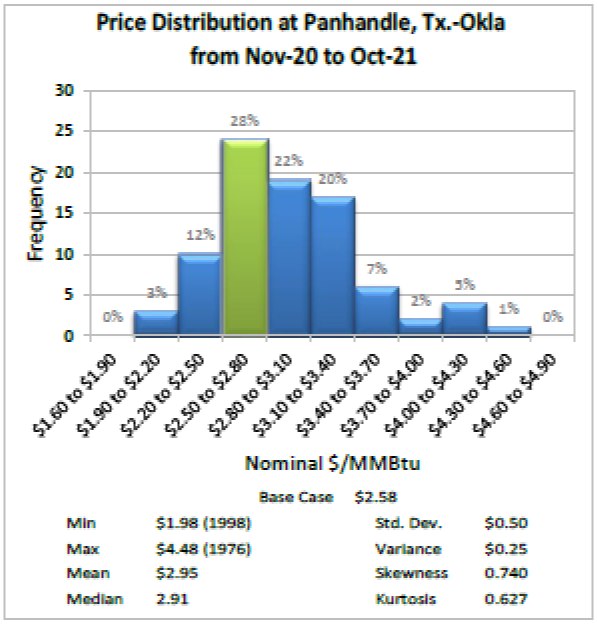


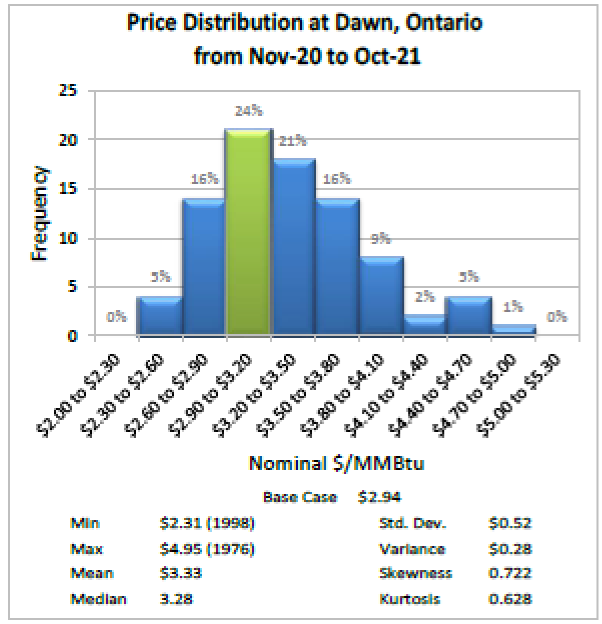


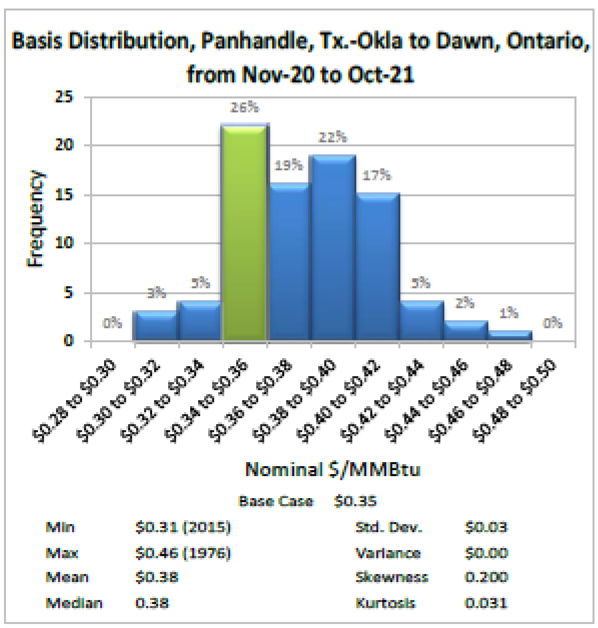


Source: ICF GMM® – Gas Price Risk Report

Exhibit 13: Dawn, Ontario and Panhandle, TX-Okla Price Distributions from Nov-20 to Oct-21

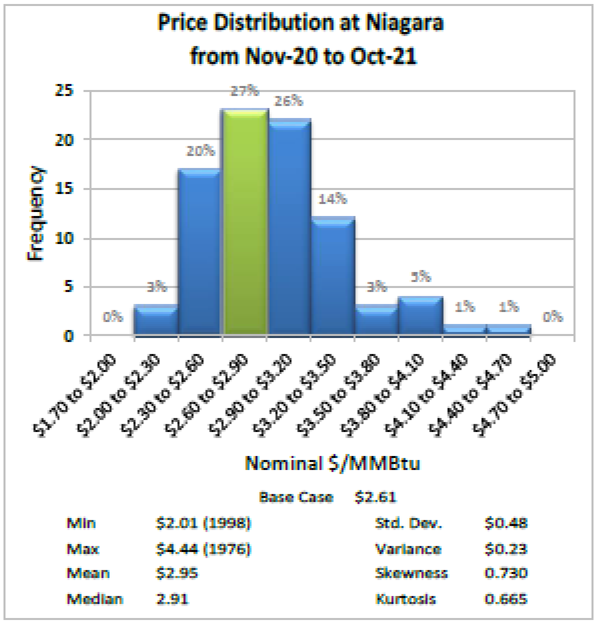


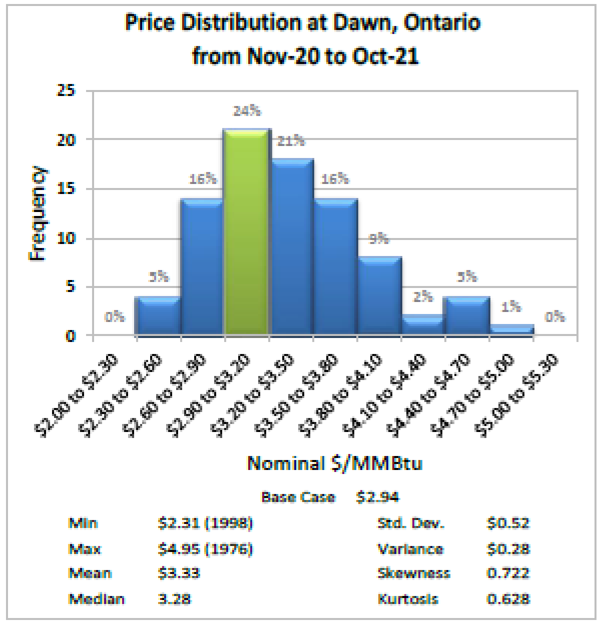


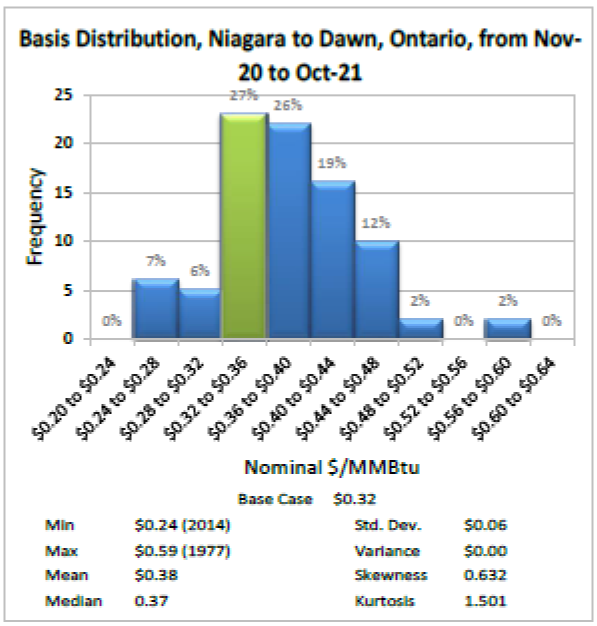


Source: ICF GMM® – Gas Price Risk Report

Exhibit 14: Dawn, Ontario and Niagara Price Distributions from Nov-20 to Oct-21

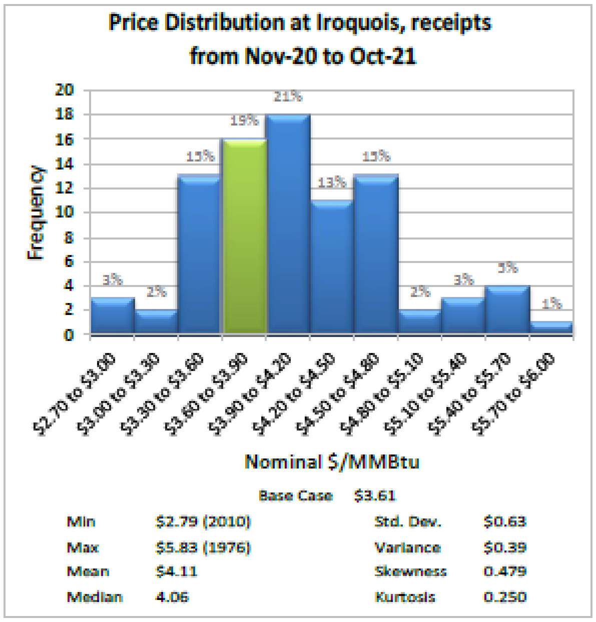


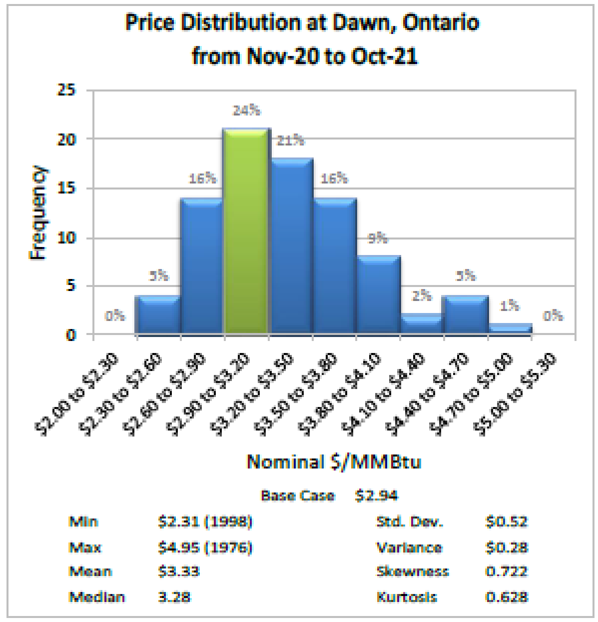


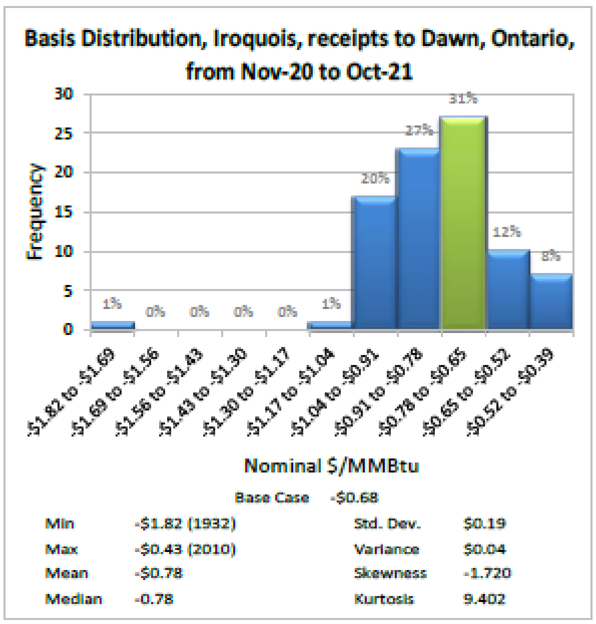


Source: ICF GMM® – Gas Price Risk Report

Exhibit 15: Dawn, Ontario and Iroquois Price Distributions from Nov-20 to Oct-21

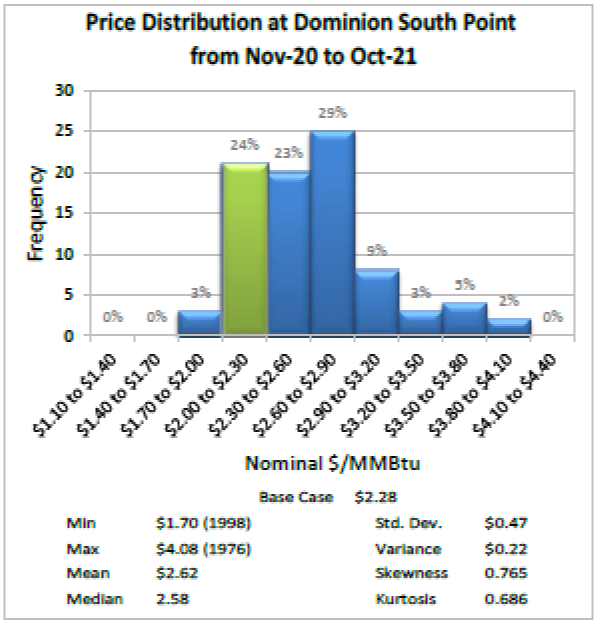


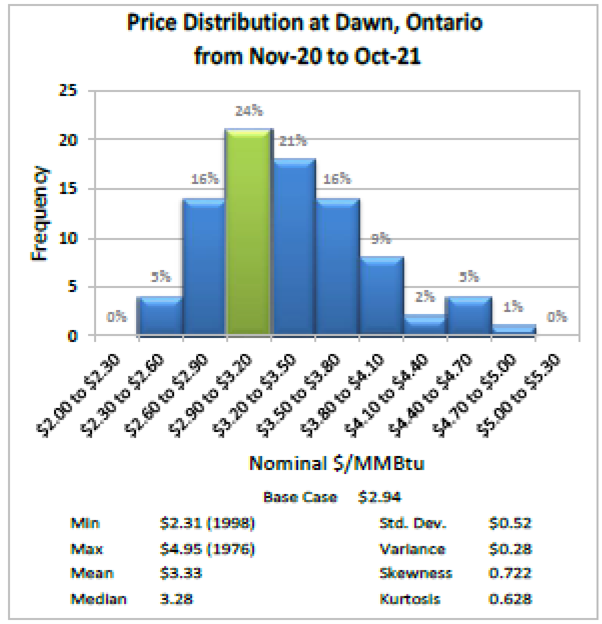


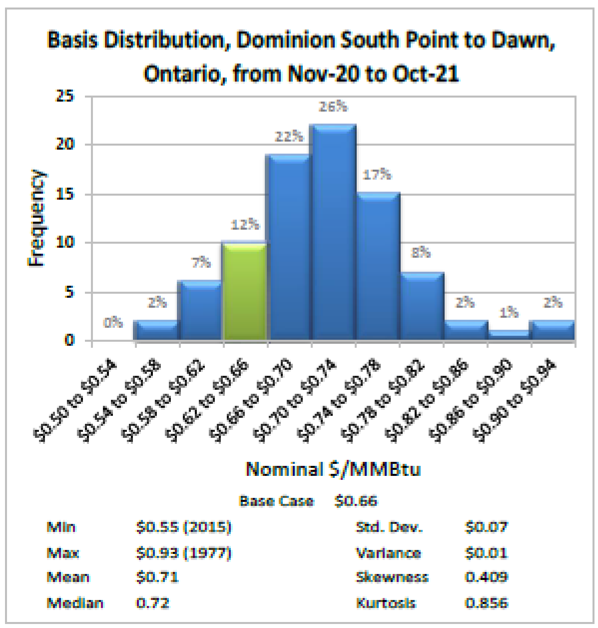


Source: ICF GMM® – Gas Price Risk Report

Exhibit 16: Dawn, Ontario and Dominion South Point Price Distributions from Nov-20 to Oct-21

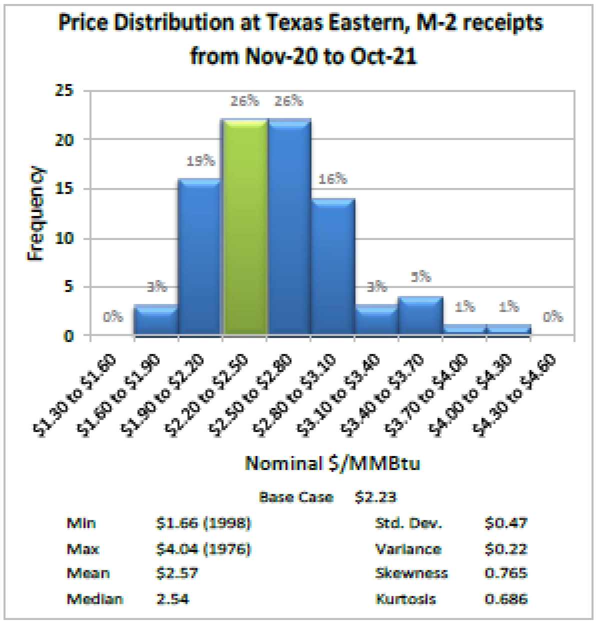


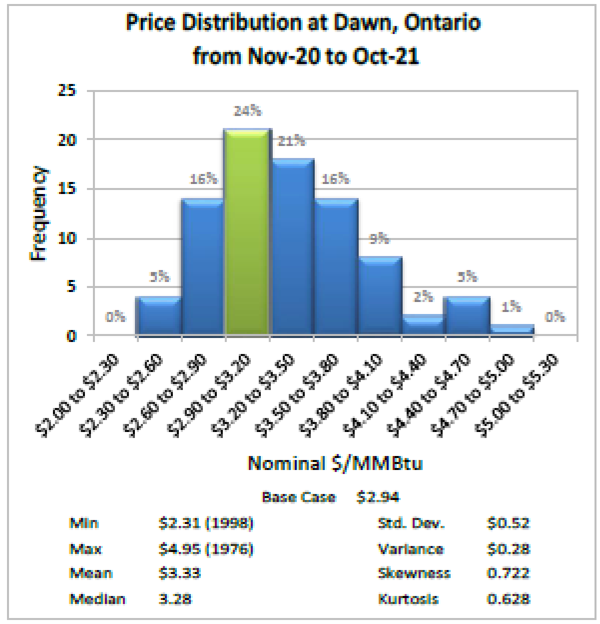


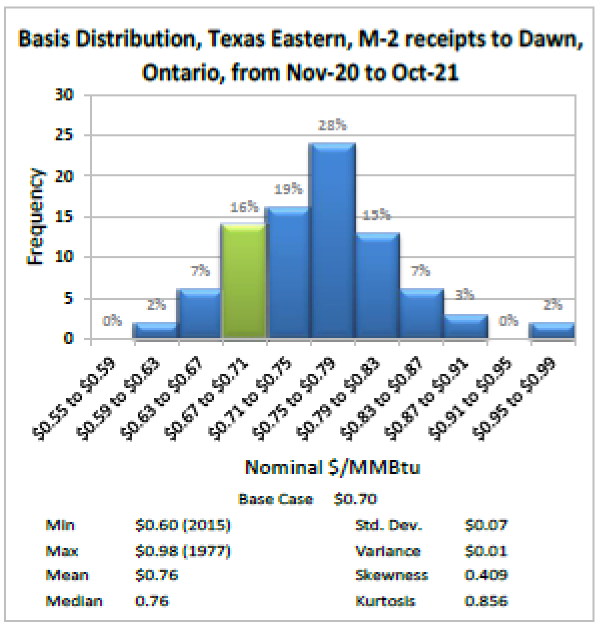


Source: ICF GMM® – Gas Price Risk Report

Exhibit 17: Dawn, Ontario and Texas Eastern M-2 Price Distributions from Nov-20 to Oct-21

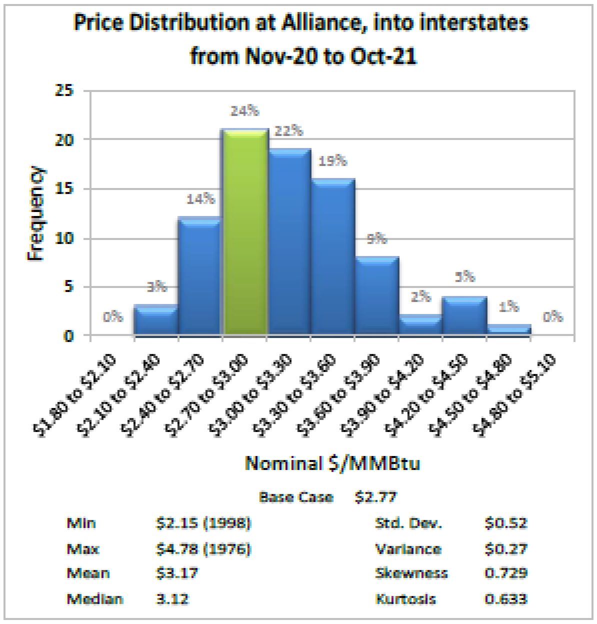


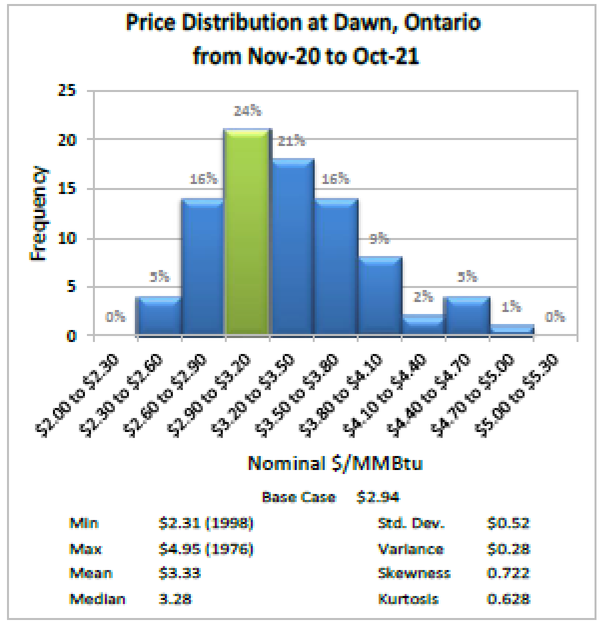


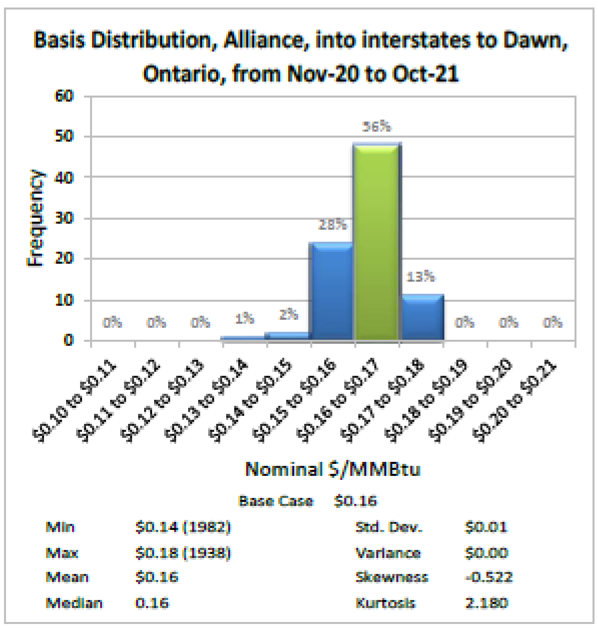


Source: ICF GMM® – Gas Price Risk Report

Exhibit 18: Dawn, Ontario and Alliance, into Interstates Price Distributions from Nov-20 to Oct-21







Source: ICF GMM® – Gas Price Risk Report

Appendix C: Natural Gas Price Forecast for Three Scenarios

Base Case

Month	AECO	Empress	Dawn	Henry Hub	Chicago	MichCon
Nov-20	$1.92	$2.27	$3.02	$2.94	$2.87	$2.92
Dec-20	$2.05	$2.37	$3.17	$3.11	$3.07	$3.07
Jan-21	$2.17	$2.46	$3.28	$3.24	$3.16	$3.18
Feb-21	$2.31	$2.62	$3.30	$3.14	$3.17	$3.20
Mar-21	$2.24	$2.57	$3.18	$3.05	$3.03	$3.07
Apr-21	$1.75	$2.02	$2.84	$2.77	$2.64	$2.73
May-21	$1.67	$1.94	$2.73	$2.75	$2.57	$2.62
Jun-21	$1.67	$1.93	$2.73	$2.78	$2.57	$2.63
Jul-21	$1.67	$1.92	$2.76	$2.82	$2.60	$2.66
Aug-21	$1.67	$1.92	$2.64	$2.83	$2.50	$2.54
Sep-21	$1.54	$1.79	$2.63	$2.83	$2.46	$2.52
Oct-21	$1.87	$2.11	$2.93	$2.86	$2.77	$2.83

Cold Case

Month	AECO	Empress	Dawn	Henry Hub	Chicago	MichCon
Nov-20	$2.19	$2.53	$3.36	$3.20	$3.19	$3.25
Dec-20	$3.36	$3.68	$4.52	$4.35	$4.46	$4.41
Jan-21	$8.67	$8.96	$9.45	$9.63	$9.61	$9.46
Feb-21	$14.88	$15.19	$15.81	$15.50	$15.76	$15.70
Mar-21	$2.54	$2.87	$3.67	$3.25	$3.32	$3.56
Apr-21	$2.49	$2.75	$3.66	$3.52	$3.44	$3.54
May-21	$2.03	$2.31	$3.25	$3.17	$3.06	$3.14
Jun-21	$1.08	$1.34	$2.20	$2.10	$2.00	$2.09
Jul-21	$0.58	$0.69	$1.53	$1.47	$1.34	$1.43
Aug-21	$1.54	$1.80	$2.43	$2.46	$2.25	$2.32
Sep-21	$1.29	$1.54	$2.52	$2.63	$2.32	$2.41
Oct-21	$1.82	$2.06	$3.04	$2.90	$2.85	$2.93

Warm Case

Month	AECO	Empress	Dawn	Henry Hub	Chicago	MichCon
Nov-20	$1.10	$1.45	$2.17	$2.12	$2.03	$2.07
Dec-20	$2.40	$2.71	$3.51	$3.43	$3.41	$3.40
Jan-21	$2.28	$2.57	$3.30	$3.29	$3.15	$3.19
Feb-21	$2.32	$2.63	$3.21	$3.07	$3.07	$3.10
Mar-21	$0.42	$0.52	$0.86	$0.73	$0.67	$0.74
Apr-21	$0.75	$1.02	$1.81	$1.73	$1.62	$1.70
May-21	$0.60	$0.87	$1.58	$1.69	$1.44	$1.47
Jun-21	$0.57	$0.67	$1.37	$1.40	$1.22	$1.27
Jul-21	$2.05	$2.30	$3.20	$3.27	$3.05	$3.09
Aug-21	$1.52	$1.77	$2.39	$2.58	$2.26	$2.28
Sep-21	$1.20	$1.45	$2.24	$2.37	$2.08	$2.14
Oct-21	$1.67	$1.91	$2.69	$2.61	$2.55	$2.59

Base Case

Month	PEPL	Niagara	Iroquois	Dominion South	TETCO M2	Alliance Trading Point
Nov-20	$2.63	$2.81	$3.48	$2.45	$2.40	$2.86
Dec-20	$2.86	$2.96	$4.48	$2.50	$2.48	$3.06
Jan-21	$2.89	$3.05	$5.83	$2.48	$2.46	$3.15
Feb-21	$2.86	$3.07	$5.36	$2.49	$2.47	$3.16
Mar-21	$2.81	$2.95	$4.06	$2.45	$2.40	$3.02
Apr-21	$2.39	$2.61	$3.21	$2.24	$2.19	$2.63
May-21	$2.40	$2.31	$2.81	$2.10	$2.05	$2.56
Jun-21	$2.41	$2.38	$2.80	$2.19	$2.12	$2.56
Jul-21	$2.46	$2.48	$2.86	$2.27	$2.20	$2.59
Aug-21	$2.43	$2.31	$2.70	$2.12	$2.05	$2.49
Sep-21	$2.33	$2.04	$2.70	$1.93	$1.88	$2.45
Oct-21	$2.52	$2.38	$3.07	$2.13	$2.08	$2.76

Cold Case

Month	PEPL	Niagara	Iroquois	Dominion South	TETCO M2	Alliance Trading Point
Nov-20	$2.88	$3.18	$3.86	$2.72	$2.67	$3.18
Dec-20	$4.14	$4.20	$6.20	$3.78	$3.76	$4.45
Jan-21	$9.37	$8.49	$11.44	$8.14	$8.11	$9.60
Feb-21	$15.18	$15.58	$19.42	$14.80	$14.78	$15.75
Mar-21	$2.97	$3.05	$4.28	$2.51	$2.47	$3.31
Apr-21	$3.07	$3.27	$4.08	$2.87	$2.82	$3.43
May-21	$2.78	$2.40	$3.37	$2.21	$2.17	$3.05
Jun-21	$1.76	$1.38	$2.31	$1.24	$1.17	$1.99
Jul-21	$1.16	$1.00	$1.65	$0.79	$0.73	$1.33
Aug-21	$2.11	$2.07	$2.51	$1.83	$1.76	$2.24
Sep-21	$2.11	$1.47	$2.62	$1.38	$1.33	$2.31
Oct-21	$2.50	$2.24	$3.27	$1.99	$1.94	$2.84

Warm Case

Month	PEPL	Niagara	Iroquois	Dominion South	TETCO M2	Alliance Trading Point
Nov-20	$1.81	$2.07	$2.54	$1.57	$1.52	$2.02
Dec-20	$3.18	$3.18	$4.41	$2.84	$2.82	$3.40
Jan-21	$2.91	$2.94	$4.81	$2.42	$2.40	$3.14
Feb-21	$2.80	$2.78	$4.20	$2.29	$2.27	$3.06
Mar-21	$0.52	$0.70	$1.41	$0.52	$0.47	$0.66
Apr-21	$1.42	$1.57	$2.14	$1.20	$1.15	$1.61
May-21	$1.34	$1.19	$1.64	$0.99	$0.94	$1.43
Jun-21	$1.11	$1.00	$1.42	$0.81	$0.74	$1.21
Jul-21	$2.90	$2.94	$3.40	$2.74	$2.67	$3.04
Aug-21	$2.20	$2.18	$2.44	$1.95	$1.88	$2.25
Sep-21	$1.97	$1.61	$2.30	$1.51	$1.46	$2.07
Oct-21	$2.29	$2.07	$2.78	$1.85	$1.80	$2.54

Summary of November 1, 2019 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-2021
2	Empress to Union EDA FT	Empress	Union EDA	1,089	GJ	31-Oct-2022
3	Empress to Union NDA FT	Empress	Union NDA	4,442	GJ	31-Oct-2021
4	Empress to Union WDA FT	Empress	Union WDA	39,880	GJ	31-Oct-2021
5	Empress to Union WDA FT	Empress	Union WDA	11,527	GJ	31-Oct-2021
6	Empress to Union SSMDA FT	Empress	Union SSMDA	2,700	GJ	31-Oct-2021
7	Empress to Union SSMDA FT	Empress	Union SSMDA	12,800	GJ	31-Oct-2021
8	Empress to Union SSMDA FT	Empress	Union SSMDA	6,143	GJ	31-Oct-2021
9	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	31-Oct-2021
10	Empress to Union MDA FT	Empress	Union MDA	1,043	GJ	31-Oct-2021
11	Parkway to Union EDA FT	Parkway	Union EDA	30,000	GJ	31-Oct-2024
12	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	31-Oct-2024
13	Parkway to Union EDA FT	Parkway	Union EDA	9,128	GJ	31-Oct-2033
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 NCDA FT	Parkway	Union NCDA	661	GJ	31-Oct-2031
20	Parkway to Union NCDA FT	Parkway	Union NCDA	439	GJ	31-Oct-2031
21	Parkway to Union NCDA FT	Parkway	Union NCDA	887	GJ	31-Oct-2032
22	Parkway to Union NCDA FT	Parkway	Union NCDA	2,000	GJ	31-Oct-2032
23	Parkway to Union NCDA FT	Parkway	Union NCDA	6,912	GJ	31-Oct-2033
24	Parkway to Union NCDA FT	Parkway	Union NCDA	884	GJ	31-Oct-2033
25	Parkway to Union NDA FT	Parkway	Union NDA	10,000	GJ	31-Oct-2031
26	Parkway to Union NDA FT	Parkway	Union NDA	67,000	GJ	31-Oct-2031
27	Parkway to Union NDA FT	Parkway	Union NDA	24,000	GJ	31-Oct-2031
24	Parkway to Union NDA FT	Parkway	Union NDA	9,000	GJ	31-Oct-2031
25	Parkway to Union NDA FT	Parkway	Union NDA	10,401	GJ	31-Oct-2031
28	Parkway to Union NDA FT	Parkway	Union NDA	6,228	GJ	31-Oct-2031
28	TCPL FT - Total			382,384	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
29	NCDA	Parkway	Union NCDA	13,704	GJ	31-Oct-2024
30	WDA	Parkway	Union WDA	31,420	GJ	31-Oct-2024
31	SSMDA	Dawn	Union SSMDA	35,022	GJ	31-Oct-2024
32	NDA	Parkway	Union NDA	48,375	GJ	31-Oct-2024
33	EDA	Parkway	Union EDA	26,351	GJ	31-Oct-2024
34	TCPL Firm STS Withdrawal - Total			154,872	GJ	
	TransCanada Storage Transportation Service Firm Injection					
35	WDA	Union WDA	Parkway	3,150	GJ	31-Oct-2024
36	EDA	Union EDA	Parkway	1,000	GJ	31-Oct-2024
37	NDA	Union NDA	Parkway	49,100	GJ	31-Oct-2024
38	TCPL Firm STS Injection - Total			53,250	GJ	
	Centra Transmission Holdings Inc. [2]					
39	Centra Transmission Holdings Inc.	Spruce	Union MDA	149.6	10^3m^3	31-Oct-2020
40	Centra Pipelines Minnesota Inc.	Sprague	Baudette	5,281	MCF	31-Oct-2020
41	CTHI FT - Total			5,745	GJ	

Conversion Factor	1.055056
Heat Content (as of April 1/19)	38.4

Note:
(1) Excludes NEXUS capacity allocated from the South portfolio.
(2) Renewal letters sent in April 2019 to renew for 1 year to October 31, 2020.

Summary of November 1, 2019 Upstream Transportation Contracts

Union South 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 ECDA FT	Empress	Union ECDA	3,000	GJ	31-Oct-2021
2	Dawn to Union CDA FT	Dawn	Union ECDA	8,000	GJ	31-Oct-2021
3	Niagara to Kirkwall FT	Niagara	Kirkwall	21,101	GJ	31-Oct-2022
4	Kirkwall to Union CDA FT	Kirkwall	Union CDA (Amended)	135,000	GJ	31-Oct-2032
5	TCPL FT - Total			167,101	GJ	
	Panhandle Eastern Pipe Line Field Zone					
6	PEPL FT(1)	Panhandle Field Zone	Ojibway (Union)	35,000	DTH	31-Oct-2025
7	PEPL FT (2)	Panhandle Field Zone	Ojibway (Union)	22,000	DTH	31-Oct-2027
8	PEPL - Total			60,138	GJ	
	Vector Pipelines					
9	Vector US FT1	Chicago	Cdn/US Interconnect	80,000	DTH	31-Oct-2022
10	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,404	GJ	31-Oct-2022
11	Vector - Total			84,404	GJ	
	NEXUS					
12	NEXUS - FT(3)(4)	Kensington	St. Clair (Union)	75,000	DTH	31-Oct-33
13	NEXUS - FT(3)(4)	Clarington	St. Clair (Union)	75,000	DTH	31-Oct-21
				158,258	GJ	
	Other:					
14	St.Clair Pipelines L.P. (St.Clair Pipeline)	St. Clair/Intl Border	St. Clair/Intl Border	214,000	GJ	31-Oct-2023
15	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) Union has contracted for 35,000 DTH/day.
(2) Union has contracted for 22,000 DTH/day.
(3) Union has contracted for 150,000 DTH/day and allocates 50,000 DTH/day to the North Portfolio.
(4) 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.

Panhandle Landed Cost Analysis

2017-2027 Transportation Contracting Analysis

	Route	Point of Supply	Basis Differential $US/mmBtu	Supply Cost $US/mmBtu	Unitized Demand Charge $US/mmBtu	Commodity Charge $US/mmBtu	Fuel Charge $US/mmBtu	100% LF Transportation Inclusive of Fuel $US/mmBtu	Landed Cost $US/mmBtu	**Landed Cost $Cdn/G**	Point of Delivery
	(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	(K)	(L)
(2)	**TCPL Niagara**	Niagara	-0.293	4.2342	0.1801	0.0000	0.0110	0.1911	$4.43	**$5.62**	Dawn
(2)	**NEXUS**	Dominion Sth Point	-0.914	3.6134	0.7991	0.0000	0.0956	0.8947	$4.51	**$5.72**	Dawn
(1)	**Dawn**	Dawn	0.036	4.5633	0.0000	0.0000	0.0000	0.0000	$4.56	**$5.79**	Dawn
	PEPL SH (Max FT Rate)	PEPL (REX - Putnam)	-0.201	4.3262	0.1791	0.0091	0.0592	0.2475	$4.57	**$5.81**	Dawn
(2)	**Vector (2016-2022)**	Chicago	-0.172	4.3551	0.1802	0.0017	0.0456	0.2275	$4.58	**$5.82**	Dawn
	PEPL SH (REX - Audrain Max FT Rate)	PEPL (REX - Audrain)	-0.223	4.3041	0.2385	0.0167	0.1023	0.3575	$4.66	**$5.92**	Dawn
(1)	**Vector (Max Rate)**	Chicago	-0.172	4.3551	0.2704	0.0017	0.0456	0.3177	$4.67	**$5.93**	Dawn
(1)	**GLGT to TCPL (Max Rate)**	Northern Michigan	-0.178	4.3492	0.3096	0.0091	0.0678	0.3865	$4.74	**$6.01**	Dawn
(2) *	**Panhandle Longhaul (Max FT Rate)**	Panhandle Field Zone	-0.325	4.2023	0.4540	0.0438	0.1664	0.6641	$4.87	**$6.18**	Dawn
(2)	**Trunkline / Panhandle (2012-2017)**	Trunkline ELA Zone	0.028	4.5550	0.2195	0.0262	0.1794	0.4251	$4.98	**$6.32**	Dawn
	Trunkline / Panhandle (Max Rate)	Trunkline Field Zone 1A	-0.056	4.4716	0.3591	0.0237	0.1608	0.5436	$5.02	**$6.37**	Dawn
(1)	**TCPL SWDA**	Empress	-1.074	3.4532	1.4147	0.0000	0.1506	1.5653	$5.02	**$6.37**	Dawn
	Trunkline / Panhandle (Max Rate)	Trunkline ELA Zone	0.028	4.5550	0.4828	0.0262	0.1794	0.6884	$5.24	**$6.66**	Dawn

(1) For Reference Only
(2) Existing Union Gas Contract
* indicates path referenced in evidence for this analysis

Assumptions used in Developing Transportation Contracting Analysis:

	Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2017 - Oct 2018	Nov 2018 - Oct 2019	Nov 2019 - Oct 2020	Nov 2020 - Oct 2021	Nov 2021 - Oct 2022	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
	Henry Hub (NYMEX)	Henry Hub	$4.20	$4.09	$4.03	$4.03	$4.27	$4.42	$4.64	$4.90	$5.26	$5.43	$4.53
	TCPL Niagara	Niagara	$4.10	$3.89	$3.88	$3.81	$3.94	$4.05	$3.96	$4.52	$5.09	$5.10	$4.23
	NEXUS	Dominion Sth Point	$3.46	$3.28	$3.23	$3.18	$3.29	$3.38	$3.31	$3.85	$4.53	$4.62	$3.61
	Dawn	Dawn	$4.34	$4.16	$4.15	$4.09	$4.32	$4.41	$4.46	$4.89	$5.35	$5.47	$4.56
	PEPL SH (Max FT Rate)	PEPL (REX - Putnam)	$4.10	$3.92	$3.91	$3.87	$4.07	$4.18	$4.24	$4.67	$5.08	$5.23	$4.33
	Vector (2016-2022)	Chicago	$4.11	$3.93	$3.93	$3.89	$4.11	$4.21	$4.27	$4.70	$5.13	$5.27	$4.36
	PEPL SH (REX - Audrain Max FT Rate)	PEPL (REX - Audrain)	$4.05	$3.88	$3.88	$3.84	$4.05	$4.16	$4.22	$4.66	$5.07	$5.22	$4.30
	Vector (Max Rate)	Chicago	$4.11	$3.93	$3.93	$3.89	$4.11	$4.21	$4.27	$4.70	$5.13	$5.27	$4.36
	GLGT to TCPL (Max Rate)	Northern Michigan	$4.13	$3.93	$3.93	$3.88	$4.11	$4.21	$4.26	$4.68	$5.12	$5.25	$4.35
	Panhandle Longhaul (Max FT Rate)	Panhandle Field Zone	$3.93	$3.75	$3.79	$3.76	$3.96	$4.06	$4.12	$4.55	$4.97	$5.12	$4.20
	Trunkline / Panhandle (2012-2017)	Trunkline ELA Zone	$4.25	$4.14	$4.06	$4.05	$4.29	$4.44	$4.66	$4.92	$5.28	$5.45	$4.55
	Trunkline / Panhandle (Max Rate)	Trunkline Field Zone 1A	$4.15	$4.04	$3.98	$3.98	$4.22	$4.36	$4.58	$4.84	$5.19	$5.37	$4.47
	TCPL SWDA	Empress	$3.28	$3.03	$3.08	$3.04	$3.24	$3.34	$3.37	$3.75	$4.14	$4.26	$3.45
	Trunkline / Panhandle (Max Rate)	Trunkline ELA Zone	$4.25	$4.14	$4.06	$4.05	$4.29	$4.44	$4.66	$4.92	$5.28	$5.45	$4.55

Sources for Assumptions:

Gas Supply Prices (Col D):	ICF Q4 2016 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 =	$1.339 CDN	From Bank of Canada Closing Rate November 1, 2016
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
Union's Analysis Completed:	Nov-16		

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

Dawn to Parkway NCOS Landed Cost Analysis
2021-2031 Transportation Contracting Analysis

Route	Point of Supply	Supply Cost $US/mmBtu	Unitized Demand Charge $US/mmBtu	Commodity Charge $US/mmBtu	Fuel Charge $US/mmBtu	100% LF Transportation Inclusive of Fuel $US/mmBtu	Landed Cost $US/mmBtu	Landed Cost $Cdn/G	Point of Delivery	Comments
Niagara to Kirkwall	Niagara	3.1692	0.1640	0.0000	0.0065	0.1705	$3.34	**$4.08**	Kirkwall	
Union Dawn to Parkway	Dawn	4.0849	0.0998	0.0000	0.0306	0.1304	$4.22	**$5.15**	Union Parkway	
TCPL NBJ to Union Parkway Belt	Empress	3.2464	1.0825	0.0000	0.1433	1.2258	$4.47	**$5.47**	Union Parkway	
TCPLEMPtoUPB	Empress	3.2464	1.5487	0.0000	0.1338	1.6825	$4.93	**$6.03**	Union Parkway	
TCPL Iroquois to Parkway Belt	Iroquois	4.8679	0.3587	0.0000	0.0312	0.3899	$5.26	**$6.43**	Union Parkway	

(1) For Reference Only
(2) Existing Union Gas Contract
* indicates path referenced in evidence for this analysis

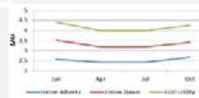
Assumptions used in Developing Transportation Contracting Analysis:

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	Nov 2026 - Oct 2027	Nov 2027 - Oct 2028	Nov 2028 - Oct 2029	Nov 2029 - Oct 2030	Nov 2030 - Oct 2031	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
Niagara to Kirkwall	Niagara	$2.31	$2.70	$2.53	$2.59	$2.99	$3.26	$3.65	$3.79	$3.89	$3.98	$3.17	0.20%
Union Dawn to Parkway	Dawn	$3.13	$3.72	$3.96	$3.89	$3.88	$3.99	$4.29	$4.54	$4.67	$4.78	$4.08	0.75%
TCPL NBJ to Union Parkway Belt	Empress	$2.48	$3.05	$3.32	$3.20	$3.15	$3.23	$3.29	$3.48	$3.58	$3.68	$3.25	4.41%
TCPLEMPtoUPB	Empress	$2.48	$3.05	$3.32	$3.20	$3.15	$3.23	$3.29	$3.48	$3.58	$3.68	$3.25	4.12%
TCPL Iroquois to Parkway Belt	Iroquois	$3.96	$4.57	$4.80	$4.73	$4.76	$4.87	$4.99	$5.21	$5.33	$5.45	$4.87	0.64%

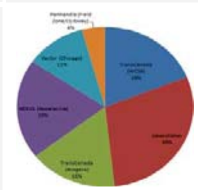
Sources for Assumptions:

Gas Supply Prices (Col D):	ICF Q3 2018 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 =	$1.290 CDN	From Bank of Canada Daily Rate August 29, 2018
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	

Performance Metrics - Enbridge Gas Inc.

OEB Guiding Principle	Performance Categories	Intent of Measures	Measures	Sample	2020	2021	2022	2023	2024
Cost-Effectiveness The gas suppy plans will be cost-effecitve. Cost-effectivenes is achieved by appropriately balancing the principles and in executing the supply plan in an economically efficient manner.	Policies & 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					
			Transacting counterparties have met appropriate credit requirements	100%					
	Weather Variance[1]	Illustrates weather risk in EGI's Plan correlated with price variances (e.g. Positive HDD variances tends to lead to higher prices)	HDD Variance - Enbridge CDA	-4%					
			HDD Variance - Enbridge EDA	-3%					
			HDD Variance - Union North West	3%					
			HDD Variance - Union North East	11%					
			HDD Variance - Union South	4%					
	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	20%					
			Monthly	25%					
			Seasonal	30%					
			Annual or longer	25%					
		Illustrates price stability and consistency in EGI's Plan	Reference Price[2]						

Performance Metrics - Enbridge Gas Inc.

OEB Guiding Principle	Performance Categories	Intent of Measures	Measures	Sample	2020	2021	2022	2023	2024
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%					
	Storage	Demonstrates EGI's execution of its storage inventory strategy	Percentage of actual storage target at November 1 compared to the Plan	100%					
			Percentage of actual storage target at February 28 compared to the Plan	100%					
			Percentage of actual storage target at March 31 compared to the Plan	100%					
	Communication	Ensure ongoing communciation 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	12/yr					
			Instances when QRAM expected bill impacts exceed +/- 25%	0					
			Communicated to ratepayers when bill impacts exceed +25%	C					
	Diversity	Illustrates EGI's diversity of basin, contract term, counterparties and supply procurement in the Plan	Supply basin diversity[3]						
			Percentage of contracts with remaining terms of: 1-5 years 6-10 years > 10 years	 50% 15% 35%					
			Total number of unique counterparties	50					
			Total number of receipt points	20					
	Reliability	Reports EGI's experience with pipeline and supply disruptions demonstrating the reliability of the portfolio	Number of days of force majeure on upstream pipelines	1					
			Number of days of force majeure on upstream pipelines impacting customers' security of supply	0					
			Number of days of failed delivery of supply	1					
			Number of days of failed delivery of supply impacting customers security of supply	0					
			Number of days of forced majeures on storage assets	0					

Performance Metrics - Enbridge Gas Inc.

OEB Guiding Principle	Performance Categories	Intent of Measures	Measures	Sample	2020	2021	2022	2023	2024
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 Plan	C					
			DSM savings addressed in Plan	C					
			Federal Carbon Pricing Program addressed in Plan	n/a					
			Percentage of RNG portfolio	0%					

Footnotes:

C - Compliant, NI - Needs Improvement

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

2 - As filed in QRAM proceeding

3 - For data see section 9.3 and section 16.3