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VIA RESS and EMAIL

March 1, 2024

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

Dear Nancy Marconi:

Re: EB-2024-0067 – Enbridge Gas Inc. (Enbridge Gas)
2024 Annual Update to 5 Year Gas Supply Plan

The Framework for the Assessment of Distributor Gas Supply Plans (EB-2017-0129) (Framework) included a submission schedule which outlined the second 5-Year Gas Supply Plan for the following implementation year be filed on January 1, 2024.

Given the expected timing of the OEB decision in the 2024 Rebasing application (EB-2022-0200), Enbridge Gas requested and was granted a one-year extension to the deadline to file its next 5-Year Gas Supply Plan.

Please find attached Enbridge Gas's 2024 Annual Update to its 5 Year Gas Supply Plan. This is the fifth Annual Update to the 5-Year Gas Supply Plan that Enbridge Gas has filed with the OEB.

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

Enbridge Gas intends to answer questions submitted by stakeholders on the Annual Update at the Stakeholder Conference.

With regards to the filing of the next 5-Year Gas Supply Plan, Enbridge Gas requests a filing date of March 1, 2025, consistent with the approved timing for the Annual Updates, and proposes that the gas supply planning period covered by the 5-Year Gas Supply Plan, will be for November 1, 2024, to October 31, 2029. This approach ensures continuity of gas years for comparison purposes, and filing of the most current gas supply plan approved by Enbridge Gas's executive.

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

Sincerely,

Richard Wathy
Digitally signed by Richard Wathy
Date: 2024.03.01 09:13:57 -05'00'

Richard Wathy
Technical Manager, Regulatory Applications

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

2024 Annual Gas Supply Plan Update

EB-2024-0067

Enbridge Gas Inc.
March 1, 2024

Table of Contents

1. Administrative Information

1.1 Introduction

On January 1, 2019, Enbridge Gas Distribution (EGD) and Union Gas Limited (Union) amalgamated to form Enbridge Gas Inc. (Enbridge Gas, EGI, or the Company). Enbridge Gas serves over 3.8 million residential, commercial, and industrial customers across more than 300 municipalities and more than 20 First Nations throughout Ontario.

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

Enbridge Gas filed its 5-Year Gas Supply Plan[2] (5-Year Plan) for all rate zones on May 1, 2019, based on the 2018/19 Gas Supply Plan and most recently filed the 2023 Annual Gas Supply Plan Update (2023 Annual Update) on March 1, 2023[3] and the review process focused on the 2021 Vector Pipeline contracting decision.

This document is the fifth Annual Update to the 5-Year Plan and addresses changes to the market outlook and planning and execution processes inclusive of the historical comparisons of actuals required by the Framework.

The 5-Year Plan and 2024 Annual Update should be read in conjunction with one another. This update is based on the 2023/24 Gas Supply Plan (Plan) for November 1, 2023, to October 31, 2028, which received internal senior management approval in Q3 2023 and is underpinned by current OEB-approved methodologies.

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

Enbridge Gas filed its 2024 Rebasing and Incentive Rate-Setting Mechanism application on October 31, 2022[7]. Given the expected timing of the OEB decision, the

[1] EB-2017-0129.
[2] EB-2019-0137.
[3] EB-2023-0720.
[4] Enbridge EDA, Enbridge CDA.
[5] Union MDA, Union SSMDA, Union WDA.
[6] Union EDA, Union NCDA, Union NDA.
[7] EB-2022-0200.

earliest Enbridge Gas expected it could implement the decision into the gas supply plan is November 1, 2024. As a result, Enbridge Gas requested and was granted a one-year extension on the deadline to file its next 5-Year Gas Supply Plan.[8] As part of the Settlement Agreement, several issues impacting the gas supply plan were deferred to Phase 2.[9] The next 5-Year Gas Supply Plan will include the impacts of the Phase 1 Rebasing decision, however, it is anticipated that the Phase 2 Rebasing decision impacts will be captured in the subsequent annual update, pending the timing of the Phase 2 Rebasing decision.

As such, this Annual Update does not include information on impacts to future gas supply plans related to the proposals sought in the Rebasing Application. This Annual Update continues to be prepared in accordance with OEB-approved methodologies consistent with Enbridge Gas's 5-Year Plan.

2024 Rebasing Application

Enbridge Gas filed its Rebasing Application on October 31, 2022, and received an OEB decision on December 21, 2023. The outcomes of the Phase 1 decision, where applicable, are listed below and will be included in the next 5-Year Gas Supply Plan. Given the timing of Phase 2, it is expected that the outcomes of the Phase 2 decision will be captured in the next applicable Annual Update.

Phase 1

Phase 1 Decision on the Settlement Proposal includes the following impacts to gas supply planning:

- Changes to the 2024 volume forecast (Issue 9)
- A harmonized design day demand methodology set on the basis of the coldest day in 30 years using the gas years 1993/1994 to 2022/2023 (Issue 18 c)
- Changes to UFG volumes and costs (Issue 18 d)[10]

These changes will be reflected in the next 5-Year Gas Supply Plan.

Phase 2

Phase 2 will address the following issues that impact gas supply planning:

[8] Ibid., Decision on the Settlement Proposal, August 17, 2023.
[9] Ibid., Exhibit O1, Tab 1, Schedule 1, July 12, 2023, pp.35-36.
[10] Ibid., Decision on the Settlement Proposal, August 17, 2023.

18 a) Is the 2024 gas supply cost, including the forecast of gas, transportation and storage costs, appropriate?[11]

18 c) Is the proposed harmonized approach to determining gas costs (design day, operational contingency space, unaccounted for gas, Parkway Delivery Obligation) appropriate?[12]

39) Is the proposed harmonized methodology for determining the amount of storage space and deliverability required to serve in franchise customers appropriate, and is the proposed allocation of storage space and deliverability among customers appropriate?

47) Should the cap on cost-based storage service for in-franchise customers established in the NGEIR decision remain at 199.4 PJ?

48) Is the purchase of storage service at market-based rates by Enbridge Gas from Enbridge Gas for in-franchise customers appropriate?

49) Is the proposal to add 10 PJ of market-based storage at a cost not currently included in the 2024 Test Year gas cost forecast appropriate?

53) Are the specific proposals to amend the Voluntary RNG Program and to procure low-carbon energy as part of the gas supply commodity portfolio, appropriate?

51) How should the determinations made for the Phase 2 Storage issues be addressed and implemented, including any required changes to 2024 costs and revenues, the Gas Supply Plan and gas supply deferral and variance accounts?

In the OEB-approved Phase 1 Settlement Proposal, the parties agreed that until a determination is made in Phase 2, Enbridge Gas will maintain its current levels of market-based storage, and operational contingency. Once the OEB has released its Phase 2 decision, Enbridge Gas will incorporate the impacts of the decision into the next appropriate Gas Supply Plan filing.

[11] Issue 18 part a) was partially settled as part of the Settlement Proposal approved by the OEB on August 17, 2023, with the exception of the determination of load balancing costs including storage which is deferred to in Phase 2.

[12] Issue 18 part c) was partially settled as part of the Settlement Proposal approved by the OEB on August 17, 2023, for determining gas costs, except for the amount of operational contingency space to be determined in Phase 2.

Phase 3

Phase 3 will address the following issue that impacts gas supply planning:

> 18 b) Is the proposal for a common reference price methodology to set gas costs appropriate?

Gas supply planning may also be impacted by the service harmonization and approved number of rate zones, which is also part of Phase 3. Once the OEB has released its Phase 3 decision, Enbridge Gas will capture the impacts of the decision at the next appropriate Gas Supply Plan filing.

2025 5-Year Gas Supply Plan

The Framework states that the second five-year gas supply plan is to be filed on January 1, 2024. However, due to the one-year extension granted in the 2024 Rebasing Settlement Proposal[13], and the change of the annual updates from being filed on May 1 to March 1, Enbridge Gas requests to file all gas supply plan filings on March 1, which allows for the prior year actuals to be finalized and contracting decisions to be made, regardless of whether it is for the 5-Year Plan or an Annual Update filing. Enbridge Gas proposes to file the next 5-Year Gas Supply Plan on March 1, 2025, for the period covering November 1, 2024 to October 31, 2029.

1.2 Significant Changes

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

This Annual Update captures notable changes including:

1. Market changes and general impacts in Section 2.1;
2. Public policy initiatives in Section 2.2;
3. An updated demand forecast in Section 3;
4. Energy transition initiatives in Section 4.2; and
5. Contracting changes in Section 4.4.

The Framework recognizes the role of annual updates as a mechanism to update changes to gas supply plans:

[13] EB-2022-0200, Decision on the Settlement Proposal, August 17, 2023.

> The annual gas supply plan update is an important tool for distributors to identify significant events that result in a change to the gas supply plans.[14]

Updates included in this Annual Update primarily address: information about recent trends in the North American natural gas market, changes to the Enbridge Gas transportation portfolio; updated renewable natural gas (RNG) and responsibly sourced gas (RSG) activities consistent with previous annual updates; and updated annual and design day demand forecasts prepared under OEB-approved methodologies that are consistent with the 5-Year Plan.

2. Market Overview

This section reflects publicly-available information on the natural gas market from the U.S. Energy Information Administration (EIA) and the Canada Energy Regulator (CER),[15] as well as information Enbridge Gas has access to from publicly available capacity reports for upstream pipelines.

2.1 Market Outlook

In 2023, the North American energy market continued its recovery from the impacts of the global COVID-19 pandemic and also stabilized from the post-pandemic natural gas price spike and extreme volatility that was experienced through 2022.

The price spike, which started in late 2021, was driven primarily by global energy supply disruptions caused by the Russian/Ukraine conflict. This resulted in record LNG exports from North America to replace Russian supplies into major European markets and higher prices for natural gas worldwide. These factors culminated in a North American natural gas inventory position reaching historically low levels that lasted for most of 2022 through the start of winter 2022/23. This extended stretch of low domestic inventory levels and ongoing global uncertainty caused domestic prices to increase and experience extreme volatility that lasted through February of 2023.

In February of 2023, low demand resulting from an extremely mild winter and higher production of natural gas in response to high prices from the previous year resulted in a surplus of North American natural gas inventory relative to historic norms. The natural gas inventory surplus position has continued through the start of the 2023/24 winter and

[14] EB-2017-0129, p.14.
[15] These publicly available forecasts are not created by Enbridge Inc. or any of its affiliates. Inclusion of these forecasts within this evidence does not mean that Enbridge Inc. or its affiliates endorse, agree with or support the accuracy of these forecasts. The publicly available forecasts are provided for informational purposes only in compliance with Framework direction.

has resulted in relatively low and stable prices across North America. Forward natural gas prices are relatively flat through the end of summer 2024.

As a result of this price decline and stabilization from the price spike of 2021-2022, Enbridge Gas's commodity reference prices have correspondingly trended down, with January 2024 QRAM forward gas prices being down an average of over 50% since the peak prices in 2022.

North American Supply

In its 2023 Energy Future (EF2023) report, the CER provides outlooks for Canada's natural gas supply and demand under three energy transition scenarios:

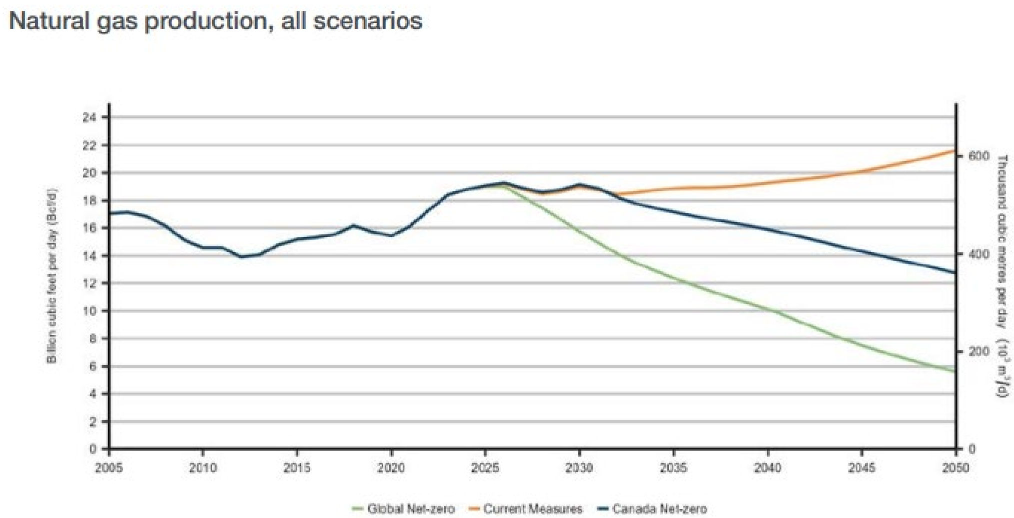
- Current Measures Scenario: The least aggressive scenario with only limited future actions assumed to reduce GHG emissions and no assumed requirement for Canada to achieve net-zero emissions.
- Canada Net-Zero Scenario: Assumes Canada will achieve net-zero by 2050. The EF2023 report does recognize many uncertainties around Canada's pathway to net-zero. This scenario assumes that global GHG reductions are less aggressive than Canada's, impacting Canada's supply/demand balance through the magnitude of forecast supply exports from Canada.
- Global Net-Zero Scenario: Is the most aggressive scenario where Canada reaches net-zero by 2050 and global action is also at a much more rapid pace to reduce GHG emissions.

CER recognizes the uncertainty inherent in its 2023 Energy Future report, stating "The results in EF2023 are not predictions about the future and nor are they policy recommendations. Rather, they are the product of scenarios based on a specific premise and set of assumptions. Relying on just one scenario to understand the energy outlook implies too much certainty about what could happen in the future."[16]

As shown in Figure 1, in all but the most aggressive of the global GHG emission reduction scenarios, Canada's natural gas production is expected to stay relatively flat at over 18 Bcf/day for the next decade. In the longer term, through 2050, the report projects a wide range from a 24% increase (21.5 Bcf/day) to a 68% decrease (5.5 Bcf/day) across the scenarios from 2022 levels.

[16] Canada's Energy Future 2023, June 20, 2023, p.4, https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/index.html.

Figure 1: Canadian Natural Gas Production[17]



Historically and across all scenarios, Canada's natural gas production is dominated by Alberta and British Columbia. Any growth that is projected is expected to come from the Montney formation in northeast British Columbia and this area's percentage share of Canada's production will continue to grow across all scenarios.

EIA forecasts production of natural gas in the U.S. to continue to grow through 2050 in its Reference Case by 15% from 2022 to just over 40 trillion cubic feet. This projection comes with a range of 20% higher to 25% lower depending on the scenario assumptions, as shown in Figure 2. Where production projections are in excess of the consumption forecast, projected demand for LNG exports is driving U.S. production.

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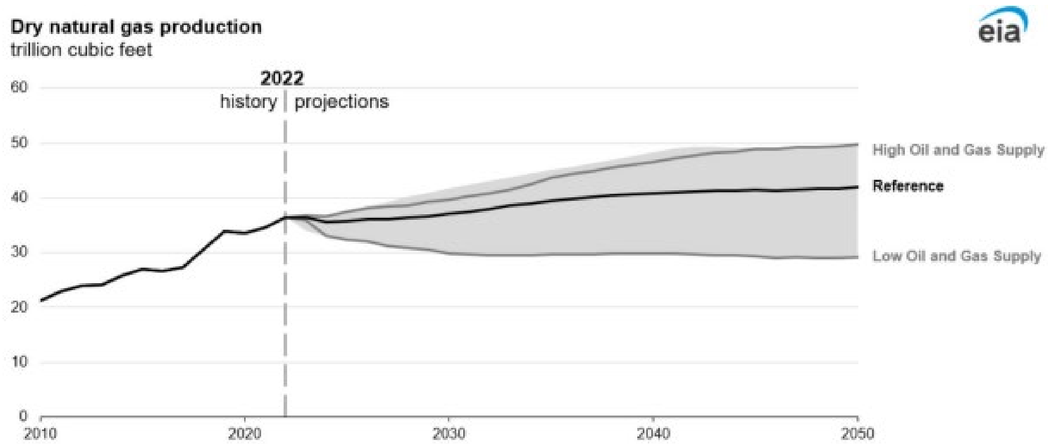
[17] Canada's Energy Future 2023, June 20, 2023, p.14, https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/index.html.

Figure 2: U.S. Natural Gas Production[18]



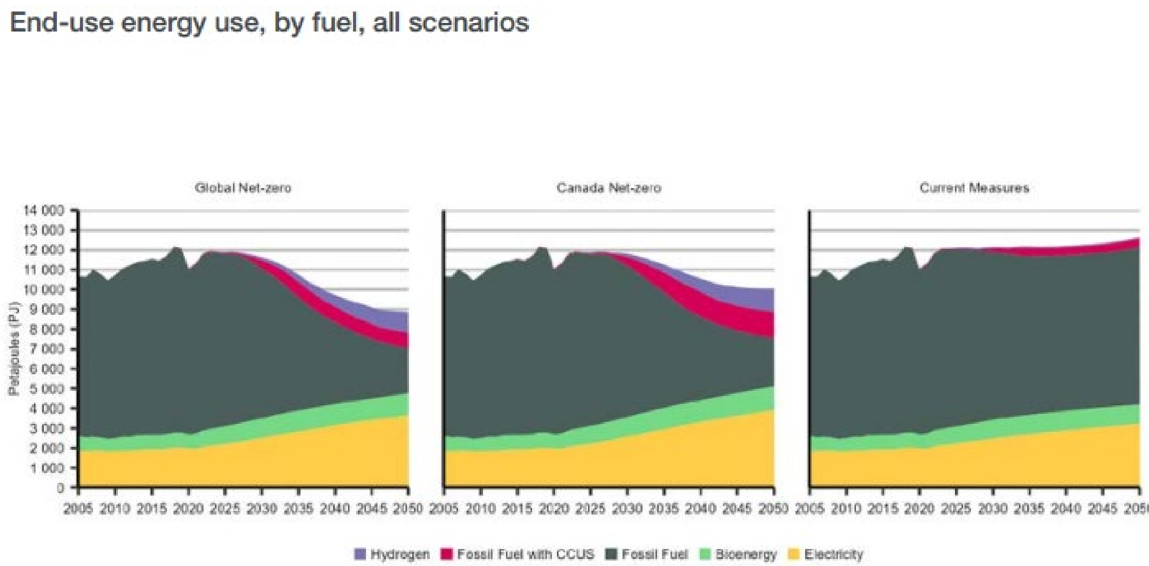
Shale gas and associated natural gas from oil wells are the primary sources for any projected long-term production growth. Increased shale gas production is mainly projected in the Appalachian basin and the Texas-Louisiana salt basin, with an increase in associated natural gas from increased production wells in the Permian basin.

Natural Gas Demand

In EF2023, the CER forecasts the energy consumption mix, inclusive of natural gas, under the same three scenarios described above. As shown in Figure 3, electricity, hydrogen and bio-fuels make up a greater share of Canada's energy use across all scenarios, while the use of fossil fuels decreases. This forecast shift in make-up of energy sources has a wide range across the three scenarios.

[18] Annual Energy Outlook 2023, March 16, 2023, p.23, https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Release_Presentation.pdf.

Figure 3: Canada's Energy Use[19]



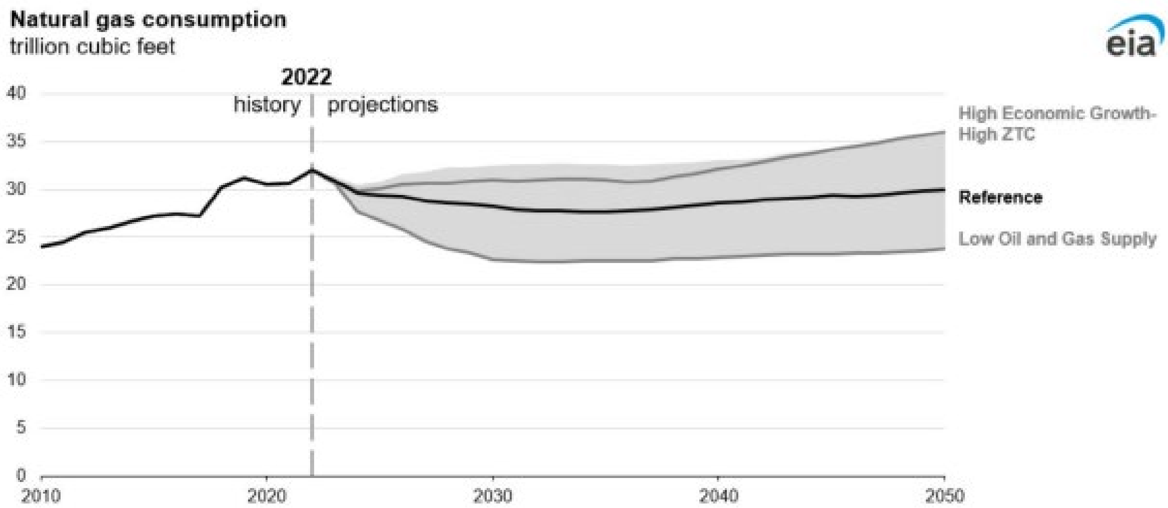
A portion of the decrease in fossil fuel use is partially replaced by fossil fuels with Carbon Capture and Underground Storage (CCUS) in all scenarios. Even in the most aggressive of the scenarios, natural gas still plays an important role in Canada's energy mix through the forecast out to 2050.

In all scenarios, Canada's end-use energy demand grows slowly in the short-term but declines in the longer term. In both of the net-zero scenarios end-use demand declines by 22% by 2050 from 2021 levels, mostly due to assumptions around more efficient use of energy, and technology advancements. In the Current Measures scenario, energy use is stable until 2040 and then starts to increase slowly again after that.

According to the EIA, in the United States electrification is projected to displace combustion fuels in the long-term to varying degrees dependent on the assumptions used, and the EIA has made projections for natural gas demand under a range of scenarios. As shown in Figure 4, the range of projected natural gas demand is wide on both sides of the EIA's reference case. The reference case projects relatively stable natural gas demand through 2050 at an average of approximately 30 trillion cubic feet with variations between 18% higher or 14% lower.

[19] Canada's Energy Future 2023, June 20, 2023, p.8, https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/index.html).

Figure 4: U.S. Natural Gas Consumption[20]



Natural Gas Price Signals

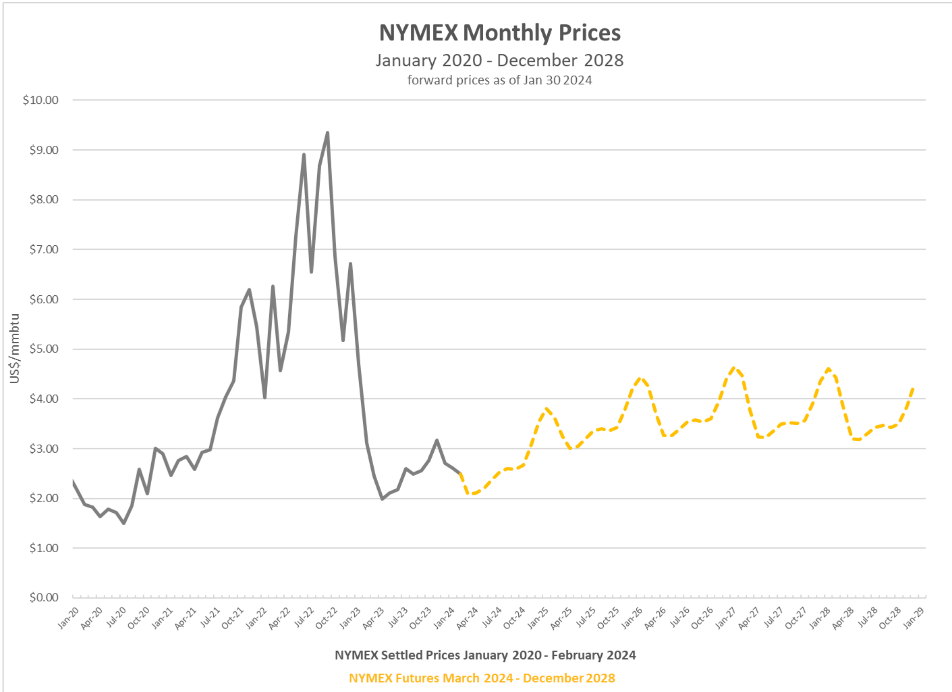
Through 2022, the natural gas markets experienced high prices and volatility due to economies re-emerging from a global pandemic, low storage inventory levels, and increased exports of LNG driven largely by global demand increases resulting from the Russia/Ukraine conflict and associated embargoes on Russian natural gas. This occurrence was following several years of consistently low prices across the domestic natural gas market.

After reaching peak prices during the second half of 2022, prices began to decrease in late 2022 and then dropped significantly in February 2023. The significant price decrease was due to a mild 2022/23 winter that contributed to a surplus inventory position across North America. This surplus continued through the start of the 2023/24 winter. Full inventory, a slow start to inventory withdrawals through November, and forecasted warm weather for the rest of the winter have resulted in forward natural gas prices in the short term being relatively low through the end of summer 2024.

Natural gas prices that trade on the New York Mercantile Exchange (NYMEX) at Henry Hub are the primary price for the North American natural gas market and are used to calculate locational basis differentials. As of January 30, 2024, the NYMEX forward curve ranges from $2.10 US/MMBtu in the near term to $3.82 US/MMBtu for next winter's peak, with a long-term average price of $3.48 US/MMBtu through 2028 as shown in Figure 5.

[20] Annual Energy Outlook 2023, March 16, 2023, p.23, https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Release_Presentation.pdf.

Figure 5: NYMEX Natural Gas Prices[21]

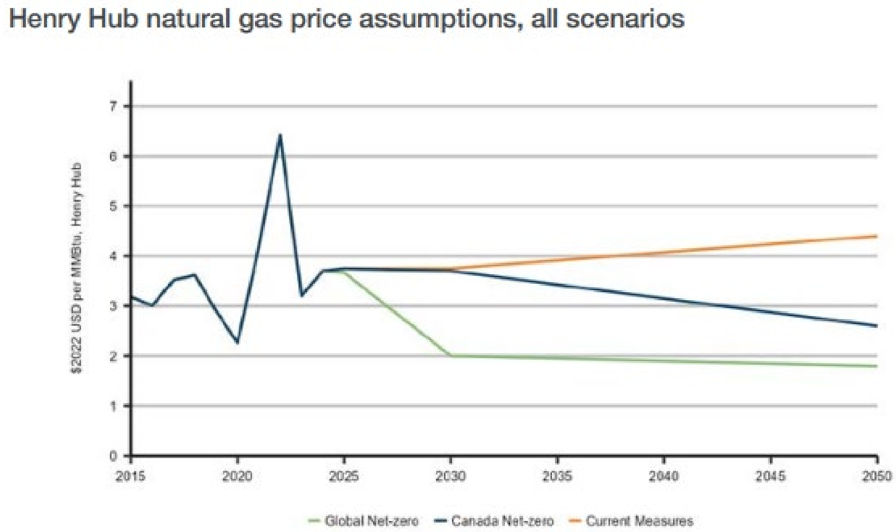


Looking forward, variations from normal weather, which impact inventory levels, the ongoing geo-political factors related to the Russia/Ukraine conflict, and supply/demand balance fundamentals will continue to impact and provide volatility to the natural gas prices, causing variances from any point-in-time forward curve snapshot as shown in Figure 5.

The CER has produced long-term natural gas price forecasts under its three Energy Future scenarios, as shown in Figure 6. Under the Current Measures Scenario average natural gas prices at Henry Hub are projected in a range similar to current forward market prices. Under the Canada-Net-Zero Scenario projected prices start a steady decline after 2030 caused by lower projected demands. In the most aggressive GHG emissions reducing scenario, prices start to decline more significantly and earlier than the Canada-Net-Zero scenario, driven by projections of more significant decreases in demand. In all scenarios, prices at Henry Hub are expected to be below $5 US/MMBtu through 2050.

[21] NYMEX monthly settled prices and forward curve as of November 29, 2023.

Figure 6: NYMEX Natural Gas Price Projections[22]



Transportation Market Overview

This section describes market changes relating to natural gas transportation which have a direct impact on Enbridge Gas's gas supply planning and related supply option analysis. In general, existing transportation capacity to Dawn and Enbridge Gas delivery areas has become increasingly scarce since the original 5-year Gas Supply Plan. This is a concerning trend as it has the potential to constrain the ability for Enbridge Gas to ensure adequate supply deliveries to its system to meet the design demands of customers in the future. As is the case with the CER demand forecast discussed in the section above, Enbridge Gas acknowledges that the energy transition is expected to result in lower annual demands for natural gas in the future. However, the extent and timing of the impacts on both annual and design day needs of Enbridge Gas's customers remain uncertain. These impacts will also not likely occur uniformly across the Enbridge franchise area. Enbridge Gas continues to see strong demands from its customer base in Ontario, particularly during cold periods in the winter. As the supplier of last resort, Enbridge Gas must ensure that its gas supply portfolio is adequate to meet these immediate demands. Contracts for upstream transportation capacity to Enbridge Gas's system play a very important role in ensuring the necessary system reliability and flexibility to operate in these uncertain conditions. Contracted upstream capacity to Enbridge Gas's system is considered in the design of Enbridge Gas's transmission and distribution systems, which can help reduce the need to meet customer demands with longer term infrastructure projects.

[22] Canada's Energy Future 2023, June 20, 2023, p.36, https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/index.html.

The energy transition has resulted in reductions to planned expansions of transportation capacity across North America, relative to the past decade. While limited new transmission infrastructure is being constructed, customer demands for natural gas throughout much of North America vary, with many regions seeing demand growth over the past few years. This is resulting in transportation capacity scarcity on many paths upstream of Enbridge Gas's system, which increases the value of existing infrastructure and the negotiating position of transportation capacity providers. The resulting impacts to buyers in the North American natural gas market are beginning to show through upstream transportation providers requesting higher tolls and longer-term contracts for their existing capacity.

In response to this trend, Enbridge Gas is taking a longer-term view in its assessments of existing capacity offered to the market (i.e. securing capacity when it becomes available, taking into account the potential that it will not be available later), particularly in areas of Enbridge Gas's system that have few alternatives for meeting customer demand (i.e. Union North rate zones). As outlined in the sections below, Enbridge Gas has significant contracting flexibility on nearly every one of its upstream transportation paths. This flexibility generally allows for the Company to secure capacity (either new or renewed) at longer terms, where required, while retaining flexibility to respond to uncertain future demand impacts of the energy transition through reducing or eliminating existing contracted transportation capacity. This can be seen in Figure 9.

To date, Enbridge Gas has been successful in negotiating tolls at or near pre-existing levels and keeping the contracted terms of upstream transportation capacity relatively short. In the sections below, Enbridge Gas describes the specific capacity availability and associated risks pertaining to paths the Company actively contracts.

Existing Pipeline Transportation Capacity

In the 2023 Annual Update, Enbridge Gas noted that capacity on the TCPL Mainline was scarce and has become a significant consideration when Enbridge Gas evaluates transportation alternatives. The availability of existing transportation capacity on TCPL has not improved since the last annual update and Enbridge Gas has observed that available capacity has become scarce on several other pipelines used to ship gas to its system.

The absence of available capacity results in greater competition for any capacity that does become available. On TCPL, where FT tolls are fixed, shippers compete for existing and new capacity by bidding for extended contract terms. As an example, in June 2023, TCPL closed an open season for existing capacity that included the Enbridge EDA and the export point of Iroquois. The Enbridge EDA and Iroquois are in similar locations on the TCPL system in eastern Ontario and therefore bids to those locations compete for the same capacity on an economic basis. TCPL has reported future contracts[23] on the Empress to Iroquois path with terms of up to 26 years, presumably awarded in the open season. Since the toll from Empress to Enbridge EDA is slightly lower than the toll to Iroquois, Enbridge Gas would need to bid for capacity with a slightly longer term to successfully compete with Iroquois bidders. This trend is magnified when the difference between tolls is greater. For example, in order for a short haul bid (i.e. Parkway to Enbridge EDA) to be successful against a bid for a higher-toll path (such as Empress to Enbridge EDA), a term of over 60 years would be required.

On FERC regulated pipelines, where a maximum toll is set but negotiated rates are permitted, pipelines have been seeking maximum tolls and longer terms from shippers.

Vector Pipeline (Vector)

The Vector pipeline has been sold-out of eastbound capacity to Dawn for several years and has also seen high utilization of westbound capacity to Chicago. In their October 2023 customer meeting presentation[24], Vector identified further load growth along the pipeline driven by the conversion of an electric powerplant from coal to gas in Michigan and other powerplants in Indiana, Michigan and Ontario. Vector identified two potential projects that could increase either eastbound or westbound capacity as early as November 2026 by redeploying an underutilized compressor to another compressor station along the Vector path. It is expected that Vector will hold an open season in Q1 2024 to solicit interest from shippers for both projects.

Enbridge Gas Dawn to Dawn (Vector)

In September 2023, Enbridge Gas announced an open season for up to 317,000 GJ/d of new C1 firm transportation capacity beginning November 1, 2026, from Dawn (Facilities) to Dawn (Vector). The open season package stated that a monthly demand charge premium to the posted toll would be required to recover facilities costs. Enbridge Gas subsequently announced a reverse open season in November 2023 for capacity on the Dawn to Dawn (Vector) path. No further public information regarding this open season has been released.

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[23] TC Energy, Future Contract Demand Energy (CDE) Report, January 2, 2024. https://www.tccustomerexpress.com/docs/ml_contracts/Future_CDE.pdf.
[24] Vector Pipeline, Customer Meeting, October 12, 2023. https://www.vector-pipeline.com/~/media/EepEeqMep/Site-Documents/Vector/News-Releases/Vector-2023-Customer-Meeting.pdf?rev=18c4a4a5d1ba4847bdb172846244a9d6&hash=882BEFAEF4508B3D261D538CF7F3A226.

Great Lakes Gas Transmission (GLGT)

In the 2022 TransCanada U.S. customer meeting, it was reported that receipts at Emerson continue to grow with high utilization and eastbound capacity to this point is currently sold-out. Enbridge Gas is not aware of any expansion plans to increase capacity on the GLGT system to Dawn.

GLGT shippers are starting to see the impacts of capacity scarcity through longer terms being demanded for both new and renewing contracts. In 2023, GLGT offered shippers with contract expiration dates of October 31, 2024 the option to extend their contracts by five years at maximum rate without having to go through the right of first refusal (ROFR) process. Enbridge Gas understands that all but one impacted shipper accepted the five-year renewal offer.

TransCanada Pipelines Limited (TCPL)

TCPL continues to focus on making their existing capacity available to the market, completing facility upgrades and maintenance work at points of constraint, and creating services that help Western Canadian Sedimentary Basin (WCSB) supply reach eastern North American markets. During 2023, maintenance and integrity work was undertaken on the Western Mainline (WML) segment of the TCPL Canadian Mainline (TCPL Mainline) that will continue into 2024. In addition, TCPL sought market interest by way of a new capacity open season in 2023 to provide additional capacity through the Eastern Ontario Triangle (ET) to markets served by and downstream of the TransCanada Quebec and Maritimes Pipeline (TQM) system. TCPL has not yet made the results of this open season public. A notable risk associated with TCPL new capacity open seasons is the ability for TCPL to request term extensions to all contracted capacity that could be used to support a new capacity expansion to a date not less than five years after the expected in-service date of the expansion facilities (term-up provision). If a customer does not elect to extend the term of their contract then the contract renewal rights are forfeited. For example, Enbridge Gas could be required to extend the terms of all of its contracted TCPL capacity to a date up to five years beyond the date expansion facilities are built along a specific path, regardless of whether Enbridge Gas has requested any of the new capacity for itself. As of the date of this filing, Enbridge Gas does not expect to be impacted by a term-up provision associated with the 2023 TCPL new capacity open season.

2024 Mainline Tolls & Abandonment Surcharges

In 2022, the earning sharing mechanism on the WML segment of the TCPL Mainline was triggered based on the balance in the WML Short-Term Adjustment Account (STAA). In accordance with the terms of the TCPL Mainline Settlement Agreement, the

WML rate riders resulting from the dispersal of the WML STAA are recalculated each year thereafter to include an additional year's shared earnings amortized over a four-year period to 2027.

In 2023, the earning sharing mechanism on the ET segment of the TCPL Mainline was triggered based on the balance in the ET STAA. Similar to treatment of the WML STAA, ET rate riders will be amortized over a period of 4 years to 2027 and apply to both long-haul and short-haul paths. All WML and ET rate riders are effective January 1, 2024 by CER order TG-006-2023. Further information related to the STAA dispersal and rate rider toll impacts can be found on the CER website (document number C27675).

Due to the increased contracting on both the WML and ET segments of the TCPL Mainline, abandonment surcharges on the TCPL Mainline continue to decrease from 2023 levels. Abandonment surcharges are as approved in CER order TG-007-2023.

These toll reductions were implemented in the January 2024 QRAM effective January 1, 2024.[25]

Existing TCPL Mainline Capacity & Constraints

Increased TCPL Mainline contracting and maintenance activities over the last several years has resulted in both the WML and ET segments being at or near capacity. As a result, Firm Transportation (FT) capacity has been unavailable on most of the TCPL Mainline, restricting the ability to contract for incremental capacity to serve Enbridge Gas delivery areas. Enbridge Gas expects that capacity may be available at various times over the next five years through existing capacity open seasons because of de-contracting, line maintenance, and integrity work. This scarcity of capacity availability is a significant consideration when Enbridge Gas evaluates transportation alternatives, as demonstrated in the Company's open season participation during 2023, which is discussed further in Section 4.1. Enbridge Gas will continue to monitor capacity availability and analyze opportunities as they arise.

TCPL Mainline capacity of approximately 1.5 PJ/d is contracted from Empress to the Union Dawn delivery point using TCPL's Dawn Long Term Fixed Price (Dawn LTFP) service. The Dawn LTFP service includes a 10-year contract term, with almost all contracts covering the 2017 to 2027 period[26]. Dawn LTFP contracts are not renewable but may be converted to FT service at the end of the contract term. Both Empress and Dawn constitute significant sources of natural gas supply for Enbridge Gas, and

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[25] EB-2022-0285, Exhibit B, Tab 1, Schedule 1, pp.2-3; Exhibit D, Tab 1, Schedule 1, p.1.
[26] TransCanada Mainline Index of Customers, https://www.tccustomerexpress.com/888.html. Approximately 90% of Dawn LTFP contracts are for the 2017 to 2027 period. Remaining contracts expire in 2028 or 2029.

therefore, Enbridge Gas continues to monitor the status of the Dawn LTFP service and the potential market price implications at Empress and Dawn.

Panhandle Pipelines (Panhandle)

As noted in previous annual updates, Panhandle filed a rate case with the FERC in 2019 and shippers have paid interim tolls since March 1, 2020.

On February 14, 2023, Panhandle filed final compliance tolls in response to the FERC's Opinion. The compliance tolls were put in place beginning with the October 2023 billing period. On November 30, 2023, Panhandle filed a notice with the FERC that it has refunded amounts for Panhandle's shippers for the period March 1, 2020 through September 30, 2023. These amounts totaled over $206 million USD. Enbridge Gas's refund was in excess of $20 million CAD and was credited to ratepayers in the January 2024 QRAM filing[27].

Panhandle has filed an appeal with the United States Court of Appeals for the District of Columbia for a review of the Compliance Order and the refund that Panhandle was directed to pay to its customers. Enbridge Gas will continue to monitor Panhandle's appeal process and any revisions to the reimbursement will be reflected in the next applicable QRAM.

2.2 Public Policy Updates

The following section provides information on impacts to gas supply planning in order to adapt to public policy changes. Public policy items related to topics that impact gas supply planning such as energy transition, low carbon fuels and integrated resource planning, are also being addressed in Enbridge Gas's Rebasing application[28] though the discussion in that case is longer term in nature.

Natural Gas Expansion Program (NGEP)

In their report to the Government of Ontario released December 10, 2020, the OEB originally indicated that 200+ projects could be considered for potential natural gas expansion funding. On June 9, 2021, the Government of Ontario announced that 28 projects across 43 communities were selected for potential funding in the second phase of the NGEP with 27 of these projects having been proposed by Enbridge Gas. The government's goal with the passing of regulation (O.Reg. 451/21) identifying these 28

[27] EB-2023-0330.
[28] EB-2022-0200.

projects for phase 2 was to prioritize connecting the greatest number of customers as broadly as possible across Ontario, in the most economically feasible way.

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

Federal Carbon Charge (FCC)

Enbridge Gas filed an application[29] on September 28, 2023, seeking OEB approval for rates effective April 1, 2024, to recover costs associated with meeting its obligations under the federal Greenhouse Gas Pollution Pricing Act (GGPPA) and the provincial Emissions Performance Standards (EPS).

As of April 1, 2024, the Federal Carbon Charge that Enbridge Gas must remit to the Government of Canada under the GGPPA for eligible volumes of natural gas will increase from \$65 per tonne of carbon dioxide equivalent (tCO_2e) to \$80 per tCO_2e.

The demand forecast underpinning this Annual Update includes the federal carbon charge in the price-related demand driver variables used in its regression analysis. Enbridge Gas assumes \$65 per tCO_2e in 2023, escalating at a rate of \$15/tCO_2e per year until reaching \$170/tCO_2e in 2030.

Federal Clean Fuel Regulation

In June 2022, the federal government finalized the Clean Fuel Regulation (CFR), which requires liquid fossil fuel producers and importers to reduce the carbon intensity of the fuels used in Canada. The CFR does not impose a compliance obligation on gaseous or solid fuels; however, natural gas distributors can participate in the CFR where credits are generated for the production or import of low carbon fuels such as RNG and hydrogen. As a result, Enbridge Gas anticipates that RNG or hydrogen procured as part of its supply portfolio may include CFR credits which would lower the cost of these fuels for ratepayers where the CFR credits are sold to entities with a CFR compliance obligation. The potential availability and value of CFR credits for existing RNG and hydrogen procurement is uncertain, nor have CFR credit prices been reported publicly, and as such, the impacts of the CFR have not been considered in this Annual Update.

[29] EB-2023-0196.

Integrated Resource Planning

Since the 2023 Annual Update, there have been no impacts on the demand forecast or gas supply portfolio from IRPAs beyond what is already reflected in DSM impacts.

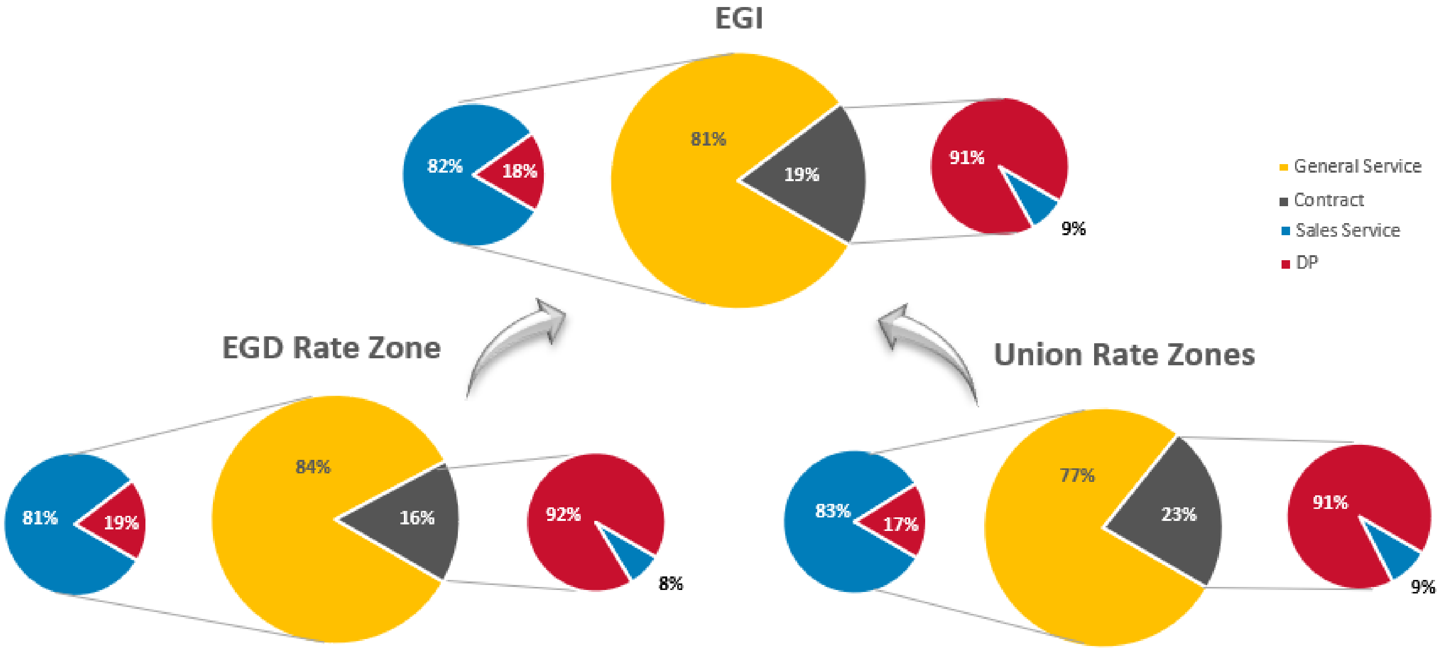
3. Demand Forecast Analysis

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

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

Enbridge Gas's proportion of general service and contract customers volume is outlined in Figure 7. This is further split by sales service and DP customer types.

Figure 7: Service Types



3.1 Annual Demand

This Annual Update is based on the demand forecast for the general service market and contract market rate classes which are prepared separately for the EGD and Union rate zones using OEB-approved methodologies at the time the budget was created[30]. The demand forecast for this Plan was prepared in spring 2023 and received internal senior management approval in Q3 2023. As such, any changes as a result of the 2024 Phase 1 Rebasing decision will be captured in future gas supply plans and their respective filings.

The current forecast was produced in the spring of 2023 and reflects the best information available at the time. This includes actual 2022 consumption data, and updated demand driver variables. Table 1 below illustrates the annual demand forecast for each rate zone included in this Annual Update[31].

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

Table 1
Annual Demand Forecast

Line No.	Particulars (TJ)	2023/24	2024/25	2025/26	2026/27	2027/28
		(a)	(b)	(c)	(d)	(e)
	EGD					
1	General Service	382,674	383,499	384,574	385,774	387,047
2	Contract	73,285	73,185	72,592	72,000	71,408
3	Total EGD	455,959	456,684	457,166	457,774	458,455
	Union North West					
4	General Service	14,762	14,823	14,859	14,856	14,926
5	Contract	1,775	1,772	1,769	1,767	1,765
6	Total Union North West	16,537	16,595	16,628	16,623	16,691
	Union North East					
7	General Service	37,664	37,812	37,957	38,017	38,170
8	Contract	3,682	3,674	3,667	3,660	3,654
9	Total Union North East	41,346	41,486	41,624	41,677	41,824
	Union South					
10	General Service	172,047	170,795	170,222	169,817	170,252
11	Contract	60,024	59,923	59,802	59,678	59,554
12	Total Union South	232,071	230,719	230,025	229,495	229,805
13	Total Demand Forecast	745,912	745,483	745,443	745,570	746,775

As outlined in Table 2, the current annual demand forecast is showing approximately 1.0% lower demand compared to the 2023 Annual Update as a result of lower general service and contract market demand. Compared to the previous forecast, general service demands are about 1.0% lower on average, driven by lower average use and DSM savings. The contract market overall is an average of 1.2% lower than the previous plan as a result of updated customer forecasts and shifted consumption from bundled DP to semi-unbundled. Enbridge Gas's total annual demand is expected to be flat over the next five years, increasing marginally by an average of 0.03% year-over-year within the forecast period.

Table 2
2024 Annual Demand Forecast vs 2023 Annual Demand Forecast

Line No.	Particulars (TJ)	2023/24 2024 Plan	2023/24 2023 Plan	2023/24 Variance	2024/25 2024 Plan	2024/25 2023 Plan	2024/25 Variance	2025/26 2024 Plan	2025/26 2023 Plan	2025/26 Variance	2026/27 2024 Plan	2026/27 2023 Plan	2026/27 Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	EGD												
1	General Service	382,674	388,036	(5,362)	383,499	390,728	(7,229)	384,574	392,632	(8,058)	385,774	394,611	(8,837)
2	Contract	73,285	72,666	619	73,185	72,247	937	72,592	71,644	948	72,000	71,032	968
3	Total EGD	455,959	460,702	(4,743)	456,684	462,975	(6,292)	457,166	464,276	(7,110)	457,774	465,643	(7,869)
	Union North West												
4	General Service	14,762	14,279	483	14,823	14,234	589	14,859	14,226	633	14,856	14,201	655
5	Contract	1,775	1,619	156	1,772	1,562	209	1,769	1,550	219	1,767	1,538	229
6	Total Union North West	16,537	15,898	638	16,595	15,796	799	16,628	15,776	852	16,623	15,740	884
	Union North East												
7	General Service	37,664	39,086	(1,422)	37,812	38,919	(1,107)	37,957	38,878	(920)	38,017	38,860	(843)
8	Contract	3,682	3,890	(208)	3,674	3,911	(237)	3,667	3,875	(208)	3,660	3,839	(178)
9	Total Union North East	41,346	42,976	(1,631)	41,486	42,830	(1,344)	41,624	42,753	(1,129)	41,677	42,699	(1,021)
	Union South												
10	General Service	172,047	169,651	2,396	170,795	168,785	2,010	170,222	168,577	1,645	169,817	168,314	1,503
11	Contract	60,024	60,013	10	59,923	61,659	(1,736)	59,802	63,292	(3,490)	59,678	64,909	(5,231)
12	Total Union South	232,071	229,664	2,407	230,719	230,444	275	230,025	231,869	(1,845)	229,495	233,223	(3,728)
13	Total Demand Forecast	745,912	749,241	(3,329)	745,483	752,045	(6,562)	745,443	754,674	(9,231)	745,570	757,304	(11,734)

Assuming 1% colder/warmer weather, Enbridge Gas's general service volume forecast would be approximately 0.7% higher/lower. In the contract market, a 1% colder/warmer weather assumption would have negligible impact as customers in this market are predominantly not heat-sensitive.

Customer behaviour, energy efficiency advances, DSM savings, fluctuations in natural gas prices, the FCC[32], and market conditions impacted by government and regulator policies and decisions, continue to play a role on impacting both general service and contract market demand.

3.2 Design Day Demand

EGD rate zone design day demand weather conditions are based on a 1 in 5 recurrence interval[33] using a lognormal distribution. The Union rate zones design day demand weather conditions are based on the coldest-observed degree day.[34] Table 3 below illustrates the design day demand forecast for each rate zone that was prepared in spring 2023.

Table 3
Design Day Demand Forecast

Line No.	Rate Zone (TJ/d)	2023/24	2024/25	2025/26	2026/27	2027/28
		(a)	(b)	(c)	(d)	(e)
1	EGD	4,101	4,118	4,135	4,153	4,170
2	Union North West	138	140	141	141	142
3	Union North East	460	453	456	457	461
4	Union South	3,396	3,460	3,515	3,652	3,674

In comparison to the 2023 Annual Update shown in Table 4, design day demands have slightly increased in the EGD and Union North rate zones reflecting general growth across the rate zones. The forecast for the Union South rate zone shows declines from

[32] The forecast assumes $65 per tCO2e in 2023 with a $15 per year increase annually thereafter until it reaches $170 tCO2e as described in Section 2.2.
[33] A recurrence interval is defined as the average frequency, in years, in which an actual weather event or HDD level is expected to exceed that of the design level one time. For example, a 1 in 10 recurrence interval would mean that the HDD level assumed on design day is expected to be exceeded once every ten years. Another way to express this statement is that there is a 10% probability that the specified design day HDD value would be exceeded in any given year.
[34] In the coldest day method, the design day HDD value is selected by choosing the coldest day on record and using this HDD value to derive the design day demand that is used to establish the gas supply and transportation portfolio.

2024/25 to 2026/27, with the net decrease in demand due to shifts in customer specific attachment timing in the contract rate market and revised assumptions such as lower expected general service market growth.

Table 4
2024 Design Day Demand Forecast vs. 2023 Design Day Demand Forecast

		2023/24			2024/25			2025/26		
Line No.	Rate Zone (TJ/d)	2024 Plan	2023 Plan	Variance	2024 Plan	2023 Plan	Variance	2024 Plan	2023 Plan	Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	EGD	4,101	4,087	14	4,118	4,104	14	4,135	4,120	15
2	Union North West	138	136	3	140	135	5	141	135	6
3	Union North East	460	433	27	453	432	22	456	432	24
4	Union South	3,396	3,372	24	3,460	3,470	(10)	3,515	3,626	(111)

4. Current Portfolios

4.1 Commodity Portfolio

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

As described below, Enbridge Gas holds firm transportation contracts from multiple supply basins for each rate zone. This allows access to a diverse commodity portfolio, providing reliable and secure supply, aligned with the guiding principles as outlined in the Framework.

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

To serve Union North West, Enbridge Gas holds firm transportation contracts connecting to supply basins in Western Canada via the TCPL Mainline. In addition, the Union North West rate zone can receive supply from third-party services, such as peaking services or delivered supply arrangements. Enbridge Gas may also consider transportation on Great Lakes Pipeline.

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

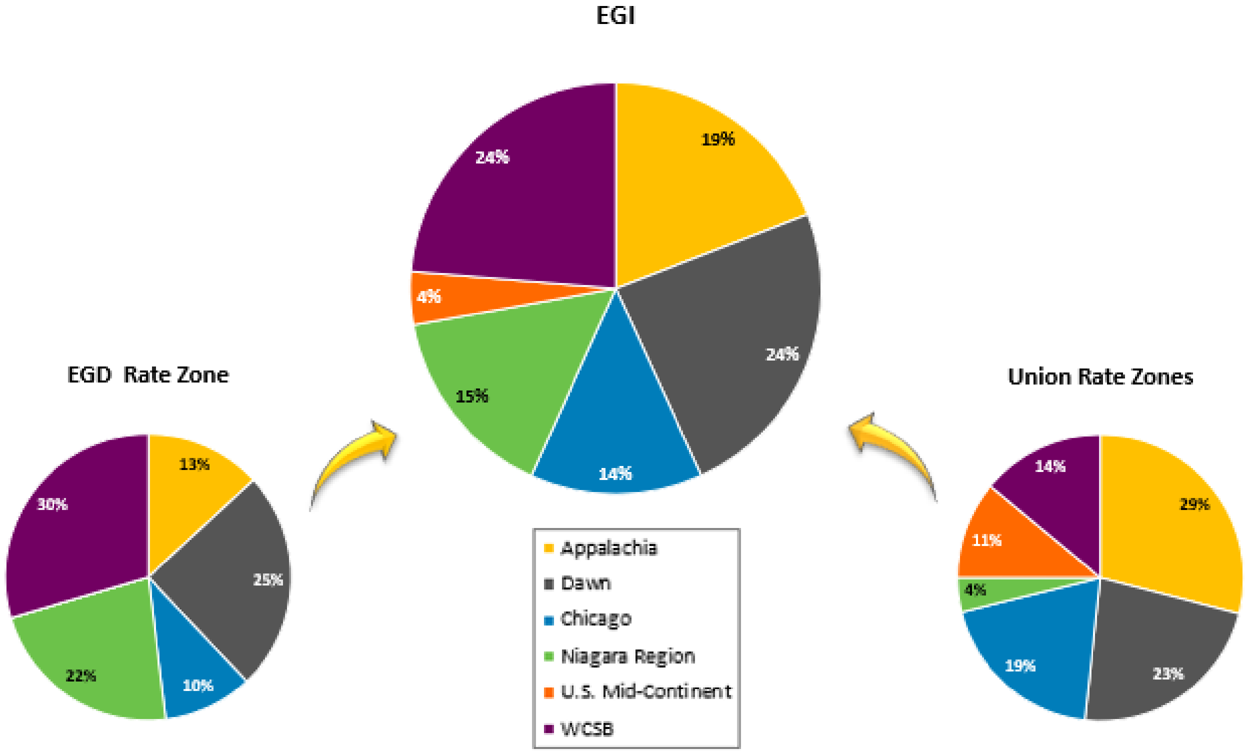
Similarly, Enbridge Gas holds firm transportation contracts on multiple upstream pipelines to serve Union South, providing access to supplies in Appalachia, Chicago, Western Canada, the U.S. Mid-Continent and Niagara. Dawn purchases are also included as part of the Union South supply portfolio. Table 5 provides the sources of supply assumed for sales service customers with an illustration in Figure 8.

Table 5
Sources of Supply

Line No.	Particulars (TJ)	2023/24	2024/25	2025/26	2026/27	2027/28
		(a)	(b)	(c)	(d)	(e)
	EGD					
1	Appalachia	43,087	42,970	42,970	42,970	43,087
2	Chicago	33,021	32,931	32,931	32,931	33,021
3	Niagara Region	73,471	73,270	73,270	73,270	73,471
4	Dawn	81,303	82,986	83,521	83,793	83,637
5	Peaking/Seasonal	77	76	93	111	128
6	WCSB	97,062	96,799	96,813	97,115	97,099
7	Total EGD	328,021	329,031	329,597	330,189	330,444
	Union North West					
7	WCSB	16,301	15,651	13,439	16,730	14,378
	Union North East					
8	Appalachia	19,308	19,255	19,255	19,255	19,308
9	Dawn	6,309	7,505	9,920	6,550	9,045
10	WCSB	2,708	2,700	2,700	2,700	2,708
11	Total North East	28,325	29,460	31,875	28,506	31,061
	Union South					
12	Appalachia	38,615	38,510	38,510	38,510	38,615
13	Chicago	38,615	38,509	38,509	38,509	38,615
14	Niagara Region	7,723	7,702	7,702	7,702	7,723
15	Dawn(1)	39,044	38,437	38,401	38,027	37,664
16	U.S. Mid-Continent	22,011	21,950	21,950	21,950	22,011
17	WCSB	8,821	8,797	8,797	8,797	8,821
18	Total South	154,828	153,905	153,870	153,495	153,448
19	Total Supply Forecast	527,476	528,048	528,781	528,920	529,330

Note:
(1) Includes Ontario Production.

Figure 8: 2023/24 Sources of Supply



4.2 Energy Transition in the Gas Supply Portfolio

Enbridge Gas recognizes the importance of emissions reduction in Ontario, as well as the important role that Enbridge Gas plays in supporting the achievement of greenhouse gas (GHG) emissions reduction targets.

Pursuing energy transition through Enbridge Gas's gas supply portfolio provides a significant opportunity for Ontario to meet its GHG emissions reduction goals in alignment with the gas supply guiding principles. To date, Enbridge Gas has supported the energy transition through the existing Voluntary RNG (VRNG) Program, the inclusion of RSG in the gas supply portfolio, and the purchase of hydrogen through the Low Carbon Energy Project. Moving forward, Enbridge Gas has proposed to evolve the inclusion of low carbon energy in the gas supply portfolio as part of Phase 2 of its Rebasing Application[35].

As part of this Annual Update, Enbridge Gas is not proposing changes to its current approach in procuring RNG or RSG.

[35] EB-2022-0200.

Voluntary Renewable Natural Gas Program

RNG is a carbon-neutral fuel that can help fight climate change. Created by capturing methane emissions from organic waste, landfills and wastewater treatment plants, RNG will play an important role in Ontario's clean energy future. RNG can be used to fuel transit fleets, power industry and heat homes and businesses, and is an effective solution to help companies and communities reduce GHG emissions.

RNG provides two distinct emissions reduction benefits. First, methane is captured that would have otherwise been released or flared to atmosphere at the waste source. Second, the renewable natural gas created from the captured methane displaces the need for a molecule of conventional natural gas in energy supply. When a molecule of RNG is consumed, it is not subject to the federal carbon charge.

Enbridge Gas launched a VRNG the program on April 1, 2021[36] and as of October 31, 2023, 3,559 customers have enrolled in the program. As of October 31, 2023, Enbridge Gas has made two purchases of RNG as part of the VRNG program, procuring 3,360 GJ in total, with 2,260 GJ procured in the 2022/2023 gas year. Enbridge Gas continues to monitor the forecast 12-month revenues based on actual participants and will procure additional RNG based on this forecast revenue when this amount is sufficient to procure a tranche of RNG.

This program has had lower than forecast enrollment from customers. However, to secure Ontario's access to RNG, Enbridge Gas has proposed to evolve the VRNG program into a low carbon energy program starting in 2025 to be addressed in Phase 2 of Enbridge Gas's Rebasing Application[37].

Responsibly Sourced Natural Gas

The market for conventional natural gas is evolving to include an increased focus and management of the methane emissions released through the production of natural gas. This focus is evident through the continued development of RSG certifications. Recently proposed policy in Canada and the US aim to further cap methane emissions in natural gas production. In addition, Canada and the US have acknowledged improvements in the measurement of methane emissions is required to provide a more robust accounting. In November 2023, Canada, the US, and 10 other countries established a

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[36] As approved on a pilot basis by the OEB on September 25, 2020.
[37] EB-2022-0200.

working group that will develop a consensus-based approach for monitoring GHGs across the international supply chain.[38]

RSG certifications measure a conventional natural gas producer's conformance to several standards, including methane emissions, while driving continuous improvement in the supply chain. The Equitable Origins EO100, MiQ, and Project Canary's Trustwell certifications are the certifications that are actively used by producers to monitor their conformance to specific ESG standards. Each of these certifications have unique standard requirements that producers must meet to become certified. Two RSG certifications, MIQ and Project Canary's Trustwell, have standard limits on methane intensity during the production of natural gas to obtain certification.

Procuring RSG offers Enbridge Gas customers greater transparency into the ESG attributes of their natural gas supply. This can be accomplished by using existing North American Energy Standards Board (NAESB) contracts, relationships with existing suppliers and requires no upfront costs to implement. Enbridge Gas continues to signal to the market that it is interested in procuring RSG with the goal of encouraging more suppliers to implement practices to lower emissions and achieve ESG attribute goals in accordance with certification.

Low Carbon Energy Project

Enbridge Gas submitted a revised Leave to Construct application for the Low Carbon Energy Project (LCEP) with the OEB on March 31, 2020. Following OEB approval in the fall of 2020, construction started on the hydrogen blending facilities. Construction and commissioning were completed in September 2021, and the plant began blending up to 2% hydrogen by volume on October 1, 2021, for approximately 3,600 customers in Markham, Ontario. From November 2022 through the end of October 2023, the energy equivalent of hydrogen that has been blended into the system and purchased as part of the Gas Supply Plan is 1,661 GJ.

4.3 Transportation Portfolio

To manage risk, Enbridge Gas holds a diverse portfolio of transportation contracts to meet the design day needs of each delivery area. This diverse portfolio aims to reduce exposure to the risk of both supply constraints in any one basin and also price spikes as a result of basin-specific conditions. As described above, available upstream transportation capacity delivering supply to Enbridge Gas's delivery areas is currently

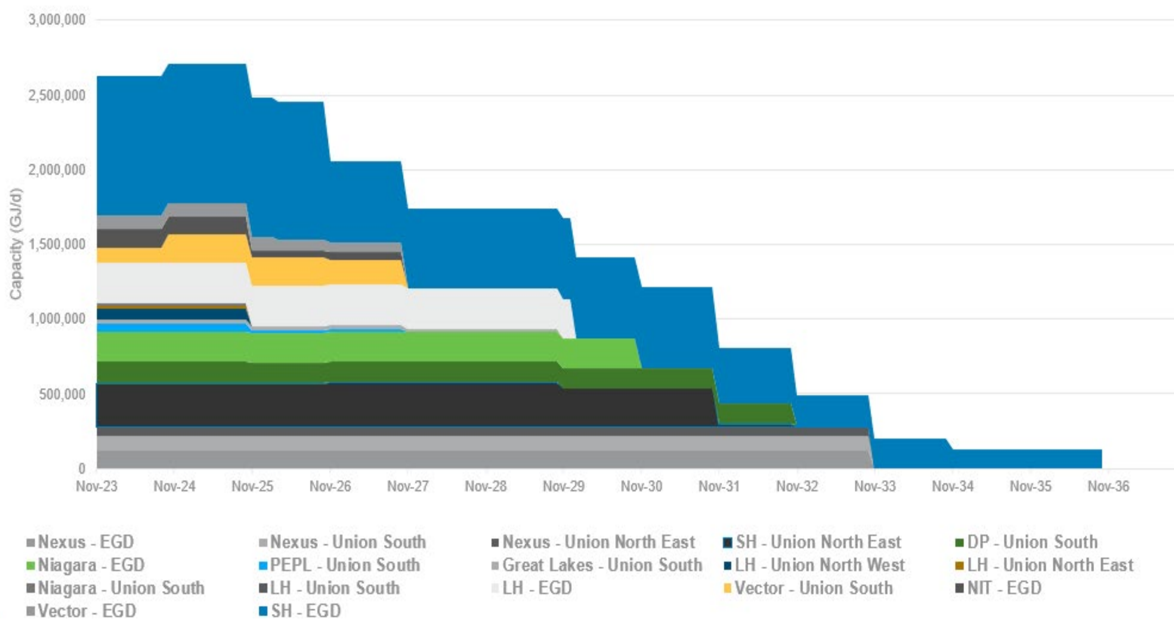
[38] Energy.gov, MMRV Framework Public Announcement, November 15, 2023, https://www.energy.gov/sites/default/files/2023-11/MMRVFramework_PublicAnnouncement_15Nov2023.pdf.

scarce, with minimal availability or known relevant planned expansions. As discussed previously, Enbridge Gas expects this to become an important factor in decision making in future contracting considerations.

Figures 1-3 in Appendix A provide a visual representation of all contracted transportation services for the EGD and Union rate zones as of November 1, 2023. A complete listing of the transportation capacity currently contracted for EGD, Union North, and Union South rate zones is provided in Appendix B.

Enbridge Gas ensures that it has diversity in the length of contract terms within its transportation portfolio. This diversity allows flexibility to respond to changes in demand and/or supply in future years. Figure 9 below depicts Enbridge Gas transportation agreements and their current term expiries as of November 1, 2023. Many of these contracts include renewal rights that can be exercised at the discretion of Enbridge Gas.

Figure 9: Transportation Portfolio Term



4.4 Transportation Portfolio Changes

Enbridge Gas continuously monitors market conditions and will enter into contracts throughout the planning period as required to manage the gas supply portfolio.

The following section addresses transportation portfolio changes since the 2023 Annual Update. The format of this section is consistent with the Transportation Contracting Analysis filing requirements as outlined in EB-2005-0520[39].

Transportation Contracting Analysis

During 2023, Enbridge Gas has made the following portfolio changes:

1. Centra Transmission Holdings Inc. (CTHI)
    a. Effective November 1, 2023, Enbridge Gas has contracted for 5.4 10^3m^3 (~206 GJ/d) of incremental capacity from Spruce to Sprague and from Rainy River to Fort Francis for a 1-year term.

2. Centra Pipelines Minnesota Inc. (CPMI)
    a. Effective November 1, 2023, Enbridge Gas has contracted for an incremental 192 mcf/d (~206 GJ/d) of incremental capacity from Sprague to Baudette for a 1-year term.

3. NEXUS Pipeline (NEXUS)
    a. Effective November 1, 2023, Enbridge Gas has contracted for 25,000 GJ/d of incremental capacity from Clarington to Kensington for a 2-year term.
    b. Effective November 1, 2024, Enbridge Gas has contracted for the extension of 40,000 GJ/d of existing capacity on NEXUS from Clarington to Kensington for a 2-year term.

4. Great Lakes Gas Transmission (GLGT)
    a. Effective November 1, 2024, Enbridge Gas has renewed 20,000 Dth/d (21,101 GJ/d) of existing capacity from Emerson to St. Clair on GLGT for a 5-year term.
    b. Effective November 1, 2024, Enbridge Gas has renewed 21,101 GJ/d of existing capacity from St. Clair to Dawn on Great Lakes Pipeline Canada Ltd. for a 5-year term.

5. Nova Gas Transmission Limited Pipeline (NGTL)
    a. Effective November 1, 2024, Enbridge Gas renewed 50,000 GJ/d of existing capacity from Nova Inventory Transfer (NIT) to Empress on NGTL for a 3-year term.

6. TransCanada Pipelines Limited (TCPL)
    a. Effective November 1, 2024, Enbridge Gas has contracted for 18,876 GJ/d of incremental capacity from Union Parkway Belt to Enbridge CDA on TCPL for a 3-year term.

[39] EB-2005-0520, Settlement Agreement, Exhibit B.

   b. Effective November 1, 2024, Enbridge Gas has reserved 18,876 GJ/d of incremental capacity from Dawn to Parkway on the Dawn Parkway System on behalf of in-franchise customers.

7. Vector Pipeline
   a. Effective November 1, 2024, Enbridge Gas has renewed 65,000 Dth/d (68,578 GJ/d) of existing capacity from Chicago to the US/Canadian border for a 3-year term.
   b. Effective November 1, 2024, Enbridge Gas has renewed 68,578 GJ/d of existing capacity from the US/Canadian border to Dawn for a 3-year term.
   c. Effective November 1, 2024, Enbridge Gas has contracted for 84,404 GJ/d of incremental capacity from Dawn-Vector to St. Clair for a 3-year term.

8. St. Clair Pipelines
   a. Bluewater River Crossing - Effective November 1, 2024, Enbridge Gas has renewed 127,000 GJ/d of existing capacity with St. Clair Pipelines connecting the Bluewater Gas system in Michigan to the Enbridge Gas system near Sarnia for a 1-year term.
   b. St. Clair River Crossing - Effective November 1, 2024, Enbridge Gas renewed 214,000 GJ/d capacity with St. Clair Pipelines connecting the MichCon/DTE system in Michigan to the Enbridge Gas system near Courtright for a 1-year term.

Rationale for CTHI and CPMI Capacity

Enbridge Gas's preferred planning strategy for meeting peak day shortfalls is to purchase third-party services for up to 2% of the design day demand and to purchase firm transportation for shortfalls beyond that amount.

In most delivery areas, Enbridge Gas can purchase peaking services from marketers with deliveries into the delivery area to meet peak day requirements. The Union MDA can only be served via the CTHI/CPMI system which flows from a point on the TCPL system in Manitoba into Minnesota and then back into Ontario terminating near the town of Fort Francis, Ontario. There are only four shippers with capacity on the CTHI/CPMI system and none of those shippers are marketers. Therefore, peaking services with deliveries to the MDA are not an option. Any solution to meet design demands in the Union MDA must include transportation capacity on CTHI/CPMI. CTHI and CPMI pipelines have available capacity that can be contracted for 1-year increments by requesting capacity during the annual renewal process.

Capacity on the TCPL Mainline is sold out. There is no capacity available from Empress (a liquid supply point) to the Centrat MDA where the CTHI/CPMI system begins.

However, since the Centrat MDA is a delivery area on the TCPL Mainline with several marketers and producers holding capacity that would have the Centrat MDA[40] considered to be within path, Enbridge Gas was able to secure peaking services to the Centrat MDA and contracted for incremental firm transportation on the CTHI/CPMI system to meet peak demands in the Union MDA. The total annual cost of this incremental transportation is approximately $63,000.

The benefits of this capacity include:

i. Contracts supports Enbridge Gas's objective of structuring a portfolio with a diversity of contract terms and supply basins;
ii. Firm transportation purchase is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable cost;
iii. Provides a fixed-rate toll which provides toll certainty on a portion of Enbridge Gas's upstream transportation portfolio.

As peaking service to the Centrat MDA combined with CTHI and CPMI capacity was the only option available to the Union MDA, no landed cost analysis was completed.

Rationale for NEXUS Capacity

In the 2023 Annual Update, Enbridge Gas explained that during the summer of 2022, Enbridge Gas extended 40,000 Dth/d of NEXUS Pipeline capacity from Clarington to Kensington for the term November 1, 2022 to October 31, 2024 (two years) at a toll of $0.24/Dth/d without renewal rights. The 40,000 Dth/d was a reduction from the 75,000 Dth/d of Clarington capacity Enbridge Gas held under its NEXUS contract for four years expiring October 31, 2022. Enbridge Gas did not have renewal rights on the 75,000 Dth/d of Clarington capacity and had to negotiate with NEXUS for further capacity extensions. In the summer of 2023, Enbridge Gas extended the 40,000 Dth/d of NEXUS capacity from Clarington to Kensington for an additional two years to October 31, 2026 and also added 25,000 Dth/d of incremental Clarington to Kensington capacity for a 2-year term starting November 1, 2023. The new and extended capacity is priced at $0.24/Dth/d and does not contain renewal rights.

The incremental and renewed Nexus capacity from Clarington to Kensington does not change the contracted deliveries from NEXUS to Enbridge Gas's system, but rather continues and expands Enbridge Gas's access to the Clarington supply point which is located in the NEXUS supply zone at the junction of NEXUS and Texas Eastern Pipeline. Clarington has proven to be a liquid and economic supply point for Enbridge Gas, while the other contracted receipt point, Kensington, continues to develop as a

[40] TC Energy, Future Contract Demand Energy (CDE) Report, January 2, 2024, https://www.tccustomerexpress.com/docs/ml_contracts/Future_CDE.pdf.

new point of supply in the market but has much lower liquidity and fewer sellers offering supply. As demonstrated in the landed cost analysis at Appendix C, the incremental cost of this transportation capacity is more than offset by lower commodity prices at Clarington.

The benefits of this capacity include:

i. Supports the acquisition of supply from upstream markets, increasing diversity of contract terms and supply points;
ii. Provides flexibility to access other supply points along the path;
iii. Provides Enbridge Gas with receipt flexibility within the path; and
iv. Landed cost is competitively priced relative to Kensington supply.

A comparison of landed costs for the NEXUS capacity can be found in Appendix C.

Rationale for GLGT Capacity

Enbridge Gas's existing GLGT capacity had an initial term of five years and was set to expire on October 31, 2024. The GLGT Tariff contains a provision for pipeline and shipper to mutually agree upon contract extension terms prior to the invocation of a Right of First Refusal (ROFR) process. Accordingly, GLGT offered Enbridge Gas a 5-year contract extension at the maximum Tariff rate.

GLGT capacity into Dawn is currently sold out and if Enbridge Gas were to reduce its contract levels on GLGT, it would be unlikely to be able to recontract in the foreseeable future. As noted in Section 2.1, the scarcity of available pipeline capacity to Dawn on GLGT and many other alternative upstream pipelines results in a higher risk of the ROFR process requiring a commitment beyond a 5-year term. Recognizing this risk Enbridge Gas accepted the offer and renewed its capacity for a 5-year term beginning November 1, 2024.

The renewed GLGT capacity provides a competitively priced, reliable and flexible transportation option that maintains Enbridge Gas's supply diversity, particularly in the Union South commodity portfolio. Additionally, an important secondary benefit of GLGT capacity to Dawn is the ability to supply the Sarnia Industrial Line (SIL).

The benefits of this capacity include:

i. Supports the acquisition of supply from upstream markets, maintaining diversity of contract terms and supply basins;
ii. Provides flexibility to access other supply points along the path, including Emerson, Farwell and Crystal Falls;
iii. GLGT renewal provides Enbridge Gas with delivery point flexibility within the path including Michigan storage and Sarnia;

iv. The right to renew this capacity through ROFR is a component of the agreement which ensures secure access to this transportation in the future;
v. Provides Enbridge Gas with both receipt and delivery flexibility within the path, including potential deliveries to the SSMDA;
vi. Provides flexibility as the capacity can be segmented and used bi-directionally;
vii. Landed cost of gas flowing to Enbridge Gas along this route is competitively priced; and
viii. Provides potential access to Michigan storage.

A comparison of landed costs for the GLGT capacity relative to the viable alternatives can be found in Appendix D.

Rationale for NGTL Renewal

Enbridge Gas has contracts to flow up to 260,000 GJ/d on the TCPL Mainline from Empress for the EGD rate zone until December 31, 2030. Rather than purchasing all supply at Empress, NGTL capacity provides Enbridge Gas with the ability to diversify its gas purchases between Empress and AECO. NGTL capacity is currently sold out and if Enbridge Gas were to reduce its contract levels on NGTL it would be unlikely to be able to recontract in the foreseeable future.

Contracting for a term of three years qualifies Enbridge Gas to continue to take advantage of a 5% reduction to the regulated toll. Landed cost analysis indicates that NOVA capacity provides an economic benefit to rater payers when this toll reduction and liquids extraction savings are considered.

The benefits of this capacity include:

i. Contract supports Enbridge Gas's objective of structuring a portfolio with a diversity of contract terms and supply basins;
ii. Firm transportation capacity provides diversity to meet the firm requirements at Empress;
iii. Firm transportation purchase is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable cost;
iv. Term of three years results in a 5% discount to the regulated toll;
v. Facilitates longer-term liquids extraction benefits; and
vi. Landed cost of gas flowing to Empress along this route is competitively priced and has an end date that aligns with the gas year.

A comparison of landed cost for NGTL renewal options can be found in Appendix E.

Rationale for TCPL and Enbridge Gas Capacity

TCPL held an Existing Capacity Open Season (ECOS) and New Capacity Open Season (NCOS) from May 17 to June 14, 2023, for FT and Non-Renewable Firm Transportation (FT-NR) transportation with various quantities having service dates beginning October and November 1, 2023, and also April and November 1, 2024.

Enbridge Gas's preferred planning strategy for meeting design day shortfalls is to purchase third-party services for up to 2% of the design day demand and to purchase firm transportation for shortfalls beyond that amount. Enbridge Gas regularly monitors the availability of firm transportation and, as noted in Section 2.1, available capacity on TCPL has been very limited. Therefore, this was a rare and attractive opportunity to secure incremental capacity to meet forecasted design day growth in the Enbridge CDA.

Enbridge Gas submitted a bid for capacity from Parkway to Enbridge CDA and was awarded 18,876 GJ/d of existing capacity commencing on November 1, 2024 for a 3-year term. The 18,876 GJ/d of incremental capacity is necessary to meet growth in the Enbridge CDA and has renewal rights which secures Enbridge Gas's ongoing access to this transportation capacity without having to support an infrastructure expansion and engage in associated long term contract commitments.

Enbridge Gas held a NCOS from June 6 to July 18, 2023, for up to 96,000 GJ/d of M12 and M12X transportation with receipt points of either Dawn or Kirkwall and delivery points of Kirkwall or Parkway starting November 1, 2027. The NCOS stated that earlier start dates may be considered.

Enbridge Gas bid for 18,876 GJ/d of Dawn to Parkway capacity starting November 1, 2024 to serve in-franchise customers in the EGD Rate Zone. The volume and start date matched the transportation awarded to Enbridge Gas by TCPL from Parkway to the Enbridge CDA. The requested capacity was awarded using existing capacity beginning in 2024. There are no facility expansion requirements on the Enbridge Gas system related to this capacity.

The benefits of this capacity include:

i. Contract supports Enbridge Gas's objective of structuring a portfolio with a diversity of contract terms and supply basins;
ii. Contract term aligns with the gas year and provides flexibility to adjust committed volumes in future years;
iii. Firm transportation purchase is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable cost; and
iv. Supports the acquisition of supply from upstream markets, maintaining diversity of contract terms and supply basins; and

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

A comparison of landed costs for TCPL Mainline capacity relative to the viable alternatives can be found in Appendix F.

Rationale for Vector Renewal and Backhaul Capacity

Enbridge Gas held a contract with Vector pipelines for 65,000 Dth/d from Chicago to Dawn which was set to expire on October 31, 2024. This contract included renewal rights whereby Enbridge Gas had the option to renew the capacity for an additional three years at the existing negotiated toll of $0.18 US/Dth by providing notice to Vector no later than 12 months prior to the contract expiration.

As outlined in the Sarnia Expansion Pipeline Project[41], 5-Year Gas Supply Plan[42], Sarnia Industrial Line Reinforcement[43], 2023 Annual Gas Supply Plan Update[44] and OEB Vector Contracting Decision[45] capacity on the Vector pipeline to Dawn provides a competitively priced, reliable and flexible transportation option that offers supply diversity at Chicago as well as along the Vector pipeline route, and also provides an important secondary benefit of maintaining Enbridge Gas's ability to serve the SIL, which is used to support gas deliveries to both general service and contract customers across the Sarnia region.

Vector capacity to Dawn is sold out, and if Enbridge Gas reduced its contract levels on Vector, it would be unlikely to be able to recontract in the foreseeable future. All other available alternatives would reduce Enbridge Gas's diversity by reducing Chicago purchases and increasing Appalachia or Dawn purchases.

As discussed in both the 2022 and 2023 Annual Updates, the natural gas market at Chicago has experienced volatility over the past few years and this has resulted in increases to forward settlement prices during winter months at Chicago. While Enbridge Gas does not use forward market settlement data to inform long-term contracting decisions, the divergence between long-term forecast pricing at Chicago and forward settlement pricing was a significant topic of interest with certain stakeholders in previous Annual Updates. Prior to renewing the Vector contract, Enbridge Gas engaged ICF to conduct an analysis of Chicago and Dawn pricing. The analysis discusses ICF's long-term price expectations at Chicago relative to Dawn and also the importance of the supply diversity to Enbridge Gas provided by access to the Chicago market. The

[41] EB-2014-0333, p.4-11.
[42] EB-2019-0137, p.91-94.
[43] EB-2019-0218, p.9-15.
[44] EB-2023-0072, Appendix F.
[45] EB-2023-0326.

analysis also investigates the divergence of forward market settlement prices from ICF's fundamentals-based forecast. In summary:

> ICF, in its Q3 2023 base case projections, expects demand at both Chicago and Dawn to remain stable over the long term. As a result, the day-ahead natural gas prices at Chicago trade at a discount to Dawn most of the time and only peaks during extreme cold-weather events in which the demand spikes are seen upstream of Chicago and not at Dawn.
>
> The futures market, however, projects natural gas prices at Chicago to be at a significant premium to Dawn, which is out of sync with the day-ahead prices and market fundamentals given the placement of Chicago with respect to Dawn as well as the stable demand dynamics at both Chicago and Dawn.
>
> …
>
> Hence, ICF recommends that Enbridge Gas continue to base their longer-term re-contracting decisions on the market fundamentals represented by the day-ahead prices as well as the supply diversity and reliability benefits associated with access to an additional market center, rather than the near-term futures market trends.
>
> In ICF's opinion, the long-term benefits to Enbridge Gas of continuing to hold its capacity and supply agreements on Vector will exceed short-term costs that may be incurred due to short-term forward price trends that diverge from market fundamentals.

The report has been provided at Appendix G.

Enbridge Gas elected to renew its capacity on the Vector pipeline for a term of 3 years beginning November 1, 2024, with further renewal rights beyond the initial extension. As part of this renewal, Enbridge Gas negotiated a toll reduction of $0.02 US/Dth/d. The resulting toll of $0.16 US/Dth/d is the same or lower than the toll paid by Enbridge Gas for all of its other contracts on Vector pipelines.

As discussed in the 2021 Sarnia Industrial Line Reinforcement Project[46] filing, Enbridge Gas has historically relied upon deliveries of gas supply from its contracted capacity on Vector, GLGT, and St. Clair (NEXUS) as well as third party deliveries to meet peak design requirements on the SIL. Over the past several years, natural gas market dynamics have shifted and pipeline capacity across North America has become constrained. This has resulted in increased frequencies of supply constraints in key demand markets surrounding Dawn, including Michigan, Chicago, and markets throughout the U.S. Northeast and U.S. Mid-Continent. During these events, natural gas

[46] EB-2019-0218.

prices in these markets experience significant spikes in order to attract required supplies. Consequently, Enbridge Gas has noted a significant reduction in the reliability of third-party supply deliveries to the SIL during peak events in the winter. For example, during Winter Storm Elliott from December 23 to 27, 2022, both Vector and Great Lakes pipelines were physically exporting from Dawn, leaving no third-party deliveries that could be diverted to the SIL.

In order to reduce Enbridge Gas's reliance on third party deliveries to support SIL design day demand, Enbridge Gas contracted for 84,404 GJ/d of firm Vector Canada backhaul from Dawn-Vector to St. Clair. The capacity is considered to be backhaul because it flows counter to the direction gas has typically flowed on the Vector system. This volume aligns with the capacity held by Enbridge Gas on the Dawn to Dawn-Vector path on behalf of its in-franchise customers. This capacity, which contains renewal rights, provides firm, economic access to Dawn supply for meeting SIL demands. The toll associated with this capacity is $0.023 CAD/GJ/d and represents the lowest cost alternative for meeting SIL design day requirements. Without this capacity, Enbridge Gas would need to investigate incremental contracts for upstream transportation capacity into the SIL or infrastructure alternatives to ensure continued security of supply for customers relying on the SIL. Furthermore, should future design day requirements on the SIL decline or the future cost of contracted supplies on Vector, GLGT, or St. Clair Pipelines become uneconomic, the backhaul Vector contract will support Enbridge Gas's ability to decontract on more expensive upstream supply paths while maintaining security of supply to the SIL.

Enbridge Gas's renewal of Chicago to Dawn capacity and the incremental Dawn-Vector to St. Clair capacity results in continued firm and reliable capacity to support the SIL without reliance on third party deliveries, which have become significantly more risky. Furthermore, the incremental costs associated with the backhaul contract are nearly offset by the toll reduction in the forward-haul contract, meaning that this increased security of supply has a negligible incremental cost to ratepayers relative to pre-contracting levels.

The benefits of the Vector capacity renewal include:

i. Contracts supports Enbridge Gas's objective of structuring a portfolio with a diversity of contract terms and supply basins;
ii. Firm transportation purchase is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable cost;
iii. Landed cost of gas flowing from Chicago and Dawn along this route is competitively priced and has an end date that aligns with the gas year;
iv. Provides a fixed-rate toll which provides toll certainty on a portion of Enbridge Gas's upstream transportation portfolio;

v. Vector renewal supports the acquisition of supply from upstream markets, maintaining diversity of contract terms and supply basins;
vi. Vector renewal provides flexibility to access multiple supply sources at Joliet and other points along the path;
vii. Vector renewal provides Enbridge Gas with delivery point flexibility within the path including Michigan storage and Sarnia; and,
viii. Vector renewal provides flexibility as the capacity can be segmented and used bi-directionally.

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

The benefits of the Vector backhaul capacity include:

i. Firm transportation purchase is consistent with the gas supply principle of ensuring secure and reliable gas supply to support SIL design day at a reasonable cost;
ii. Term of 3 years results in a discount to the maximum regulated toll;
iii. The right to renew this capacity is a component of the agreement which ensures secure access to this transportation in the future;

Enbridge Gas has no supplies reliant upon the Vector backhaul capacity, so no landed cost analysis has been prepared.

Rationale for Bluewater River Crossing Renewal

The Bluewater River Crossing capacity has an annual cost of approximately $1.3 million and provides access to Michigan storage provider, Bluewater Gas Storage, increasing competition for storage services in the Great Lakes region, and provides security of supply for Enbridge Gas customers. Bluewater Gas Storage is not a liquid trading location but does provide interruptible wheeling services to move gas to different points on their system and firm storage services that could deliver to the Bluewater River Crossing on a firm basis. Volumes transported into Canada via the Bluewater River Crossing can benefit the Sarnia market by providing supply that can be directed to the SIL. It is important to note that Enbridge Gas is not able to rely upon the interruptible service to provide supply to the SIL on a design day and the Company does not currently have a contract for firm storage service with Bluewater Gas Storage. Therefore, the Bluewater River Crossing contract enables an important back-up supply option for the Sarnia market but is not relied upon in the design of the SIL.

The benefits of this capacity include:

i. Firm transportation purchase is consistent with the gas supply principle of ensuring secure and reliable access to gas supply and storage services at a reasonable cost;
ii. Provides fixed-rate tolls which provide toll certainty on a portion of Enbridge Gas's transportation portfolio;
iii. Transportation capacity from St. Clair Pipelines are flexible options because they are purchased for at term of 1-year and has renewal rights; and
iv. Transportation capacity on this path provides access to Michigan pipeline and storage systems, increasing competition and optionality.

Bluewater River Crossing is the only direct link between Bluewater Gas Storage and the Enbridge Gas system. Enbridge Gas has no supplies reliant upon this path, so no landed cost analysis has been prepared.

Rationale for St. Clair River Crossing Renewal

The St. Clair River Crossing facilitates the delivery of 158,258 GJ/d of NEXUS capacity to Ontario. It also provides access to the Michcon/DTE system, providing access to MichCon supply and storage and increasing competition for storage services in the Great Lakes region. Volumes transported into Canada via the St.Clair River Crossing can be directed to the SIL at Courtright and benefit the Sarnia market.

The benefits of this capacity include:

i. Firm transportation purchase is consistent with the gas supply principle of ensuring secure and reliable gas supply at a reasonable cost;
ii. Provides fixed-rate tolls which provide toll certainty on a portion of Enbridge Gas's transportation portfolio;
iii. Transportation capacity from St. Clair Pipelines are flexible options because they are purchased for at term of 1-year and has renewal rights; and
iv. Transportation capacity on this path provides access to Michigan pipeline and storage systems, increasing competition and optionality.

St. Clair River Crossing capacity is the only direct link between the DTE/Michcon system and Enbridge Gas system. Not renewing this capacity would strand NEXUS deliveries in Michigan and would eliminate several potential sources of supply. As a result, no landed cost analysis has been prepared.

4.5 Storage Portfolio

In accordance with the Natural Gas Electricity Interface Review (NGEIR) Decision[47] and confirmed in the OEB's Decision and Order regarding the amalgamation of EGD and Union and the associated rate-setting mechanism (MAADs decision)[48], the amount of cost-based storage reserved for EGD rate zone customers is 99.4 PJ and 100 PJ is reserved for Union rate zone customers.

The allocation of storage to natural gas distribution customers is based upon methodologies approved by the OEB as part of the Natural Gas Storage Allocation Policies Decision[49] and the quantity was confirmed in the MAADs decision.

Table 6 illustrates the in-franchise storage requirement for each rate zone. As outlined in Table 6, the Union rate zone in-franchise storage requirement has increased as a result of the increasing demand forecast discussed in Section 3.1.

Table 6
Storage Requirement Forecast

Line No.	Particulars (PJ)	2023/24	2024/25	2025/26	2026/27	2027/28
		(a)	(b)	(c)	(d)	(e)
	EGD					
	In-franchise Storage Requirement					
1	In-franchise Customer Requirement	125.7	125.7	125.7	125.7	125.7
	Cost-Based Storage					
2	Tecumseh	99.4	99.4	99.4	99.4	99.4
3	Crowland	0.3	0.3	0.3	0.3	0.3
4	Market Based Storage	26.0	26.0	26.0	26.0	26.0
5	Space Allocated for In-franchise Use	125.7	125.7	125.7	125.7	125.7
	Union					
	In-franchise Storage Requirement					
6	System Integrity	9.5	9.5	9.5	9.5	9.5
7	In-franchise Customer Requirement	88.6	87.8	88.1	89.6	89.9
8		98.1	97.3	97.6	99.1	99.5
	Cost-Based Storage					
9	Dawn	100.0	100.0	100.0	100.0	100.0
10	Excess Utility Space Available	1.9	2.7	2.4	0.9	0.5

In addition to the cost-based storage available to customers in the EGD rate zone, Enbridge Gas holds 13 service agreements equaling 26.0 PJ of storage capacity at

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

market-based rates. The size and term of each service agreement varies. Each year Enbridge Gas conducts analysis to determine its storage requirements.

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

The inclusion of storage assets in the gas supply plan provides a cost-effective, reliable and secure alternative to purchasing natural gas when required by customers, which is consistent with the OEB’s guiding principles. Enbridge Gas ensures that it has diversity in the length of contract terms within its storage portfolio. This diversity allows flexibility to respond to changes in demand in future years.

Storage provides further operational flexibility and aligns with the planning target to fill storage on November 1, maintain sufficient inventory on February 28 to meet the design day storage withdrawal requirement, and on March 31 to meet planning requirements.

4.6 Unutilized Capacity

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

In the Union North rate zones, the upstream transportation portfolio is sized to meet design day demand. Logically, the amount of supply transported to meet average annual demand is less than the capacity needed to meet requirements on design day. As a result, a portion of Enbridge Gas’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, Enbridge Gas will use this capacity to meet incremental supply requirements.

For the Union South rate zone, Enbridge Gas plans for upstream pipeline capacity to flow at 100% utilization each day of the year. On a planned basis, when demand is less than upstream supply, the excess supply is injected into storage, and when demand is greater than upstream supply, natural gas is withdrawn from storage and transported to Union South in-franchise customers. Consequently, there is no planned unutilized capacity in Union South.

Table 7 illustrates the total planned unutilized capacity by rate zone.

Table 7
Planned Unutilized Capacity

Line No.	Particulars (PJ)	2023/24	2024/25	2025/26	2026/27	2027/28
		(a)	(b)	(c)	(d)	(e)
1	EGD	-	-	-	-	-
2	North West	10.4	11.0	13.2	9.9	12.4
3	North East	8.3	7.0	4.6	8.1	5.6
4	South	-	-	-	-	-
5	Total Planned Unutilized Capacity	18.7	18.0	17.8	18.0	18.0

5. Supply Option Analysis

Enbridge Gas's gas supply, storage, and transportation portfolio has been developed over time and is guided by its approved gas supply planning principles and North American natural gas market conditions. Enbridge Gas'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 as outlined in Section 2.1. Several other factors such as contract terms, renewal rights, operational requirements and supply source constraints are also significant factors influencing Enbridge Gas's supply option analyses and decisions. Each individual gas supply, storage, and transportation evaluation cannot be considered independently and needs to be considered as part of the overall portfolio and strategy.

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

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

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

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

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

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

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

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

Finally, Enbridge Gas'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, Enbridge Gas 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.

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

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

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

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

5.1 Design Day Analysis

Each year, Enbridge Gas conducts a design day position analysis in which projected design day demand is compared against existing contracted assets for that rate zone's delivery areas. A design day shortfall occurs when there is more demand than capacity through existing assets to meet design day demand. Forecast shortfalls are monitored throughout the length of the gas supply plan and analyzed on an annual basis. Enbridge Gas evaluates the requirements over the entire forecast period and the gas supply plan does not include any excess assets; only those necessary to meet firm customer requirements.

Enbridge Gas considers the availability of assets into the delivery area and assesses all viable alternatives. If there are no constraints in the delivery area or risk to the future availability of capacity, services will be acquired on a short-term basis to give Enbridge Gas the flexibility to adjust contracted capacity as requirements and market conditions are subject to change over time. If the delivery area is constrained, Enbridge Gas 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 Enbridge Gas bidding into an open season with a minimum commitment term.

EGD Rate Zone

The EGD rate zone demand and supply balance, which identifies Enbridge Gas's design day position, is outlined in Table 8. The forecast shows a shortfall in nearly every year resulting from growth in the Enbridge CDA and Enbridge EDA.

In 2023, Enbridge Gas contracted for available transportation capacity through open seasons to manage forecasted shortfall positions. These multi-year transportation purchases allow for peak day shortfalls to be managed without increasing Enbridge Gas's reliance on third-party services or having to support a facilities build. The purchase of 18,876 GJ/d of short-haul transportation beginning November 1, 2024 to the Enbridge CDA is discussed in Section 4.4 and its impact is included in Table 8, line 5.

Table 8
EGD Rate Zone Design Day Position

Line No.	Particulars (TJ/d)	EGD CDA 2023/24	EGD CDA 2024/25	EGD CDA 2025/26	EGD CDA 2026/27	EGD CDA 2027/28	EGD EDA 2023/24	EGD EDA 2024/25	EGD EDA 2025/26	EGD EDA 2026/27	EGD EDA 2027/28
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Demand										
1	Gross Demand	3,449	3,459	3,470	3,482	3,493	748	755	762	768	775
2	Curtailment	(71)	(71)	(71)	(71)	(71)	(26)	(26)	(26)	(26)	(26)
3	Net Demand	3,378	3,389	3,400	3,411	3,422	723	729	736	742	749
	Supply Asset										
4	TCPL Long-haul	5	5	5	5	5	260	260	260	260	260
5	TCPL Short-haul	768	787	787	787	787	368	368	368	368	368
6	TCPL STS	284	284	284	284	284	81	81	81	81	81
7	EGI D-P	2,194	2,194	2,194	2,194	2,194	-	-	-	-	-
8	In-Franchise Supply	64	64	64	64	64	0	0	0	0	0
9	Third-Party Services	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
10	Total Supply	3,315	3,334	3,334	3,334	3,334	709	709	709	709	709
11	Excess(Shortfall)	(63)	(55)	(66)	(77)	(88)	(14)	(20)	(27)	(33)	(40)
12	*Shortfall % of Net Demand*	*1.9%*	*1.6%*	*1.9%*	*2.3%*	*2.6%*	*1.9%*	*2.8%*	*3.7%*	*4.5%*	*5.3%*

Enbridge CDA

Supply Options

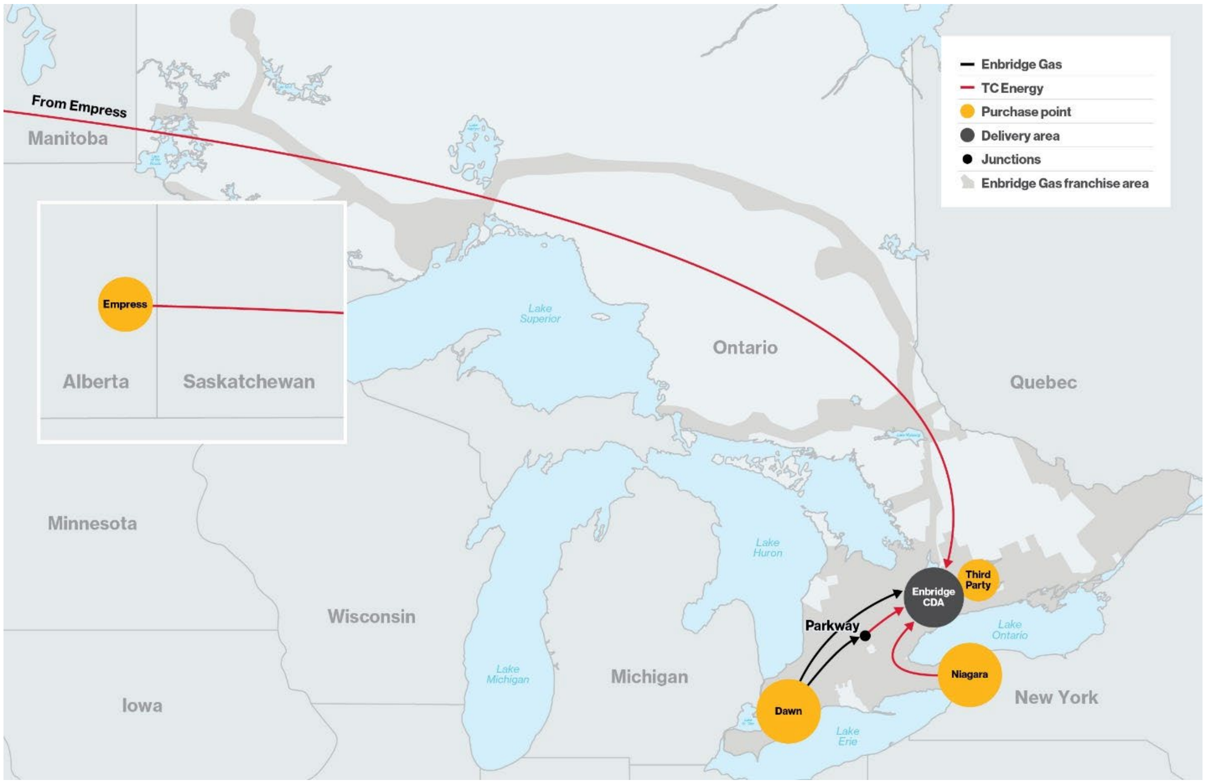
Table 9 provides a list of options which may be available to Enbridge Gas[50,51] at various times over the next five years to meet the shortfalls identified in Table 8. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 10 provides a representative map of the paths described in the options.

Table 9
Enbridge CDA Supply Options

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

[50] 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.
[51] Third-party considers both peaking service and delivered service. Delivered services have limited participants so disclosing costs could impact the market. Therefore, when considering costs, peaking service is the option being considered as there are more counterparties and disclosing pricing will not impact the market.

Figure 10: Enbridge CDA Supply Options Map



Evaluation Matrix

Each of the options outlined in Table 9 were evaluated for their reliability, flexibility, diversity and annual costs, as described at the beginning of Section 5. Table 10 summarizes the analysis.

Table 10
Enbridge CDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($ million/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	↑	→	↑	32.22	<1%	No
Short-haul: D-P	↑	→	→	9.35	<1%	No
Short-haul: Dawn	↑	→	→	5.38	<1%	No
Short-haul: Niagara	→	→	→	6.59	<1%	No
Third Party	→	↓	↑	4.44	<1%	Unknown

For reference, the symbols in Table 10 describe whether a particular option has a positive ↑, neutral →, or negative ↓ impact on the ability of the option to satisfy a design day shortfall as compared to Enbridge Gas's current portfolio.

Preferred Planning Strategy

Since the 5-Year Plan was filed, there has been no change in options to serve. The scarcity of TCPL Mainline capacity is a material change in the evaluation matrix, limiting options to meet forecasted shortfalls in the Enbridge CDA. The preferred strategy is still to procure a third-party service in the near term for up to 2% of design day needs and to evaluate transportation options as they become available to manage future design day day growth. Enbridge Gas has purchased 18,876 GJ/d of existing short-haul capacity to the Enbridge CDA starting November 1, 2024 as described in Section 4.4. Enbridge Gas will continue to monitor any shortfall positions and make decisions using the best available information at that time.

Enbridge EDA

Supply Options

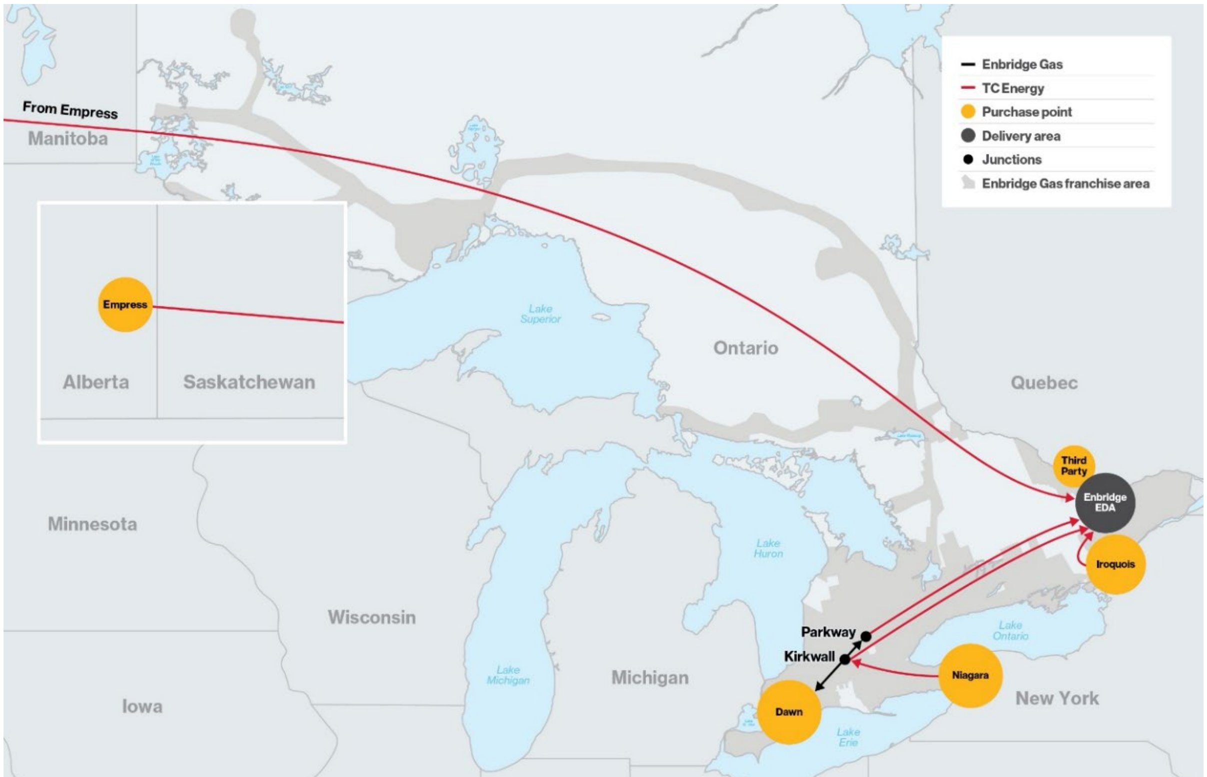
Table 11 provides a list of options which may be available to Enbridge Gas[52] at various times over the next five years to meet the shortfalls identified in Table 8. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 11 provides a representative map of the paths described in the options.

Table 11
Enbridge EDA Supply Options

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

[52] The list of options in Table 11 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.

Figure 11: Enbridge EDA Supply Options Map



Evaluation Matrix

Each of the options outlined in Table 11 were evaluated for their reliability, flexibility, diversity, and annual costs, as described at the beginning of Section 5. Table 12 summarizes the analysis.

Table 12
Enbridge EDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($ million/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	↑	→	→	12.99	<1%	No
Short-haul: D-P	↑	→	→	6.22	<1%	No
Short-haul: Niagara	→	→	↑	5.72	<1%	No
Short-haul: Iroquois	→	→	→	3.25	<1%	No
Third-Party	→	↓	↑	1.75	<1%	Unknown

For reference, the symbols in Table 12 describe whether a particular option has a positive, neutral, or negative impact on the ability of the option to satisfy a design day shortfall as compared to Enbridge Gas's current portfolio.

Preferred Planning Strategy

Since the 5-Year Plan was filed, there has been no change in options to serve. The scarcity of TCPL Mainline capacity is a material change in the evaluation matrix, limiting the availability of options to meet forecasted shortfalls in the Enbridge EDA. The preferred strategy is still to procure a third-party service in the near term for up to 2% of design day needs and to evaluate transportation options as they become available to manage future design day growth. Enbridge Gas will continue to monitor any shortfall positions and make decisions using the best available information at that time, which may include purchasing transportation capacity that may be available from time to time. that may be available from time to time.

Union North Rate Zones

The Union North rate zone demand and supply balance which identifies Enbridge Gas's design day position is outlined in Table 13. It should be noted that the table includes increased peak-day reliance on LNG in the Union NDA, which allows Enbridge Gas to shift STS withdrawals to manage peak day requirements in the Union NCDA. As noted in section 4.4, Enbridge Gas purchased incremental transportation capacity on CTHI and CPMI pipelines to meet design day demands in the Union MDA. This cost-effectively manages peak day growth in these delivery areas. The Union North East forecast shows a 17 TJ/d shortfall between 2023/24 and 2027/28. The Union North West forecasts a shortfall of 7 TJ/d in the Union WDA in 2023/24 growing to 10 TJ/d in 2027/28.

Since no shortfalls are forecast in the Union SSMDA or the Union NCDA, no supply option analysis has been provided.

Table 13
Union North Rate Zones Design Day Position

Line No.	Particulars (TJ/d)	North West 2023/24	North West 2024/25	North West 2025/26	North West 2026/27	North West 2027/28	North East 2023/24	North East 2024/25	North East 2025/26	North East 2026/27	North East 2027/28
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Demand										
1	Union North(1)	138	140	141	141	142	460	453	456	457	461
	Supply Asset										
2	TCPL Long-Haul	81	81	81	81	81	8	8	8	8	8
3	TCPL Short-Haul	-	-	-	-	-	120	120	120	120	120
4	North Dawn T-Service	-	-	-	-	-	33	33	33	33	33
5	LNG	-	-	-	-	-	33	31	32	33	35
6	Redelivery from Storage										
7	*From Parkway*										
8	STS Withdrawals	31	31	31	31	31	88	88	88	88	88
9	STS Pooled Withdrawals	-	-	-	-	-	17	17	17	17	16
10	Short-haul Firm	-	-	-	-	-	119	119	119	119	119
11	Enhanced Market Balancing	-	-	-	-	-	25	25	25	25	25
12	*From Dawn*										
13	STS Withdrawals	18	18	18	18	19	-	-	-	-	-
14	Third-Party Services	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
15	Total Supply	131	131	131	131	132	443	441	442	443	444
16	Excess(Shortfall)	(7)	(9)	(9)	(10)	(10)	(17)	(12)	(14)	(15)	(16)
17	*Shortfall % of Demand*	*5.2%*	*6.5%*	*6.7%*	*6.8%*	*7.4%*	*3.7%*	*2.7%*	*3.1%*	*3.2%*	*3.6%*

Note:
(1) Includes Sales Service, Bundled DP, North Dawn T-Service.

Union EDA

Supply Options

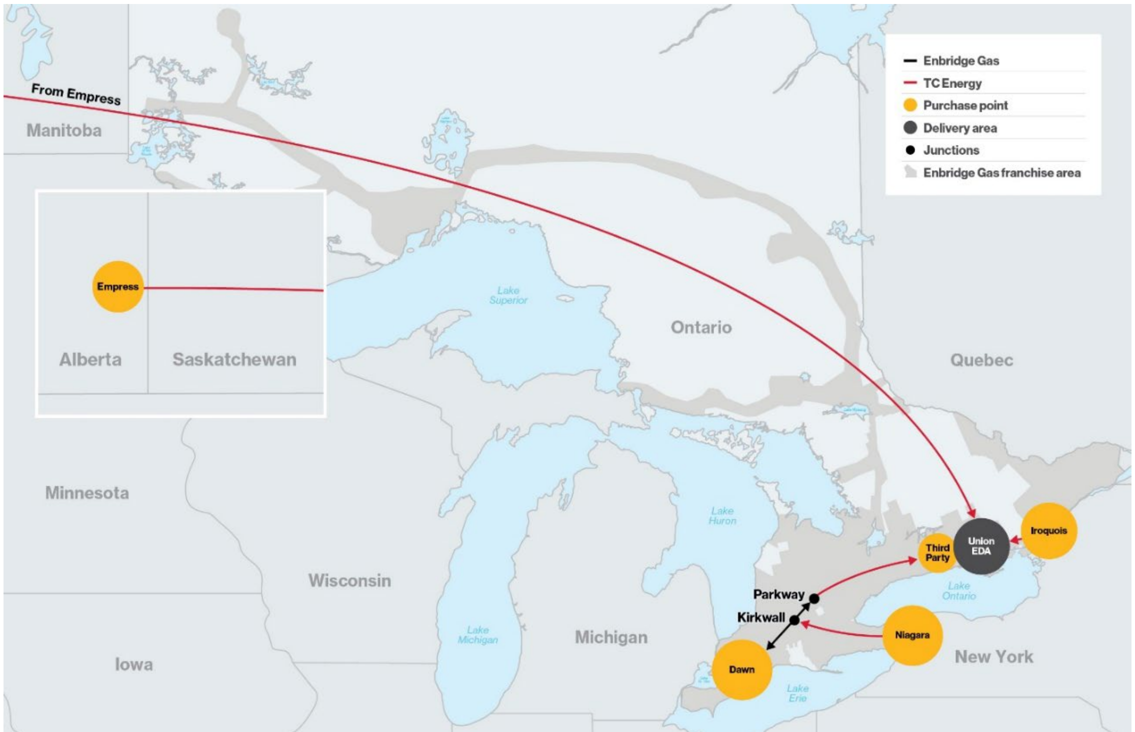
Table 14 provides a list of options which may be available to Enbridge Gas[53] at various times over the next five years to meet the shortfall identified in Table 13. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 12 provides a representative map for the paths of the supply options.

Table 14
Union EDA Supply Options

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

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

Figure 12: Union EDA Supply Options Map



Evaluation Matrix

Each of the options outlined in Table 14 were evaluated for their reliability, flexibility, diversity and landed costs, as described at the beginning of Section 5. Table 15 summarizes the analysis.

Table 15
Union EDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($ million/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	positive	positive	positive	7.51	>1%	No
Short-haul: D-P	positive	neutral	neutral	3.02	<1%	No
Short-haul: Niagara	neutral	neutral	positive	3.18	<1%	No
Short-haul: Iroquois	neutral	neutral	positive	1.90	<1%	No
Third-Party	neutral	negative	positive	0.97	<1%	Unknown

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

Preferred Planning Strategy

Since the 5-Year Plan was filed, there has been no change in options to serve. The scarcity of TCPL Mainline capacity is a material change in the evaluation matrix, limiting the availability of options to meet forecasted shortfalls in the Union EDA. The preferred strategy is still to procure a third-party service in the near term for up to 2% of design day needs and to evaluate transportation options as they become available to manage future design day growth. Enbridge Gas will continue to monitor any shortfall positions and make decisions using the best available information at that time, which may include purchasing transportation capacity that may be available from time to time.

Union NDA

Supply Options

Table 16 provides a list of options which may be available to Enbridge Gas[54] at various times over the next five years to meet the shortfall identified in Table 13. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 13 provides a representative map for the paths of the supply options.

Table 16
Union NDA Supply Options

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

[54] The list of options in Table 16 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.

Figure 13: Union NDA Supply Options Map

Evaluation Matrix

Each of the options outlined in Table 16 were evaluated for their reliability, flexibility, diversity and landed costs, as described at the beginning of Section 5. Table 17 summarizes the analysis.

Table 17
Union NDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($ million/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	↑	↑	→	9.46	>1%	No
Short-haul: D-P	↑	→	→	6.87	>1%	No
LNG	→	↑	↑	0.71	<1%	Yes
Third-Party	↓	↓	↑	2.56	<1%	Unknown

For reference, the symbols in Table 17 describe whether a particular option has a positive ↑, neutral →, or negative ↓ impact on the ability of the option satisfy a design day shortfall as compared to Enbridge Gas's current portfolio.

Preferred Planning Strategy

As stated in Enbridge Gas's 2020 Annual Update to the 5-year Gas Supply Plan, third-party services will be considered as an option to meet a shortfall[55] and will utilize LNG to meet shortfalls in the Union NDA within the capabilities of the LNG system and recognizing that the LNG system is also relied upon for system integrity purposes.

Union MDA

Supply Options

Table 18 provides a list of options which may be available to Enbridge Gas[56] at various times over the next five years to meet the shortfall identified in Table 13. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 14 provides a representative map for the paths of the supply options.

Table 18
Union MDA Supply Options

Option	Option Details				
	Provider(s)	Service	Receipt Point	Transfer Point	Delivery Point
Long-haul	TCPL + Energy Fundamentals	FT-LH	Empress	Centrat MDA	Union MDA
Third-Party + FT	Market Participants + FT	Peaking, FT	Centrat MDA	Sprague	Union MDA

[55] EB-2020-0135, pp.7-8.
[56] The list of options in Table 16 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.

Figure 14: Union MDA Supply Options Map

Evaluation Matrix

Each of the options outlined in Table 18 were evaluated for their reliability, flexibility, diversity and landed costs, as described at the beginning of Section 5. Table 19 summarizes the analysis.

Table 19
Union MDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($ million/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	neutral	neutral	neutral	0.16	<1%	No
Third-Party + FT	negative	negative	positive	0.15	<1%	Unknown

For reference, the symbols in Table 19 describe whether a particular option has a positive, neutral, or negative impact on the ability of the option to satisfy a design day shortfall as compared to Enbridge Gas's current portfolio.

Preferred Planning Strategy

Enbridge Gas's preferred planning strategy for meeting peak day shortfalls is to purchase third party services for up to 2% of the peak day demand and to purchase firm transportation for shortfalls beyond that amount. In other delivery areas, Enbridge Gas can purchase peaking services from marketers with deliveries into the delivery area to meet peak day requirements, however, as described in Section 4.4, the Union MDA has limited options. In the MDA, Enbridge Gas's preferred strategy is to purchase peaking supply to the Centrat MDA combined with firm transportation from the Centrat MDA to Union MDA.

Union WDA

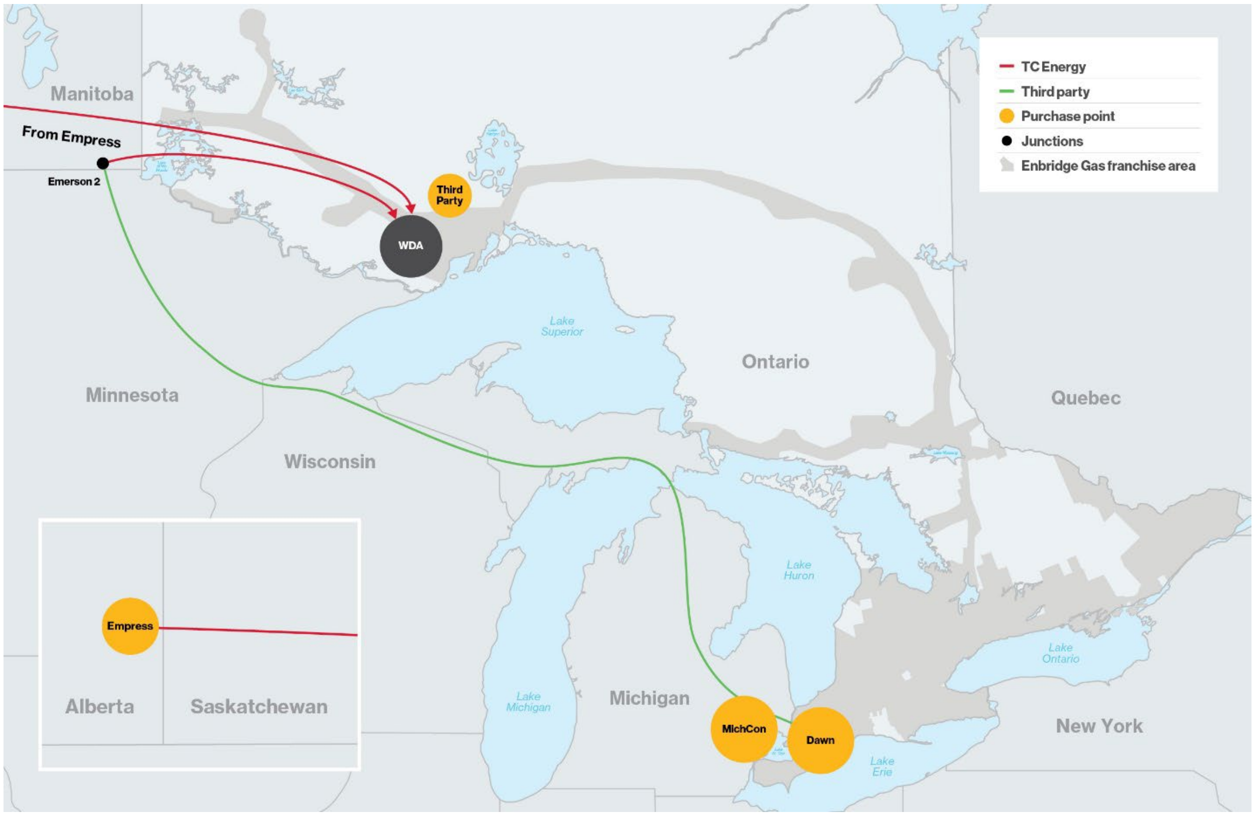
Supply Options

Table 20 below provides a list of options which may be available to Enbridge Gas at various times over the next five years to meet the shortfall identified in Table 13. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 15 provides a representative map for the paths of the supply options.

Table 20
Union WDA Supply Options

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

Figure 15: Union WDA Supply Options Map



Evaluation Matrix

Each of the options outlined in Table 20 were evaluated for their reliability, flexibility, diversity and landed costs, as described at the beginning of Section 5. Table 21 summarizes the analysis.

Table 21
Union WDA Evaluation Matrix

Option	Reliability	Flexibility	Diversity	Costs ($ million/yr)	Average Cost/Customer Impact	Available Capacity
Long-haul	⮕	⮕	⮕	1.65	<1%	No
Short-haul: D-P	⮕	⮕	⬆	3.36	>1%	No
Great Lakes	⮕	⮕	⬆	2.04	~1%	No
Third-Party	⮕	⬇	⬆	0.71	<1%	Unknown

For reference, the symbols in Table 21 describe whether a particular option has a positive ⬆, neutral ⮕, or negative ⬇ impact on the ability of the option to satisfy a design day shortfall as compared to Enbridge Gas's current portfolio.

Preferred Planning Strategy

Since the 5-Year Plan was filed, there has been no change in options to serve. The scarcity of TCPL Mainline capacity is a material change the Evaluation Matrix, limiting the availability of options to meet forecasted shortfalls in the Union WDA. The preferred strategy is still to procure a third-party service in the near term and to evaluate transportation options as they become available to manage future peak day growth. Enbridge Gas will continue to monitor any shortfall positions and make decisions using the best available information at that time, which may include purchasing transportation capacity that may be available from time to time.

Union South Rate Zone

Enbridge Gas's Union South rate zone design day demand to supply position is outlined below in Table 22. Enbridge Gas currently forecasts no excess or shortfall in the Union South rate zone over the term of the Plan.

Table 22
Union South Rate Zone Design Day Position

Line No.	Particulars (TJ/d)	2023/24	2024/25	2025/26	2026/27	2027/28
		(a)	(b)	(c)	(d)	(e)
	Demand					
1	Union South[(1)]	3,396	3,460	3,515	3,652	3,674
	Supply Asset					
2	Great Lakes	21	21	21	21	21
3	NEXUS	106	106	106	106	106
4	Non-obligated (e.g. Power Plants)	421	421	421	421	421
5	Ontario Dawn	572	579	583	579	585
6	Ontario Parkway	227	229	227	314	312
7	Panhandle	60	60	60	60	60
8	Storage	1,859	1,914	1,967	2,021	2,040
9	TCPL Long-Haul	3	3	3	3	3
10	TCPL Niagara	21	21	21	21	21
11	Vector	106	106	106	106	106
12	Total Supply	3,396	3,460	3,515	3,652	3,674
13	Excess (Shortfall)	-	-	-	-	-

Note:
(1) Includes Sales Service, Bundled DP, T-Service.

5.2 Average Day Requirement

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

Consistent with the annual demand forecast developed by Enbridge Gas found in Section 3.1, Table 23 shows both the annual and average daily demand expected over the five-year period of the Plan for system sales service customers.

Table 23
Average Day Demand for System Sales Customers

Line No.	Demand by Rate Zone (TJ)	2023/24	2024/25	2025/26	2026/27	2027/28	Growth 2023 → 2028
		(a)	(b)	(c)	(d)	(e)	(f)
	EGD						
1	Annual Demand	311,119	312,239	312,722	313,330	314,010	2,891
2	Daily Demand	850	855	857	858	860	10
	Union						
3	Annual Demand	191,962	190,793	190,250	189,752	190,261	(1,701)
4	Daily Demand	524	523	521	520	521	(3)

As Table 23 shows, the annual demand for the EGD rate zone is expected to increase by roughly 2,891 TJ over the five years, or roughly 10 TJ/d of average day demand and the Union rate zones is expected to decrease by 1,701 TJ over the five years or roughly 3 TJ/d. As a result, Enbridge Gas is not currently seeking to increase gas supply assets to serve annual demand changes and will rely upon increased purchases at Dawn to meet this growth. A supply option analysis for average day requirements is presented to determine if additional transportation assets upstream of Dawn may provide additional reliability, flexibility, diversity and cost effectiveness.

In the event of reductions to average day demands, Enbridge Gas will reduce its planned purchases at Dawn. If demand reductions occur in an area of Enbridge Gas's system that is not connected to storage, (i.e. the Union North West rate zone), then Enbridge Gas will reduce its planned commodity purchases at Empress, which will increase the amount of unutilized transportation capacity to this area. Then, as transportation contracts to these areas expire, Enbridge Gas will evaluate the need for these transportation contracts to meet design day demands and may elect to turn back some of the contracted capacity.

Supply Options

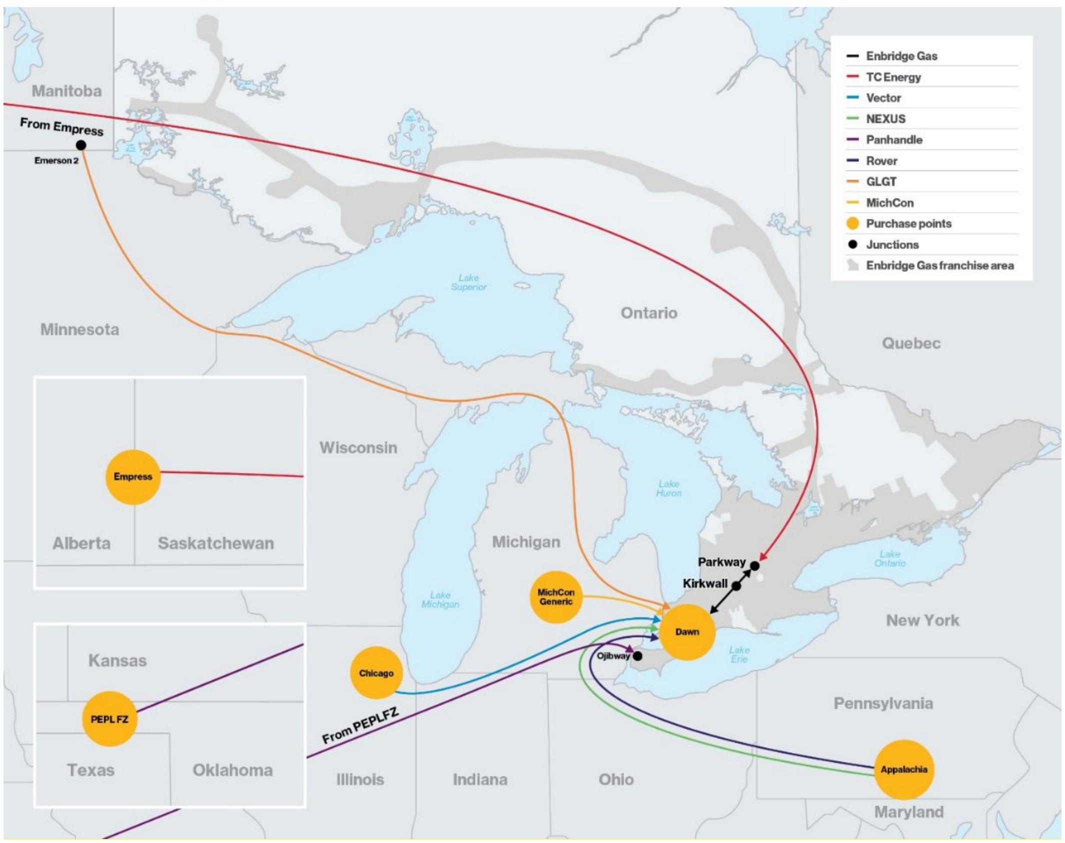
Table 24 provides a list of options which may be available to Enbridge Gas[57], at various times over the five-year period. Some alternatives do not have sufficient available capacity with existing infrastructure. Figure 16 provides a representative map for the paths of the supply options.

[57] Table 24 is not an exhaustive summary of all options, but rather is a short-list of options that do not disclose commercially sensitive information and offers the reliability and flexibility required to manage average day demand growth.

Table 24
Average Day Growth Supply Options

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

Figure 16: Average Day Growth Supply Options Map



Evaluation Matrix

Each of the options outlined in Table 24 were evaluated for their reliability, flexibility, diversity and landed costs, as described at the beginning of Section 5. Table 25 summarizes the analysis.

Table 25
Average Day Growth Supply Matrix

Option	Relative to Status Quo			Costs ($/GJ/d)	Average Cost/Customer Impact - Relative to Status Quo	Available Capacity
	Reliability	Flexibility	Diversity			
Dawn	-	-	-	5.42	-	Yes
Great Lakes	⇨	⇨	⇨	5.55	<1%	No
MichCon	⇨	⇨	⇧	5.55	<1%	No
Vector	⇨	⇨	⇨	5.50	<1%	No
Panhandle	⇨	⇨	⇨	5.85	<1%	Yes
NEXUS	⇨	⇨	⇨	5.99	<1%	Yes
Rover	⇨	⇨	⇧	5.71	<1%	No
Niagara	⇨	⇨	⇨	5.28	<1%	No

For reference, the symbols in Table 25 describe whether a particular option has a positive ⇧, neutral ⇨, or negative ⇩ impact on the ability of the option to satisfy average day growth as compared to the current portfolio.

Preferred Planning Strategy

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

5.3 Transportation Contract Renewals

Enbridge Gas evaluates its expiring contracts within the term of the Plan and determines whether these contracts should be renewed. There are 58 contracts requiring renewal analysis and these have been organized into two categories below.

Design Day Renewals

Each of the contracts in Table 26 are included within the design day analyses previously presented for each rate zone and have been required to serve each rate zone on a design day for many years.

Table 26
Upcoming Design Day Contract Expiries
As of November 1, 2024

Rate Zone	Path	Pipeline	Contract Quantity		Expiry Date
Union North West	Sprague to Baudette	Centra Pipelines Minnesota Inc.	5,473	Mcf	31-Oct-24
Union North West	Spruce to Union MDA	Centra Transmission Holdings	155	10^3	31-Oct-24
Union North West	Empress to Centrat MDA	TCPL	4,522	GJ	31-Oct-25
Union North West	Empress to Centrat MDA	TCPL	1,043	GJ	31-Oct-25
Union North West	Empress to Union WDA	TCPL	39,880	GJ	31-Oct-25
Union North West	Empress to Union WDA	TCPL	11,527	GJ	31-Oct-25
Union North East	Empress to Union NDA	TCPL	4,056	GJ	31-Oct-25
Union North East	Empress to Union NCDA	TCPL	1,412	GJ	31-Oct-25
Union North West	Empress to Union SSMDA	TCPL	2,700	GJ	31-Oct-25
Union North West	Empress to Union SSMDA	TCPL	6,143	GJ	31-Oct-25
Union North West	Empress to Union SSMDA	TCPL	12,800	GJ	31-Oct-25
Union North East	Empress to Union EDA	TCPL	1,089	GJ	31-Oct-25
Union North West	STS - Union WDA	TCPL	3,150	GJ	31-Oct-26
Union North East	STS - Union EDA	TCPL	5,000	GJ	31-Oct-26
Union North East	STS - Union NDA	TCPL	49,100	GJ	31-Oct-26
Union North East	STS - Union NCDA	TCPL	13,704	GJ	31-Oct-26
Union North West	STS - Union WDA	TCPL	31,420	GJ	31-Oct-26
Union North West	STS - Union SSMDA	TCPL	35,022	GJ	31-Oct-26
Union North East	STS - Union NDA	TCPL	48,375	GJ	31-Oct-26
Union North East	STS - Union EDA	TCPL	26,351	GJ	31-Oct-26
Union North East	Union Parkway Belt to Union EDA	TCPL	30,000	GJ	31-Oct-26
Union North East	Union Parkway Belt to Union EDA	TCPL	5,000	GJ	31-Oct-26
Union North East	Empress to Union EDA	TCPL	4,000	GJ	31-Oct-27
Union North West	Empress to Union WDA	TCPL	3,396	GJ	31-Oct-27

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

Preferred Planning Strategy

Each of the firm contracts identified above are key components in ensuring the reliability of Enbridge Gas's gas supply plan. Further, when coupled with an increasing need for assets on design day, Enbridge Gas's preferred planning strategy is to continue to renew each contract on an annual basis. This approach supports the OEB's guiding principles by ensuring security of supply, flexibility, and the reliability of the gas supply plan and secures capacity where alternatives are scarce or not available. Enbridge Gas will retain significant flexibility to respond to changing design day demand requirements should a need arise to reduce the amount of firm transportation in the portfolio. Enbridge Gas will continue to monitor market conditions and make renewal decisions using the best available information at that time.

Average Day Renewals

The average day contracts due for renewal over the term of the Plan listed in Table 27 are assets held upstream of Dawn or provide diversity of supply.

Table 27
Upcoming Average Day Contract Expiries
As of November 1, 2024

Rate Zone	Path	Pipeline	Contract Quantity		Expiry Date
Union South	Bluewater/Intl Border to Bluewater/Intl Border	St. Clair Pipelines L.P. (Bluewater Pipeline)	127,000	GJ	31-Oct-24
Union South	St. Clair/Intl Border to St. Clair/Intl Border	St. Clair Pipelines L.P. (St. Clair Pipeline)	214,000	GJ	31-Oct-24
Union South	FZ (Markwest) to Ojibway	Panhandle	35,000	Dth	31-Oct-25
Union South	Union Dawn to Union ECDA	TCPL	8,000	GJ	31-Oct-25
Union South	Empress to Union ECDA	TCPL	3,000	GJ	31-Oct-25
Union South	Niagara Falls to Kirkwall	TCPL	21,101	GJ	31-Oct-25
Union South	Empress to Emerson 2	TCPL	21,418	GJ	31-Oct-25
Union South	Chicago to US/Cdn Border	Vector Pipeline	80,000	Dth	31-Oct-25
Union South	US/Cdn Border to Dawn	Vector Pipeline	84,404	GJ	31-Oct-25
EGD	AECO to Empress	NOVA Transmission	75,000	GJ	31-Oct-25
EGD	Union Parkway Belt to Enbridge CDA	TCPL	153,700	GJ	31-Oct-26
EGD	Union Parkway Belt to Enbridge CDA	TCPL	92,822	GJ	31-Oct-26
EGD	Union Parkway Belt / Kirkwall to Enbridge EDA	TCPL	35,089	GJ	31-Oct-26
EGD	Union Parkway Belt / Kirkwall to Enbridge EDA	TCPL	35,806	GJ	31-Oct-26
EGD	Union Dawn to Iroquois	TCPL	40,000	GJ	31-Oct-26
EGD	Union Parkway Belt to Enbridge CDA	TCPL	37,370	GJ	31-Oct-26
EGD	Union Dawn to Enbridge CDA	TCPL	4,818	GJ	31-Oct-26
EGD	Union Parkway Belt to Enbridge EDA	TCPL	9,716	GJ	31-Oct-26
EGD	Union Dawn to Enbridge CDA	TCPL	145,000	GJ	31-Oct-26
EGD	Union Parkway Belt to Enbridge CDA	TCPL	572	GJ	31-Oct-26
EGD	Union Parkway Belt to Vic Square #2 CDA	TCPL	85,000	GJ	31-Oct-26
EGD	Union Dawn to Enbridge EDA	TCPL	114,000	GJ	31-Oct-26
Union South	Alliance to St. Clair (US Interconnect)	Vector Pipeline	20,000	Dth	31-Oct-26
Union South	St. Clair (Canada) to Dawn	Vector Pipeline	21,101	GJ	31-Oct-26
EGD	Alliance to St. Clair (US Interconnect)	Vector Pipeline	20,000	Dth	31-Oct-26
EGD	St. Clair (Canada) to Dawn	Vector Pipeline	21,101	GJ	31-Oct-26
Union South	FZ (Cheyenne) to Ojibway	Panhandle	22,000	Dth	31-Oct-27
EGD	AECO to Empress	NOVA Transmission	50,000	GJ	31-Oct-27
EGD	Alliance to St. Clair (US Interconnect)	Vector Pipeline	65,000	Dth	31-Oct-27
EGD	St. Clair (Canada) to Dawn	Vector Pipeline	68,579	GJ	31-Oct-27
EGD	Union Parkway Belt to Enbridge CDA	TCPL	18,876	GJ	1-Nov-27

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

Preferred Planning Strategy

As noted in Section 5.2, the options to serve average day have not changed. As discussed in Section 2.1, the lack of available capacity on many paths is a material difference in the evaluation matrix. Enbridge Gas's preferred strategy is to continue to renew the contracts and in doing so, secure capacity where alternatives are scarce or not available. Enbridge Gas will continue to monitor market conditions and will make renewal decisions using the best available information at that time.

5.4 Storage Capacity Renewals

Enbridge Gas holds 26.0 PJ of market storage capacity for use in the EGD rate zone. This storage capacity is held across 13 different non-renewable service agreements of varying terms and volumes. This diversity in term and volume allows Enbridge Gas 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 asset in the Enbridge Gas portfolio. Storage is located close to the EGD rate zone increasing reliability and security of supply. Storage assets are a cost-effective means to manage the purchase of supply, as it allows for the purchase of the commodity in the summer, when prices typically tend to be lower, and withdrawal in the winter when prices tend to be higher. Further, storage service agreements provide a reliable asset that the utility typically nominate within the day to help balance demand requirements.

Preferred Planning Strategy

Enbridge Gas's preferred planning strategy for storage expiries is to continue to issue blind storage RFPs to the market each year to replace any capacity that is expiring as discussed in Section 4.5.

Enbridge Gas held a blind RFP from September 25 to October 16, 2023, to replace 11 PJ of storage services that expire at the end of March 2023. Enbridge Gas used the blind RFP process and contracted for 11 PJ of new storage services starting April 1, 2024, with terms between one and five years. Bid details will be filed confidentially with the OEB as part of the 2024 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding, expected to be filed in 2025.

5.5 Summary of Supply Option Analysis

Enbridge Gas'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 where market conditions are continuously evolving. The portfolio contemplates the North American market as a whole, as well as the resulting impacts on the Ontario market. To serve each rate zone, Enbridge Gas uses capacity on multiple upstream pipelines to access several supply basins and market hubs. These pipelines provide access to supplies in Western Canada, Chicago, Dawn, U.S. Mid-Continent, Niagara and Appalachia.

As part of its ongoing process, Enbridge Gas will continue to evaluate the portfolio for each rate zone to ensure it meets the needs identified in the gas supply plan, balancing the guiding principles set forth by the OEB in the Framework.

6. Gas Supply Plan Execution

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

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

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

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

To manage risk, Enbridge Gas procures supply regularly throughout the year from creditworthy counterparties at multiple trading points, based on the upstream transportation portfolio, using a layered approach with consideration to diversity of delivery term and supplier. Appendix I provides actual supplier diversity by basin for 2022/23 by highlighting the number of counterparties and the range of supply provided by each counterparty.

Contracting for supply in this manner allows Enbridge Gas to provide a stable, cost-effective solution for ratepayers while still maintaining the flexibility required to manage to seasonal storage inventory targets. This flexibility is also valuable when demand changes during extreme weather events.

6.1 Procurement Process and Policy

Enbridge Gas purchases natural gas for system operations and the regulated system gas supply portfolio for all rate zones.

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

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

- Actual and forecast consumption relative to planned consumption for its sales service customers;
- Seasonal balancing requirements for sales service customers at key control points;
- Weather variances for all sales customers and outside of checkpoint balancing for bundled DP customers in the Union rate zones;

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

7. 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.[58]

7.1 Heating Degree Days

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

Table 28
Actual vs Plan Annual HDDs

		2020/21			2021/22			2022/23		
Line No.	Particulars (HDD)	Actual	Plan	Variance	Actual	Plan	Variance	Actual	Plan	Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	EGD Central	3,277	3,645	(10%)	3,607	3,634	(1%)	3,265	3,566	(8%)
2	EGD Eastern	3,917	4,373	(10%)	4,428	4,343	2%	3,895	4,299	(9%)
3	EGD Niagara	3,087	3,429	(10%)	3,408	3,419	0%	3,121	3,398	(8%)
4	Union North West	4,650	4,964	(6%)	5,383	4,950	9%	4,900	4,877	0%
5	Union North East	4,349	4,964	(12%)	4,821	4,950	(3%)	4,395	4,877	(10%)
6	Union South	3,399	3,772	(10%)	3,744	3,757	0%	3,409	3,704	(8%)

Variance explanations as shown in Table 28:

- 2020/21 – HDDs were lower than budget across all weather zones due to warmer than expected temperatures.
- 2021/22 - HDDs were relatively close to budget across most weather zones: colder than expected in EGD Eastern and Union North West; and warmer in EGD Central, EGD Niagara, Union North East and Union South.

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

- 2022/23 – HDDs were lower than budget due to warmer than expected temperatures in all weather zones except for Union North West, which was close to budget.

7.2 Annual Demand

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

Table 29

Actual vs. Planned Annual Demand

Line No.	Particulars (TJ)	2020/21 Actual	2020/21 5-Year Plan	2020/21 Annual Update	2020/21 Variance to 5-Yr	2020/21 Variance to Update
		(a)	(b)	(c)	(d)	(e)
	EGD					
1	General Service	358,982	384,233	388,193	(25,251)	(29,211)
2	Contract	71,594	73,227	70,625	(1,633)	969
3	Total EGD	430,576	457,460	458,819	(26,884)	(28,243)
	Union North West					
4	General Service	12,943	13,886	14,335	(943)	(1,392)
5	Contract	3,250	1,330	1,636	1,920	1,614
6	Total Union North West	16,193	15,216	15,971	977	222
	Union North East					
7	General Service	35,057	35,967	38,290	(910)	(3,233)
8	Contract	4,355	3,683	3,763	672	592
9	Total Union North East	39,412	39,650	42,053	(238)	(2,641)
	Union South					
10	General Service	159,712	163,321	175,431	(3,609)	(15,719)
11	Contract	56,972	51,720	54,127	5,252	2,845
12	Total Union South	216,684	215,041	229,558	1,643	(12,874)
13	Total Demand Forecast	702,865	727,367	746,401	(24,502)	(43,536)

Line No.	Particulars (TJ)	2021/22 Actual	2021/22 5-Year Plan	2021/22 Annual Update	2021/22 Variance to 5-Yr	2021/22 Variance to Update
		(f)	(g)	(h)	(i)	(j)
	EGD					
1	General Service	385,135	384,182	381,835	953	3,300
2	Contract	77,313	72,789	70,000	4,524	7,313
3	Total EGD	462,448	456,971	451,835	5,477	10,613
	Union North West					
4	General Service	14,344	13,814	14,579	530	(235)
5	Contract	3,376	1,372	1,441	2,004	1,935
6	Total Union North West	17,720	15,185	16,020	2,535	1,700
	Union North East					
7	General Service	36,903	35,765	39,107	1,138	(2,204)
8	Contract	4,399	3,955	3,554	444	845
9	Total Union North East	41,302	39,720	42,660	1,582	(1,358)
	Union South					
10	General Service	172,079	162,482	173,820	9,597	(1,741)
11	Contract	59,121	52,144	55,729	6,977	3,392
12	Total Union South	231,200	214,626	229,549	16,574	1,651
13	Total Demand Forecast	752,670	726,502	740,065	26,168	12,605

Line No.	Particulars (TJ)	2022/23 Actual	2022/23 5-Year Plan	2022/23 Annual Update	2022/23 Variance to 5-Yr	2022/23 Variance to Update
		(k)	(l)	(m)	(n)	(o)
	EGD					
1	General Service	359,231	384,703	386,703	(25,472)	(27,472)
2	Contract	78,922	72,353	73,456	6,569	5,466
3	Total EGD	438,153	457,056	460,159	(18,903)	(22,006)
	Union North West					
4	General Service	13,097	13,742	14,133	(645)	(1,036)
5	Contract	2,500	1,363	1,579	1,137	921
6	Total Union North West	15,597	15,105	15,713	492	(116)
	Union North East					
7	General Service	35,007	35,558	38,816	(551)	(3,809)
8	Contract	4,343	5,198	3,911	(855)	432
9	Total Union North East	39,350	40,756	42,727	(1,406)	(3,377)
	Union South					
10	General Service	159,526	161,632	168,743	(2,106)	(9,217)
11	Contract	58,480	52,436	58,439	6,044	41
12	Total Union South	218,006	214,068	227,182	3,938	(9,176)
13	Total Demand Forecast	711,106	726,985	745,780	(15,879)	(34,674)

Variance explanations:

- 2020/21 – Warmer than normal weather decreased demand below both the 5-Year Gas Supply Plan and Annual Update
- 2021/22 – New customer attachments and growth from existing customers contributed to higher demand in applicable rate zones.
- 2022/23 – The decline in actual annual demand compared to both the 5-Year Gas Supply Plan and the Annual Update was driven by warmer weather experienced in the general service market.

7.3 Commodity Portfolio

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

Table 30
Actual vs. Planned Sources of Supply

Line No.	Particulars (TJ)	2020/21 Actual	2020/21 Plan	2020/21 Variance	2021/22 Actual	2021/22 Plan	2021/22 Variance	2022/23 Actual	2022/23 Plan	2022/23 Variance
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	EGD									
1	Appalachia	40,393	43,117	(2,725)	41,452	43,151	(1,699)	40,018	43,140	(3,122)
2	Chicago	25,892	25,194	698	25,742	32,980	(7,238)	21,943	32,963	(11,020)
3	Niagara Region	72,989	73,355	(366)	73,070	73,341	(271)	73,095	73,194	(99)
4	Dawn	86,802	101,670	(14,868)	110,825	86,748	24,077	85,489	91,943	(6,454)
5	Peaking/Seasonal	-	82	(82)	-	23	(23)	-	41	(41)
6	WCSB	89,780	90,562	(781)	94,680	92,580	2,100	94,447	95,653	(1,206)
7	Total EGD	315,856	333,980	(18,124)	345,769	328,823	16,946	314,992	336,934	(21,942)
	Union North West									
8	WCSB	19,294	15,485	2,980	19,811	11,851	7,960	21,533	11,467	10,066
9	Ontario/Dawn	137		137			-	-		-
10	Total North West	19,431	15,485	3,117	19,811	11,851	7,960	21,533	11,467	10,066
	Union North East									
11	Appalachia	18,040	19,255	(1,214)	18,612	19,254	(642)	19,015	19,255	(240)
12	Dawn	12,010	7,915	143	13,374	11,432	1,942	11,577	12,068	(491)
13	WCSB	1,483	1,364	118	1,590	1,493	97	2,940	2,700	240
14	Total North East	31,533	28,534	(953)	33,577	32,180	1,397	33,532	34,024	(492)
	Union South									
15	Appalachia	36,630	38,510	(1,879)	33,008	38,510	(5,501)	33,644	38,510	(4,866)
16	Chicago	26,194	30,807	(4,613)	32,747	38,509	(5,763)	30,926	38,509	(7,583)
17	Niagara Region	7,316	7,702	(386)	8,873	7,702	1,171	7,702	7,702	0
18	Dawn	31,396	43,992	(12,596)	36,195	34,799	1,396	28,306	30,991	(2,685)
19	U.S. Mid-Continent	21,938	21,950	(12)	21,246	21,950	(704)	17,255	21,950	(4,695)
20	WCSB	8,791	8,797	(5)	8,765	8,797	(32)	8,806	8,797	9
21	Total South	132,266	151,758	(19,492)	140,834	150,267	(9,433)	126,640	146,459	(19,820)
22	Total Supply	499,086	529,757	(35,452)	539,990	523,121	16,870	496,697	528,884	(32,188)

Note:
(1) Ontario Production is included as part of the Dawn number in the Union South total.

Variance explanations:

- 2020/21 – Warmer than normal weather decreased demand and gas supply deliveries relative to budget.

- 2021/22 – Colder than normal weather increased demand and gas supply deliveries relative to budget, primarily driven by the EGD rate zone.
- 2022/23 – Warmer than normal weather decreased demand and gas supply deliveries relative to budget.

7.4 Unutilized Capacity

The purpose of this section is to provide a brief review of the prior three years, comparing the unutilized capacity underlying each gas supply plan to actual unutilized capacity for each respective time period.

Table 31
Actual vs. Planned Unutilized Capacity

		2020/21			2021/22			2022/23		
Line No.	Particulars (PJ)	Actual	Plan	Variance	Actual	Plan	Variance	Actual[1]	Plan	Variance
1	EGD	-	-	-		-	-	-	-	-
2	North West	6.0	9.7	(3.8)	6.0	13.6	(7.7)	4.0	13.9	(6.4)
3	North East	3.0	5.9	(3.0)	1.9	1.8	0.1	4.7	2.4	(3.6)
4	South	19.6	-	19.6	9.5	-	9.5	18.6	-	18.6
5	Total unutilized capacity	28.5	15.6	13.0	17.4	15.5	1.9	27.3	16.3	8.5

Note:
(1) Actual 2022/2023 unutilized capacity volume allocations are preliminary. Final allocations will be filed in the 2023 Non-Commodities Deferral proceeding.

Variance explanations:

- 2020/21 – The actual unutilized capacity incurred was higher than planned primarily due to warmer than normal weather.
- 2021/22 – The actual unutilized capacity was relatively flat to planned, reflective of minor demand and supply variances for the Union rate zones.
- 2022/23 – The actual unutilized capacity incurred was higher than planned primarily due to warmer than normal weather.

8. Performance Measurement

Enbridge Gas has developed performance metrics that reflect the criteria the OEB has established to monitor effectiveness of the Plan, how the guiding principles have been achieved, and drive continuous improvement. Enbridge Gas's performance metrics include a rolling 3-year average of historical levels for each measure where applicable. Enbridge Gas's performance metrics for 2022/23 can be found in Appendix J with a brief explanation of each measure's intent.

Some of the performance metrics for 2022/23 show a change in trend from prior years. These include a change to the percentage of long-term contracts and an increase in instances of failed delivery of supply on upstream transportation pipelines.

The percentage of contracts with remaining terms of greater than 10 years has decreased because few new contracts with terms of greater than 10 years have been added to the portfolio since the initial 5-year plan was filed. Enbridge Gas does note a trend in the market where existing pipeline capacity is being contracted for longer terms.

Enbridge Gas was also impacted by 161 days of failed supply deliveries and 15 days where a force majeure was called by upstream transportation providers. None of these instances resulted in impacts to deliveries to customers. These instances are outside of Enbridge Gas's control, and Enbridge Gas promptly responds to each instance by evaluating market conditions and replacing supplies where necessary. Enbridge Gas is consistently reviewing its portfolio to ensure reliability and security of supply and will continue to monitor this trend across its portfolio and take actions to improve portfolio reliability as opportunities arise.

Figure 1: EGD Rate Zone Transportation Map

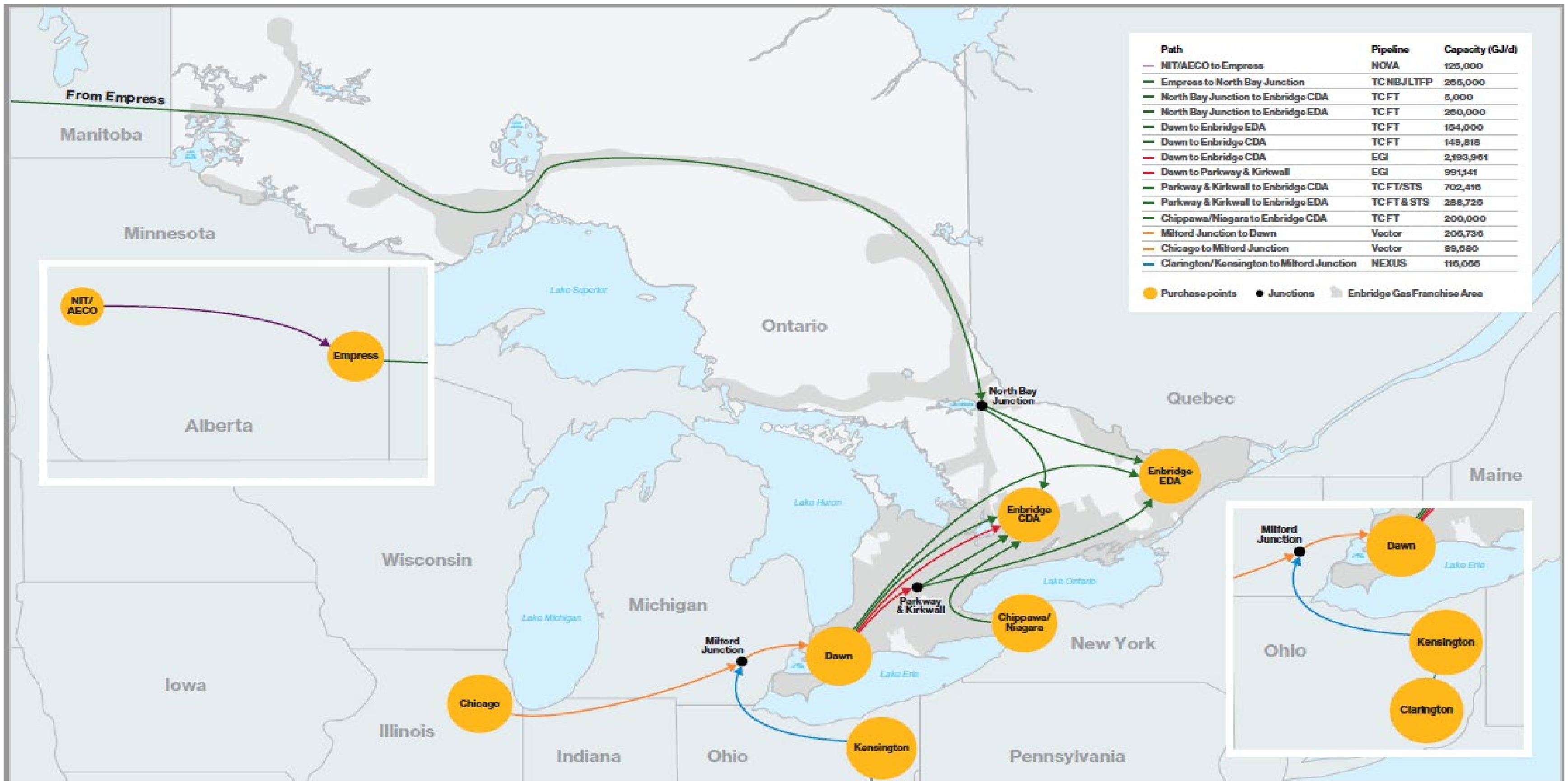


Figure 2: Union North Rate Zones Transportation Map

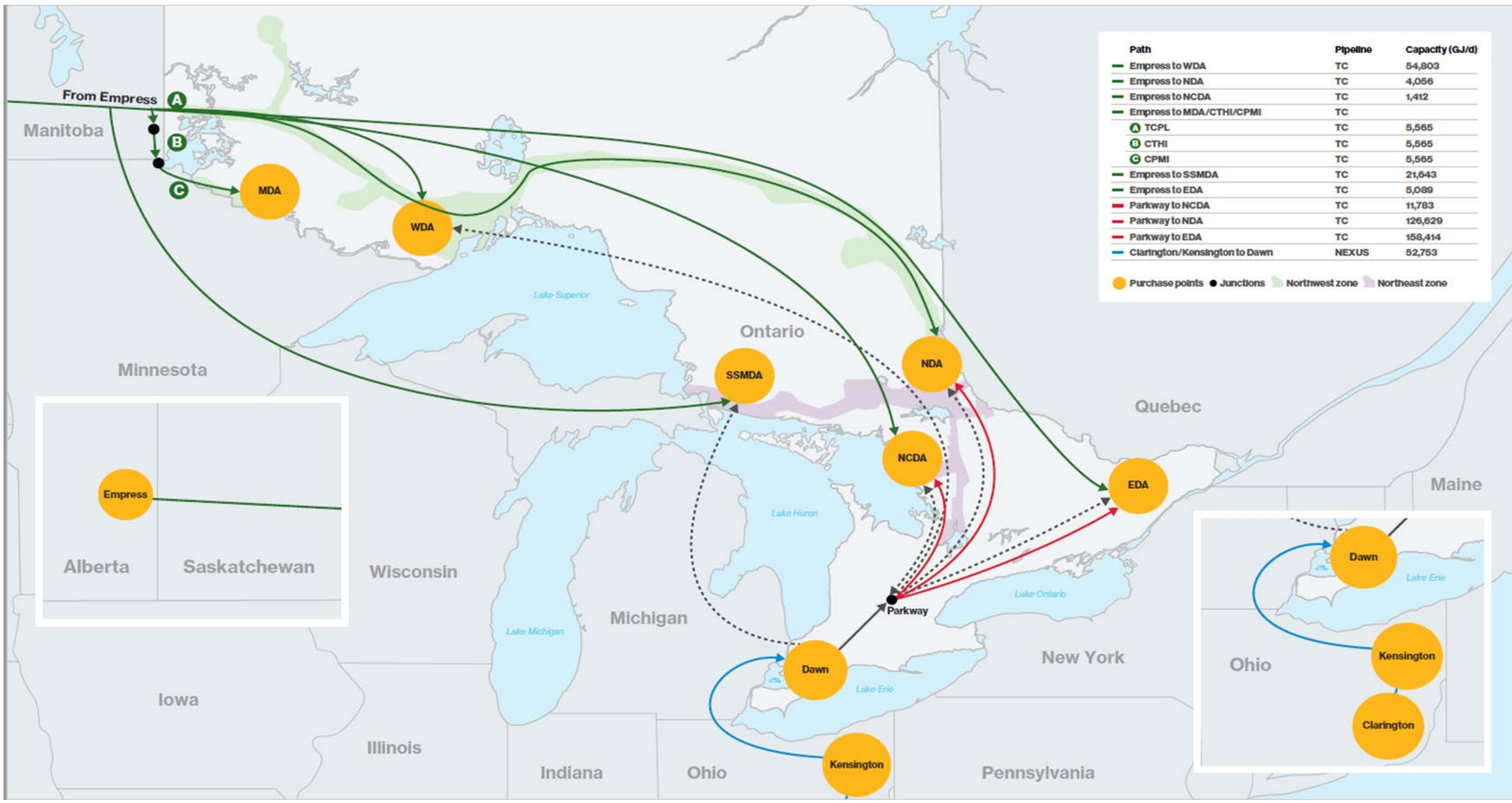
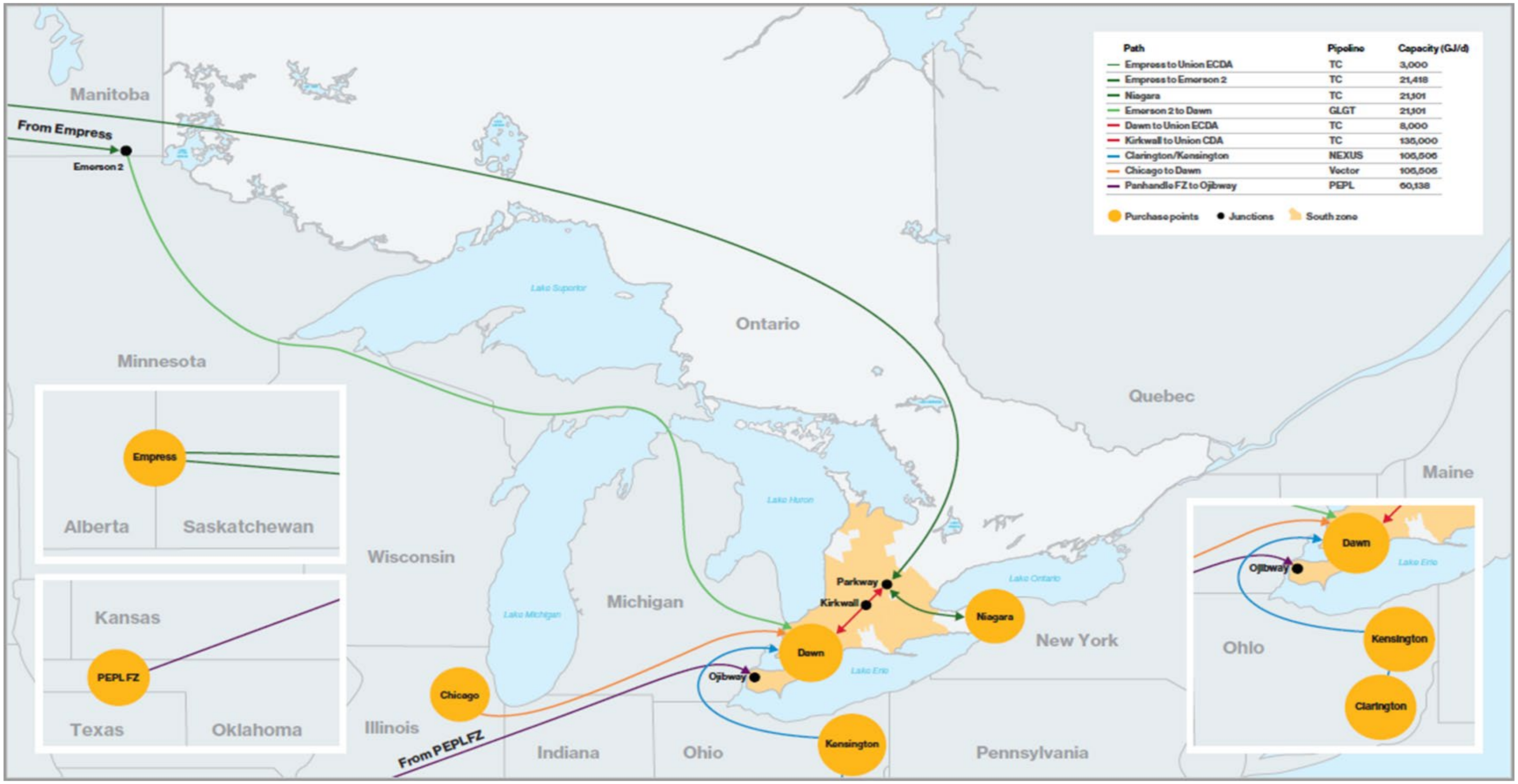


Figure 3: Union South Rate Zone Transportation Map



Summary of November 1, 2023 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	Dawn to CDA FT	Union Dawn	Enbridge CDA	4,818	GJ	31-Oct-2026
2	Dawn to CDA FT	Union Dawn	Enbridge CDA	145,000	GJ	31-Oct-2026
3	Dawn to EDA FT	Union Dawn	Enbridge EDA	114,000	GJ	31-Oct-2026
4	Dawn to Iroquois FT	Union Dawn	Iroquois	40,000	GJ	31-Oct-2026
5	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	572	GJ	31-Oct-2026
6	Parkway to CDA FT-SN	Union Parkway Belt	Victoria Square #2 CDA	85,000	GJ	31-Oct-2026
7	Chippawa to CDA	Chippawa	Enbridge Parkway CDA	123,441	GJ	31-Oct-2030
8	Niagara Falls to CDA	Niagara Falls	Enbridge Parkway CDA	76,559	GJ	31-Oct-2030
9	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	163,044	GJ	31-Dec-2030
10	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	70,000	GJ	31-Dec-2030
11	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	5,000	GJ	31-Dec-2030
12	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	26,956	GJ	31-Dec-2030
13	NBJ to Enbridge CDA	North Bay Junction	Enbridge CDA	5,000	GJ	31-Dec-2030
14	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	163,044	GJ	31-Dec-2030
15	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	70,000	GJ	31-Dec-2030
16	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	26,956	GJ	31-Dec-2030
17	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	170,000	GJ	31-Oct-2031
18	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	40,093	GJ	31-Oct-2032
19	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	70,000	GJ	31-Oct-2032
20	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	15,000	GJ	31-Oct-2032
21	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	8,375	GJ	31-Oct-2032
22	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	24,484	GJ	31-Oct-2032
23	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	6,000	GJ	31-Oct-2032
24	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	13,114	GJ	31-Oct-2032
25	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	75,000	GJ	31-Oct-2034
26	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	100,000	GJ	31-Oct-2036
27	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	25,000	GJ	31-Oct-2036
28	TCPL FT - Total			1,666,456	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
29	CDA	Parkway	Enbridge CDA	153,700	GJ	31-Oct-2026
30	CDA	Parkway	Enbridge CDA	92,822	GJ	31-Oct-2026
31	CDA	Parkway	Enbridge CDA	37,370	GJ	31-Oct-2026
32	EDA	Parkway/Kirkwall	Enbridge EDA	35,089	GJ	31-Oct-2026
33	EDA	Parkway	Enbridge EDA	35,806	GJ	31-Oct-2026
34	EDA	Parkway	Enbridge EDA	9,716	GJ	31-Oct-2026
35	TCPL Firm STS Withdrawal - Total			364,503	GJ	
	TransCanada Storage Transportation Service Firm Injection					
36	CDA	Parkway	Enbridge CDA	153,700	GJ	31-Oct-2026
37	CDA	Parkway	Enbridge CDA	92,822	GJ	31-Oct-2026
38	CDA	Parkway	Enbridge CDA	37,370	GJ	31-Oct-2026
39	EDA	Parkway/Kirkwall	Enbridge EDA	35,089	GJ	31-Oct-2026
40	EDA	Parkway	Enbridge EDA	35,806	GJ	31-Oct-2026
41	EDA	Parkway	Enbridge EDA	9,716	GJ	31-Oct-2026
42	TCPL Firm STS Injection - Total			364,503	GJ	
	NOVA Transmission					
43	NIT to Empress	NIT	Empress	50,000	GJ	31-Oct-2024
44	NIT to Empress	NIT	Empress	75,000	GJ	31-Oct-2025
45	Nova Transmission - Total			125,000	GJ	
	Vector Pipeline					
46	Vector US FT1	Alliance	St. Clair	65,000	DTH	31-Oct-2024
47	Vector Canada FT1	St. Clair	Dawn	68,579	GJ	31-Oct-2024
48	Vector US FT1	Chicago	Cdn/US Interconnect	20,000	DTH	31-Oct-2026
49	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	21,101	GJ	31-Oct-2026
50	Vector US FT1	Milford Junction	St. Clair	110,000	DTH	31-Oct-2033
51	Vector Canada FT1	St. Clair	Dawn	116,056	GJ	31-Oct-2033
52	Vector - Total			205,736	GJ	
	NEXUS					
53	NEXUS - FT	Kensington	Milford Junction	55,000	DTH	31-Oct-33
54	NEXUS - FT	Clarington	Milford Junction	55,000	DTH	31-Oct-33
55	NEXUS - Total			116,056	GJ	

Conversion Factor 1.055056

Summary of November 1, 2023 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 EDA FT	Empress	Union EDA	1,089	GJ	31-Oct-2025
2	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	31-Oct-2025
3	Empress to Union MDA FT	Empress	Union MDA	1,043	GJ	31-Oct-2025
4	Empress to Union NCDA FT	Empress	Union NCDA	1,412	GJ	31-Oct-2025
5	Empress to Union NDA FT	Empress	Union NDA	4,056	GJ	31-Oct-2025
6	Empress to Union SSMDA FT	Empress	Union SSMDA	2,700	GJ	31-Oct-2025
7	Empress to Union SSMDA FT	Empress	Union SSMDA	12,800	GJ	31-Oct-2025
8	Empress to Union SSMDA FT	Empress	Union SSMDA	6,143	GJ	31-Oct-2025
9	Empress to Union WDA FT	Empress	Union WDA	39,880	GJ	31-Oct-2025
10	Empress to Union WDA FT	Empress	Union WDA	11,527	GJ	31-Oct-2025
11	Parkway to Union EDA FT	Parkway	Union EDA	30,000	GJ	31-Oct-2026
12	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	31-Oct-2026
13	Empress to Union EDA FT	Empress	Union EDA	4,000	GJ	31-Oct-2027
14	Empress to Union WDA FT	Empress	Union WDA	3,396	GJ	31-Oct-2027
15	Parkway to Union EDA FT	Parkway	Union EDA	75,000	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 (EMB)	Parkway	Union EDA	25,000	GJ	31-Oct-2031
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 NDA FT	Parkway	Union NDA	10,000	GJ	31-Oct-2031
22	Parkway to Union NDA FT	Parkway	Union NDA	67,000	GJ	31-Oct-2031
23	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
26	Parkway to Union NDA FT	Parkway	Union NDA	6,228	GJ	31-Oct-2031
27	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	31-Oct-2032
28	Parkway to Union NCDA FT	Parkway	Union NCDA	887	GJ	31-Oct-2032
29	Parkway to Union NCDA FT	Parkway	Union NCDA	2,000	GJ	31-Oct-2032
30	Parkway to Union EDA FT	Parkway	Union EDA	9,128	GJ	31-Oct-2033
31	Parkway to Union NCDA FT	Parkway	Union NCDA	6,912	GJ	31-Oct-2033
32	Parkway to Union NCDA FT	Parkway	Union NCDA	884	GJ	31-Oct-2033
33	TCPL FT - Total			389,394	GJ	
	TransCanada Storage Transportation Service Firm Withdrawal					
34	EDA	Parkway	Union EDA	26,351	GJ	31-Oct-2026
35	NCDA	Parkway	Union NCDA	13,704	GJ	31-Oct-2026
36	NDA	Parkway	Union NDA	48,375	GJ	31-Oct-2026
37	SSMDA	Dawn	Union SSMDA	35,022	GJ	31-Oct-2026
38	WDA	Parkway	Union WDA	31,420	GJ	31-Oct-2026
39	TCPL Firm STS Withdrawal - Total			154,872	GJ	
	TransCanada Storage Transportation Service Firm Injection					
40	WDA	Union WDA	Parkway	3,150	GJ	31-Oct-2026
41	EDA	Union EDA	Parkway	5,000	GJ	31-Oct-2026
42	NDA	Union NDA	Parkway	49,100	GJ	31-Oct-2026
43	TCPL Firm STS Injection - Total			57,250	GJ	
	Centra Transmission Holdings Inc.					
44	Centra Transmission Holdings Inc.	Spruce	Union MDA	155.0	10^3m^3	31-Oct-2024
45	Centra Pipelines Minnesota Inc.	Sprague	Baudette	5,473	MCF	31-Oct-2024
46	CTHI FT - Total			6,014	GJ	

Conversion Factor	1.055056
Heat Content (as of April 1/23)	38.80

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

Summary of November 1, 2023 Upstream Transportation Contracts

Union South Rate Zone

Line	Upstream Pipeline	Primary Receipt Point	Primary Delivery Point	Contract	Contract	Contract
	TransCanada Pipeline Ltd.					
1	Dawn to Union CDA FT	Dawn	Union ECDA	8,000	GJ	31-Oct-2025
2	Empress to Emerson 2 FT	Empress	Emerson 2	21,418	GJ	31-Oct-2025
3	Empress to Union ECDA FT	Empress	Union ECDA	3,000	GJ	31-Oct-2025
4	Niagara to Kirkwall FT	Niagara	Kirkwall	21,101	GJ	31-Oct-2025
5	Kirkwall to Union CDA FT	Kirkwall	Union CDA	135,000	GJ	31-Oct-2032
6	TCPL FT - Total			188,519	GJ	
	Panhandle Eastern Pipe Line Company L.P.					
7	PEPL FT	Panhandle Field Zone	Ojibway (Union)	35,000	DTH	31-Oct-2025
8	PEPL FT	Panhandle Field Zone	Ojibway (Union)	22,000	DTH	31-Oct-2027
9	PEPL - Total			60,138	GJ	
	Vector Pipelines L.P.					
10	Vector US FT1	Chicago	Cdn/US Interconnect	80,000	DTH	31-Oct-2025
11	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,404	GJ	31-Oct-2025
12	Vector US FT1	Chicago	Cdn/US Interconnect	20,000	DTH	31-Oct-2026
13	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	21,101	GJ	31-Oct-2026
14	Vector - Total			105,505	GJ	
	NEXUS Gas Transmission, LLC					
15	NEXUS - FT(1)(2)	Kensington	St. Clair (Union)	150,000	DTH	31-Oct-2033
				158,258	GJ	
	Great Lakes Gas Transmission					
16	GLGT	Emerson	St. Clair	20,000	DTH	31-Oct-2024
				21,101	GJ	
	Great Lakes Pipeline Canada Ltd.					
17	Great Lakes Pipeline Canada Ltd.	St. Clair	Union SWDA	21,101	GJ	31-Oct-2024
	Other:					
18	St. Clair Pipelines L.P. (St. Clair Pipeline)	St. Clair/Intl Border	St. Clair/Intl Border	214,000	GJ	31-Oct-2024
19	St. Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Intl Border	Bluewater/Intl Border	127,000	GJ	31-Oct-2024

Conversion Factor 1.055056

Note:

(1) EGI has contracted for 150,000 DTH/day and allocates 50,000 DTH/day to the Union North portfolio.

Clarington Capcity
November 2023- October 2026 Transportation 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/GJ	Point of Delivery	Comments
(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	(K)	(L)	
NEXUS via St. Clair: Clarington to Dawn	Clarington	-0.3053	2.9464	1.17	0.00	0.0922	1.2663	$4.21	**$5.396**	Dawn	
NEXUS via St. Clair: Kensington to Dawn	Kensington	0.0981	3.3498	0.93	0.00	0.0725	1.0063	$4.36	**$5.580**	Dawn	

Supply Assumption used in Developing Transportation Contracting Analysis: Kensington Gas Price $0.50 more costly than Clarington.

Annual Gas Supply & Fuel Ratio Forecasts		**Nov 2023 - Oct 2024**	**Nov 2024 - Oct 2025**	**Nov 2025 - Oct 2026**	**Average Annual Gas Supply Cost $US/mmBtu Col (D) above**	**Fuel Ratio Forecasts Col (G) above**
NEXUS via St. Clair: Clarington to Dawn	Dominion South Point	$ 2.66	$ 2.95	$ 3.23	**$ 2.95**	3.13%
NEXUS via St. Clair: Kensington to Dawn	Dominion South Point	$ 2.66	$ 2.95	$ 3.23	**$ 2.95**	2.17%

Sources for Assumptions:

Gas Supply Prices (Col D): ICF Q3 2023

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 EGI's Analysis

Foreign Exchange (Col K) $1 US = $1.352 CDN From Bank of Canada Closing Rate September 14, 2023

Energy Conversions (Col K) 1 dth = 1 mmBtu = 1.055056

$1.28

EGI's Analysis Completed: Sep-23

GLGT Renewal
2024-2029 Transportation Analysis

Route (A)	**Point of Supply** (B)	**Basis Differential $US/mmBtu** (C)	**Supply Cost $US/mmBtu** (D) = Nymex + C	**Unitized Demand Charge $US/mmBtu** (E)	**Commodity Charge $US/mmBtu** (F)	**Fuel Charge $US/mmBtu** (G)	**100% LF Transportation Inclusive of Fuel $US/mmBtu** (I) = E + F + G	**Landed Cost $US/mmBtu** (J) = D + I	**Landed Cost $Cdn/GJ** (K)	**Point of Delivery** (L)	**Comments**
Dawn	Dawn	0.4844	4.2701				0.0000	$4.27	**$5.61**	Dawn	
TC: Great Lakes to Dawn	Empress	-0.2830	3.5027	0.61	0.01	0.1421	0.7605	$4.26	**$5.60**	Dawn	
TC: Niagara to Dawn	Niagara	0.1937	3.9794	0.17	0.00	0.0186	0.1947	$4.17	**$5.48**	Dawn	
MichCon: MichCon to Dawn	SE Michigan	0.3840	4.1697	0.15	0.00	0.0524	0.2039	$4.37	**$5.74**	Dawn	
Vector: Chicago to Dawn	Chicago	0.3820	4.1678	0.16	0.00	0.0196	0.1811	$4.35	**$5.71**	Dawn	
Panhandle: Panhandle FZ to Dawn	Panhandle Field Zone	0.1980	3.9838	0.51	0.04	0.1247	0.6770	$4.66	**$6.12**	Dawn	Includes C1 to Dawn
NEXUS-Clar2Dawn	Dominion South Point	-0.3152	3.4705	1.17	0.00	0.0965	1.2685	$4.74	**$6.22**	Dawn	
Rover to Dawn	Dominion South Point	-0.3152	3.4705	0.98	0.05	0.0212	1.0507	$4.52	**$5.94**	Dawn	

Supply Assumptions used in Developing Transportation Contracting Analysis:

Annual Gas Supply & Fuel Ratio Forecasts	**Point of Supply Col (B) above**	**Nov 2024 - Oct 2025**	**Nov 2025 - Oct 2026**	**Nov 2026 - Oct 2027**	**Nov 2027 - Oct 2028**	**Nov 2028 - Oct 2029**	**Average Annual Gas Supply Cost $US/mmBtu Col (D) above**	**Fuel Ratio Forecasts Col (G) above**
Dawn	Dawn	$ 3.54	$ 3.99	$ 4.46	$ 4.65	$ 4.71	**$ 4.27**	
TC: Great Lakes to Dawn	Empress	$ 2.88	$ 3.30	$ 3.67	$ 3.79	$ 3.87	**$ 3.50**	4.06%
TC: Niagara to Dawn	Niagara	$ 3.33	$ 3.71	$ 4.18	$ 4.37	$ 4.31	**$ 3.98**	0.47%
MichCon: MichCon to Dawn	SE Michigan	$ 3.45	$ 3.88	$ 4.36	$ 4.55	$ 4.60	**$ 4.17**	1.26%
Vector: Chicago to Dawn	Chicago	$ 3.44	$ 3.88	$ 4.35	$ 4.56	$ 4.60	**$ 4.17**	0.47%
Panhandle: Panhandle FZ to Dawn	Panhandle Field Zone	$ 3.30	$ 3.71	$ 4.16	$ 4.36	$ 4.39	**$ 3.98**	3.13%
NEXUS-Clar2Dawn	Dominion South Point	$ 2.95	$ 3.23	$ 3.68	$ 3.87	$ 3.62	**$ 3.47**	2.78%
Rover to Dawn	Dominion South Point	$ 2.95	$ 3.23	$ 3.68	$ 3.87	$ 3.62	**$ 3.47**	0.61%

Sources for Assumptions:

Gas Supply Prices (Col D): ICF Q3 2023

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 = $1.386 CDN From Bank of Canada Closing Rate October 27, 2023

Energy Conversions (Col K) 1 dth = 1 mmBtu = 1.055056

$1.31

EGI's Analysis Completed: Oct-23

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

NGTL Contract Renewal
2024-2029 Transportation Analysis

Route (A)	Point of Supply (B)	Basis Differential $US/mmBtu (C)	Supply Cost $US/mmBtu (D) = Nymex + C	Unitized Demand Charge $US/mmBtu (E)	Commodity Charge $US/mmBtu (F)	Fuel Charge $US/mmBtu (G)	100% LF Transportation Inclusive of Fuel $US/mmBtu (I) = E + F + G	Landed Cost $US/mmBtu (J) = D + I	Landed Cost $Cdn/GJ (K)	Point of Delivery (L)	Comments
AECO to Empress 1-year	AECO	-0.746	3.372	0.151	0.00	0.0000	0.151	$3.523	**$4.543**	Empress	$0.015 Cad Subtracted from total for extraction
AECO to Empress 3-year	AECO	-0.746	3.372	0.146	0.00	0.0000	0.146	$3.518	**$4.535**	Empress	$0.015 Cad Subtracted from total for extraction
AECO to Empress 5-year	AECO	-0.746	3.372	0.138	0.00	0.0000	0.138	$3.511	**$4.526**	Empress	$0.015 Cad Subtracted from total for extraction
	Empress	-0.609	3.509	0.000	0.00	0.0000	0.000	$3.509	**$4.539**	Empress	

Supply Assumptions used in Developing Transportation Contracting Analysis:

Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2024 - Oct 2025	Nov 2025 - Oct 2026	Nov 2026 - Oct 2027	Nov 2027 - Oct 2028	Nov 2028 - Oct 2029	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
AECO to Empress 1-year	AECO	$ 2.91	$ 3.31	$ 3.42	$ 3.57	$ 3.65	**$ 3.37**	0.00%
AECO to Empress 3-year	AECO	$ 2.91	$ 3.31	$ 3.42	$ 3.57	$ 3.65	**$ 3.37**	0.00%
AECO to Empress 5-year	AECO	$ 2.91	$ 3.31	$ 3.42	$ 3.57	$ 3.65	**$ 3.37**	0.00%
Empress	Empress	$ 3.04	$ 3.44	$ 3.56	$ 3.71	$ 3.79	**$ 3.51**	0.00%

Sources for Assumptions:

Gas Supply Prices (Col D): ICF Q2 2023

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 = $1.365 CDN From Bank of Canada Closing Rate September 7, 2023

Energy Conversions (Col K) 1 dth = 1 mmBtu = 1.055056

$1.29

EGI's Analysis Completed: Sep-23

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

2024-2027 Transportation Contracting Analysis

	Route (A)	Point of Supply (B)	Basis Differential $US/mmBtu (C)	Supply Cost $US/mmBtu (D) = Nymex + C	Unitized Demand Charge $US/mmBtu (E)	Commodity Charge $US/mmBtu (F)	Fuel Charge $US/mmBtu (G)	100% LF Transportation Inclusive of Fuel $US/mmBtu (I) = E + F + G	Landed Cost $US/mmBtu (J) = D + I	Landed Cost $Cdn/GJ (K)	Point of Delivery (L)	Comments
	TC-Emp2EnbCDA(LH)	Empress	-0.4365	3.7010	0.93	0.00	0.1600	1.0930	$4.79	**$6.10**	EGD CDA	
	TC-Dawn2EnbCDA	Dawn	0.0185	4.1560	0.22	0.00	0.0431	0.2654	$4.42	**$5.63**	EGD CDA	

Supply Assumptions used in Developing Transportation Contracting Analysis:

	Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2024 - Oct 2025	Nov 2025 - Oct 2026	Nov 2026 - Oct 2027	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
	TC-Emp2EnbCDA(LH)	Empress	$ 3.91	$ 3.76	$ 3.43	**$ 3.70**	4.32%
	TC-Dawn2EnbCDA	Dawn	$ 4.35	$ 4.21	$ 3.91	**$ 4.16**	1.04%

Sources for Assumptions:

Gas Supply Prices (Col D): ICF Q1 2023 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 = $1.344 CDN From Bank of Canada Closing Rate June 2, 2023

Energy Conversions (Col K) 1 dth = 1 mmBtu = 1.055056

EGI's Analysis Completed: Jun-23

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

Chicago Natural Gas Price Analysis

Prepared for:
Enbridge Gas

Prepared by:
Andrew Griffith and Michael Sloan
ICF

October 20, 2023

1. Executive Summary

1.1 Purpose

Prior to 2021, Chicago natural gas prices were consistently lower than prices at Dawn, and the natural gas forward prices were consistent with the day-ahead prices. However, since early 2021, the Chicago natural gas price forward prices have diverged from the ensuing Chicago day-ahead prices, with the forward strip remaining consistently higher than the day-ahead prices. This shift in market behavior has resulted in a shift in the price relationship between Chicago and Dawn from a Chicago discount to a Chicago premium relative to Dawn in the futures market even though the Chicago day-ahead prices have on average continued to trade at a discount.

In August 2023, Enbridge Gas asked ICF to analyze the causes for the divergence between the Chicago natural gas forward prices and the Chicago day-ahead prices in order to identify the causes of this change in market pricing behavior and to assess the outlook for this shift in market pricing. This report discusses ICF's analysis of this market shift and explains ICF's conclusion that the increase in Chicago forward pricing relative to Dawn reflects a market risk premium associated with extreme winter weather and potential price volatility, rather than a shift in market fundamentals. The report also summarizes the natural gas market trends impacting the Chicago natural gas price and the spread between Chicago and Dawn specifically to assess the long-term relationship between the Chicago and Dawn markets.

Enbridge Gas contracts for capacity on the Vector pipeline from Chicago to Dawn, which provides it with access to Chicago natural gas supply. ICF's assessment is expected to be used by Enbridge Gas to help evaluate the future value of Vector pipeline capacity as part of the Enbridge Gas supply portfolio. Given the lack of available pipeline capacity between the Chicago and Ontario markets, Enbridge Gas likely would be unable to re-contract for capacity on Vector or other pipelines in the Chicago to Dawn corridor without paying a significant premium if the existing capacity is allowed to expire given the scarcity of pipeline capacity. Based on the Vector Pipeline's index of customer data, between Q3 2020 and Q3 2023, firm transportation capacity contracts on Vector accounting for 2.3 Bcf/d of capacity reached their expiration date have been renewed while an additional 1.0 Bcf/d of new contracts were added. This is a clear indication that the customers value the contracted capacity on the pipeline.

Additionally, based on the ICF review, financial markets are currently building in a significant risk premium into the forward curve at Chicago in response to recent price volatility and extreme price events in the region. In the absence of similar extreme price events, ICF expects this risk premium to decline over time. While the Chicago price hub has experienced recent price volatility contributing to the futures market premium at that location, future events could lead to similar increases in forward pricing at other price locations. If that occurs, the supply portfolio diversity provided by sourcing gas at Chicago will become increasingly valuable. This report discusses why ICF's expectations that the increase in Chicago forward pricing relative to Dawn is likely to be a short-term trend and why the diversity of supply provided by access to the Chicago market is important for Enbridge Gas.

1.2 Context

During Winter Storm Uri in February 2021, the day-ahead Chicago natural gas price spiked to $136.68/MMBtu while other price hubs in the region, including Dawn, remained relatively stable. Day-ahead prices in the Dawn market reached $9.18/MMBtu. In response to that price spike, and other temporary price increases like the ones seen in December 2022 during Winter Storm Elliot, when the Chicago price reached $16.90/MMBtu, the futures market has diverged from the market fundamentals observed in the day-ahead prices and ICF's fundamentals-based forecasts that are used by Enbridge Gas. On average, since Winter Storm Uri, between March 2021 and August 2023, the day-ahead natural gas prices at Chicago have traded at a discount or at parity with price hubs such as Dawn, where Chicago averaged $4.28/MMBtu and Dawn averaged $4.29/MMBtu. ICF's forecasts also include a discount for Chicago's natural gas prices relative to Michcon and Dawn similar to the day-ahead market. However, the forward curve has at times included a premium of more than $1/MMBtu for Chicago's winter prices in comparison with Dawn.

Some of the price volatility observed in the context above has been driven by fundamental changes in North American natural gas markets that are transforming the natural gas price relationships between different natural gas market centers. The shale gas revolution changed the quantity of available natural gas supply across North America. While there are shale gas plays in a variety of regions (including Western Canada, the Gulf Coast, and the Mid-Continent), most of the natural gas production growth since 2015 has occurred in the Marcellus and Utica shale plays in the Northeastern U.S. and growth there is expected to continue, albeit at a slower pace than during the past seven years. As a result, the utilization and significance of pipeline infrastructure to bring low-cost gas from the producing regions to demand centers has increased. Largely in response to the increased availability of supply, demand growth has been driven by the increase in natural gas demand for heating, power generation, industrial use, liquefied natural gas (LNG) exports, and pipeline exports to Mexico. Since 2021, on days with extremely high natural gas demand, the increased utilization and sometimes insufficient capacity of infrastructure led to increased prices at Chicago and increased price spreads between Chicago and Dawn due to its reliance on pipeline deliveries. Dawn, which has better access to natural gas storage and pipelines, has not experienced similar price spikes recently.

Key Natural Gas Market Terminology

- ***Basis*** *refers to the difference in price between Henry Hub and another natural gas price hub (although it could be between any two locations).*
- ***Bid-week prices*** *represent the price of gas that will flow every calendar day during the forthcoming calendar month. These are based on trading conducted in the fifth, fourth and third business days before the start of the contract month.*
- ***Day-ahead prices*** *for a particular day are determined on the preceding day by traders using localized supply and demand conditions. On the last day before a weekend, public holiday or other industry-agreed non-trading days, day-ahead indexes also include the weekend, public holiday and/or other industry-agreed nontrading days.*
- ***Futures market****: A trade center for quoting prices on contracts for the delivery of a specified quantity of a commodity at a specified time and place in the future. Trades in the futures market determine the forward price.*
- ***Forward price****: The predetermined delivery price for the delivery of a specified quantity of natural gas at a specified time and place in the future. The* ***forward curve*** *shows the forward price for numerous dates (often months) in the future.*
- ***Prompt month*** *(front month) prices refer to the forward prices from a trade date for the immediate next month. For example, prompt-month contracts traded in August are typically for delivery in September.*
- ***Trade date*** *refers to the date on which the trading is being done. On a particular trade date, the prices are set for the forward (future)* ***contract date****.*

1.3 Summary of Findings

Since early 2021, the Chicago and Dawn forward curves and bid-week prices, which are financial products that result from the buying and selling of future natural gas supply, have projected that natural gas prices at Chicago will trade at a significant premium to Dawn. ICF forecasts, however, which are calculated using ICF's Gas Market Model (GMM) and are based on the market fundamentals such as the cost of production, the forecasted demand, and the cost of transportation, have projected the premium to be much lower during the same period. ICF's fundamentals-based forecasts largely have been supported in the day-ahead market. This is mainly because Chicago has access to the Western Canada, Mid-Continent, Haynesville, Bakken, and Rockies production basins. Dawn gets most of its gas from the Marcellus/Utica basins and Western Canada sedimentary basins. ICF, in its Q3 2023 base case projections, expects demand at both Chicago and Dawn to remain stable over the long term. As a result, the day-ahead natural gas prices at Chicago trade at a discount to Dawn most of the time and only peaks during extreme cold-weather events in which the demand spikes are seen upstream of Chicago and not at Dawn.

The futures market, however, projects natural gas prices at Chicago to be at a significant premium to Dawn, which is out of sync with the day-ahead prices and market fundamentals given the placement of Chicago with respect to Dawn as well as the stable demand dynamics at both Chicago and Dawn. This is also supported by the day-ahead prices seen in the past at Chicago. For example, the day-ahead price averaged $3.24/MMBtu for Chicago and $3.25/MMBtu for Dawn in January 2023, while the bid-week price that traded in December 2022 for January 2023 was $6.04/MMBtu at Chicago and $4.72/MMBtu at Dawn. This example illustrates the premium added to the prices at Chicago in the peak winter months by the futures markets, which does not align with the market fundamentals when there are no extreme cold-weather events.

Moreover, the index of customers data for key pipelines like Vector over the past couple of years suggests the pipeline is fully contracted and that customers are retaining and renewing the capacity contracts since the pipeline is critical in supplying gas to and from Chicago. The latest index of customers data from Q3 2023 indicates that the pipeline is fully contracted by BP Canada Energy Marketing Corp, Enbridge Gas Distribution Inc/Union Gas Limited, and the Rover Pipeline LLC. This makes re-contracting on the pipeline challenging if any of the contracts expire. Hence, ICF recommends that Enbridge Gas continue to base their longer-term re-contracting decisions on the market fundamentals represented by the day-ahead prices as well as the supply diversity and reliability benefits associated with access to an additional market center, rather than the near-term futures market trends.

In ICF's opinion, the long-term benefits to Enbridge Gas of continuing to hold its capacity and supply agreements on Vector will exceed short-term costs that may be incurred due to short-term forward price trends that diverge from market fundamentals.

Market Fundamentals – ICF's Approach

*The **Gas Market Model** (GMM) simulates regional natural gas markets in the United States and Canada by solving for gas production, transmission/pipelines flows, storage injections & withdrawals, gas consumption, and gas prices. Forecasts are generated for each month between now and December 2045 for 121 regional market centers (nodes). The model uses a sequential non-linear optimization, representing the anticipated market outcomes for future months.*

The objective function in the model optimizes total net economic benefit, that is, consumers' and producers' surplus minus costs. Model optimization has several constraints, equations representing physical limits of production, storage and transmission capacity and a series of "balance equations" that ensure that supply and demand are equal at each node.

*Natural gas prices in GMM are determined by the marginal (or incremental) value of natural gas at 121 nodes. Gas prices are evaluated based on **the balance of supply and demand in a regional marketplace**. These prices are indicative of ICF's view of the national market and reflect our most current base case data and modeling assumptions at the time of derivation.*

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. Prices are also influenced by "pipeline discount curves", which reflect the change in basis or the marginal value of gas transmission into and out of each node as a function of load factor. The pipeline discount curves are calibrated to actual observed flows and basis between market areas. On the demand-side of the equation, prices are represented by a curve that captures the 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.

*The **fundamental based price forecast is driven by the supply demand dynamics** and is different from a **forward/futures pricing** as the latter **is driven by market sentiments**. Extreme weather forecasts or concerns on gas supply volumes or natural gas storage inventories or any speculation around changing regulations or any uncertainty in the natural gas markets gets captured in the futures price, creating an unnecessary premium/discount over the fundamental view.*

2. Historical Price Spreads

Historically, Chicago has been a significant supply hub for natural gas delivered into Ontario through Dawn. The last major change to the fundamental natural gas market dynamics between Chicago and Dawn was in 2018, when the last NEXUS, Rover, and Vector pipeline expansions came online, and the bulk of the TC Energy Dawn Long-Term Fixed Price contracts came into effect. In the five years prior to these developments (2013-2017), the day-ahead prices at Chicago averaged a $0.26/MMBtu discount relative to Dawn. In 2019 and 2020, after these developments, the day-ahead prices at Dawn traded near parity to Chicago, with Chicago averaging $0.02/MMBtu more than Dawn. However, that positive spread was driven by instances, mostly driven by weather, when the daily prices at Chicago rose above the prices at Dawn. There were 10 days in which the Chicago price was more than

$0.25/MMBtu above the Dawn price in 2019 and 2020 and, if those are removed, the Chicago price averages a $0.01/MMBtu discount to the Dawn price during that period.

The 2020 average natural gas day-ahead prices at Chicago hit a historic low of $1.88/MMBtu with Dawn trading at $1.87/MMBtu, marking the lowest annual average in over 7 years. The year commenced with relatively low prices, influenced by a mild winter and the economic repercussions of the COVID-19 pandemic which curtailed both natural gas production and consumption. As March 2020 arrived, spring weather and pandemic-related responses caused a decline in gas demand, thereby intensifying the price reduction. Notably, June 2020 saw the Chicago and Dawn prices dip to $1.55/MMBtu and $1.57/MMBtu, respectively, the lowest average monthly value in over 7 years. Subsequently, the latter half of 2020 witnessed price increases due to diminished natural gas production and a surge in LNG exports. This culminated in December's average of $2.44/MMBtu at Chicago and $2.41/MMBtu at Dawn.

In 2021, the natural gas day-ahead prices at Chicago experienced a huge price spike in the month of February due to Winter Storm Uri, leading to an annual average price of $5.13/MMBtu, about 42% more than Dawn's annual average price. Day-ahead prices at Chicago reached $136.68/MMBtu whereas prices at Dawn only reached $9.18/MMBtu during the storm period. Winter Storm Uri, which occurred from February 13th to February 17th, 2021, led to increased demand from Texas to the Midwest U.S. while also causing a significant, temporary loss of production due to freeze-offs and pipeline force majeures. Natural gas deliveries from Texas into the Midwest declined as Texas used the natural gas available within the region to meet its own demand during the storm. U.S. dry natural gas production in February 2021, was 67.9 Bcf per day, down by 8%, compared to January 2021 as reported by EIA. The substantial winter heating and power demand for natural gas, coupled with reduced production, triggered the significant price hikes.

Winter Storm Uri had a significant adverse financial impact on multiple energy companies and utilities. For example:

- Vistra Energy estimated a $1.6 billion loss, primarily driven by unmet gas contracts with third parties, leading to high replacement gas costs, and reduced power generation capacity due to insufficient gas supply and pipeline issues.[1]
- Black Hill Corp incurred $2.1 million in incremental fuel costs, which were not recoverable through its fuel cost recovery mechanisms, resulting in a $4.7 million decrease in its gas utilities operating income.[2]
- Exelon Corp faced a loss of net income of between $560 million and $710 million.[3]

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[1] "Vistra says Texas February freeze cost about $1.6 billion". Reuters. April 26, 2021. https://www.reuters.com/business/energy/vistra-says-texas-february-freeze-cost-about-16-billion-2021-04-26/

[2] Black Hills Corporation. (2022). Form 10-K. https://www.sec.gov/Archives/edgar/data/1130464/000095017023002759/bkh-20221231.htm.

[3] "Exelon Reports Higher Negative Impact From Texas Winter Weather Event, In Reporting Q1 Earnings". May 5, 2021. Energychoicematters.com. http://www.energychoicematters.com/stories/20210505cd.html.

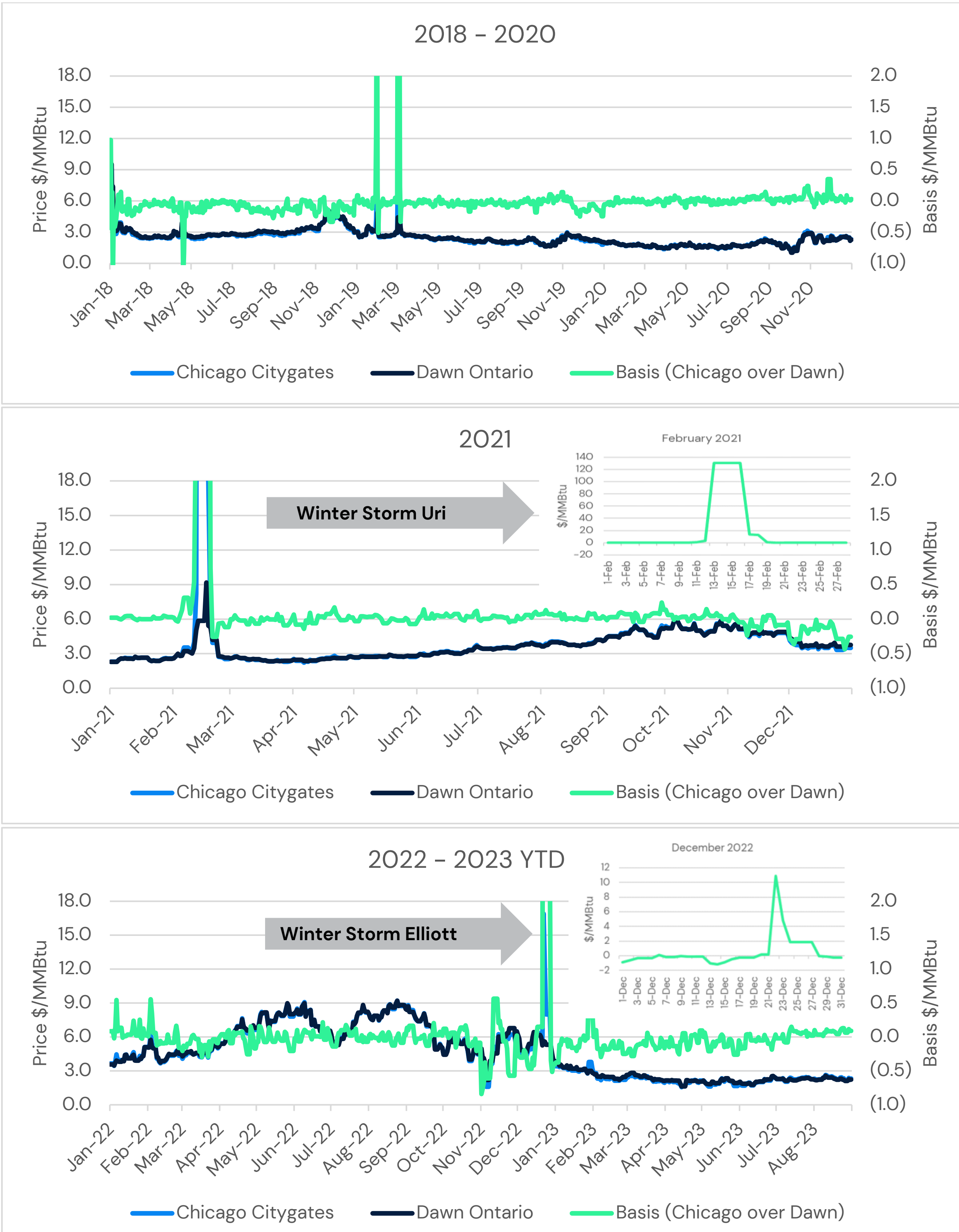
- Xcel Energy lost nearly $1 billion due to high fuel costs, with the bulk of the $965 million in net costs stemming from gas distribution and generation portions of its subsidiaries.[4]

The billions of dollars in losses by natural gas buyers during Winter Storm Uri were the catalyst for the change in the forward curve at Chicago, as the demand for financial hedges against such events in the future drove up the price of the bid-week contracts and the forward curve.

The day-ahead prices at Chicago averaged $1.51/MMBtu more than Dawn in 2021. However, if the two-week period from February 6th to February 19th are removed from the year, the Chicago price averaged a $0.01/MMBtu discount to Dawn. This two-week period included the only days in 2021 in which the Chicago price was $0.25/MMBtu more than Dawn. In fact, in December 2021, the Chicago price averaged an $0.18/MMBtu discount to Dawn and Chicago traded at an average discount of $0.04/MMBtu to Dawn in the winter of 2021/22.

[4] "Xcel takes nearly $1B fuel cost hit from February storms but still sees Q1 profit rise". April 30, 2021. Catherine Morehouse. Utility Dive. https://www.utilitydive.com/news/xcel-takes-nearly-1b-fuel-cost-hit-from-february-storms-but-still-sees-q1/599330/.

Exhibit 2-1 : Historical Day-Ahead Prices at Chicago and Dawn ($/MMBtu)



Source: Argus Day-Ahead Prices

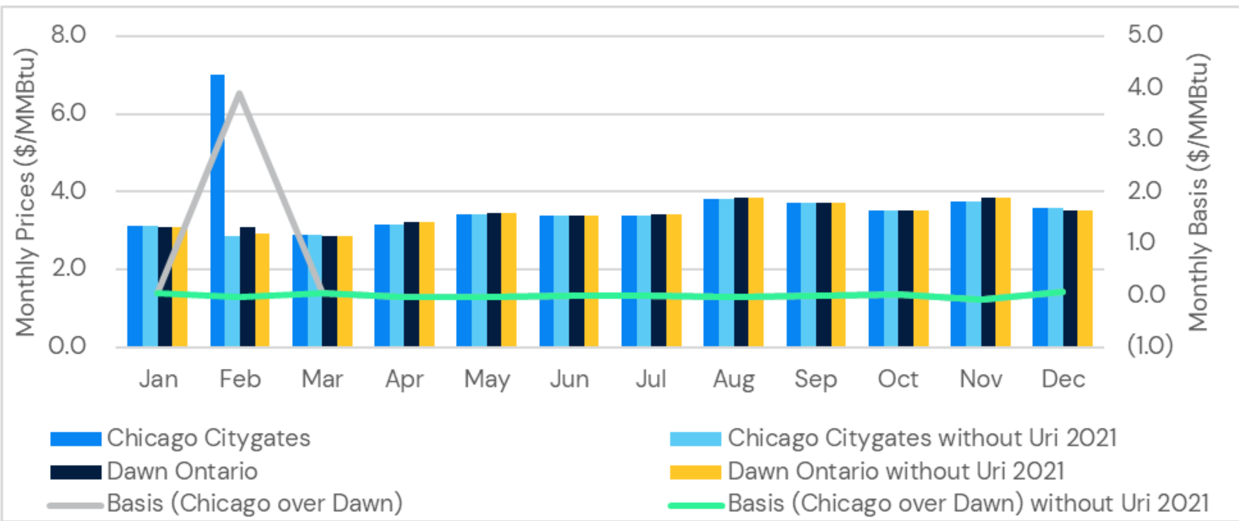
In 2022, the annual average natural gas day-ahead price at Chicago surged to $6.09/MMBtu, the highest annual average price in decades. The price oscillated widely between $1.60/MMBtu and $16.90/MMBtu, underscoring significant day-to-day volatility. The first quarter of 2022 saw a pronounced increase owing to a confluence of factors. Production freeze-offs in January and February curtailed U.S. natural gas production, while robust net withdrawals from storage fueled the price surge. By August, the Chicago natural gas day-ahead price soared to $8.30/MMBtu, marking the highest summer month price since 2013. A decline followed in October, with average prices at $5.08/MMBtu, propelled by a period of robust dry natural gas production and several consecutive weeks of relatively large injections into natural gas storage. However, on December 21st, 2022, the Chicago natural gas day-ahead prices spiked to $16.90/MMBtu as a result of Winter Storm Elliott, the highest post the Winter Storm Uri in February 2021. The winter months also contributed to price elevation, driven by the seasonal demand for space heating and amplified demand for LNG exports, especially in the Northern Hemisphere. Increased demand at LNG export facilities, notably the resumption of operations at the Freeport LNG terminal in November, further contributed to the price surge. Primarily as a result of Winter Storm Elliott, the Chicago natural gas price averaged $0.73/MMBtu more than Dawn in December 2022.

However, during January and February 2023, prices at Chicago were again below Dawn – $0.08/MMBtu below on average – as above-average temperatures in the Midwest and Northeast U.S. lowered the heating demand. The interplay of relatively mild temperatures, robust production, and higher-than-average inventories pushed natural gas prices downwards. Notably, May 2023 recorded the lowest average monthly price since June 2020, as the natural gas day-ahead price at Chicago averaged $1.94/MMBtu. As of August 31st, 2023, natural gas day-ahead prices at Chicago were at $2.33/MMBtu, 73% lower than the corresponding price in 2022 but a $0.09/MMBtu premium relative to Dawn due to the increasing power generation demand in the Midwest U.S. Even with prices at Chicago trading higher than Dawn for most days in July and August 2023, the year-to-date average through the end of August reflected a discount to Dawn of $0.05/MMBtu. With the U.S. dry natural gas production outpacing demand so far in 2023, prices have remained subdued across the country and Dawn has traded at a premium to Chicago.

Exhibit 2-2 depicts the 5-year (2018-2022) average monthly prices at Chicago and Dawn, without February 2021, when Winter Storm Uri occurred, and the same 5-year period with all the months included. Due to the high prices at Chicago in February 2021, the 5-year monthly average at February changes from $2.90/MMBtu to $7.00MMBtu and Dawn changes from $2.92/MMBtu to $3.09/MMBtu. The February 5-year average basis was much higher given the sharp increase in prices seen at Chicago during February 2021. The December 5-year average prices were more stable even with Winter Storm Elliott included. This is because the impact of Winter Storm Elliott in December 2022 was much smaller because it lasted for a shorter period compared to Uri, the natural gas storage inventories were much larger compared to February 2021, and the resulting day-ahead price at Chicago were only $16.90/MMBtu instead of $136.68/MMBtu. Since February 2021 when Winter Storm Uri occurred, the Chicago price and the Chicago to Dawn price spread has behaved the same way it did before the storm. The Chicago price averaged a $0.01/MMBtu discount between March 2021 and August 2023 and was more than $0.25/MMBtu greater than Dawn on only 14 days.

Even during December 2022, when Winter Storm Elliott occurred, the day-ahead monthly average price was $8.10/MMBtu at Chicago and $7.71/MMBtu at Dawn, a $0.39/MMBtu price spread. This is still lower than the forward curve for December 2023 dated August 8th, 2023, which includes a Chicago to Dawn spread of $0.58/MMBtu. This implies that the forward curve for the upcoming December and upcoming 2023/24 winter includes a risk of a larger, longer-lasting price spread than occurred during Winter Storm Elliott.

Exhibit 2-2 : Average 5-Year (2018-2022) Monthly Day-Ahead Price and Basis at Chicago vs Dawn ($/MMBtu)[5]



Source: Argus Day-Ahead Prices

3. Natural Gas Forward Prices in Chicago vs Dawn

Since Winter Storm Uri in February 2021, the financial markets and the resulting forward curves have included a large premium for Chicago over Dawn, which has only been justified during a handful of days of cold weather in the Midwest U.S. This forward price spread became larger in 2022 and 2023, even though the historical basis between Chicago and Dawn for the winter of 2021/22 traded at a discount of $0.05/MMBtu and winter of 2022/23 traded at a premium of $0.05/MMBtu. As discussed in the previous section, the premium in 2022/23 was due to the higher prices seen at Chicago in December 2022 during Winter Storm Elliott.

Exhibit 3-1 below showcases the volatility in the forward price curves which are still responding to Winter Storm Uri, Winter Storm Elliott, and the increased price volatility

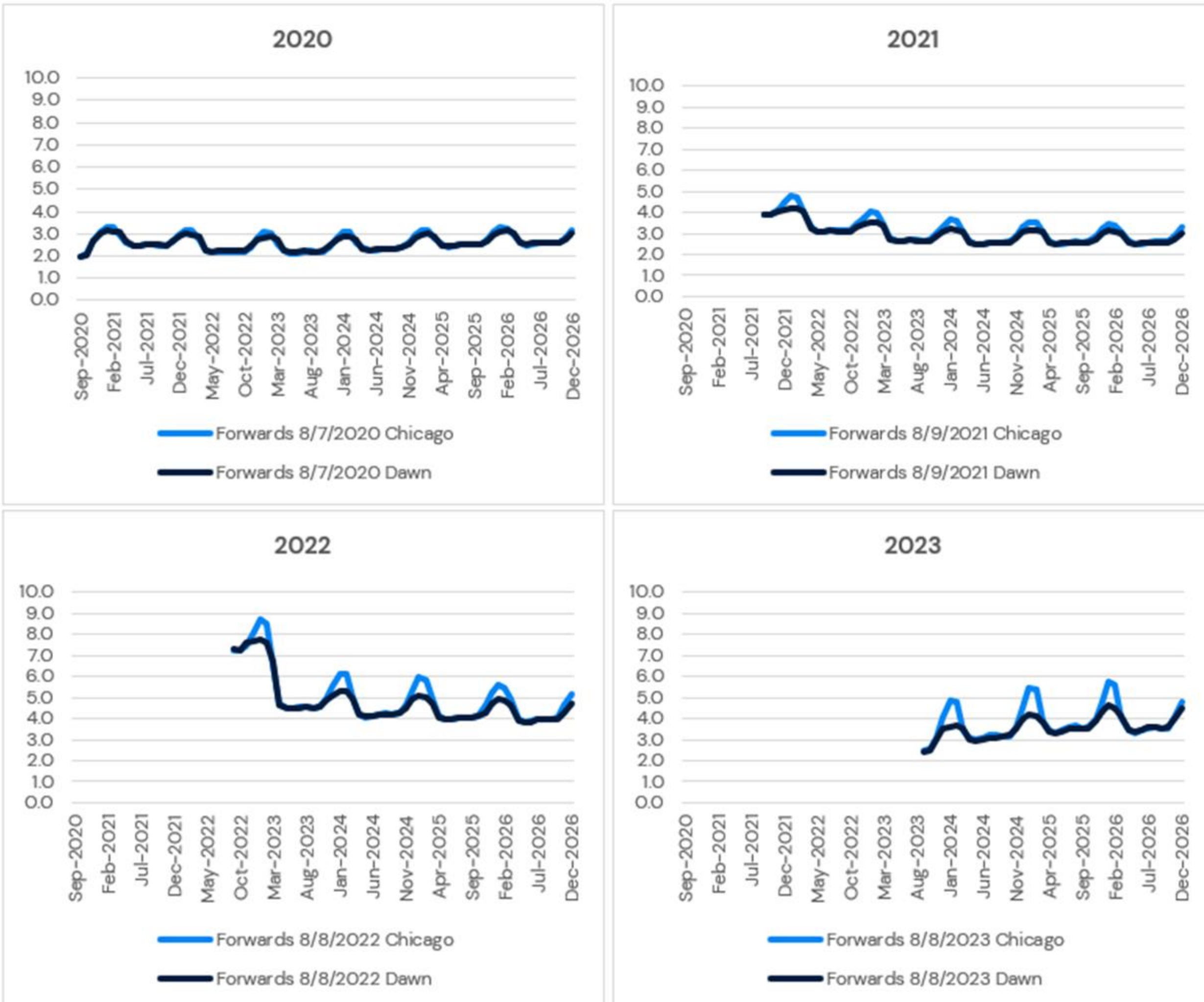
[5] The prices "without Uri 2021" exclude high prices between February 6th, 2021, to February 19th, 2021, triggered by Winter Storm Uri.

experienced across North America in 2022. The day-ahead prices are frequently much lower than the forward price as well as the bid-week price, suggesting that the buyers pay the higher prices as a hedge against price volatility and potential price increases. The bid-week price is set by transactions during the end of a given month for delivery in the following month. The most recent forward curve for the period of November 2022 to March 2023, dated August 8th, 2022, projected the price spread between Chicago and Dawn to average $0.39/MMBtu. The bid-week price spread for the same timeframe averaged $0.57/MMBtu. These forward prices were very different than the ensuing average day-ahead price spread which was a premium of just $0.03/MMBtu. ICF's Q3 2022 (released August 2022) natural gas price forecast projected the price spread to be at a discount of $0.06/MMBtu to Dawn, assuming weather normal conditions.

Previous forward curves from August 2020 to August 2022 showcase an increasing, positive price spread between Chicago and Dawn. For the months of January 2023 to August 2023, the forward curves dated August 8th, 2022, projected Chicago to be at $0.22/MMBtu premium with respect to Dawn and the bid-week price averaged at a premium of $0.27/MMBtu. The day-ahead price spread, however, averaged a $0.05/MMBtu discount. ICF's Q3 2022 base case, which was finalized about the same time as the August 8th, 2022, forward curve, projected Chicago to be at a discount of $0.10/MMBtu relative to Dawn, suggesting that the day-ahead markets are closely aligned to the fundamental view of prices rather than the forward curves.

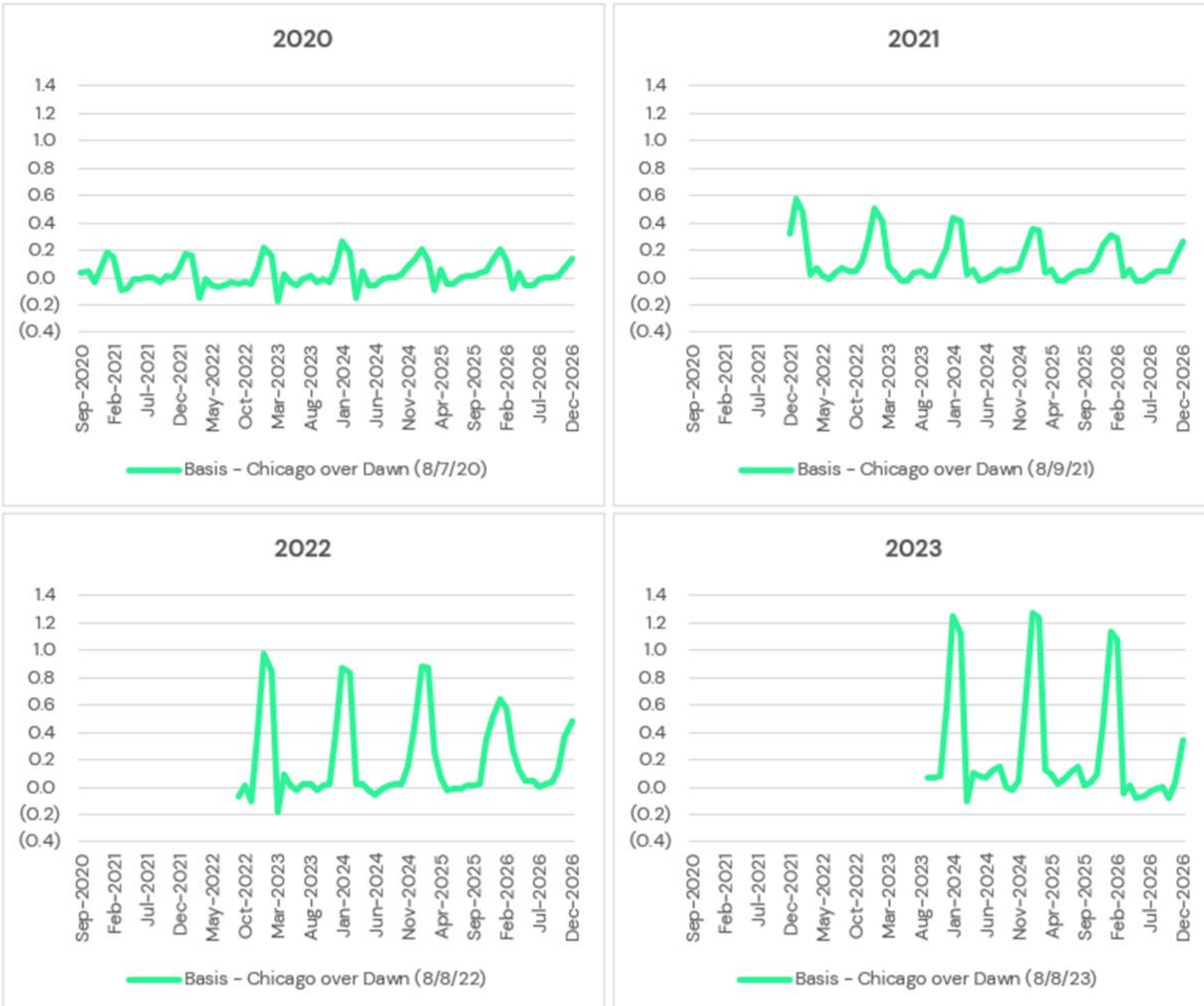
For the years of 2023 to 2026, the forward curves dated August 7th, 2020, projected an average annual premium for Chicago relative to Dawn of $0.04/MMBtu. This spread increased to $0.11/MMBtu in the August 2021 forward curves, $0.21/MMBtu in the August 2022 forward curves, and $0.24/MMBtu the August 2023 forward curves. The forward price spread has been widening on the expectation of recurring winter storms and high price volatility as seen during Winter Storm Uri.

Exhibit 3-1 : Chicago and Dawn Forward Curves in $/MMBtu (2020-2023)



Source: Argus Forward Prices

Exhibit 3-2 : Forward Price Spread Between Chicago and Dawn in $/MMBtu (2020-2023)

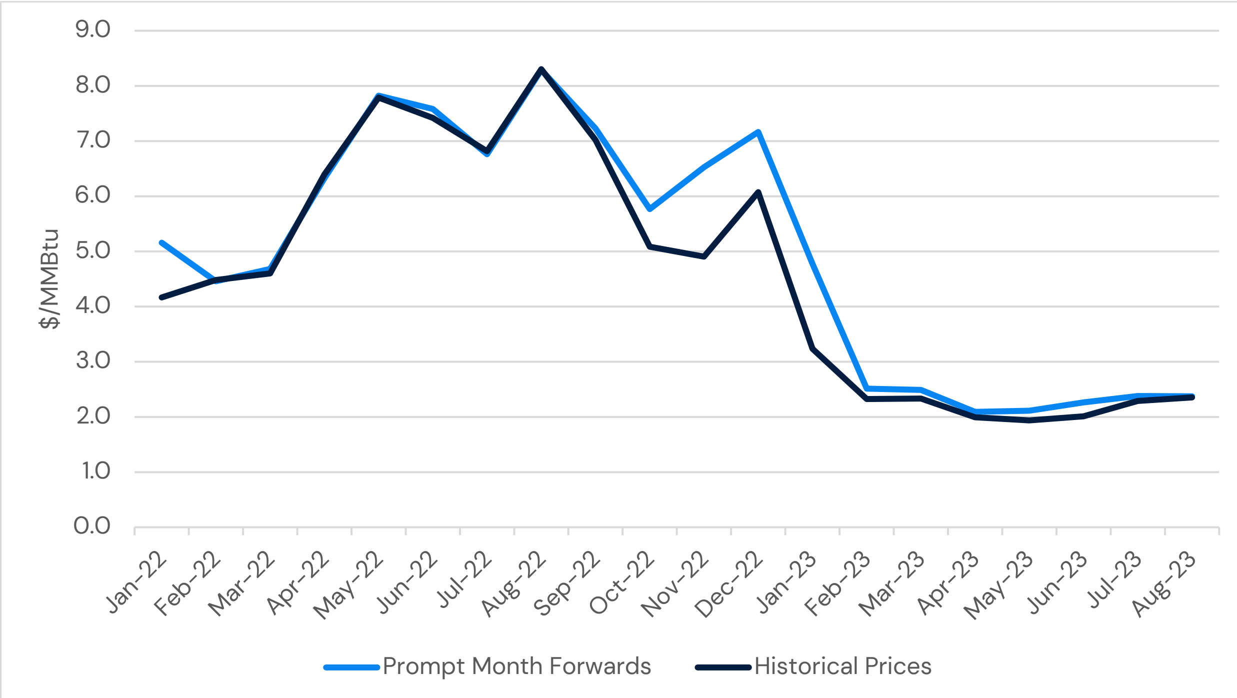


Source: Argus Forward Prices

Despite Chicago day-ahead prices averaging $0.01/MMBtu less than Dawn the past two winters, the forward curve dated August 8th, 2023, still projects a $0.59/MMBtu premium for the 2023/24 winter (Nov 2023 - Mar 2024).

Exhibit 3-3 shows the volatility of the Chicago prompt month forward prices that has been seen since the beginning of 2022. The prompt month forward prices from January 2022 (for prices in February 2022) were at $5.16/MMBtu, however the day-ahead price in February 2022 averaged $4.48/MMBtu. The exhibit emphasizes the premium built in by the forward prices for the winter period. The prompt month forward prices from December 2022 (for prices in January 2023) were at $7.16/MMBtu, however the day-ahead price in January 2023 averaged $3.23/MMBtu partly owing to the mild weather.

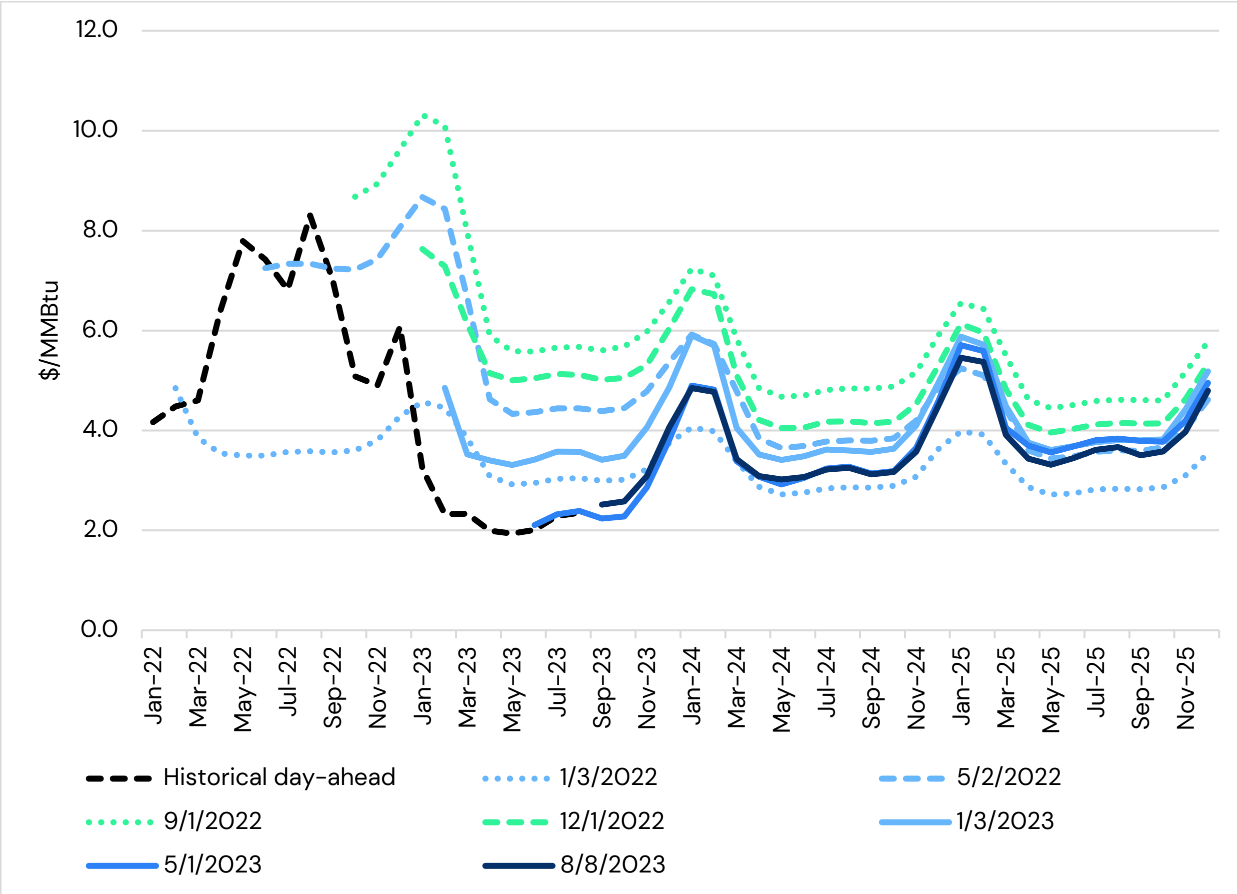
Exhibit 3-3 : Chicago Prompt Month Forward Prices from January 2022 to August 2023 ($/MMBtu)



Source: Argus Day-Ahead and Forward Prices

Exhibit 3-4 shows the change in forward price strip on different trade dates in the past two years for Chicago and compares the same to the historical day-ahead prices. On January 3rd, 2022, the forward price strip for January 2023 to August 2023, averaged $3.49/MMBtu. This increased to $7.10/MMBtu on September 1st, 2022, when day-ahead prices were high, storage levels were below the five-year average, and there was expectation that a cold winter could lead to supply shortages. However, the ensuing day-ahead prices for January 2023 to August 2023 averaged $2.31/MMBtu. The movement of the forward prices was mostly driven by price volatility and concerns about winter-weather driven supply shortages and not based on fundamental market drivers.

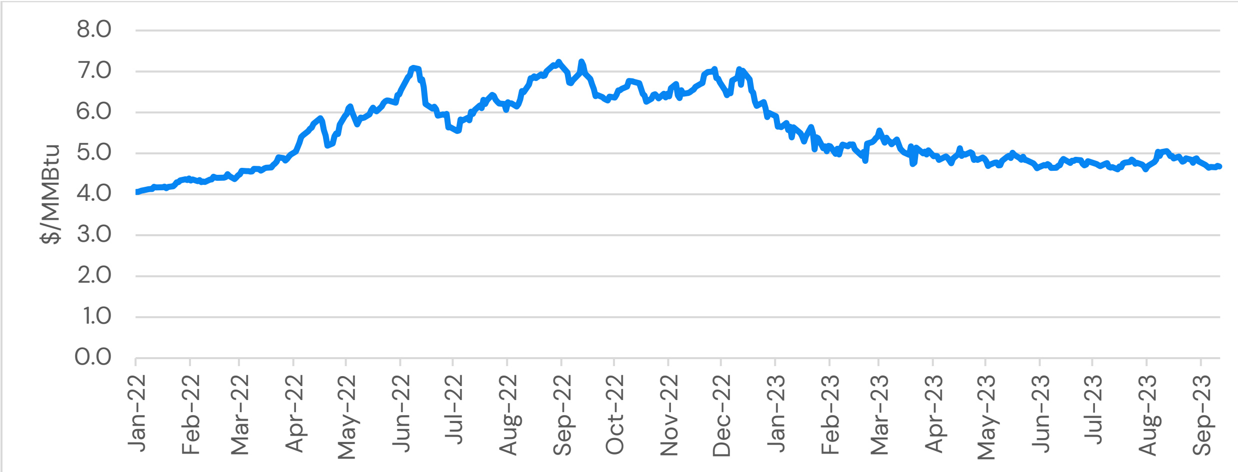
Exhibit 3-4 : Forward Pricing at Chicago Between January 2022 and August 2023 vs Day-Ahead Prices ($/MMBtu)



Source: Argus Day-Ahead and Forward Prices

Exhibit 3-5 shows the daily change in the forward prices for the month of January 2024 over the past two years. As can be seen, the January 2024 prompt month prices were lowest as per the futures strip from January 3rd, 2022, at $4.05/MMBtu and highest as per the futures strip from September 14th, 2022, at $7.24/MMBtu. This price as per the September 14th, 2022, strip was almost 50% above the current estimates of $4.68/MMBtu as of September 13th, 2023.

Exhibit 3-5 : Daily Fluctuation in January 2024 Forward Prices at Chicago



Source: Argus Forward Prices

Additionally, the forward curve is projecting a positive annual average basis at Chicago relative to Henry Hub, which is something that has only happened in one year (2021) since the shale revolution in 2015. The day-ahead prices at Chicago have traded at a discount to Henry hub over the past eight years due to the increasing demand at the U.S. Gulf Coast, adding an upward pressure on prices at Henry hub while Chicago has gained access to increasing amounts of low-cost natural gas. This suggests that the forward curve at Chicago has begun to price in historically uncommon price spikes relative to the rest of the North American market and is not fully accounting for fundamental factors such as the record North American production levels or the high storage levels. Table 1 shows the annual average basis between Chicago to Henry Hub.

Table 1 : Annual Average Basis – Chicago over Henry Hub ($/MMBtu)

	Historical	8/7/20 Forward Prices	8/9/21 Forward Prices	8/8/22 Forward Prices	8/8/23 Forward Prices
2016	(0.01)				
2017	(0.06)				
2018	(0.10)				
2019	(0.10)				
2020	(0.10)				
2021	1.31	(0.09)			
2022	(0.28)	(0.09)	0.01		
2023		(0.05)	0.00	0.08	
2024		0.00	0.04	0.07	0.05
2025		0.03	0.07	0.11	0.02
2026		0.04	0.09	0.11	0.04

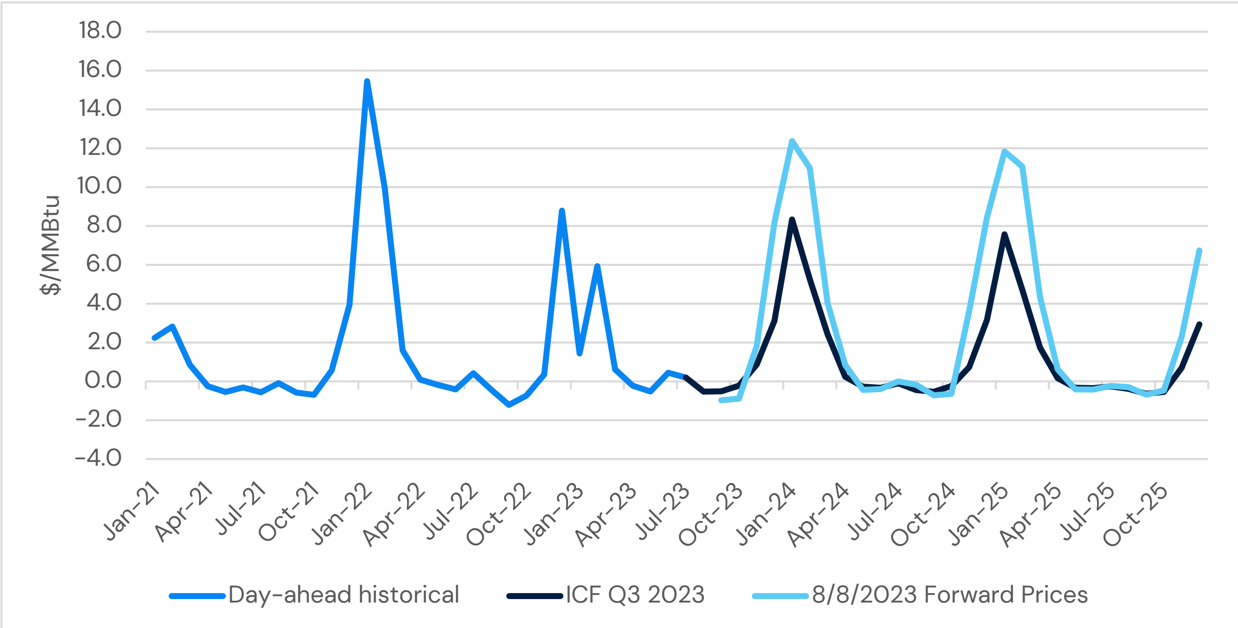
Source: Argus Day-Ahead and Forward Prices

3.1 The Influence of Market Sentiment on Natural Gas Forward Prices in Other Markets

The Chicago hub is not the only natural gas price hub that has experienced an increase in the financial premium in its forward curve over the past couple of years. Natural gas forward prices are essential for the risk management and hedging strategies of natural gas market participants. They are often influenced by near-term market developments and associated trader sentiments, which can occasionally lead to deviations from the underlying market fundamentals they represent. Recent extreme weather events and weather predictions, for example, drive the traders to determine the intrinsic value of natural gas during winter months based on the anticipated daily peak demand. The stronger the weather outlook for the upcoming winter months, the greater the expected daily peak demand for the upcoming winter, and the greater is the intrinsic value of natural gas delivered during those months. In other words, natural gas market participants will be willing to pay the futures market premium to insure against extreme price increases.

Although this is not true for all regional natural gas commodity markets, the intrinsic value of natural gas changes significantly for winter months in the Northeastern markets, particularly, Algonquin city-gates. In Exhibit 3-6 below, the forward curve shows a significant premium in the basis at Algonquin for the winter of 2023/24 compared to ICF's Q3 2023 base case. As of August 18th, 2023, working gas levels in the East region of U.S. were at 731 Bcf, 10% above the five-year average of 665 Bcf. The forward prices are based on the risk that the supply and demand balance will be tight and that high-priced LNG imports will be the marginal supply for the long periods of time during the next winter. LNG is an important fuel for New England, especially in winter, as it serves approximately 28% of supply to local gas utilities and thus prices can reach the levels of global LNG prices. ICF forecasts that basis at Algonquin and other gas hubs in the Northeast U.S. will be elevated this winter but at significantly lower levels than the forward curve. ICF projects the winter basis is expected to stay below $8.34/MMBtu. Basis at Algonquin reached the heights projected by the current forward curve in February 2015, January 2018, and January 2022.

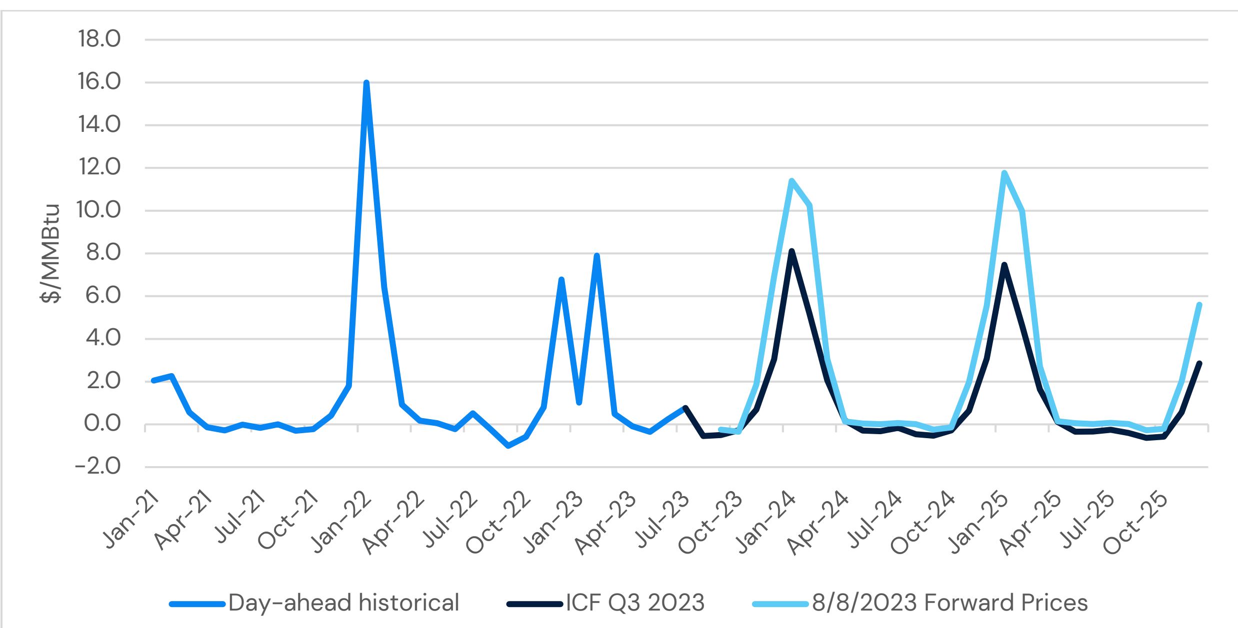
Exhibit 3-6 : Basis Between Algonquin city-gates and Henry Hub (Nominal $/MMBtu)



Source: Argus Day-Ahead and Forward Prices; ICF Q3 2023

Iroquois Zone 2, which acts as a price representative for New York also exhibits a similar trend like Algonquin. New York is also a supply constrained region and relies on pipeline deliveries to meet the peaking winter demand, hence the basis peaks during winter months. Exhibit 3-7 showcases the basis between Iroquois Zone 2 and Henry hub and the premium built in by the forward curve in the winter months, which is larger than the fundamentals forecast.

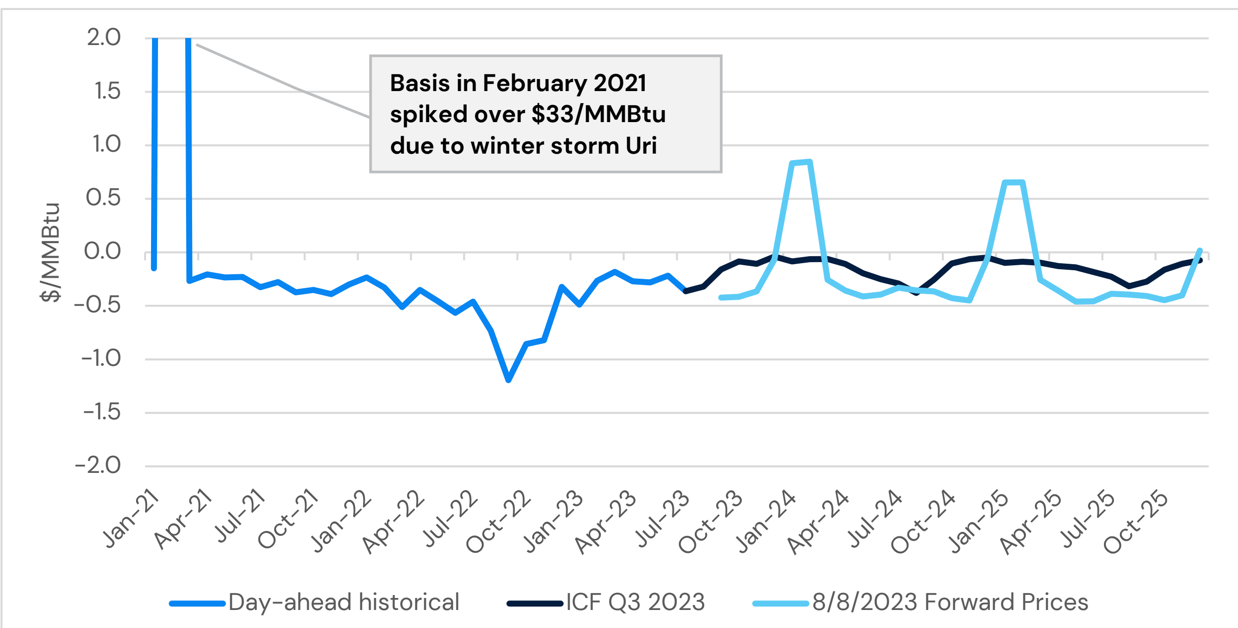
Exhibit 3-7 : Basis Between Iroquois Zone 2 and Henry Hub ($/MMBtu)



Source: Argus Day-Ahead and Forward Prices; ICF Q3 2023

Another example of markets which experience higher natural gas price forward prices as against the fundamentals view is the Panhandle Eastern Pipeline Limited (PEPL). In Exhibit 3-8 the forward curve shows a significant premium in the basis at PEPL for the winter of 2023/24 compared to ICF's Q3 2023 base case. This price hub includes gas deliveries into Panhandle Eastern Pipeline on two laterals running from Texas and Oklahoma, southwestern Kansas, upstream of the compressor station in Haven, Kansas, into Montana. ICF's fundamental analysis of the region concludes that there is likely to be modest growth in gas-fired generation as a result of coal plant and nuclear retirements but also that this region has significant access to low-cost Marcellus and Utica gas. Therefore, the area's prices are projected to be close to Henry Hub throughout the ICF Q3 2023 forecast. The forward prices are based on the risk that the Marcellus and Texas/Oklahoma supply might be rerouted to demand centers with tight balance for long periods of time during upcoming winters (Northeastern US and Ontario in case of Marcellus supplies and Texas along with rest of Mid-continent in case of gas supplies from Texas and Oklahoma). The PEPL forward curve prices for the upcoming 2023/24 winter (December 2023 to February 2024), which average $0.54/MMBtu, have not been seen in recent historical winters. The PEPL 2022/23 winter (December 2022 to February 2023) average day-ahead prices were $0.36/MMBtu.

Exhibit 3-8 : Basis Between Panhandle and Henry Hub (Nominal $/MMBtu)

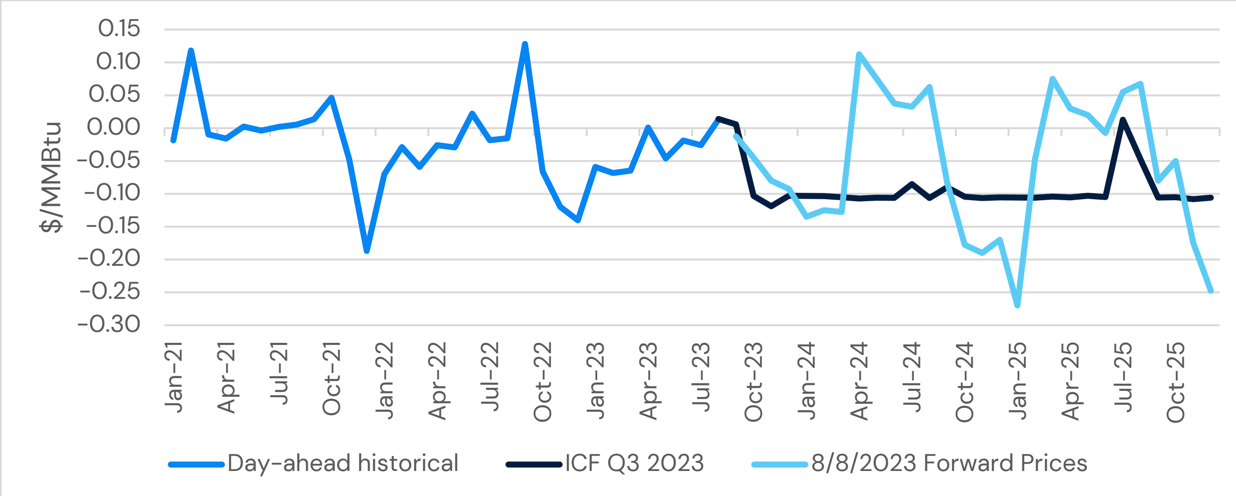


Source: Argus Day-Ahead and Forward Prices; ICF Q3 2023

Below is an example of a gas market that is not currently showing higher natural gas price forward prices compared to the day-ahead prices and ICF's fundamentals view: Michcon Citygates. In Exhibit 3-9, the forward curve shows minimum to no premium in the prices at

Michcon Citygates for the winter of 2023/24 compared to ICF's Q3 2023 base case. This gas price hub includes gas deliveries into the citygates of Michigan Consolidated Gas, which serves the Detroit and Grand Rapids areas and much of north and northeast Michigan. Michcon Citygates are geographically located at interconnects with ANR Pipeline at Willow Run and Wolk-fork, MI, Panhandle Eastern Pipeline at River Rouge, Great Lakes Gas Transmission at Belle River, Union Gas at St. Clair Pipeline and Consumers Energy at Northville. Michcon Citygates is located geographically between Chicago and Dawn and has a similar diversity in its supply from multiple production basins like the Mid-continent, Western Canada, and Marcellus & Utica. Michcon Citygates is closer than Chicago and Dawn to natural gas supplies from Marcellus/Utica via the Rover, Nexus, and Vector pipeline corridor but its price spread to Dawn behaved differently during Winter Storm Uri in February 2021 and Winter Storm Elliott in December 2022. Michcon Citygates spiked $0.10/MMBtu above Dawn in February 2021 but was $0.14/MMBtu below Dawn in December 2022 and now the forward curve dated August 8th, 2023, is projecting that price for the upcoming winter (December 2023–February 2024) will be at a discount at Michcon Citygates relative to Dawn. The market and traders are placing greater weight on the most recent winter and Winter Storm Elliott instead of February 2021 and Winter Storm Uri, even though that winter included a much larger price spike and basis blowout. This suggests that the forward curve spread between Chicago and Dawn could revert to trading closer to parity for upcoming winters if we experience a winter in which the price spread stays low during a cold-weather event. The market can adjust its expectations and trading behavior quickly.

Exhibit 3-9 : Basis between Michcon Citygates and Dawn ($/MMBtu)



Source: Argus Day-Ahead and Forward Prices; ICF Q3 2023

These examples above reinforce the fact that futures markets are influenced by market sentiments or the varying weather predictions, which is most of the times different from the actual day-ahead prices observed in the past and also captured through the fundamental drivers of gas prices in ICF's Q3 2023 base case.

4. ICF's Forecast for Chicago and Dawn

4.1 Natural Gas Consumption in Chicago and Ontario & Quebec

The price spread between Chicago and Dawn is driven largely by the downstream natural gas demand not just in Chicago or Ontario & Quebec but also by the surrounding regions.

As discussed below, ICF's Q3 2023 base case projects the natural gas demand at both Chicago and Ontario & Quebec to grow modestly, however, the corresponding price forecasts in ICF's Q3 2023 base case for Chicago or Dawn do not show the price spikes built in by the futures market.

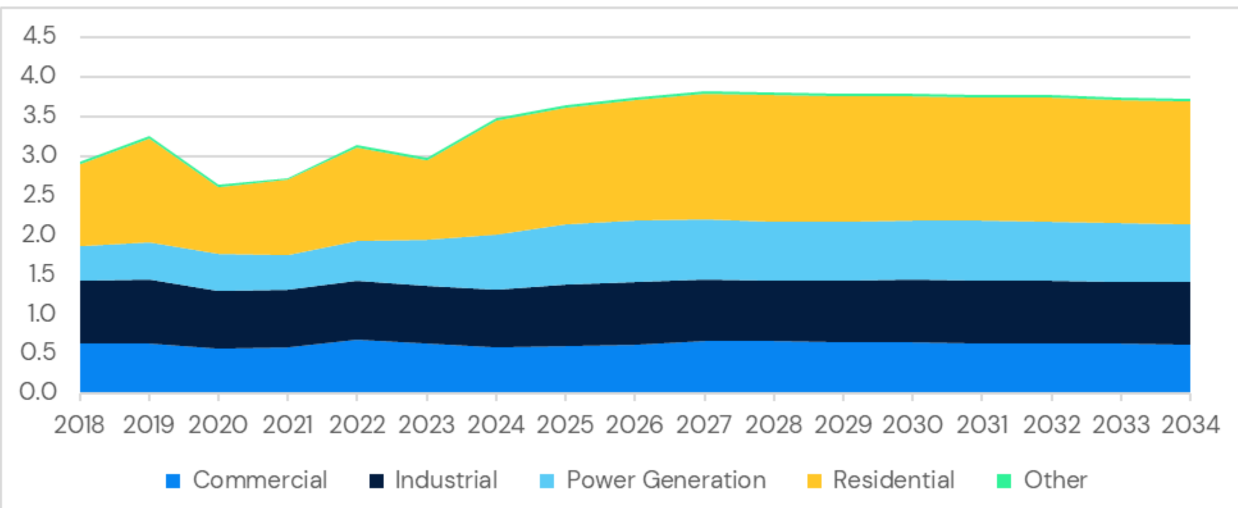
4.1.1 Natural Gas Consumption in Chicago

Natural gas consumption in Chicago is primarily driven by the residential and commercial sectors. Natural gas demand from the residential and commercial sectors in Chicago accounted for 57% of total natural gas consumption between 2018 and 2022. Monthly natural gas consumption from the residential and commercial sectors in Chicago during January 2018 to January 2022 varied from 2.5 billion cubic feet per day (Bcfd) to almost 4.1 Bcfd, primarily dependent on prevailing temperatures. Natural gas demand from the electric power sector has grown significantly over the past five years. For example, electric power sector's natural gas consumption was 13% higher in 2022 compared to 2018, with an y-o-y average growth rate of 3%. As coal power plants have retired and space-heating technologies have developed and the use of electric heat pumps has grown, natural gas consumed to generate electricity for space heating has increased along with already established direct end-use consumption for space heating.

During 2022, natural gas consumption in Chicago averaged 3.1 Bcfd, representing a 15% increase from the previous year. Compared to 2021, Chicago experienced consumption increases across all sectors, with the residential sector accounting for 38% of total natural gas consumption, higher than any other end-use sector. In January 2022, the residential and commercial sectors in Chicago combined saw a 34% increase in natural gas consumption compared to January 2021, while the electric power sector experienced a 12% increase. During the summer of 2022, which was the third warmest on record in the contiguous United States, there was a surge in demand for electricity driven by air conditioning which led to new daily records for electricity generation in July, resulting in higher natural gas consumption in the electric power sector. In December, below-normal temperatures towards the latter part of the month increased natural gas demand.

Natural gas demand from the end use sectors in 2023 in Chicago for the first half of the year was 11% lower compared to the 5-year average of 2018-2022 over the same timeframe due to mild weather.

Exhibit 4-1 : Natural Gas Consumption in Chicago (Bcfd)



Source: ICF Q3 2023

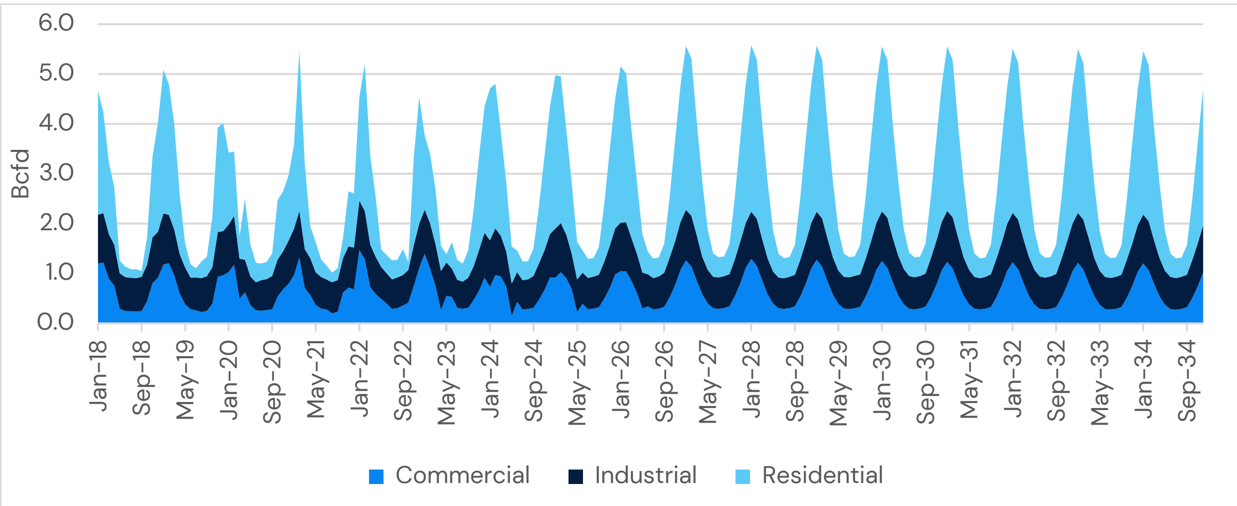
Per ICF's Q3 2023 forecast, the residential sector is forecasted to account for 41% of the total demand on average between 2023-2034. ICF projects the natural gas demand from the residential sector to grow from 1.0 Bcfd in 2023 to 1.6 Bcfd in 2027, a 58% increase. Between 2028 to 2034, the gas use in the residential sector is projected to remain flat assuming weather normal conditions.

Natural gas demand from the commercial sector is forecasted to increase 5% from 0.6 Bcfd in 2023 to 0.7 Bcfd in 2027. Between 2028 to 2034, the demand from commercial sector is projected to fall by 7% and reach 0.6 Bcfd in 2034.

The gas use from the industrial sector is projected to grow by 7% from 0.7 Bcfd in 2023 to 0.8 Bcfd in 2027. As the forecasted prices in Chicago peak in 2028, the industrial demand drops slightly and then grows back to 2027 levels by 2034.

The natural gas consumption from residential, commercial, and industrial sectors in Chicago is winter peaking as shown in Exhibit 4-2 below.

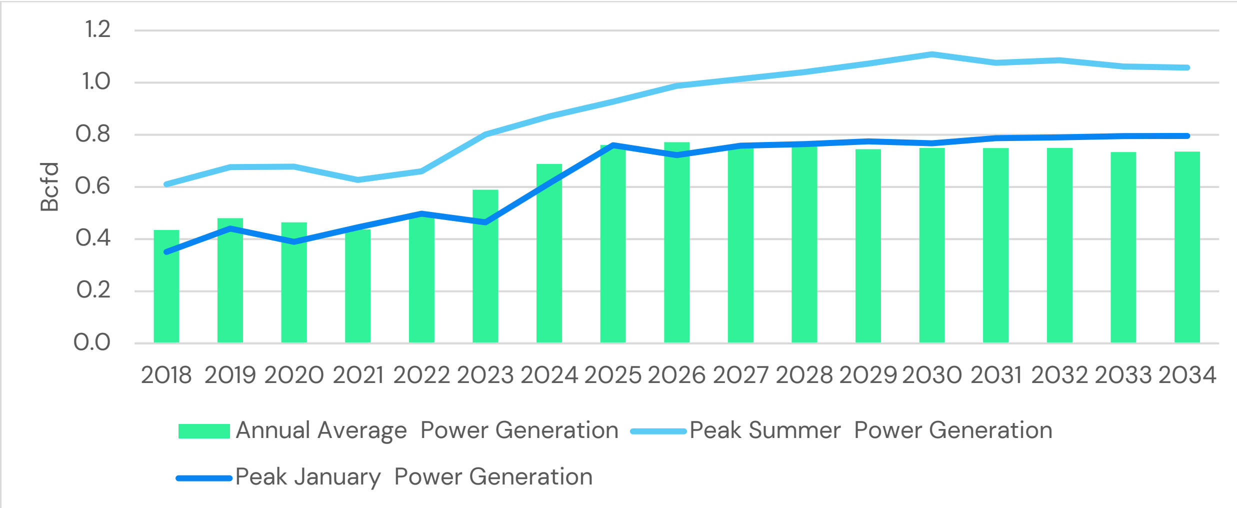
Exhibit 4-2 : Monthly Residential, Commercial, and Industrial Natural Gas Consumption (Bcfd)



Source: ICF Q3 2023

Power sector gas use peaks in the summer months (July to August) in Chicago. Demand in these months has gone as high as 0.7 Bcfd in the past 5 years (2018-2022). ICF projects a modest growth in gas-fired generation due to coal and nuclear plant retirements and electric load growth. As per ICF's Q3 2023 forecast, the power sector gas use grows from 0.6 Bcfd in 2023 to 0.8 Bcfd in 2027 on an annual average basis, showing a 29% increase. Between 2028 to 2034, the power sector demand is projected to remain flat and reach 0.7 Bcfd by 2034. The monthly power sector demand, however, is projected to reach 1.2 Bcfd in the month of July 2030. Exhibit 4-3 below shows a comparison of the annual power generation demand vs the monthly power generation demand from January and peak summer months of July and August as projected by ICF.

Exhibit 4-3 : Annual vs Monthly Power Generation Demand in Chicago (Bcfd)



Source: ICF Q3 2023

Therefore, as discussed above, ICF's Q3 2023 base case projects the RCI demand to peak in the winter months and hence, the total demand at Chicago is forecasted to increase. This does add an upward pressure on the prices at Chicago, but ICF's forecasts still do not project price increases of the same magnitude as the forward curve as there is enough supply and pipeline capacity to prevent the price spread relationship between Chicago and Dawn to change under normal weather conditions.

4.1.2 Natural Gas Consumption in Ontario & Quebec

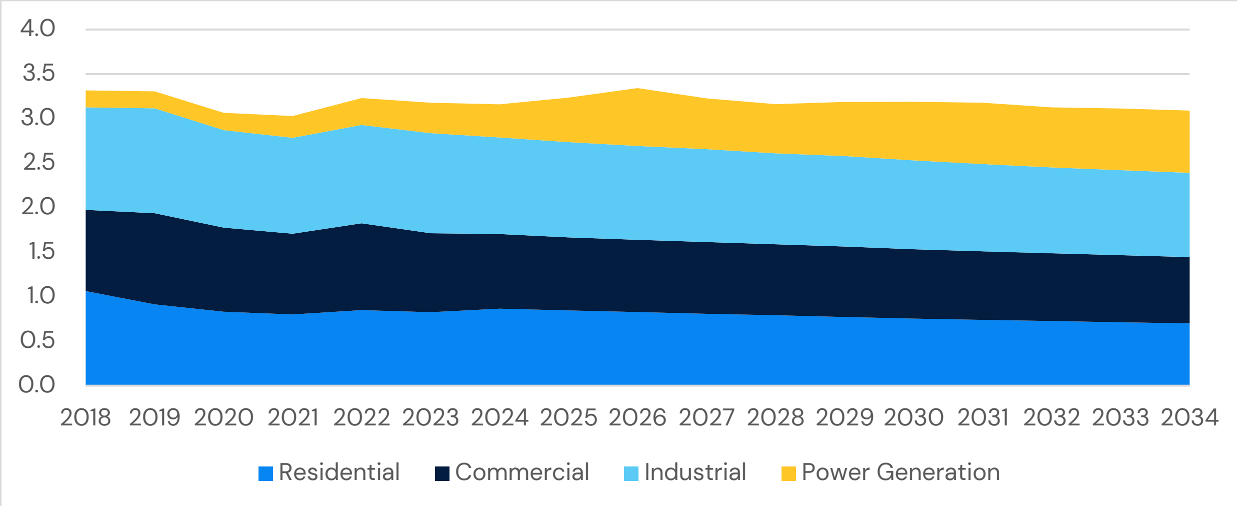
Demand in Ontario & Quebec is expected to decline slightly as decreases in the residential, commercial, and industrial (RCI) sectors are not quite offset by incremental gas-fired generation that replaces declines in nuclear generation that result from nuclear plant maintenance, refurbishment, and retirements.

Per ICF's Q3 2023 case, demand from the RCI sectors in Ontario & Quebec is expected to decline between 2023 to 2034 at an annual average rate of 1.5%. Between 2023 to 2027, the demand from the RCI sectors declines from 2.8 Bcfd to 2.7 Bcfd. After 2027, the RCI sectors witness a further decline in demand. The demand drops from 2.6 Bcfd in 2028 to 2.4 Bcfd in 2034.

The demand from the power sector, however, grows at 7% on an annual average basis between 2023 to 2034. The power demand grows from 0.3 Bcfd in 2023 to 0.6 Bcfd in 2027. After 2027, it increases further from 0.6 Bcfd in 2028 to 0.7 Bcfd in 2034.

Since there is no significant change in the natural gas use in Ontario & Quebec, ICF doesn't expect any large price changes at Dawn hub relative to other nearby price hubs.

Exhibit 4-4 : Natural Gas Demand by Sector in Ontario & Quebec (Bcfd)



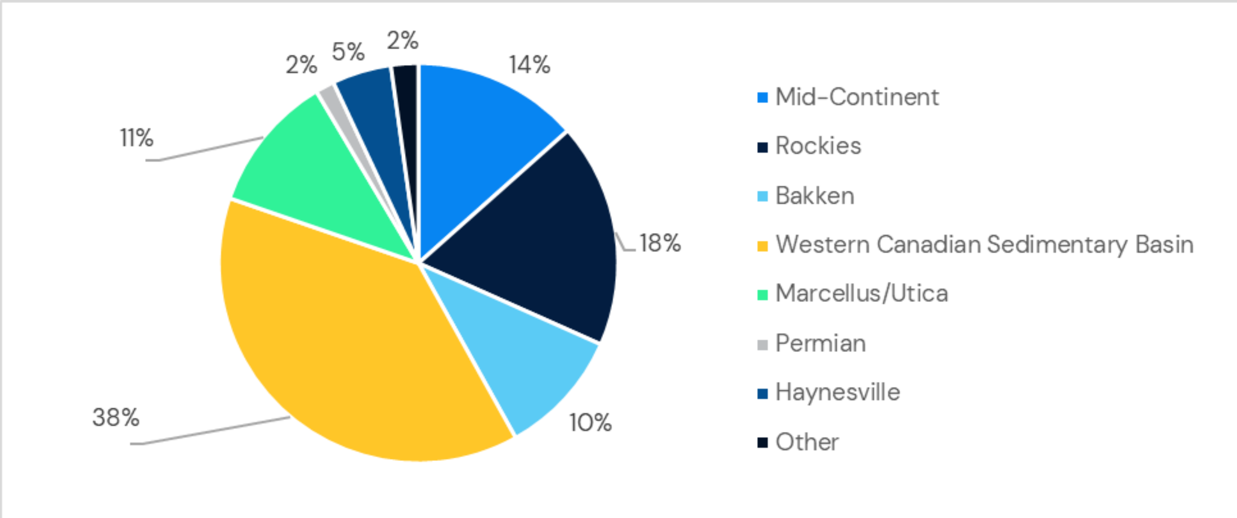
Source: ICF Q3 2023

4.2 Gas Production Outlook Around Chicago and Ontario & Quebec

4.2.1 Gas Supply Outlook at Chicago

The Rockies, Bakken, Western Canadian Sedimentary Basin, and Mid-Continent are the natural gas production regions that Chicago has direct pipeline access to. Natural gas produced from these basins is transported to Illinois via major interstate pipelines such as the Natural Gas Pipeline Company of America, Alliance Pipeline, Northern Border Pipeline, Northern Natural Gas, ANR Pipeline, Rockies Express Pipeline, and Texas Gas Transmission. Exhibit 4-5 : Chicago Supply (2023-2034 Percent Contribution by Supply Basin) shows that Chicago is centrally located and has the capability to access gas supply across these gas production hubs across North America. Between 2023 to 2034, ICF expects that over 55% of gas supply to Chicago will be sourced from Rockies and Western Canada. The Mid-Continent, Bakken, and Marcellus/Utica basins also play a pivotal role in supplying gas to Chicago, particularly during peak winter months.

Exhibit 4-5 : Chicago Supply (2023-2034 Percent Contribution by Supply Basin)



Source: ICF Q3 2023

Over the past five years, the Rockies basin has continued to be a significant player as a major natural gas supply basin. This region encompasses Colorado, Wyoming, Utah, New Mexico, and Montana. Natural gas production in the Rockies has been steady in the last half-decade, due to advancements in drilling and extraction techniques, such as hydraulic fracturing (fracking) and horizontal drilling. These innovations have enabled supply growth in Niobrara region that offsets decline in San Juan and Western Rockies plays. ICF expects gas production from the Rockies is expected to grow by 2% on average between 2023 and 2027. In the long run, production in the Rockies is expected to decline by 0.2% on average between 2027 and 2034.

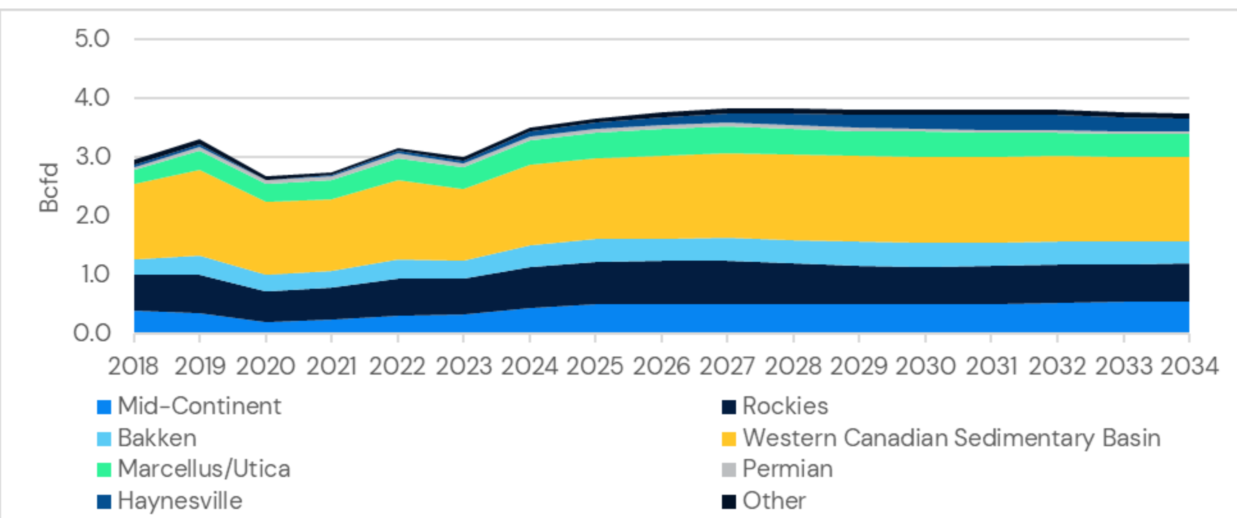
Bakken Gas Production, centered primarily in North Dakota, has emerged as a significant contributor to natural gas supply to Chicago. While renowned for its abundant shale oil resources, the Bakken Formation also holds substantial reserves of associated natural gas, and the basin is becoming increasingly gassier as more and more shale oil resources are produced. In other words, the proportion of associated natural gas is increasing from the oil & gas mixture extracted from this basin. Therefore, ICF expects that natural gas production at Bakken to steadily grow by 1% on average between 2023 and 2027. In the long run, Bakken production is expected to decline by 0.3% on average between 2027 and 2034.

Mid-Continent Gas Production, located in South Central US, is a major supply basin that contains several small fields that produce Oil & Gas. The basin spans across Oklahoma, the Texas Panhandle, Arkansas, and Kansas. The major gas plays within this supply basin include Fayetteville, Granite Wash, Mississippian and SCOOP/STACK. Among these gas plays, SCOOP/STACK is considered to be the most economical with comparatively lower gas production costs by acreage and with higher potential to grow over the next decade. SCOOP is an acronym for South Central Oklahoma Oil Province, and is spread over Carter, Garvin, Grady, McClain, Stephens, Jefferson, Love, Caddo, and Murray counties in Oklahoma. STACK stands for Sooner Trend in Anadarko basin, Canadian and Kingfisher (counties). Most of the play is located across Canadian and Kingfisher counties, together with Blaine, Dewey, Major, and Garfield counties. The SCOOP refers to geological location while the STACK refers to geographical location of the basin. ICF expects gas production from the Mid-Continent to grow by 4.3% on average between 2023 and 2027. In the long run, production in the Mid-Continent is expected to grow by 1.6% on average between 2027 and 2034.

Across the border in Western Canada, gas production is anchored by the Western Canadian Sedimentary Basin, encompassing Alberta, Saskatchewan, and parts of British Columbia and Manitoba. This basin is known for its vast oil sands, conventional oil, and natural gas reserves. ICF expects that gas production in Western Canadian Sedimentary Basin to steadily grow by 5% on average between 2023 and 2027. Longer-term production growth of this basin is tied to development of the Montney basin and high oil price environment. ICF expects natural gas production out of Western Canada to grow by 1.4% on average between 2027 and 2034.

Exhibit 4-6 below shows natural gas deliveries into Chicago by supply basin. ICF expects that gas deliveries into Chicago from Mid-Continent, Western Canada, and Haynesville to increase between 2023 and 2034. These three major supply centers allow the gas consumers at Chicago to diversify their portfolio, making them not reliant on a single source of supply. Furthermore, it should be noted that the major natural gas pipelines responsible for transporting natural gas to Chicago also transport gas to surrounding major demand centers like Northeastern U.S., New England, and Ontario & Quebec. However, due to the geographic vicinity of these supply basins to Chicago, and the path of natural gas pipelines, this region has a competitive advantage. As a result, the fundamentals forecast does not build a significant premium at Chicago Citygates.

Exhibit 4-6 : Net Gas Flows into Chicago by Supply Basin (Bcfd)



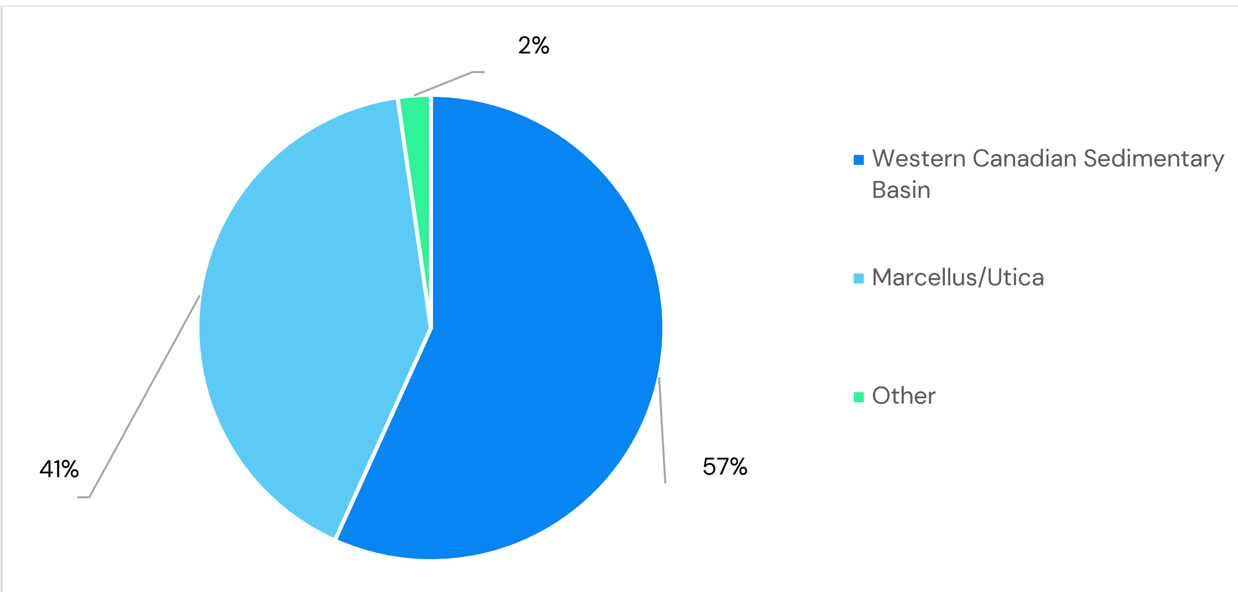
Source: ICF Q3 2023

4.2.2 Gas Supply Outlook at Ontario & Quebec

The Western Canadian Sedimentary Basin and Marcellus/Utica basins are the two major natural gas production regions that Ontario & Quebec have direct pipeline access to. Natural gas produced in the Western Canadian Sedimentary Basin is transported to Ontario & Quebec via major inter-provincial pipelines like the TC Energy Mainline and the Great Lakes Pipeline. Natural gas produced in Marcellus/Utica basins primarily is transported to Ontario via the Rover, Nexus, Vector, National Fuel, and Empire pipelines. ANR pipeline and Panhandle eastern also have interconnects with the Enbridge Gas pipeline network and TC Energy pipelines in Ontario. They bring gas supply into Ontario from the Midcontinent and Rockies.

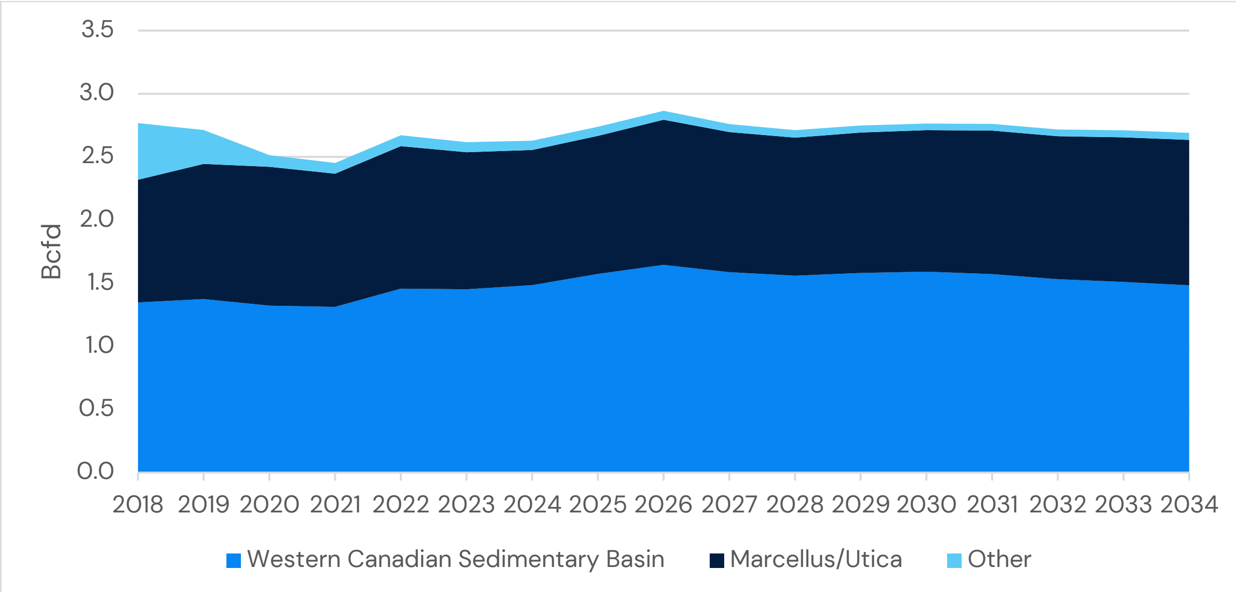
Exhibit 4-7 and Exhibit 4-8 show that Ontario & Quebec are dependent on natural gas originating from the Marcellus/Utica basins and Western Canada. Geographically, Ontario & Quebec do not have a significant amount of indigenous natural gas production and therefore are reliant on pipelines to bring gas from the U.S. and Western Canada.

Exhibit 4-7 : Ontario & Quebec Supply (2023-2034 Percent Contribution by Supply Basin)



Source: ICF Q3 2023

Exhibit 4-8 : Net Gas Flows into Ontario & Quebec by Supply Basin (Bcfd)



Source: ICF Q3 2023

4.3 Gas Pipeline Infrastructure Into and Around Chicago

Gas pipeline infrastructure in North Illinois and Chicago plays a critical role in supplying natural gas to end users across the demand region. Chicago is strategically positioned due to its proximity to multiple interstate gas pipelines in North Central US. Illinois is a key crossroads point for inter-state pipelines like the Natural Gas Pipeline of America (NGPL), Northern Natural Gas, Northern Border Pipeline, ANR Pipeline, Alliance Pipeline, Texas Gas Transmission, Rockies Express, Panhandle Eastern, and Midwestern Gas Transmission. These pipelines together form a network of gas pipeline infrastructure that form a grid around Chicago enabling it to access gas supply for major supply hubs like the Marcellus/Utica, Rockies, Bakken, Western Canadian Sedimentary Basin, and Mid-Continent. Table 2 below gives a summary of major gas pipelines around Chicago, their pipeline route, and where these pipelines source their natural gas.

Table 2 : Interstate Pipelines that Supply Natural Gas to Chicago

Gas Pipeline Name	Pipeline Route	Pipeline Capacity into North Illinois/Chicago (MMcfd)	Gas Supply Source Description
Alliance Pipeline	From Alliance Border Crossing in North Dakota to North Illinois/Chicago	1,750	Western Canadian Sedimentary Basin and Bakken
ANR Pipeline	From Kansas to North Illinois/Chicago	700	Mid-Continent
ANR Pipeline	From Southern Ohio to Indiana	950	Marcellus and Utica
Midwestern Gas Transmission	From Indiana to North Illinois/Chicago	650	Gas is sourced from pipeline interconnects within Indiana with Texas Gas Transmission, Rockies Express, ANR Pipeline and Panhandle Eastern
Natural Gas Pipeline of America (NGPL)	From South Illinois to North Illinois/Chicago	1,894	Permian and Haynesville
Natural Gas Pipeline of America (NGPL)	From Iowa to North Illinois/Chicago	1,775	Rockies
Northern Border Pipeline	From Iowa to North Illinois/Chicago	1,000	Western Canadian Sedimentary Basin and Bakken
Northern Natural Gas	From Iowa to North Illinois/Chicago	575	Rockies
Texas Gas Transmission	From Southern Ohio to Indiana	425	Marcellus and Utica
Panhandle Eastern	From Southern Ohio to Indiana	150	Marcellus and Utica
Rockies Express Pipeline	From Southern Ohio to Indiana	2,000	Marcellus and Utica
Vector Pipeline	From Dawn to Chicago	1,300	Marcellus and Utica

4.4 Gas Pipeline Infrastructure Into and Around Ontario & Quebec

Gas pipeline infrastructure into and around Ontario & Quebec brings gas from the Western Canadian Sedimentary Basin as well as the Marcellus/Utica basins into Dawn. There is a small amount of local natural gas production at Dawn, Ontario but the region relies primarily on natural gas imports from nearby supply sources along with the storage facilities within the region. Table 3 below lists down the pipelines that supply natural gas into Ontario & Quebec. These pipeline deliveries into Ontario & Quebec along with the storage facilities at Dawn help keep the prices at Dawn below other price hubs in the region, especially during high demand periods, preventing them from spiking during winter months when there is need for additional heating demand.

Table 3 : Interstate Pipelines that supply natural gas to Ontario & Quebec

Gas Pipeline Name	Pipeline Route	Pipeline Capacity into Ontario & Quebec (MMcfd)	Gas Supply Source Description
ANR Pipeline Co	From the Midcontinent and Gulf Coast through Michigan to Dawn	256	Midcontinent, Gulf Coast, Marcellus & Utica
Bluewater Pipeline Co	From Michigan to Dawn	250	Underground gas storage
Great Lakes Gas Transmission	From the TC Energy Mainline at the Manitoba/Minnesota border through Michigan to Dawn	2,026	Marcellus & Utica
Iroquois Gas Transmission System	Bidirectional flows between Ontario and New York	2,050	Western Canadian Sedimentary Basin and Marcellus & Utica
Panhandle Eastern	From Texas and Oklahoma through Michigan to Dawn	100	Midcontinent and Permian
TC Energy Mainline	From Alberta to Ontario & Quebec	3,500	Western Canadian Sedimentary Basin
Enbridge Gas	From Parkway to Dawn	3,000	Western Canadian Sedimentary Basin and Marcellus & Utica
Vector Pipeline	From Illinois through Michigan to Dawn	1,290	Midcontinent, Gulf Coast, Marcellus and Utica
St. Clair/DTE Michcon	From Michigan to Dawn	225	Underground gas storage and Marcellus & Utica

4.5 Storage Capacity at Ontario & Quebec and Illinois

Underground storage is an important component of natural gas pipelines and becomes critical in regions with large winter heating requirements. Ontario & Quebec and Illinois both have access to strategically located natural gas storage facilities, which play a pivotal role in ensuring stable and reliable natural gas supply particularly during the challenging peak winter months. According to EIA's underground natural gas storage data by state, as of July 2023, Illinois state has a total storage capacity of 1,018 Bcf across 28 underground storage fields. Dawn, on the other hand, has a total storage capacity of 290.8 Bcf across 36 underground storage fields. Ontario also has access to an additional 1,076 Bcf of underground storage capacity at Michigan through interstate natural gas pipelines that run from Michigan into Ontario. On the demand side, Chicago has an average 5-months winter demand of 4.1 Bcfd whereas Ontario has an average 5-month winter demand of 0.7 Bcfd.

With greater direct access to natural gas storage, Dawn is better positioned to manage variation on seasonal load patterns, balancing winter daily load and rapidly cycling volatile gas loads as compared to Chicago. Hence, during the 2021 winter storm Uri, day-ahead prices at Chicago saw a much greater premium as compared to Dawn.

4.6 Outlook for the Natural Gas Price Basis between Chicago and Dawn

Per ICF's Q3 2023 natural gas price forecast, the annual average prices at Chicago are projected to range between \$2.44/MMBtu to \$3.92/MMBtu (in real 2022\$) between 2023 to

2034, while the monthly prices go as high as $4.55/MMBtu (in February 2028). Annual average prices at Dawn are projected to range between $2.49/MMBtu to $4.00/MMBtu (in real 2022$) between 2023 to 2034, while the monthly prices go as high as $4.57/MMBtu (in February 2028).

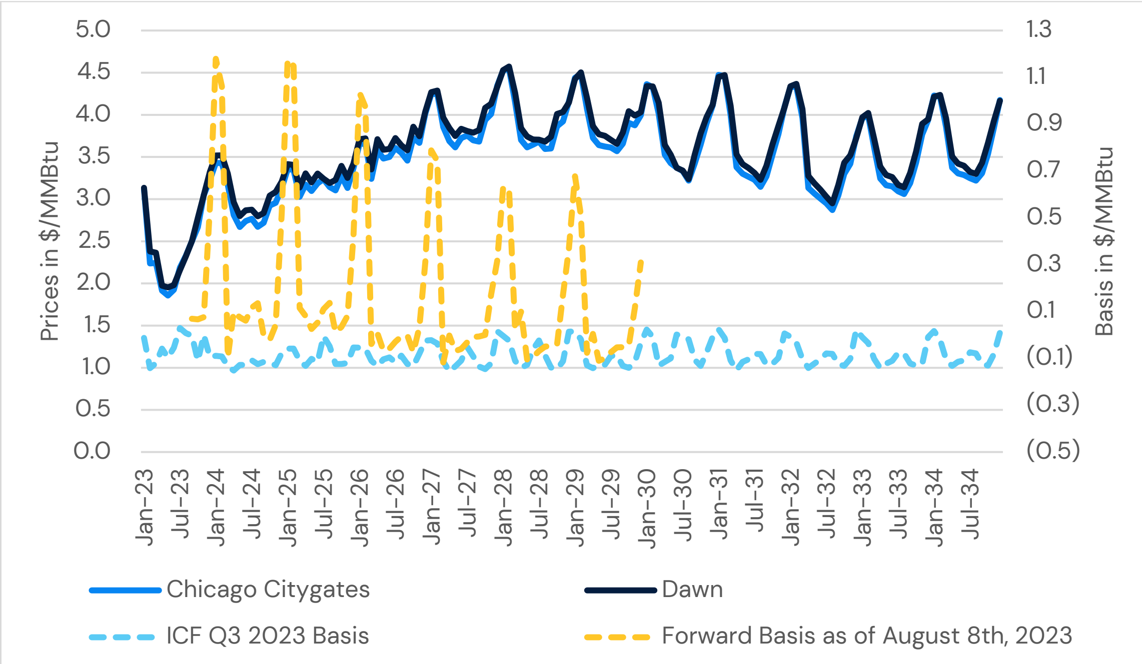
Natural gas prices at Chicago in 2023 are projected to average $2.55/MMBtu, which is a huge drop from the high prices seen in 2021 and 2022. Lower prices in 2023 are driven mostly by continued supply growth, lower than expected domestic demand and storage inventories being over 5-year average levels.

Prices at Chicago are projected to trade at an average discount of $0.10/MMBtu to Dawn for the upcoming winter (December 2023 to February 2024). Also, for the next two winters (December 2024 to February 2025 and December 2025 to February 2026), ICF continues to project Chicago to trade at a discount of $0.07/MMBtu on average. The forward curve as of August 8th, 2023, has, however, built in a premium on the Chicago basis with respect to Dawn. Exhibit 4-9 compares ICF's view on the basis with the forward prices. The basis at Chicago over Dawn as per the forward prices is close to $0.96/MMBtu on average for the next two winters, with basis going over $1/MMBtu in the months of January and February.

ICF's Q3 2023 forecast projects the monthly price at Chicago will trade between a $0.02/MMBtu premium and a $0.16/MMBtu discount to Dawn between August 2023 to December 2034. The basis is mostly negative with Chicago trading at a discount to Dawn. It is only during peak winter months beginning during the winter of 2028/29 that the basis becomes slightly positive as increased heating demand in Chicago leads to higher pricing. This is still much lower than the futures market projections for the winter months. The annual average basis between 2024 to 2034 is projected by ICF to be a discount of $0.09/MMBtu.

ICF's Q3 2023 forecast of a Chicago discount relative to Dawn is well supported by the market fundamentals and the historical day-ahead price trends. While ICF projects a small growth in demand at Chicago and a small decline in demand at Dawn, the changes on their own are not enough to change the price relationship between Chicago and Dawn in the near-term or to the degree suggested by the forward curve. On the supply side, Chicago is well positioned to access natural gas from multiple regions, which limits price spikes at Chicago under normal weather conditions and ensures they do not last for extended periods of time when they do happen. The day-ahead prices at Chicago can trade at a premium to Dawn, as they did in July and August 2023 (a $0.05/MMBtu premium) due to increased power sector demand amid hotter than normal weather across the US mid-continent region. However, the average prices, as shown by the 2023 year-to-date (January to August 2023) day-ahead prices, still show Chicago trading at a discount of $0.05/MMBtu to Dawn, which is in-line with ICF's fundamental view on the price basis.

Exhibit 4-9 : ICF's Fundamental Forecast vs Forward Prices – Chicago and Dawn (2022$/MMBtu)



Source: Argus Forward Prices; ICF Q3 2023

5. Conclusion

Since early 2021, the Chicago and Dawn forward curves and bid-week prices have valued natural gas futures in the Chicago market at a premium relative to the forward curves and bid-week prices at Dawn. However, unlike the Dawn market, the futures market prices at Chicago generally have been out of sync with the day-ahead market prices. For example, the day-ahead price averaged $3.24/MMBtu for Chicago and $3.25/MMBtu for Dawn in January 2023, while the bid-week price that traded in December 2022 for January 2023 was $6.04/MMBtu at Chicago and $4.72/MMBtu at Dawn.

ICF's assessment of natural gas markets in and around Chicago and Dawn documented in this report indicates that the divergence of the futures prices from the day-ahead price reflects a risk premium that is currently much greater in the Chicago market than in the Dawn market.

The current risk premium observed in the Chicago futures prices reflects recent experience by the market participants in the Chicago market, including major and unexpected, albeit short term spikes in prices resulting in large financial losses by many of the participants in this market.

During the same period, prices at Dawn did not experience the same extreme price spikes witnessed at Chicago. Prices at Dawn are not immune to these types of price spikes; the day-ahead prices at Dawn reached $44.42/MMBtu in March 2014 due to extreme cold weather in the first three months of 2014. However, Dawn has not seen any major price spikes since the pipeline projects on the NEXUS, Rover, and Vector pipelines were completed in 2018 and the introduction of the TC Energy Dawn Long-Term Fixed Price contracts. As a result, the risk premium in the futures market at Dawn has been much lower than in the Chicago market.

Despite the risk premium built into recent futures market pricing in Chicago, the day-ahead natural gas prices at Chicago trade at a discount to Dawn most of the time and only peak during extreme cold-weather events in which the demand spikes are seen upstream of Chicago and not at Dawn.

The risk premiums in the futures markets reflect expectations of market uncertainty driven by changes in weather, price volatility, and other market events such as production freeze-offs and pipeline force majeures. These events are challenging to project and to assess. As a result, the market tends to assess the impact of these events based on recent observed history, and the market assessment of the impacts of these events will change over time as different events impact gas markets in different ways. The market perception of risk, and the risk premium associated with holding natural gas futures is likely to be significantly different in the long term than it is in the short term.

ICF currently forecasts modest changes in the demand over the next ten years at Chicago and Dawn. However, we have not seen and are not forecasting any changes in the market fundamentals at either location sufficient to justify the change in the forward curve at Chicago seen since 2021. Also, with Chicago positioned between the Western Canada Sedimentary Basin, Mid-continent, Bakken and Marcellus/Utica production regions, there is, on average, sufficient supply to keep prices near or below Dawn, as seen in the day-ahead prices.

ICF's fundamentals-based forecasts largely have been consistent with the day-ahead market. ICF, in its Q3 2023 base case projections, expects demand at both Chicago and Dawn to remain stable over the long term. As observed in other markets, ICF expects the risk premium in the Chicago and Dawn futures prices to move toward the market fundamental, resulting in a declining premium between Chicago and Dawn. as evidenced by shifts seen in the forward curve at Michcon.

While the timing of any realignment between day-ahead and futures prices will depend on actual market behavior and cannot be projected with any degree of certainty, recent changes to the forward curve at Michcon suggest that the forward pricing at Chicago could shift closer to day-ahead pricing after just one winter of day-ahead pricing trading at a discount, similar to the shift in Michcon futures prices after the Michcon day-ahead prices did not rise above Dawn during Winter Storm Elliott in December 2022.

In addition, ICF expects the supply diversity provided by the ability to source gas for the Ontario market through Chicago to remain valuable. Recent trading at the PEPL hub shows that other potential supply points can also start trading at premiums to Dawn, suggesting the continuing value of supply portfolio diversity.

Enbridge Gas contracts for capacity on the Vector pipeline, which provides it with access to Chicago natural gas supply. The index of customers data for key pipelines in the Chicago to Dawn corridor indicates that these pipelines are fully contracted and that customers are retaining and renewing the capacity contracts. For Vector, the latest index of customers data from Q3 2023 indicates that the pipeline is fully contracted by BP Canada Energy Marketing Corp, Enbridge Gas Distribution Inc/Union Gas Limited, and the Rover Pipeline LLC. Hence, Enbridge Gas likely would be unable to re-contract at existing rates for capacity on Vector or on other pipelines between Chicago and Dawn if the existing capacity on Vector is allowed to expire.

While the link between the market fundamentals and the financial markets has changed at Chicago since 2021, it is most likely to revert toward the supply and demand fundamentals in the long term. In the meantime, other Enbridge Gas supply hubs could experience disruptions or price volatility that lead to increased forward premiums, making Chicago prices more attractive even if the risk premium built into the Chicago futures markets fails to subside or subsides more slowly than expected.

Given the lack of incremental pipeline capacity, any change in pipeline capacity holdings in these markets will have long-term implications, and decisions regarding pipeline capacity should reflect a long-term perspective on costs and benefits. Hence, ICF recommends that Enbridge Gas base their pipeline re-contracting decisions on the long-term market fundamentals as well as the supply diversity and reliability benefits associated with access to an additional market center, rather than the near-term futures market trends.

In ICF's opinion, the long-term benefits to Enbridge Gas of continuing to hold its capacity and supply agreements on Vector likely will exceed any short-term costs that may be incurred due to short-term forward price trends that have diverged from the market fundamentals.

Vector Renewal
2024-2027 Transportation Analysis

Route (A)	Point of Supply (B)	Basis Differential $US/mmBtu (C)	Supply Cost $US/mmBtu (D) = Nymex + C	Unitized Demand Charge $US/mmBtu (E)	Commodity Charge $US/mmBtu (F)	Fuel Charge $US/mmBtu (G)	100% LF Transportation Inclusive of Fuel $US/mmBtu (I) = E + F + G	Landed Cost $US/mmBtu (J) = D + I	Landed Cost $Cdn/GJ (K)	Point of Delivery (L)	Comments
Dawn	Dawn	0.2112	3.9969				0.0000	$4.00	**$5.25**	Dawn	
TC: Great Lakes to Dawn	Empress	-0.5015	3.2842	0.61	0.01	0.1333	0.7516	$4.04	**$5.30**	Dawn	
TC: Niagara to Dawn	Niagara	-0.0445	3.7412	0.17	0.00	0.0175	0.1936	$3.93	**$5.17**	Dawn	
MichCon: MichCon to Dawn	SE Michigan	0.1115	3.8973	0.15	0.00	0.0490	0.2005	$4.10	**$5.38**	Dawn	
Vector: Chicago to Dawn	Chicago	0.1071	3.8928	0.16	0.00	0.0183	0.1798	$4.07	**$5.35**	Dawn	
Panhandle: Panhandle FZ to Dawn	Panhandle Field Zone	-0.0629	3.7228	0.51	0.04	0.1165	0.6688	$4.39	**$5.77**	Dawn	
NEXUS-Clar2Dawn	Dominion South Point	-0.5000	3.2857	1.17	0.00	0.0913	1.2633	$4.55	**$5.97**	Dawn	
Rover to Dawn	Dominion South Point	-0.5000	3.2857	0.98	0.05	0.0200	1.0495	$4.34	**$5.69**	Dawn	

Supply Assumptions used in Developing Transportation Contracting Analysis:

Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2024 - Oct 2025	Nov 2025 - Oct 2026	Nov 2026 - Oct 2027	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
Dawn	Dawn	$ 3.54	$ 3.99	$ 4.46	**$ 4.00**	
TC: Dawn LTFP	Empress	$ 2.88	$ 3.30	$ 3.67	**$ 3.28**	3.79%
TC: Great Lakes to Dawn	Empress	$ 2.88	$ 3.30	$ 3.67	**$ 3.28**	4.06%
TC: Niagara to Dawn	Niagara	$ 3.33	$ 3.71	$ 4.18	**$ 3.74**	0.47%
MichCon: MichCon to Dawn	SE Michigan	$ 3.45	$ 3.88	$ 4.36	**$ 3.90**	1.26%
Vector: Chicago to Dawn	Chicago	$ 3.44	$ 3.88	$ 4.35	**$ 3.89**	0.47%
Panhandle: Panhandle FZ to Dawn	Panhandle Field Zone	$ 3.30	$ 3.71	$ 4.16	**$ 3.72**	3.13%
NEXUS-Clar2Dawn	Dominion South Point	$ 2.95	$ 3.23	$ 3.68	**$ 3.29**	2.78%
Rover to Dawn	Dominion South Point	$ 2.95	$ 3.23	$ 3.68	**$ 3.29**	0.61%
Panhandle: Panhandle FZ to Ojibway	Panhandle Field Zone	$ 3.30	$ 3.71	$ 4.16	**$ 3.72**	2.55%

Sources for Assumptions:

Gas Supply Prices (Col D): ICF Q3 2023

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 = $1.386 CDN From Bank of Canada Closing Rate October 27, 2023

Energy Conversions (Col K) 1 dth = 1 mmBtu = 1.055056

$1.31

EGI's Analysis Completed: Oct-23

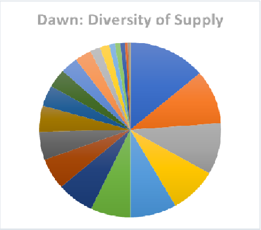
Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

Enbridge Gas Inc.

Supplier Diversity by Basin

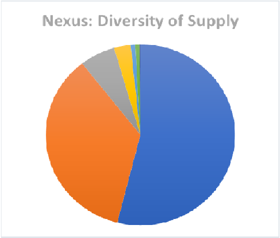
Dawn

Supply Provided	Number of Suppliers
0-2 PJ	10
2-5 PJ	5
5+ PJ	11



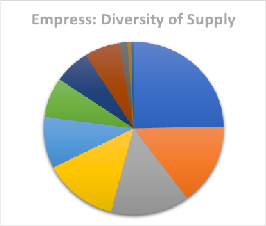
NEXUS

Supply Provided	Number of Suppliers
0-2 PJ	3
2-5 PJ	1
5+ PJ	3



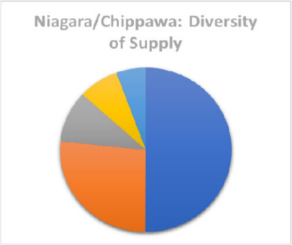
Empress

Supply Provided	Number of Suppliers
0-2 PJ	3
2-5 PJ	0
5+ PJ	8



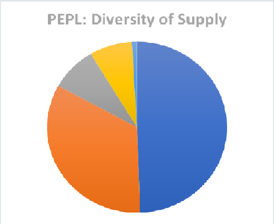
Niagara/ Chippawa

Supply Provided	Number of Suppliers
0-2 PJ	0
2-5 PJ	1
5+ PJ	4



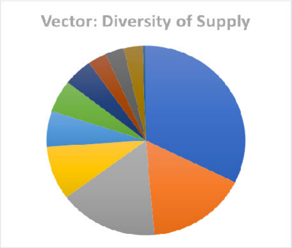
PEPL

Supply Provided	Number of Suppliers
0-2 PJ	3
2-5 PJ	0
5+ PJ	2



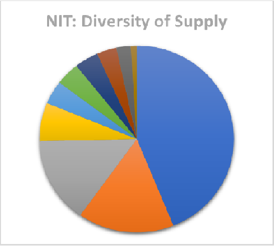
Vector

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



NIT

Supply Provided	Number of Suppliers
0-2 PJ	6
2-5 PJ	1
5+ PJ	3



2022/23 PERFORMANCE METRICS Enbridge Gas Inc.

OEB Guiding Principle	Performance Category	Intent of Measure	Measure	2020/21 Results	2021/22 Results	2022/23 Results	3-Year Average[1]
COST EFFECTIVENESS							
The gas supply plans will be cost-effective. Cost-effectiveness is achieved by appropriately balancing the principles and in executing the supply plan in an economically efficient manner.	Policies and Procedures	Demonstrates EGI's consideration of timely pricing information and the utility's ability to transact according to internal policies for managing counterparty risk	Procurement plan reviewed and approved as outlined in the policy	C	C	C	n/a
			Transacting counterparties have met appropriate credit requirements	C	C	C	n/a
	Weather Variance[2]	Illustrates weather risk in EGI's Plan correlated with price variances (e.g. positive HDD variances tend to lead to higher prices)	HDD Variance - EGD CDA	(10%)	(1%)	(8%)	(6%)
			HDD Variance - EGD EDA	(10%)	2%	(9%)	(6%)
			HDD Variance - EGD Niagara	(10%)	0%	(8%)	(6%)
			HDD Variance - Union North West	(6%)	9%	0%	1%
			HDD Variance - Union North East	(12%)	(3%)	(10%)	(8%)
			HDD Variance - Union South	(10%)	0%	(8%)	(6%)
	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	2%	5%	1%	3%
			Monthly	24%	18%	25%	22%
			Seasonal	37%	59%	41%	46%
	2022-2023		Annual or longer	37%	18%	33%	29%
		Illustrates price stability and consistency in EGI's Plan	Reference Price[3]	Please see EB-2022-0072, Appendix I, page 5.	Please see EB-2023-0072, Appendix H, page 3.	Please see page 3.	N/A
RELIABILITY AND SECURITY OF SUPPLY							
The gas supply plans will ensure the reliable and secure supply of gas. Reliability and security of supply is achieved by ensuring gas supply to various receipt points to meet planned peak day and seasonal gas delivery requirements.	Design Day	Demonstrates the extent to which EGI is able to procure assets required to meet design day demand, indicating the reliability of the plan	Acquired assets to meet design day requirements, as identified by the plan	100%	100%	100%	100%
	Storage	Demonstrates EGI's execution of its storage inventory strategy	Percentage of actual storage target at November 1 compared to the plan	96%	100%	96%	97%
			Percentage of actual storage target at February 28 compared to the plan	83%	100%	100%	94%
			Percentage of actual storage target at March 31 compared to the plan	100%	100%	100%	100%
	Communication	Ensure ongoing communication and understanding between planning and operations teams	Meet once a month at a minimum to discuss inventory position relative to targets and what action is required	C	C	C	C
			Instances when QRAM expected bill impacts exceed +/- 25%	3	3	1	2
			Communicated to ratepayers when bill impacts exceed +25%	C	C	C	C
	Diversity		Supply basin diversity				
			Ontario/Dawn	29%	26%	25%	27%
			WCSB	25%	21%	26%	24%
			Appalachia	17%	20%	19%	19%
			Niagara Region	16%	18%	16%	17%
			Chicago	9%	10%	11%	10%
			U.S. Mid-Continent	4%	3%	4%	4%
			Percentage of contracts with remaining terms of:				
			1-5 years	43%	56%	43%	47%
			6-10 years	32%	33%	52%	39%
			> 10 years	25%	12%	5%	14%
			Total number of unique counterparties	56	55	55	55
			Total number of firm receipt points	22	25	25	24

OEB Guiding Principle	Performance Category	Intent of Measure	Measure	2020/21 Results	2021/22 Results	2022/23 Results	3-Year Average[1]
	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 that reduced capacity	0	14	15	10
			Number of days of force majeure on upstream pipelines impacting customers' security of supply	0	0	0	0
			Number of days of failed delivery of supply (including force majeure)	82	113	161	119
			Number of days of failed delivery of supply impacting customers security of supply	0	0	0	0
			Number of days of force majeure on storage assets	0	0	0	0
PUBLIC POLICY							
The gas supply plan will be developed to ensure that it supports and is aligned with public policy where appropriate.	Supporting Policy	Reports public policy considered in EGI's Plan	Community expansion addressed in the plan	C	C	C	n/a
			DSM savings addressed in the plan	C	C	C	n/a
			Federal Carbon Pricing Program addressed in the Plan	C	C	C	n/a
			Percentage of RNG in the portfolio	0%	0%	0%	0%
			Emissions abated through procurement of RNG and hydrogen (tCO_2e)[4]	0	117	196	104
			Percentage of RSG in the portfolio	0	0.4%	5.8%	2.1%
			OEB-approved supply-side IRP alternatives implemented in the Plan	0	0	0	0

Notes:

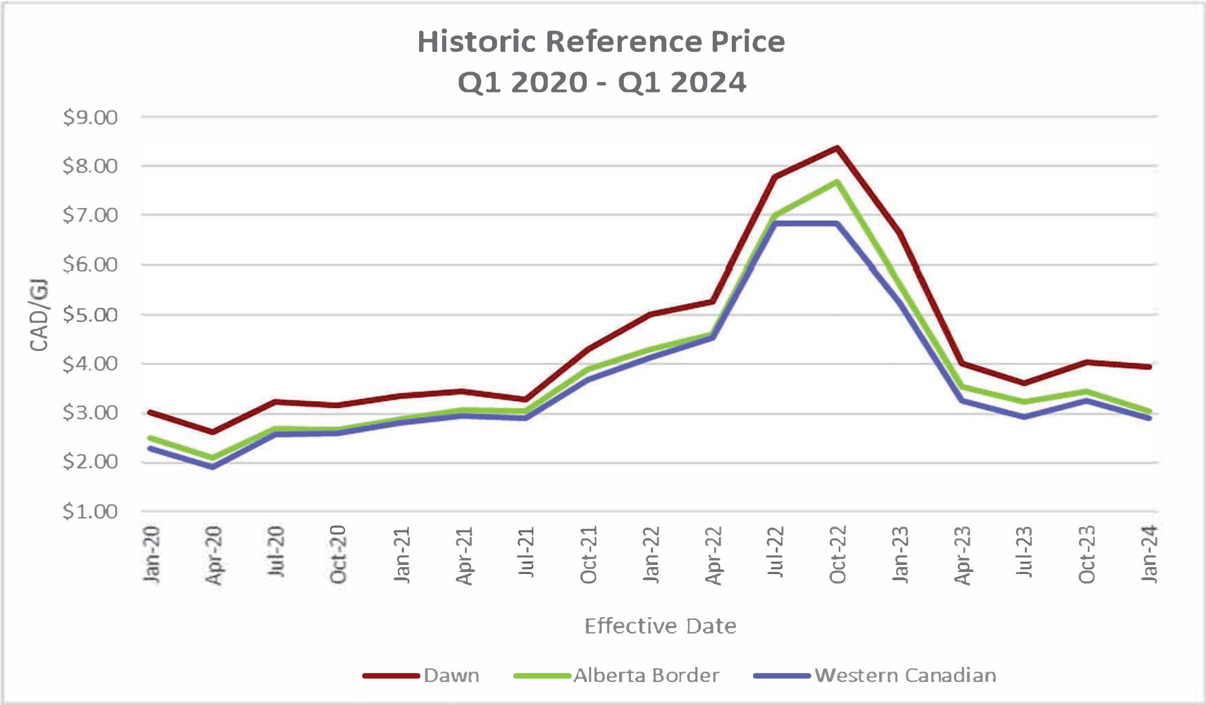
C - Compliant, NI - Needs Improvement

1 - 3-year rolling average for benchmarking purposes

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

3 - As filed in QRAM proceeding

4 - Environment and Climate Change Change Canada. (2022, April 14). 2022 National Inventory Report 1990-2020: Greenhouse Gas Sources and Sinks in Canada. Part 2. Table A6.1-1 and Table A6.1-3. https://unfccc.int/documents/461919


Historic Reference Price
Q1 2020 - Q1 2024
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
CAD/GJ
Jan-20
Apr-20
Jul-20
Oct-20
Jan-21
Apr-21
Jul-21
Oct-21
Jan-22
Apr-22
Jul-22
Oct-22
Jan-23
Apr-23
Jul-23
Oct-23
Jan-24
Effective Date
Dawn
Alberta Border
Western Canadian