EPCOR Natural Gas Limited Partnership

2024 Annual Gas Supply Plan Update

(2023-2025 Gas Supply Plan)

Southern Bruce

EB-2024-0139

Contents

Table of Figures

1. Administrative Information

1.1. Introduction

On October 25, 2018, the Ontario Energy Board ("Board" or "OEB") issued its Report of the Ontario Energy Board: Framework for the Assessment of Distributor Gas Supply Plans ("Framework") which set out a new requirement for all rate-regulated natural gas distributors in the Province of Ontario to file five year gas plans in January 2019. In April 2023, EPCOR Natural Gas Limited Partnership ("EPCOR" or "ENGLP") filed a three-year Southern Bruce Supply Plan ("Supply Plan") for the period 2023-2025 (EB-2023-0111).

ENGLP has developed the following update to the Supply Plan ("Supply Plan Update") in accordance with the criteria and guiding principles of (i) cost-effectiveness, (ii) reliability and security of supply and (iii) public policy, as defined in the Framework.

The guiding Principles for the Assessment of Gas Supply Plans are defined as follows:

i. **Cost-effectiveness** – The gas supply plan will be cost-effective. Cost-effectiveness is achieved by appropriately balancing the principles and in executing the supply plan in an economically efficient manner.

ii. **Reliability and security of supply** – The gas supply plan 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.

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

In addition to the Board's guiding principles above, a key consideration in this Supply Plan Update continues to be **flexibility** and obtaining competitive prices vis-à-vis alternative fuels. Southern Bruce is still a relatively new operation with little historical data; therefore, supply planning in the period covered by this plan is done with limited historical data and consumption profiles based on customers' gas usage in their first few years of service. Thus, there continues to be a considerable focus how the plan can be flexible in cost effectively providing reliable supply to Southern Bruce customers in cases when actual demand deviates from the forecasted demand profile used for planning purposes. This must be balanced with the need to provide a burner tip rate which attracts new customers.

To satisfy the Framework requirements, EPCOR developed a demand forecast that reflects its expected annual load profile over the three year rate period starting April 1st 2023 and ending March 31st 2026 in its most recently three-year Supply Plan. The demand forecast was used as an input in determining the appropriate mix of gas supply purchases given contracted storage and transportation assets. In this Supply Plan Update, actual consumption data is reported for April 2023 to March 2024, and the demand forecast is extended to March 31st, 2027.

Applying the Framework's guiding principles of cost-effectiveness and reliability and security of supply, any incremental local gas supply will be assessed against the landed costs of natural gas supply alternatives to ensure this supply will be competitive with any alternative supply source for EPCOR's rate payer. This approach ensures that cost-effectiveness is balanced against reliability and security of supply, which considers flexibility and diversity in commodity procurement. The Supply Plan reflects the notion that cost-effectiveness is not paramount to reliability, or vice versa, rather the two principles are assessed together and the final supply option is a balance of the two principles to ensure that customers receive reliable supply which optimizes the cost-reliability function.

The objective of the Supply Plan is to develop a right-sized portfolio of natural gas supply assets that ensures consumers receive a cost-effective, reliable and secure natural gas supply in a manner that is consistent with public policy. The portfolio is designed to strike a balance between these guiding principles, which are consistent with the Board's legislated mandate to protect the interest of consumers with respect to prices, reliability, and the quality of gas service.

The Framework requires that, where appropriate, the Supply Plan supports and is aligned with public policy objectives. This includes the Federal Carbon Pricing Program, Provincial Community Expansion, Minister of Energy Letter of Direction, and Canada Green Homes Grant.

The Supply Plan is intended to provide strategic direction that will guide EPCOR's ongoing decisions related to its natural gas portfolio such that the utility is able to meet Peak Day, seasonal, and annual demand throughout the winter and summer periods for General Service Customers in a cost-effective manner. The plan does not commit EPCOR to procuring a set volume and/or source of natural gas, but rather provides a roadmap that is sufficiently flexible, such that reliable and cost-effective natural gas commodity and storage assets can still be procured in the event of changing or unexpected demand, consumption patterns, weather, or market forces.

ENGLP is presenting the update to the three-year Supply Plan, which includes:

- Significant Changes to the Gas Supply Plan, describing the significant changes to the plan from the previously submitted Update and the resulting customer impact,
- An updated Gas Supply Plan Outlook, including updated data for the three-year Outlook, and
- A Three-Year Historical Review, which includes a historical comparison of 2020 actuals to the Outlook.

1.2. Significant Changes

This section outlines changes to the 2023 three-year Supply Plan. They are discussed in each section below in detail. The following table summarizes the changes within each section:

Section	Significant changes
2.1.1 Supply Option **3.1.3 Design Day Demand** **4.2 Transportation Portfolio**	Addition of Compressed Natural Gas (CNG) supply to support system integrity in the southern end of the system

1.3. Process, Resources, Governance

There have not been any significant changes to ENGLP South Bruce's processes or governance since the previous year's filing. ENGLP continues to follow the procedural document previously submitted in the 2023 three-year Supply Plan to highlight and summarize key components of ENGLP South Bruce's gas supply management procedures and processes. No changes to the procedural documents were made for the Supply Plan Update.

EPCOR developed an annual supply plan review process which is the starting point for the development of this Supply Plan Update. A number of variables were considered during this review process, including:

- Gas purchase performance;
- North American natural gas price drivers;
- Consumption pattern (consumption and peak demand) and connection counts;
- Demand driver such as weather and economic conditions; and
- Historical asset utilization rate (storage balance, M17 contract demand utilization, LBA balance).

This Supply Plan Update was a coordinated effort between EPCOR and ECNG Energy Group, a third-party consultant ("ECNG"). EPCOR procured ECNG for the following scope of services:

1. Develop a customer demand forecast (Demand Forecast)
2. Develop a strategy to acquire the necessary services to meet the Demand Forecast, including:
    a. Natural gas procurement strategies;
    b. Determine and advise on storage and transportation asset requirements;
    c. Ensure the Supply Plan is consistent with the Framework;
    d. Ensure the Supply Plan is consistent with the OEB's Consultation to Review Natural Gas Supply Plans (EB-2019-0137) and the Final Staff Report to the OEB issued on March 26, 2020; and
3. Annually, prepare an update to the Supply Plan (Annual Plan Update) for filing with the OEB.

In addition, EPCOR has also contracted ECNG to execute gas supply procurement, including:

1. Ongoing annual natural gas commodity procurement strategy and execute on a cost effective and reliable basis.
2. Nomination services for its natural system gas portfolio as well as for contract (Rate 16) customers.

Biographies of key ECNG personnel are included in Appendix C **– ECNG Credentials**.

Gas supply procurement strategies and processes developed for this Supply Plan Update will be executed by EPCOR and ECNG in a cost-effective manner. In addition to the development of this Supply Plan Update, there will also be an annual review of the plan, processes, and strategies to identify room for improvements. This review process is aimed for Q1 of every calendar year, and would consider the following:

- Review historical demand, and revise forecasted demand for the upcoming planning period to review and revise forecasting procedures where needed;

- Utilization of storage and transportation assets, and forecast utilization rates in the planning period and identify if existing assets are sufficient to meet deliverability requirements, and if additional storage or transportation assets are needed to meet future needs;

- Existing purchases and cost consequences of executed supply plans, and review whether existing supply plans are cost effective, flexible, and reliable in meeting demand;

- Review processes and procedures related to procurement and management of gas supply, and identify areas of improvement; and

- Supply plan risk assessment, including supplier performance and credit review.

The review process will aim to identify if additional supply, storage and transportation assets are required to serve projected demand over the planning period. The reviews are assessed against the OEB guiding principles of cost-effectiveness, reliability and security of supply, and public policy. OEB Results of this annual review process is then applied to the supply plan for the upcoming period. If additional resource requirements are identified to serve the changes in gas demand, the review will kick start the procurement process.

In addition to the monthly review, supply purchase decisions are made throughout the year to match changes in demand that deviate from the Supply Plan - for example, connection counts that deviate from the assumptions made in this Supply Plan Update, weather-related impacts, etc. To address these changes, actual and forecasted price, supply, demand, storage and LBA imbalances for Southern Bruce are reviewed on a monthly basis to determine any adjustments that need to be made in the implementation of the Supply Plan. Improvement to the procurement processes are also flagged in these meetings. EPCOR and ECNG has also developed a number of operational triggers that aim to minimize fees and maximize deliverability.

Lastly, EPCOR has developed operational guidelines and processes for supply planning and procurements that align with organization-wide policies that manages financial risk exposures, credit risk exposures, and contract execution authorities. These governance pieces act as additional layers of assurance to ensure the supply planning and procurement processes are executed in a cost-effective manner that limits risks to the rate payers.

2. Market Overview

2.1. Description of Gas Supply and Asset Options

Construction of the Southern Bruce expansion requires significant distribution and upstream asset investment for security and balancing demand with supply. EPCOR required upstream firm transportation (from Dawn) and balancing from Enbridge Gas Inc. ("Enbridge"), as it is the only service provider that can deliver such services. The EB-2019-0183 proceeding resulted in Enbridge providing M17 firm transportation and balancing services to EPCOR. EPCOR is planning to continue to serve the Southern Bruce franchise area through the M17 firm transportation service provided by Enbridge for the period covered in this Supply Plan Update.

2.1.1. Supply Option

Gas supply Option 4 chosen from the 2023 three-year Supply Plan focuses gas supply procurement at the Dawn Market hub. At this time, the supply availability is abundant at Dawn as described in the Market Outlook section below. The connectivity of the Dawn hub to the vast majority of supply basins has resulted in a low basis (difference) between NYMEX Henry Hub – benchmark price for the North American gas market at large – and Dawn (i.e Dawn is a discount to NYMEX Henry Hub). Therefore, obtaining supply in supply basins or market hubs beyond Dawn is not necessary to achieve supply reliability for customers. Price diversity is achieved by contracting options discussed in Section 5.

Three types of physical contracts at Dawn were considered for the Supply Plan: fixed price term purchase, index price term purchase, monthly (spot) and daily "cash"[1] transactions.

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[1] "Cash" transactions are physical delivery contracts for gas for one to three days at a fixed price. Cash prices reflect market conditions closely at the time of transaction.

Fixed price term purchases are physical delivery contracts where a fixed volume of gas is procured for one or more months, and the price per GJ is constant throughout the term of the contract. For this Supply Plan only fixed price forward period contracts with terms one year or less are contemplated.

Index price term purchases are physical delivery contracts where a fixed volume of gas is procured for one or more months. The price per GJ does change on a monthly or daily basis due to market conditions and how the index is made. The following two indices are considered for the Supply Plan:

- ICE NGX Union Dawn Day Ahead Index (DDAI) in $CAD/GJ converted from $US/MMBtu[2];
- Gas Daily Dawn Daily Index in $CAD/GJ converted from $US/MMBtu;

For this Supply Plan Update, EPCOR has chosen to transact with ICE NGX Union Dawn Day Ahead Index.

NGX index DDAI is the preferred choice for the following reasons:

- All suppliers contracted with EPCOR use the NGX electronic trading platform which creates the index (ECNG's informal survey of other suppliers at Dawn also predominantly use this platform/index);
- The data is readily available through subscription by EPCOR; and
- The trading data is deeper than Gas Daily (more transactions, more volume used to arrive at the daily index market price).

[2] Foreign exchange rate are as specified in the contract terms (do we want to say this?). Conversion from MMBtu to GJ based on the SI standard of 1.055056 GJ per mmBtu

There were no changes considered for supply options for the past year, and no changes considered for the period covered in this Supply Plan Update.

In addition, EPCOR is expecting to procure Compressed Natural Gas (CNG) on a pilot basis during periods of non-coincident peak demand. In the 2023-24 fall/winter season, EPCOR experienced delivery pressure issues in the southern parts of its distribution system. Given the expected growth of the system this year beyond what was contemplated in the CIP (largely concentrated in the southern part of its system), there is a possibility further pressure issues may present itself again in the southern end of the system during periods of non-coincident peak demand. To mitigate the risk of system deliverability issues in the southern end of the system, EPCOR is currently in negotiation with a CNG provider to start introducing CNG during periods of non-coincident peak demand. EPCOR expects to recover the commodity cost of the CNG as part of its QRAM process, and recover the non-commodity portion of the costs related to CNG through the Storage & Transportation Variance Account (S&TVA).

2.1.2. Transportation Options

Upstream transportation to Dornoch has been secured under the M17 rate for 10 years (EB-2019-0183 proceeding). This is sufficient to access the Dawn hub for supply for the first 10 years of its franchise development. Upstream transportation to Dawn follows the same rationale as the Gas Supply Options section above. For the time horizon of this Supply Plan Update, there is no cost advantage to contract additional upstream firm transportation in order to secure supply versus buying at the Dawn hub from suppliers directly. Investment in gas supply and associated upstream transportation are not required to serve the franchise in this Supply Plan Update’s time horizon as discussed in the Market Outlook section.

There were no changes considered for transportation options for the past year, and no changes considered for the period covered in this Supply Plan Update.

2.1.3. Storage Options

As an outcome of the EB-2019-0183 proceeding, EPCOR was not offered cost-based storage and related daily balancing for T3 or M9 services, which are available to other embedded parties served by Enbridge in Ontario. The option made available to EPCOR for daily balancing was a no-notice service at market price with +/- 12.5% deliverability on 25,000 GJ of space or the same LBA service offered by TCPL to Enbridge in the TCPL delivery areas WDA, NDA, NCDA, and EDA. Either service was paired with a ten year term 100,000 GJ of seasonal storage service space at market price. EPCOR selected the LBA daily balancing for two reasons. The first is that the service is a regulated service with oversight from the Canadian Energy Regulator (CER). The second is that by actively managing the daily delivery requirement coupled with fact that there are no demand charges associated with the service, it is possible to achieve similar operating flexibility at lower costs versus the alternative balancing option offered by Enbridge.

Regarding seasonal storage, EPCOR desired a storage offering at Dawn that included the ability to make multiple nominations daily either within firm contract parameters or for overrun quantities in attempts to reduce daily imbalances, having more options to balance besides buying and selling gas. There are no storage operators at Dawn other than Enbridge to provide this type of storage service. To acquire storage service in Michigan (the closest market for similar storage services) requires dealing with foreign exchange, import-export rules and additional transportation contracts on at least another pipeline to/from Dawn. Accessing storage and associated transportation to/from Michigan adds additional cost and the longer chain of nominations, which makes intra-day nominations more difficult especially for overrun in the winter. These additional items to manage were considered at this time not appropriate in exchange for the added storage service diversity as the franchise needs for storage for the period covered in this Supply Plan Update.

There were no changes considered for storage options for the past year, and no changes considered for the period covered in this Supply Plan Update. The existing storage contract have sufficient capacity for the gas supply planning period and EPCOR will not need to contract for additional storage for the period covered in this Supply Plan Update.

2.1.4. Market-Based Commodity Solutions

From time to time, a scenario may arise where a unique, short term need cannot be resolved through a standard offer. The resolution of these issues often requires solicited or unsolicited non-standard offers.

An example of such a scenario is a winter peaking service, which allows EPCOR to secure additional availability of gas from a supplier for a reservation fee during the winter to nominate additional gas in order to meet demand (at a discount up to the daily reserved volume). In some cases, the cost of such a service can be more economical than holding upstream capacity or purchasing additional deliverability from storage. A second example is where EPCOR contracts for a storage service gas is purchased in the summer and nominates it to a supplier at Dawn in return for a redelivery pattern in the late winter to reduce the amount of day to day gas needed.

As the focus of this Supply Plan is based on serving a new and growing market with significant transportation capacity and storage capacity available relative to current market size expectations, the need for market based solutions is unlikely during the time horizon of this plan and are not taken into consideration for gas supply planning at this time.

In the last three years (2021 to 2023), no market-based commodity solutions were required or deployed. In 2024, EPCOR is exploring the introduction of CNG supply to address potential pressure issues during non-coincident peak demand conditions.

2.2. Market Outlook

As an element of the risk mitigation strategy, the following overview of current and future trends is intended to inform EPCOR of any changes in natural gas market fundamentals which have the potential to impact its ability to execute the Supply Plan. The North

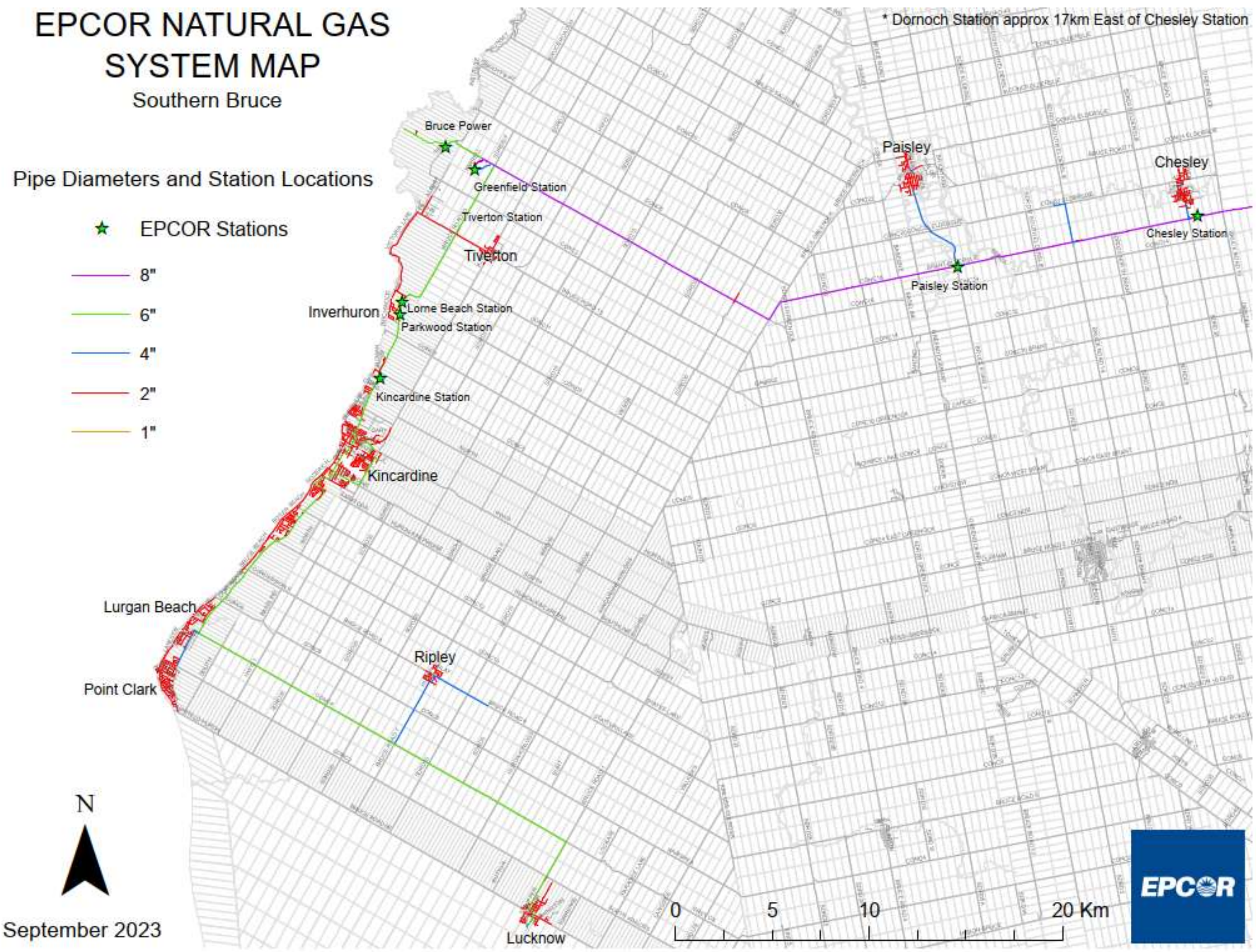
American fundamental drivers for natural gas are demand, supply, storage and indirectly crude oil and foreign exchange. ECNG provided the market trending analysis (see Appendix B **– Market Trends Analysis**).

3. Rate zone Description

The Southern Bruce distribution system is serviced from a single meter interconnect with Enbridge at Dornoch. It comprises approximately 75 km of NPS 8 to 6-inch steel high pressure ("HP") pipe, 45 km of NPS 6-inch medium density polyethylene ("MDPE") pipe and 178 km of NPS 4 and 2 MDPE distribution piping (the "Project") in the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron-Kinloss (collectively, the "Southern Bruce Municipalities"). In December 21, 2022, EPCOR filed notice to the OEB of the completion of the final phase of construction of the Southern Bruce Project which included an in-service date of December 13, 2022 [3] and will be filing its second and final post-construction report in June 2024.

[3] Re: EPCOR Natural Gas Limited Partnership ("ENGLP") Southern Bruce Project Leave to Construct Application – Conditions of Approval (EB-2018-0263): letter dated December 21, 2022

Figure 1 – Southern Bruce Distribution System Map



The utility will serve two main classes of customers: General Service and Contract Customers. Contract Customers contract for their own natural gas supplies and storage assets to manage fluctuations in demand. As such, the consumption profile of Contract Customers is not included in the demand forecast and Supply Option Analysis.

Contract Customer makes 42% of the total M17 capacity, bringing the capacity available to system gas customers to 58%. The M17 capacity allocated to the Contract Customers have not changed this past year, and is not expected to change for the period covered in this Supply Plan Update.

An option for Direct Purchase has not been taken into consideration in this Supply Plan Update for other rate classes as Direct Purchase is currently not offered. On September 1, 2020, EPCOR received an 3-year exemption pursuant to subsection 44(6) of the Ontario Energy Board Act, 1998 (“OEBA”) and Rule 1.5.1 of the Gas Distribution Access Rule (“GDAR”) for an order or orders exempting ENGLP from compliance with Rules 3 and 4 of GDAR in proceeding EB-2020-0068. In February 2023, EPCOR filed a request for extension with the OEB for to defer the Direct Purchase further program to July 1, 2025 after which EPCOR intends to offer a direct purchase program for customers.

General Service customers make up the rest of EPCOR’s natural gas system, and are comprised of residential, commercial, and agricultural customers.

In 2023, residential customers made up 66% of EPCOR Southern Bruce’s General Service demand profile, and commercial customers made up 13%. Both customer segments have flat, non-weather dependent demand requirements during the summer period (April to October), and heat-sensitive demand during the winter period (November to March).

Seasonal agricultural customers, account for the remaining 19% of General Service demand, are expected to use natural gas for production purposes, and as such, their natural gas usage is expected to vary year-on-year depending on crop yield, making it more challenging to forecast demand due to a lack of historical data.

In February 2022, EPCOR received conditional approval for Municipal Franchise Agreements with each of the Municipality of Brockton, the Municipality of West Grey, and the Township of Chatsworth and Amendments to the Certificates of Public Convenience and Necessity for each of the Municipality of Brockton, the Municipality of West Grey, and the Township of Chatsworth (EB-2021-0269. EPCOR filed a leave to construct application for the Brockton expansion (EB-2022-0246) in July 2023, but subsequently withdrew the application in December 2023.

3.1. Annual Demand

3.1.1. Customer Connection Forecast

The forecast captures year-on-year demand growth as more customers connect to the Southern Bruce distribution system. The customer connection forecast in the 2023 three-year Supply Plan was adjusted based on the observed pace of gas-consuming customer additions on the Southern Bruce system, which has been relatively consistent in the past three years (2021 to 2023). Based on current number of customer connection applications, EPCOR is expected to see a slower pace of customer connection growth in 2024 compared to previous years, with customer connection numbers expected to stay relatively steady 2025 onwards. The slowdown in customer grow was expected in the 2023 three-year Supply Plan, as EPCOR officially completed the construction of the Southern Bruce Project[4] in December 2022 and will file its second post construction report in June 2024.

[4] Re: EPCOR Natural Gas Limited Partnership ("ENGLP") Southern Bruce Project Leave to Construct Application – Conditions of Approval (EB-2018-0263): letter dated December 21, 2022

Table 1 shows the changes in customer connection forecasted in the previous three Supply Plans and Updates, actual connections in 2023, and the adjusted customer connection forecast underpinning the demand forecasts this Supply Plan Update. Note that by the end of 2025, total customer connections is expected to exceed the total customer connections forecasted in the CIP.

Table 1 – Calendar year end Customer connection forecast comparison

Year	2021 GSP Update				2022 GSP Update				2023 GSP				2024 GSP			
	Rate 1	Rate 6	Rate 11	Total	Rate 1	Rate 6	Rate 11	Total	Rate 1	Rate 6	Rate 11	Total	Rate 1	Rate 6	Rate 11	Total
2020	179	-	1	180	179	-	1	180	179	-	1	180	179	-	1	180
2021	2,614	40	3	2,657	1847	7	1	1,858	1847	7	1	1,858	1847	7	1	1,858
2022	3,703	56	6	3,765	3,112	21	6	3,139	3,388	21	5	3,414	3,388	21	5	3,414
2023	4,792	71	6	4,869	4,878	34	7	4,919	4,911	27	7	4,945	4,833	32	6	4,871
2024	5,039	91	6	5,136	5,829	34	7	5,870	5,604	32	7	5,643	5,472	53	9	5,534
2025					5,829	34	7	5,870	5,800	36	7	5,843	5,560	55	9	5,624
2026													5,610	55	9	5,674

3.1.2. Demand Forecast

To develop a natural gas supply portfolio, EPCOR first constructed a demand forecast that reflects its expected customer profile throughout the year over a three-year horizon from Planning Year 2024 to 2026 (April 2024 to March 2027). This first step ensures that EPCOR procures an efficient volume of natural gas commodity and storage assets. As EPCOR's customer base have rapidly expanded since operations began in 2020, the demand forecast must continue to be sufficiently flexible to mitigate risks associated with a scenario where actual demand growth significantly deviates from the forecast.

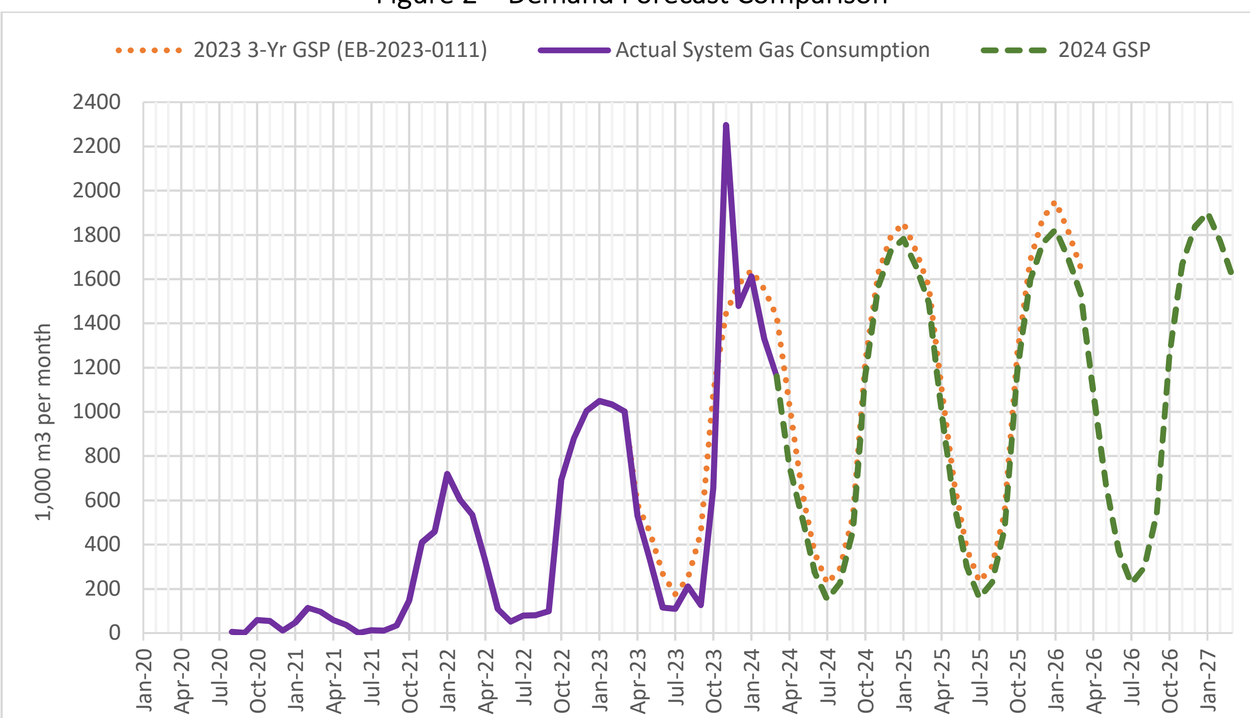
Southern Bruce customers are categorized into four rate classes:

- General Firm Service Rate 1
- Large Volume General Firm Service Rate 6
- Large Volume Seasonal Service Rate 11, and
- Contracted Firm Service Rate 16

As Rate 16 contract customers procure their own supply and manage their own storage, the focus on the Demand forecast is Rates 1, 6 and 11.

The 2024 forecast customer conversion in this Supply Plan Update reflects the customer applications received up to February 2024, as well as the forecasted pace of daily customer conversions. As shown in Figure 2, with the exception of November 2023, demand forecast in this update does not deviate significantly from the forecast in the 2023 3-year Update. The deviation in system gas consumption compared to the forecast in November 2023 was due to very high Rate 11 grain dryer consumption over an extended grain drying season. Corn harvest for 2023 in Southern Bruce was historically high compared to previous years. Further, the crop had significantly higher moisture content. The two factors combined led to significantly higher natural gas consumption for this group of customer.

Figure 2 – Demand Forecast Comparison

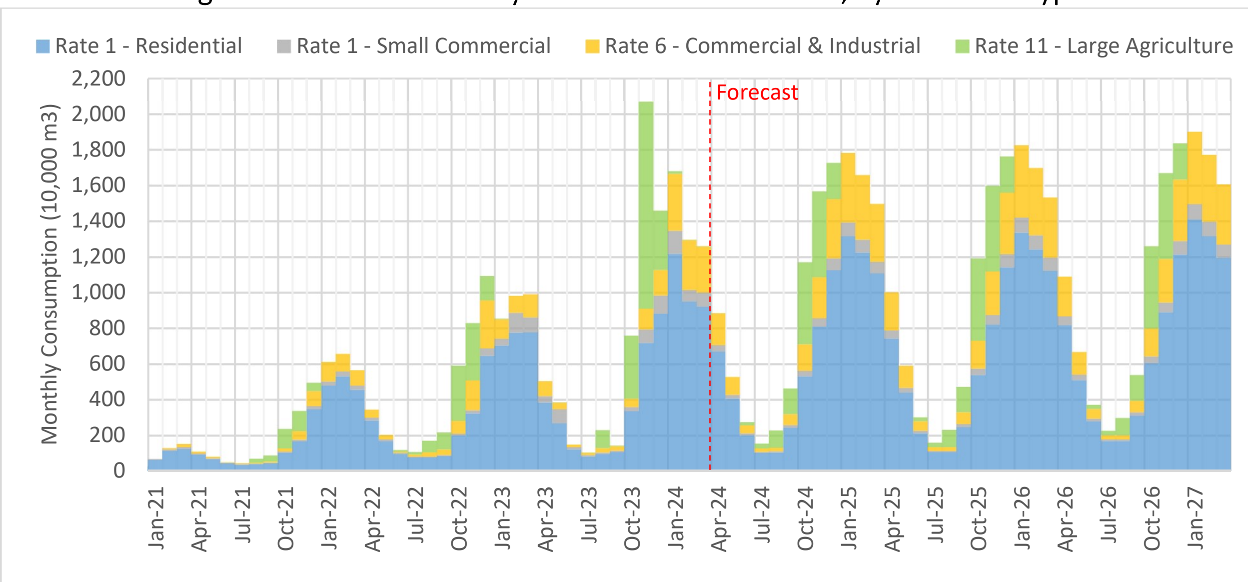


EPCOR will continue to review customer consumption patterns and expand on these findings in future Supply Plan Update filings.

For residential and commercial customers, the annual forecast was further adapted to monthly volumes by applying the monthly percentage of annual CIP-based usage from the

OEB Calculator. For large agricultural customers and grain dryers, monthly breakdown was determined through a consultative process, where the annual CIP-based usage was broken down to monthly profiles based on information received by customers on their existing energy needs. The actual and forecasted average day volume per month broken down by each customer type is shown in Figure 3.

Figure 3 - Forecast Monthly General Service Demand, by Customer Type



At present the demand forecast in this Supply Plan Update does not include potential impacts of future Demand Side Management ("DSM") programs. Refer to section 8.4 for further details.

3.1.3. Design Day Demand

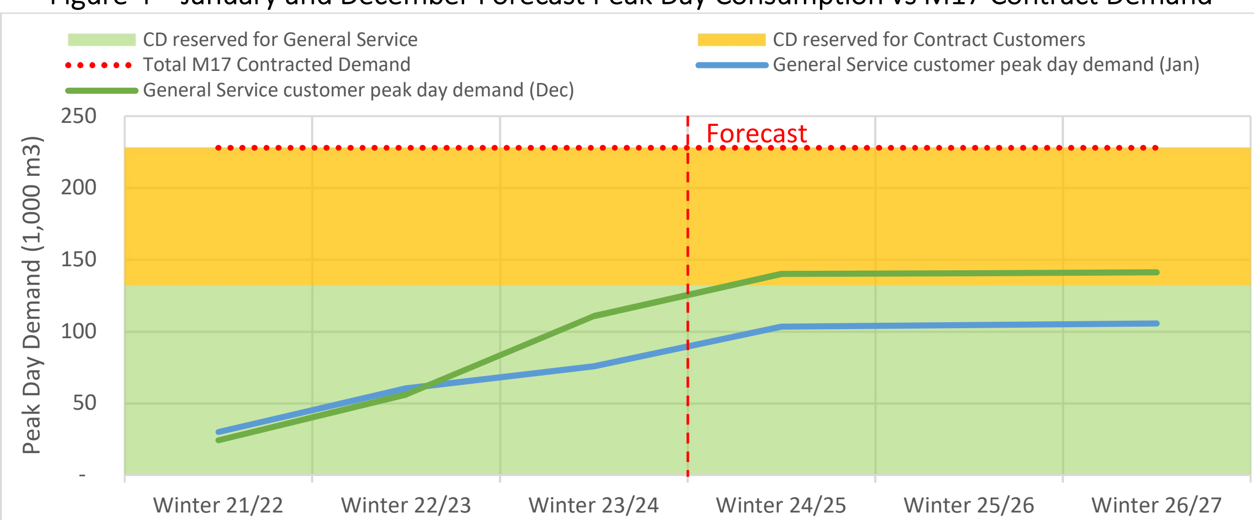
EPCOR's Contract Demand under the M17 was based on the expected capacity required to meet peak day conditions in EPCOR's Year-10 gas flow, which is 130,446 m^3 per day (or 5,110 GJ per day) for General Service customers. An additional 95,824 m^3 per day (or 3,753 GJ per day) is currently reserved for Contract Customer that supplies their own gas and manages their own storage).

The analysis for Design Day demand in this Supply Plan Update follows the methodology used in the 2023 3-year Supply Plan.

While design day peak for General Service customers is not expected to exceed the M17 capacity reserved for General Service customers in January for the period covered in this Supply Plan Update, there is a risk that if each dryers were to run on the same day during a cold day before December 15th, the General Service daily consumption for that day could exceed the capacity allocated to this group of customer.

Figure 4 below shows the expected January and December peak day demand in compared against the M17 contract demand, and the portion of that contract demand apportioned to General Service customers. For general service customers that are not grain dryers, December "peak day" is modeled to be 0.72% of average annual consumption.

Figure 4 – January and December Forecast Peak Day Consumption vs M17 Contract Demand



Based on the peak January demand forecast shown in Figure 4, EPCOR is not expecting to make full use of the Contract Demand in the three-year planning horizon covered by this Supply Plan Update. With a lower customer connection forecast in this Supply Plan Update (Table 1 in 3.1.1), the January peak day demand forecast in 2025 through 2027 is lower compared with the forecast in the 2023 three-year Supply Plan.

By Winter 26/27, January peak day demand for General Service customers is expected to be approximately 79.8% of the contract demand reserved for General Service customers. 2022 and 2023 December actual peak day demand are also revised in the forecast modeling based on actual observed peak day, and the 2025-2027 December peak day demand forecast is lower compared with the forecast in 2023 three-year Supply Plan based on updated data. From the current forecast, grain dryer consumption is expected to push peak day general service demand above the M17 capacity reserved for General Service customers by December 2024, given the number of existing and forecasted Rate 11 grain drying customer connections in 2024.

Furthermore, contracted storage assets with 1,200 GJs of firm withdrawal rights during the winter period, as well as the LBA agreement with allows for an additional +/- 2,111 GJs of daily imbalance between supply and consumption, are more than sufficient to address any concerns related to deliverability and reliability of supply during peak days within the planning period.

Note that from a contract demand / capacity perspective, the risk of a General Service Customer peak day in December remains low. In order for this situation to occur, heating degree days prior to December 16th (i.e. before EPCOR can interrupt grain dryer customer consumption under Rate 11) would need to be near-peak day demand, and all grain dryers on the system would have to be running at full capacity on the same gas day. Based on this low risk, it is not cost effective for EPCOR to contract for capacity for a relatively unlikely event. As Board Staff noted in their Review of 2022 Annual Update, EPCOR can ensure deliverability through M17 overrun during the grain drying season.

In response to low pressure observed in the 2023-2024 winter season (November to March), EPCOR updated its engineering/system modeling with current customer consumption patterns. While the contract demand contracted with Enbridge is expected to be sufficient to meet peak day demand during the drying season, the modelling results indicated that low pressure issues could persist in the Southern part of the system. In order to ensure reliability, EPCOR plans to introduce CNG on a pilot basis for the 2024-

2025 winter season. Currently EPCOR does not have enough information to assess how the introduction of CNG would impact the Supply Plan Update.

4. Current Portfolio

4.1. Commodity Portfolio

EPCOR plans to procure all supplies at the Dawn Hub for Southern Bruce as per ECNG's recommendation as part of the market outlook analysis. Southern Bruce's system supply needs are a small fraction of the Dawn market. As Supply Option 4 was chosen from the 2023 three-year Supply Plan, AECO supply is not considered in this Supply Plan Update.

For the period covered by this Supply Plan Update, Southern Bruce's winter system gas demand is expected to average less than 3,000 GJ/d – this represents approximately 0.003 Bcf/d of demand relative to the Eastern Canadian market demand of approximately 4 Bcf/d – EPCOR's portion then represents less than 0.1% of overall Eastern Canadian market demand.

The supply and demand dynamics at Dawn are expected to make it a viable source of supply for EPCOR's base supply and balancing supplies for the following reasons:

1. Dawn has excellent connectivity to the large and small basins of supply in North America;
2. The stable outlook for supply in Appalachia and Western Canadian Sedimentary Basin (WCSB);
3. There is excess capacity to Dawn to access these supplies; and
4. EPCOR's demand for supply will have no material impact on the Dawn market overall.

Based on the above, the Supply Plan Update will have the ability to deliver on the guiding principles of cost-effectiveness, reliability and security of supply.

4.2. Transportation Portfolio

EPCOR's M17 contract with Enbridge is the only Transportation Asset relevant for Southern Bruce during the period covered by this Supply Plan Update. EPCOR has contracted 227,912 m^3 per day of capacity to deliver gas from Dawn to the Dornoch Interconnect, which is sized to meet peak day demand in Year 10 (2028). EPCOR expects the transportation capacity to be more than enough to reliability meet gas demand to all Southern Bruce customers within the planning horizon.

The M17 transportation contract includes a provision for daily balancing which is facilitated by a separate Load Balancing Agreement (M17 LBA) contracted service, which is described in Section 4.4. EPCOR considers the M17 LBA another tool that can be used in the Supply Plan to ensure reliability and cost-effectiveness of supply. See Section 3.1.3 on EPCOR's approach to addressing potential dryer peak day demand for the period covered in this Supply Plan Update.

With the consideration of CNG introduced to the Supply Plan, there will likely be additional transportation cost introduced as part of delivering the CNG into the distribution system.

4.3. Storage Portfolio

EPCOR has contracted for storage from Enbridge as a key tool to manage price risk and ensure supply reliability to customers by managing variances between supply and demand. In order to avoid the situation occurring where large volumes of gas need to be purchased from the cash market, EPCOR forecasts Baseload and month-to-month purchase requirements in coordination with estimated storage withdrawal targets each month, such that the maximum deliverability from storage could be maintained until the beginning of March given a normalized weather scenario.

EPCOR has contracted for 10 years of seasonal storage service (LST) with a maximum storage balance (MSB) of 100,000 GJ (100 TJ), a standard offering to its unregulated terms and conditions which includes no firm injections in October and November and no firm withdrawals in April and May. Daily firm injection deliverability is 0.75% of MSB (750 GJ/d) when inventory is below 75% full, then the daily firm rights drop down to 0.5% of MSB (500 GJ/d) when inventory is above 75%. Similarly, daily firm withdrawal ability is 1.2% of MSB (1,200 GJ/d) when inventory is above 25%, then the daily firm rights drop down to 0.8% of MSB (800GJ/d) when inventory drops below 25%. The impact of these firm deliverability rights on the Supply Plan is noted below in the Description of the Supply Options section.

When supply exceeds demand, EPCOR will store the excess supply in its contracted storage account on a planned basis and in the M17 LBA on an unplanned basis described in the section below. Conversely, when demand exceeds supply, EPCOR will use this stored supply to service the deficiency. Storage also enables EPCOR to procure gas at times of the year (typically in the summer) when the price of gas is typically lower and/or less volatile. It should be noted that seasonal storage is not allocated to Contract Customers.

Given the supply/demand modeling conducted as part of this Supply Plan Update, EPCOR has assessed that the 100,000 GJs of seasonal storage in combination with baseload and month to month firm supplies is sufficient to meet deliverability required within the planning horizon. The current contracted storage will cover approximately one-third of expected winter demand for the threes winters covered in this Supply Plan Update. Given EPCOR's current and proposed Supply Option (purchasing 50% of expected winter demand as seasonal fixed priced contracts), the current storage contracted translates to an exposure of approximately 15% of system gas winter demand (December to March) at either prompt month purchase of index price purchase. Having a portion of expected winter demand not covered by storage or term purchases allows for additional flexibility in gas procurement – for example, in winters where actual demand is lower than forecast, it will still allow EPCOR to maximize the use of storage withdrawal for the winter season.

4.4. Daily Balancing Management

The M17 transportation contract includes a provision for daily balancing which is facilitated by a separate M17 LBA contracted service. The M17 LBA enables EPCOR to manage daily mismatches between supply (confirmed nominations) and demand (measurement estimate) at the Dornoch Interconnection Point and eliminate the accumulated imbalance on the next earliest gas day to the best of its ability. EPCOR considers the M17 LBA another tool that will be used in the Supply Plan to ensure reliability and cost-effectiveness of supply.

Supply Option 4, chosen in the 2023 three-year Supply Plan, assume that on a daily planned basis when purchased gas exceeds consumed gas, the planned excess gas first maximizes the use of the firm injection rights. Excess gas remaining after confirmed storage injection is captured as an injection into the M17 LBA as a daily imbalance and is added to the cumulative imbalance. Demand in excess of planned purchased gas and maximum allowed amount withdrawn from storage is captured as a daily imbalance and a withdrawal from the M17 LBA cumulative imbalance. If in case storage injection and withdrawal rights are not sufficient in bringing the M17 LBA into balance, spot purchases and sales are then considered. Contract customers, are apportioned a share of the M17 LBA and are responsible to manage their own supply-consumption imbalance.

Also available is the HUB service offered by Enbridge. While this pay-per-use service is interruptible, it can be useful during low interruption risk periods of the year. For HUB injections, the low risk periods are December through August. For HUB withdrawals the low risk periods are May through January. The HUB will likely be used on a short term basis only to pack and draft at minimal cost within a month or from one month to another, either in the middle of the summer or winter, to complement the use of the M17 LBA avoiding larger balancing costs during those short term periods.

4.5. Unutilized Capacity

During the period covered under this Supply Plan Update, EPCOR expects M17 transportation capacity will not be fully utilized during peak days. As EPCOR does not currently have the ability to assign its excess transportation capacity to another party (EPCOR is the only party that will be taking the gas at the Dornoch Interconnect), EPCOR will have unutilized transportation capacity for which costs will not be fully recovered from the in the planning period. In its rates application (EB2018-0264) EPCOR applied for and was granted a Storage and Transportation Variance Account for Rates 1, 6 & 11 ("S&TVA Rates 1, 6 & 11"). This account provides for EPCOR the ability to defer the recovery of the additional capacity EPCOR was required to contract with Enbridge initially in order to provide service to its customer base in future years. Accordingly, this under recovery will accrue in the S&TVA Rates 1, 6 & 11 account.

EPCOR does not expect any unutilized storage capacity during the period covered in this Supply Plan Update. The Supply Plan takes into account the full 100,000 GJs of contracted storage capacity and will utilize storage to its fullest capacity to ensure deliverability and supply cost stability.

5. Updated Gas Supply Plan Outlook

5.1. Design Day Analysis

As described in Sections 3.1.3 and 4.2, EPCOR ensures there are sufficient transportation assets to serve Southern Bruce's peak day demand within the planning horizon. While a portion of the transportation capacity from Dawn to Dornoch is reserved for the Rate 16 Contract Customers, EPCOR has included unauthorized over-run charges in its Rate 16 tariff to protect deliverability to its General Service customers during peak days. In addition, the M17 LBA agreement provides an additional safeguard to ensure availability of supply.

5.2. Average Day Requirement

This section focuses on procurement options and strategies EPCOR has contemplated and evaluated to meet Southern Bruce's expected average day demand for the planning horizon. The following operating assumptions apply for each Supply Option considered:

1) Between April and September of each year, supply would be procured to meet both monthly demand and maximize firm injection rights to fill contracted storage by September 30th (last day of firm injection right given EPCOR's storage contract). To fill the contracted storage requires 150 days to fill (100 days of 750 GJ/d plus 50 days of 500 GJ/d). EPCOR elects to start firm injections in May instead of April, as a colder than normal April can increase market prices, resulting in higher weighted average value of gas in storage.

2) October and November months have no firm injection rights, so annual strip, month to month strip, and/or spot gas are purchased to satisfy demand. EPCOR will continue to utilize storage withdrawals and the M17 LBA to supplement supply as needed on days with higher than expected demand (for example, during higher consuming days when Rate 11 grain dryers are consuming gas).

3) Commencing December 1st, firm withdrawal rights from storage are fully utilized to meet winter demand when baseload supply and month to month supply are insufficient to meet daily demand. In order to maintain highest deliverability in January and February, the plan assumes an average day withdrawals of 1,000 GJ/d during those months and maintaining Maximum Storage Balance (MSB) just above the 25% level at March 1 each year. This maintains maximum deliverability from storage for January to March in the event of a persistently cold January and February. If either colder weather or customer connections do not materialize, month to month purchases will decrease accordingly.

ECNG worked with EPCOR to build a customer commodity portfolio tracking model that tracks and forecasts demand, supply and resulting storage positions (net of fuel requirements), and potential triggers for LBA balancing requirements due to daily supply-demand mismatch. The inputs will include anticipated future connections by rate class, ongoing regression analysis for heat sensitive demand forecasting, near term weather forecasts to estimate demand plus known supply acquired, planned supply base scenarios, and resulting storage and LBA positions.

5.3. Supply Option Update

Four Supply Options were considered and modeled for the 2023 three-year Supply Plan to meet the guiding principles of cost-effectiveness and reliability and security of supply. Additional considerations include flexibility and price stability in order to manage the risk with customer demand changes. Option 4 was selected from the 2023 three-year Supply Plan, and OEB staff believes that Option 4 (including the utilization of long-term fixed-price contracts) is suitable for its current situation.

In the OEB Staff Report for the 2023 three-Year Supply Plan, OEB Staff agreed that the chosen option is beneficial for price risk management compared with the other three options. OEB staff is satisfied that EPCOR's planned procurement timing, location, and use of a mix of fixed and index pricing appropriately address the guiding principles as set out in the Gas Supply Framework.

One adjustment was made to manage system supply and demand, which deviated from the 2023 three-Year Supply Plan – no annual strip was purchased for April 2023 to March 2024, as EPCOR would not have received feedback from the Board on EPCOR's preferred supply option until November 2023. An annual strip was procured for the April 2024 to March 2025 period as per the 2023 three-Supply Plan. Figure 5 below shows the updated procurement plan that matches the demand forecast update.

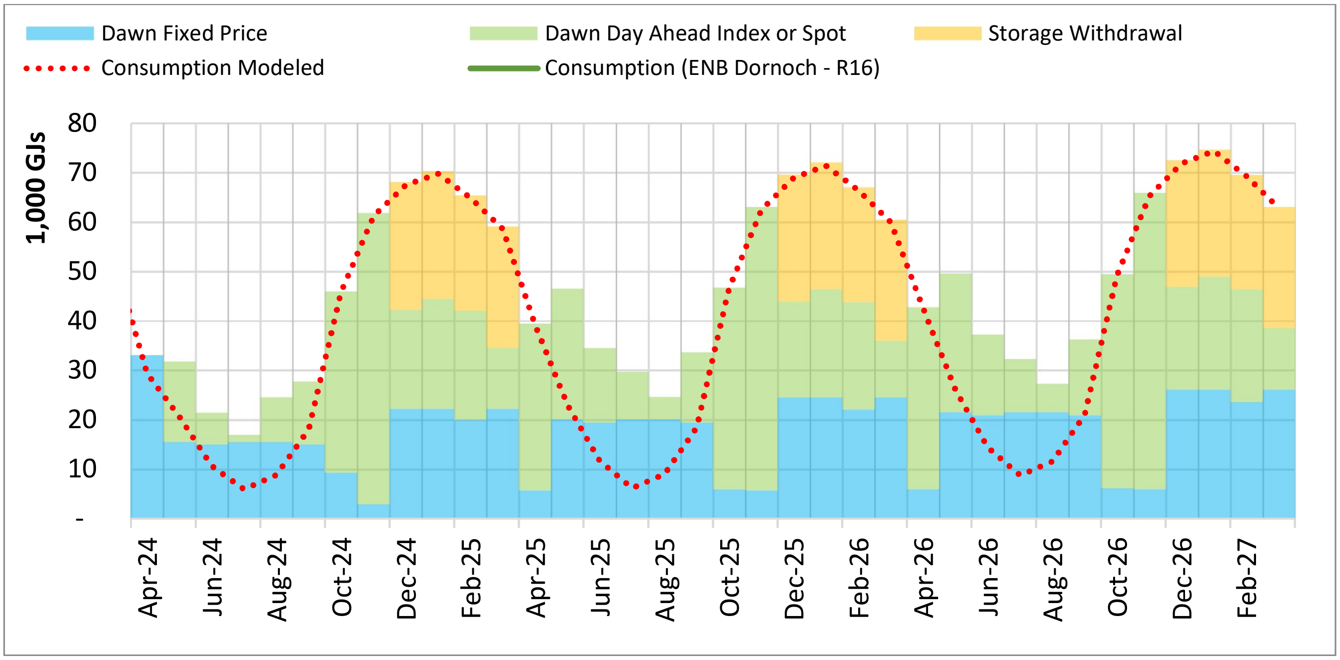


Figure 5 – OPTION 4 (Annual fixed price strip + up to 50% Seasonal Baseload Procurement @ Dawn Fixed)

6. Gas Supply Plan Execution

EPCOR continues works with ECNG to carry out the Supply Plan as per the Board's guiding principles of cost-effectiveness and reliability of supply while remaining flexible to changes in actual customer demand. EPCOR and ECNG maintain a number of checks and balances throughout the execution phase of the supply plan to ensure adherence to the board's guiding principles, with a focus on mitigation of risks highlighted in 2023 three-Year Supply Plan.

There is one major deviation to report since the 2023 three-Year Supply Plan – general service natural gas consumption in November 2023 was significantly higher than forecast due to high grain dryer consumption. Consumption for grain drying usage can vary significantly from year to year as their usage is based on the size of the crop yield and the moisture of the crops. EPCOR procured spot gas purchases to meet the grain dryer demand in 2023. As the variation in grain dryer usage vary significantly year to year, no changes are made to the Rate 11 grain dryer consumption forecast for this Supply Plan Update.

EPCOR is exploring CNG for the 2024 to address possible pressure issues identified in the southern end of the system.

6.1. Procurement Process/Policy

EPCOR and ECNG are in the process of finalizing a Natural Gas Procurement Guideline and Procedures document which has informed and will continue to inform procurement decisions impacting the Supply Plan. The document outlines the steps and rules EPCOR and ECNG adheres to during the course of natural gas procurement.

In Q1 of each calendar year, EPCOR's Energy Supply and Procurement Manager works with ECNG to develop a monthly procurement plan for the upcoming planning years (April to March). This plan outlines high-level guidance for natural gas procurement that allows for flexibility in addressing annual, seasonal, monthly and daily needs while maintaining a set of cost-effective supply and asset portfolio.

Within the year, the EPCOR's Energy Supply and Procurement Manager and the VP of Ontario directed and authorized ECNG to execute the approved Supply Plan. The Supply Plan is executed on a layered basis, with the annual Supply Plan providing high-level guidance for each planning year. Within the gas year, EPCOR will work with ECNG to assess and manage storage and transportation assets, and make adjustment to the procurement process on seasonal, monthly, daily basis supported by frequent and scheduled reviews of gas supply, storage and transportation asset utilization, and updates to customer demand profile.

Prior to the start of each planning year and each season, EPCOR will authorize ECNG to procure supply to meet forecasted demand and storage, at prices that reasonably track market conditions at the time of procurement. On a planned basis, EPCOR will direct ECNG to layer in purchases mainly through an RFP process (written and verbal), focusing on index price transactions that will track to market conditions at the time of delivery. EPCOR will also authorize fixed price transactions and term transactions (transactions of a specified volume with delivery period spanning more than a month) if it deems these transactions will contribute to price stability. ECNG have been given agency to transact on EPCOR's behalf, and both EPCOR and ECNG are part of the transaction and invoice confirmation process.

Currently, EPCOR purchases gas under the Gas Electronic Data Interchange ("gasEDI") contract with its papered suppliers with all gas delivered at the Dawn Hub. Supplier diversity will be assessed annually. Other considerations when contracting for natural gas supply include: weather variance impact on its general service customers; difference between actual versus forecasted consumption of its general service customers; storage balance and deliverability from storage during various points of the year; LBA balance during various points of the year; fuel requirements and unaccounted for gas.

7. Historical Review

The following section provides a review of the 2023 planning years, comparing the Plan for each year to the actuals experienced.

7.1. Heating Degree Days

The purpose of this section is to provide a brief review of the 2023 planning year, comparing the forecasted HDD underlying each gas supply plan to the actual HDD experienced.

Table 2 - Actual vs Plan Annual HDDs

	2023/2024		
	Planned	Actual	Variance
HDD	3,821	3,384	437

- 2023/2024 – HDDs were lower than planned due to warmer than expected temperatures, especially in December 2023, January and February 2024.

7.2. Annual Demand

The purpose of this section is to provide a brief review of the 2023 planning year, comparing the demand forecast underlying each gas supply plan to the actual throughput volume. Actual volumes have not been normalized for weather variances.

Table 3 - Actual vs Plan Annual Demand

	2023/2024		
	Planned	Actual	Variance
Annual Demand (TJ)	428	390	38

- 2023/2024 – New customer connection is slightly lower than what was modeled in the 2023 three-year Supply Plan. 2023/24 winter weather was warmer than forecasted which also contributed to lower consumption than planned.

7.3. Commodity Portfolio

The purpose of this section is to provide a brief review of the 2023 planning year, comparing the supply forecast underlying each gas supply plan to the actual supply procured.

Table 4 - Actual vs Plan Commodity Purchases

		2023/2024		
		Planned	Actual	Variance
Commodity Purchases (TJ)	Dawn	416	411	5

- 2023/24 – In the planning year ending March 31, 2024, actual purchases closely matched planned purchases

7.4. Unutilized Transportation Capacity

The purpose of this section is to provide a brief review of the 2023 planning year, comparing the Unutilized Transportation Capacity underlying each gas supply plan to the actual Unutilized Transportation Capacity incurred.

Table 5 - Actual vs Plan UDC

	2023/2024		
	Planned	Actual	Variance
Unutilized M17 Capacity (GJ)	1,581	2,078	497

- 2023/2024 – The actual Unutilized M17 Capacity was 497 GJ higher than planned, as actual peak day demand in 2023 did not reach to the forecasted level.

8. Public Policy

8.1. Community Expansion

EPCOR has been actively working to bring secure, reliable and affordable natural gas to unserved communities. The Southern Bruce project represents one of the largest community expansion projects awarded to date. EPCOR will continue to work to expand access to natural gas service to communities who are not currently connected to a natural gas distribution, and pursuant to EPCOR's obligation to serve, to any customers or communities who request natural gas service.

EPCOR is also monitoring community expansion plans and energy management plans of communities within the Southern Bruce franchise area. Specifically, EPCOR reviewed the following plans as part of this Supply Plan Update:

- Municipality of Kincardine Energy Conservation and Demand Management Plan: 2019-2024[5]
- Township of Huron-Kinloss – Climate Change and Energy Plan (2020)[6]
- The Corporation of the Municipality of Arran-Elderslie Conservation and Demand Management Plan: 2019-2024[7]
- Plan the Bruce: Bruce County Official Plan[8]

EPCOR did not find significant updates during this year's review that will impact EPCOR Southern Bruce's gas demand forecast. EPCOR expects communities will update their Conservation and Demand Management Plans and community growth plans in the next two years.

8.2. Minister of Energy Letter of Direction

On November 27, 2023, Todd Smith, Minister of Energy, provided a letter of direction to Glenn O'Farrell, Acting Chair of the Ontario Energy Board. This letter highlighted the Minister's near-term priorities for the energy portfolio focusing on continuance of energy transition and the OEB modernization. These priorities include:

- Housing, Transportation and Job Creation
- Facilitating Innovation within Ontario's Regulatory Framework
- Distributed Energy Resources (DERs) and Future Utility Business Model
- Electricity and Natural Gas Conservation
- Distribution Sector Resiliency, Responsiveness, and Cost Efficiency

5 https://www.kincardine.ca/en/municipal-office/resources/Documents/Kincardine-ECDMP-2019-2024-Final-Draft.pdf
6 https://www.huronkinloss.com/en/townhall/resources/Documents/Huron-Kinloss-Climate-Change-and-Energy-Plan_REVISED-December-2020.pdf
7 https://www.arran-elderslie.ca/en/municipal-services/resources/Documents/Conservation-and-Demand-Management-Plan-2019-2024.pdf
8 https://www.planthebruce.ca/official-plan

- Electrification and Energy Transition Panel

Specifically regarding conservation, the letter addressed the benefits and expectations of collaboration between Natural Gas and electricity distributors and operators in order to provide customers a consistent view and experience, both for residential and non-residential offerings:

Ontario continues to be a leader in energy conservation with a long history of delivering results and savings for ratepayers. While program coordination between roughly 60 local distribution electricity companies and Enbridge has historically been challenging in this space, the IESO and Enbridge have been successful in providing a one-window program for income tested customers since electricity conservation program delivery was centralized with the IESO. Building on this success, we must now turn our attention to delivering this same level of service to non-income tested residential customers. I ask that the OEB consult with the IESO and Enbridge and report back in April 2024 on how electricity and natural gas low-income and residential programs could be delivered through a single window. As the OEB begins planning for future natural gas energy efficiency programming that would take effect in 2026, I continue to look to the OEB to ensure Ontario electricity and natural gas ratepayer interests are protected and that Ontario takes every opportunity to generate deeper retrofits, more energy savings, and greater emissions reductions while ensuring natural gas costs remain affordable, stable and predictable.

In response to this, EPCOR has engaged with both Enbridge and the IESO to explore opportunities for collaboration and opportunities to leverage this framework into DSM offerings for customers in the future, as further explained in section 8.4 below.

While EPCOR continues to follow policy guidance from the Ministry, there are no direct impacts from the Minister’s letter on this filing.

8.3. Federal Carbon Pricing

As part of the Government of Canada's Federal Carbon Pricing Program ("FCPP"), a federal carbon pricing system has been implemented in Ontario, under the *Greenhouse Gas Pollution Pricing Act, 2018* ("GGPPA") with the following features:

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

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

EPCOR continues to file annual applications for FCPP rates and recoverable costs, effective April 1, most recently EB-2023-0274. EPCOR will continue to monitor and assess the potential impact of the FCPP on future customer consumption and conversion decisions.

8.4. Demand Side Management (DSM)

When preparing the 2023 update, EPCOR included commentary regarding plans to submit a DSM proposal in its next cost of service filing for Aylmer (or in a separate standalone proceeding), where the plan, the financial impacts and ratemaking implications can be addressed. While this was the intent, EPCOR is not currently ready to do so. This is largely attributable to the transitional state of the DSM framework for natural gas customers in Ontario, and specially the Enbridge DSM supplemental application to be filed in 2024.

After engaging third party vendors, as well as investigating potential collaboration with both Enbridge and the IESO (in response to the Minister of Energy's letter of direction as noted above in section 8.2), EPCOR believes that a collaborative, consistent program offering would be of best interest to its customers and the most effective way to deliver this would be through a shared arrangement with a larger provider.

In order for a DSM program offering to be successful, EPCOR would require several additional resources to prepare an application, launch, fulfill and meet the reporting obligations, which would lead to higher costs for customers if all of these roles were to be filled internally. EPCOR remains open to further collaboration discussions with the IESO and Enbridge to help achieve economies of scale in the DSM portfolio.

8.5. Renewable Natural Gas (RNG)

EPCOR understands and supports the development of an RNG market and facilitates inclusion of RNG in its gas supply portfolio. EPCOR recognizes the importance of Greenhouse Gas (GHG) abatement across the province, as well as the role that EPCOR plays in supporting the achievement of GHG emission reduction targets.

At this time, EPCOR does not hold any RNG supply in its Southern Bruce Supply Plan. EPCOR will update the Supply Plan as strategies for an RNG solution are developed and finalized in the Southern Bruce service territory. There are no updates to any RNG-related opportunities for EPCOR Southern Bruce at this time.

8.6. Integrated Resource Planning

As discussed in Section 3.1.3 this Supply Plan Update does not include potential impacts of future IRP projects. As per the OEB Staff Report for the Review of the 2023 Annual Update, the provision of information regarding IRP alternatives to facility projects are not properly part of a Gas Supply Plan review and EPCOR should not provide information with respect to options for IRP implementation in its Supply Plans.

8.7. Canada Green Homes Grant

In 2023, grant funding through the Canada Greener Homes Grant is being offered across the country to all eligible Canadian through the Home Efficiency Rebate Plus in Ontario will allow eligible homeowners to access the benefits of both programs through a single application and streamlined process regardless of their home heating fuel type.

The Canada Greener Homes Grant is no longer accepting new applications in March 2024.

EPCOR will continue to monitor and assess the potential impact of the Canada Green Homes Act on future customer consumption and conversion decisions.

9. Performance Metrics

EPCOR has drafted a performance metric scorecard in order to measure the effectiveness of the Supply Plan. Please see Appendix D **– EPCOR Southern Bruce Performance Scorecard** for details.

In the Staff Report to EB-2023-0111, OEB staff recommends that EPCOR should provide a more comprehensive list of major policy changes that would impact EPCOR's GSPs both in the long and short term. EPCOR have added a comprehensive list of major policy changes in the Scorecard starting with this Supply Plan Update.

10.Continuous Improvement Strategies

The continuous improvement to the supply planning process undertaken by EPCOR is an important element of the transparency objective of the Framework. EPCOR continues to proactively evaluate new supply and transportation options in accordance with the Framework's guiding principles.

EPCOR will also continue to proactively identify new opportunities to meet its gas supply obligations while meeting the Framework assessment criteria. EPCOR will also continue to review and improve the information it receives for market outlook and forecasting purposes.

11.Link to Other Applications

Related Application	How the Gas Supply Plan (Plan) informs the related applications	How the related application informs the Plan	Rate implications
Quarterly Rate Adjustment Mechanism	Will result in ongoing changes to the pass-through gas supply cost which are generally recovered through QRAM applications	QRAM applications include data and information which will help to inform Annual Updates and the next five year Plan	Mechanism through which most commodity and gas supply costs are passed through to customers in rates
Cost of service application for the rate stability period (2019-2028) (EB-2018-0264)	May inform mid-term updates and evidence when seeking specific deferral and variance account clearances, and service offerings, e.g. direct purchase option	The approved cost of service application set the assumptions underpinning the system configuration, customer connections, and volume forecast for the 2020 update to the Plan.	Rate schedules across rate classes defined by this filing, which include some limited gas supply charges and terms and conditions for rates.
Annual Rate Applications	Limited impact until end of rate stability term. On incentive rates formula until end of 2028 calendar year.	Not expected to influence the plan	Some gas Supply cost charges are updated pursuant to the incentive rates adjustment formula, and costs passed through to customers through Annual rate applications.
Leave to Construct Applications	The Plan provides the foundation for related Leave to Construct applications. Helps to align execution of these LTCs in accordance with the OEB's guiding principles in the EB-2017-0129 Framework.	New gas supply options, if any, resulting from new LTCs to be reflected by the Annual Update and the next iteration of the five year plan.	Any resulting changes to gas supply costs will be reflected in QRAM and/or Annual Rate applications.

Potential Projects to Expand Access to Natural Gas Distribution re: 2019 *Minister's Directive*	Projects are evaluated within the context of the framework set by the Board. Plan informs only the cost of gas supply generally speaking for bill impact and conversion analysis for bids.	Annual updates to the Plan to reflect new customer additions and any new incremental supply from existing supply points, as well as any diversity and flexibility provided by new potential points of supply and new/other suppliers as applicable.	By nature, any projects connected would be with funding which brings the P.I. to 1.0, therefore no material changes to rates, and harmonized into the existing service area and rates.
Long-Term Contract Applications	The Plan does not give rise to Long-Term Contracts, and therefore Long-Term Contract Applications are not foreseen.	EPCOR has no plans to enter into Long-Term Contracts as part of the Plan. There are limited fixed-price contracts for periods less than 12 months.	Material changes to gas supply costs resulting from Long-Term Contract applications will be reflected in QRAM and/or Annual Rate applications.

12. Appendices

Appendix A – Key Terms

AECO 5A Index: Popular index pricing instrument for the Alberta AECO Hub. Arithmetic average of daily prices, which are weighted average settlement prices for same-day delivery at AB-NIT. Tracks Alberta market prices closely.

Balancing Gas: The volume of gas purchased for the purpose of clearing the Cumulative or Daily Operating Imbalance.

Baseload Gas: The amount of natural gas delivered or contracted over a given period of time at a steady rate or price structure.

Contract Customers: The maximum volume or quantity of gas that EPCOR is obligated to deliver in any one day to a customer under all services or, if the context so requires, a particular service at the consumption point.

Contract Demand ("CD"): Means the maximum volume or quantity of Gas that Union is obligated to deliver in any one Day to EPCOR under all Services or, if the context so requires, a particular Service at the Consumption Point.

Contract Year: Means a period of twelve consecutive Months beginning on the Day of First Delivery and each anniversary date thereafter unless mutually agreed otherwise.

Dawn: Located southeast of Sarnia, Ontario, Dawn is referred to as a Hub as it represents the point where Enbridge supply, storage and transmission systems meet. A number of other pipeline systems (e.g. TCPL, Vector) are interconnected to Enbridge Gas' distribution system at Dawn.

Dawn Day Ahead Index: Popular index pricing instrument for the Ontario Dawn hub. Arithmetic average of daily prices, which are weighted average settlement prices for next-day delivery at Dawn. Tracks Ontario market prices closely.

Federal Carbon Pricing Program A Federal carbon pricing system implemented in Ontario, under the federal Greenhouse Gas Pollution Pricing Act.

Gas Day: A period of 24 consecutive hours, beginning at 10:00 am ET. The reference date for any day shall be the calendar date upon which the twenty-four (24) hour period commences.

Gas Year: A period of twelve (12) consecutive months usually beginning on

November 1st and continuing until October 31st of the following year.

Heating Degree Days (HDD):	The number of degrees that a day's average temperature is below 18°C, which is the temperature below which buildings need to be heated.
Planning Year:	A period of twelve (12) consecutive months usually beginning on April 1st and continuing until March 31st of the following year.
Rate 1 – General Firm Service Rate:	Any customer in EPCOR's Southern Bruce Natural Gas System who is an end user and whose total gas requirements are equal to or less than 10,000 m3 per year.
Rate 6 – Large Volume General Firm Service Rate:	Any customer in EPCOR's Southern Bruce Natural Gas System who is an end user and whose total gas requirements are greater than 10,000 m3 per year.
Rate 11 – Large Volume Seasonal Service:	Any customer connected directly to EPCOR's Southern Bruce Natural Gas High Pressure Steel System and who enters into a contract with EPCOR for firm contract daily demand of at least 2,739m3.
Rate 16 – Contract Firm Service Rate:	Any customer connected directly to EPCOR's Southern Bruce Natural Gas High Pressure Steel System and who enters into a contract with EPCOR for firm contract daily demand of at least 2,739m3.
WACOG:	Weighted Average Cost of Gas.
Western Canadian Sedimentary Basin (WCSB):	The Western Canadian Sedimentary Basin (WCSB) is a vast sedimentary basin underlying 1,400,000 square kilometres (540,000 sq mi) of Western Canada including south-western Manitoba, southern Saskatchewan, Alberta, north-eastern British Columbia and the southwest corner of the Northwest Territories. It consists of a massive wedge of sedimentary rock extending from the Rocky Mountains in the west to the Canadian Shield in the east. This wedge is about 6 kilometres (3.7 mi) thick under the Rocky Mountains, but thins to zero at its eastern margins.

Appendix B – Market Trends Analysis

Current and Future Natural Gas Market Trends Analysis
Provided by ECNG

As an element of the risk mitigation strategy, the following overview of current and future trends is intended to inform EPCOR of any changes in natural gas market fundamentals which have the potential to impact its ability to execute the Supply Plan. The North American (N.A.) fundamental drivers for natural gas are demand, supply, storage (near term only) and in a more limited/indirect way crude oil, underlying USD/CAD currency and in the longer term the global LNG market. “Near-term” is within the next 12 months, “Mid-term” is 1-2 years after Near-term, “Long-term” is 3-5 years after Mid-term.

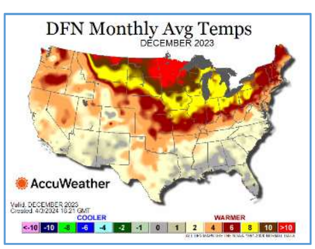
External influences in this outlook are dominated wars in Ukraine and Israel / Middle East influencing security of supplies of crude oil and natural gas. Geopolitical risk has pushed global oil prices upward much more than natural gas due to offsetting warmer than normal winters in both Europe and N.A. leaving end of winter inventories significantly higher than the 5 year averages.

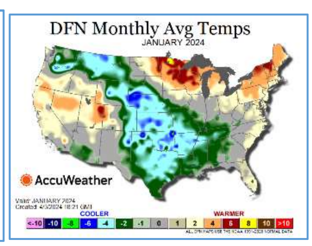
Demand Impact on pricing:

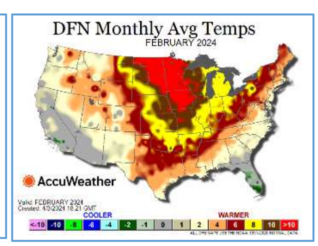
NYMEX and Dawn Near-term Mildly Bullish; Mid and Long-term Very Bullish

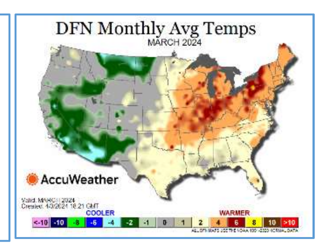
AECO Near-term Bearish; Mid and Long-term Bullish

US natural gas R&C sector consumption in Winter ‘23/’24 faltered again with winter weather even warmer vs the previous winter. The weather charts below show Departure-From-Normal in DegF with the brightest red, bright yellow and deep red being >10F, ~8F and ~6F respectively warmer than normal.

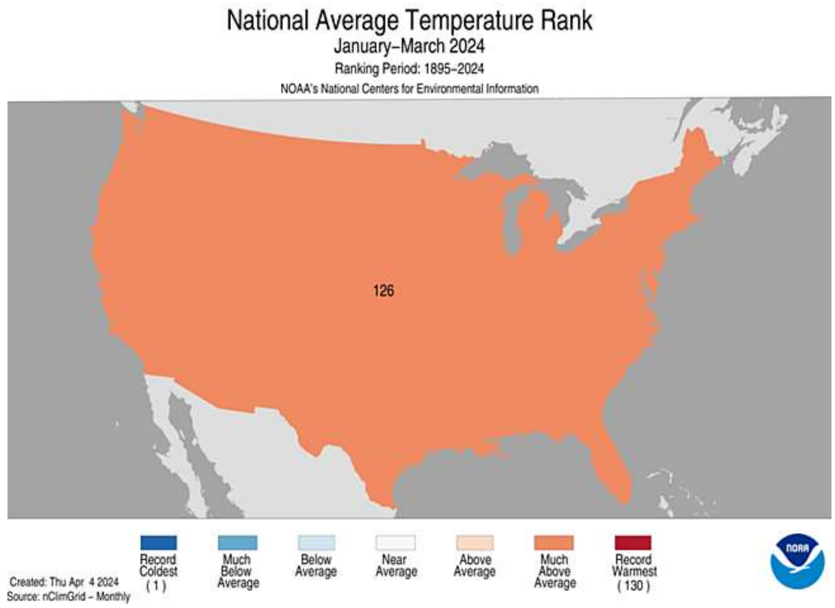






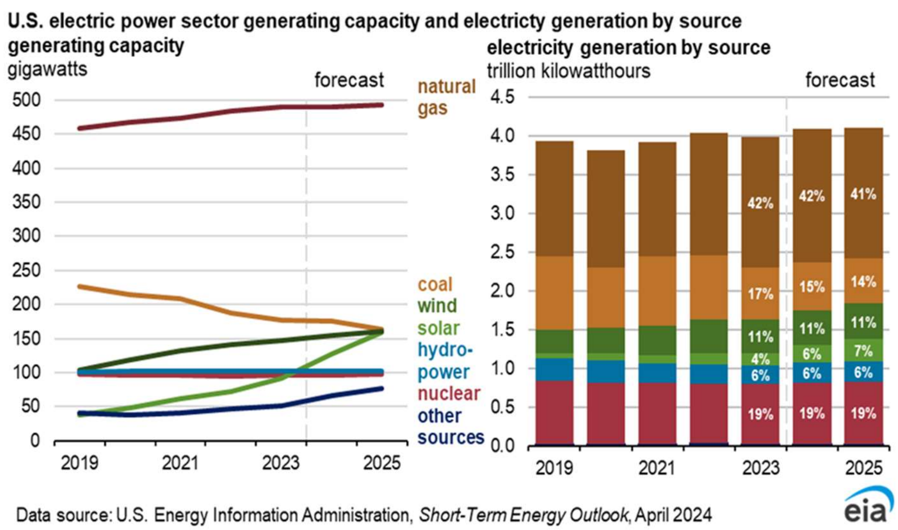


January to March 2024 heat sensitive demand saw the 126th lowest of 130 years as reported below by NOAA. (https://www.ncei.noaa.gov/access/monitoring/us-maps/maps?maps=national-tavg-rank--3--202403)



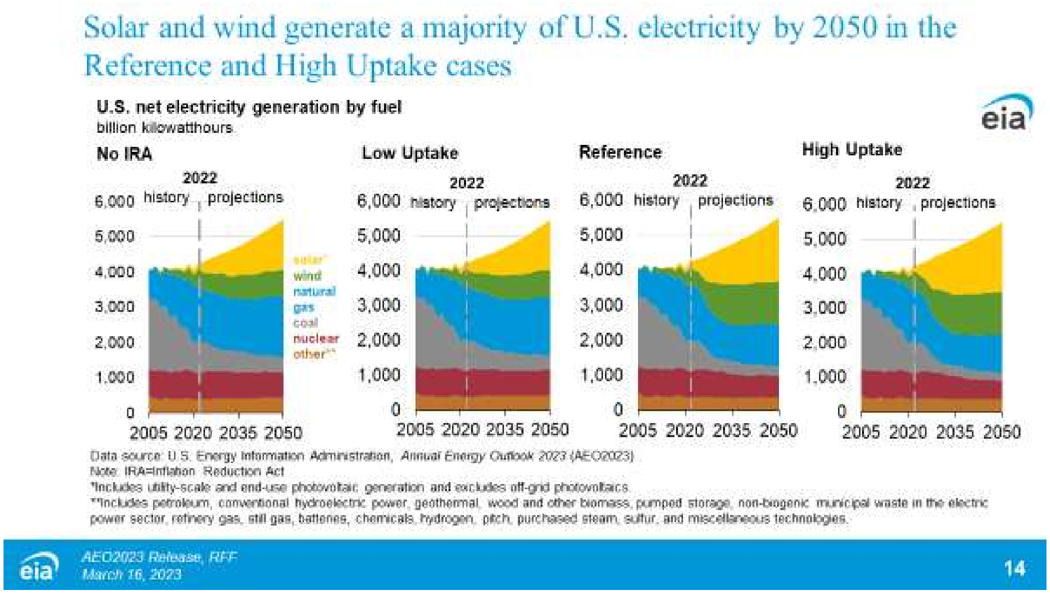
In the forecast in EIA's most recent Short Term Energy Outlook 2024 - April 2024 (STEO 2024), Industrial demand grew in 2023 vs 2022 and the EIA forecasts modest shrinkages in both 2024 and 2025 by amounts less than 0.5 Bcf/d. Surprisingly gas-fired power generation grew similarly in 2022 and 2023 with modest growth in 2024 (0.4 Bcf/d) and then a drop off in 2025 of 0.8 Bcf/d mostly due to renewables (solar and wind pushing into the generation mix).

Mid-term and Long-term gas consumption demand growth is largely expected by most forecasters in the United States (U.S.) is in gas-fired power generation. Coal-fired power generation retirements appear to be minimal in 2024 but take a steeper drop in 2025 as seen in the left graph below from STEO 2024. Interestingly in the right graph below, natural gas eclipsed 40% of the total 4 trillion kilowatt-hours generated in 2023. Gas-fired share seems to flatten out at 42% as renewables push out coal-fired generation in 2024 and 2025. Also, gas-fired generation will likely continue running more baseload hours and serve to balance the grid's needs due to intermittent renewables. The energy consuming market continues to lose its ability to fuel switch when natural gas becomes expensive and thus stimulates higher price volatility needed to encourage more supply. No recession type drivers are expected in this forecast.

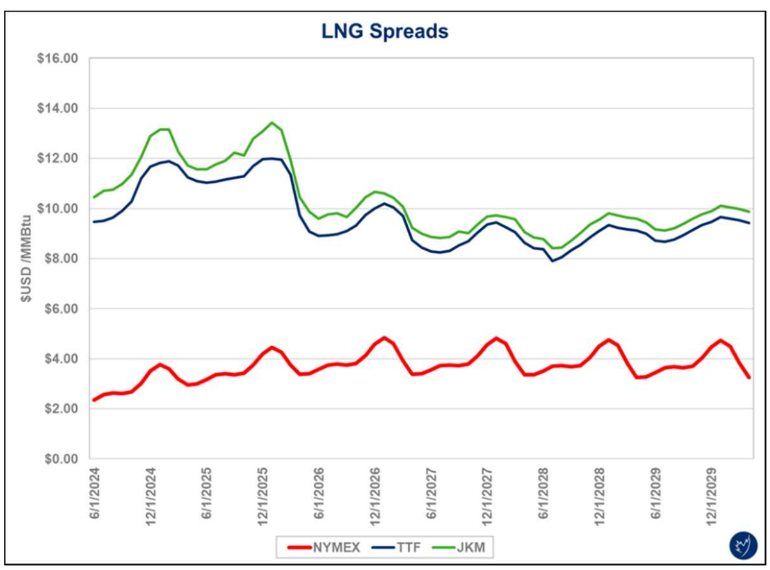


In our opinion, Industrial demand forecast variation is not as material as gas-fired power generation or LNG feedgas for exports discussed later.

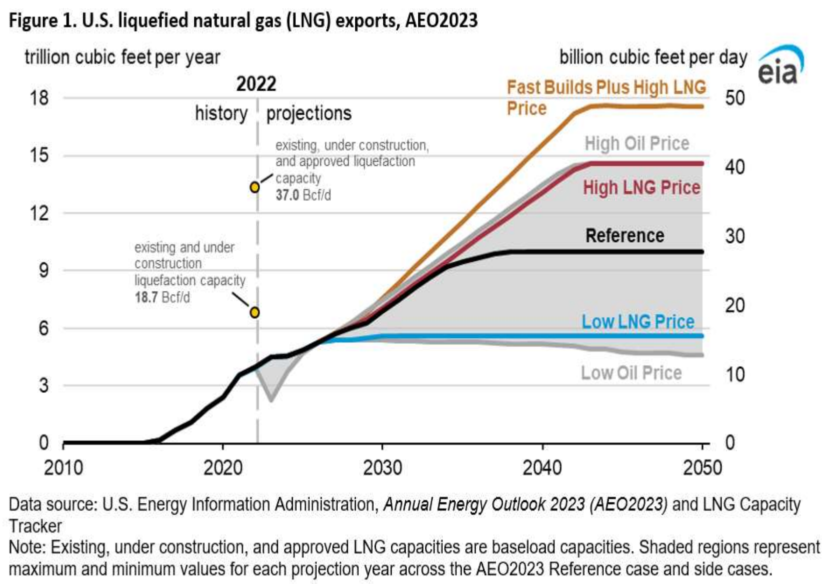
The EIA in its latest Annual Energy Outlook (AEO2023), next release expected in 2025, cites in its Reference Case a modest drop of natural gas for power generation to the end of 2030 at the expense of renewables. In its High Uptake Case (high uptake of renewables driven by federal government funding Inflation Reduction Act) natural gas consumption drops more significantly at the expense of renewables. The graphs below show these forecasted trends. ECNG's view continues to be that renewables uptake will be slow due to issues relating to siting projects, regulatory approvals, interconnection queues for generation and storage, rising costs and supply chain issues.

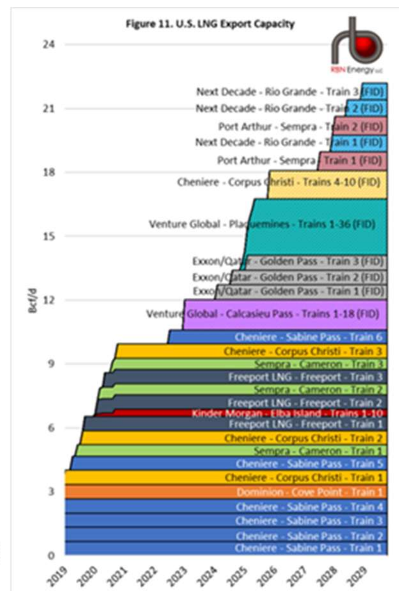


The single largest increase in demand is in exports of liquified natural gas (LNG) in the next 5 years. The chart below shows the ongoing incentive for LNG exports to move NA supply to Global markets.

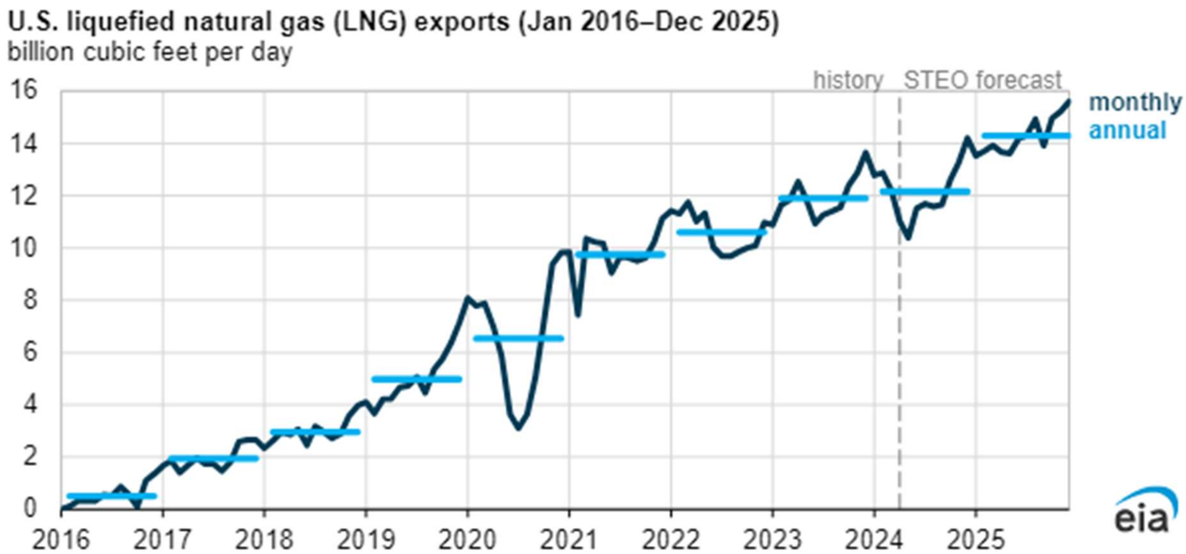


Despite the narrowing of forward pricing, numerous projects have reached Final Investment Decision (FID) and the necessary approvals to proceed to construction. The next graph below to the left, was generated as part of the AEO2023 report, however released May 23, 2023. This shows the staggering total of real potential (of projects) that are in play in the next 5 years alone that have received full regulatory approval from DOE and FERC. More recently the Biden Administration asked for a pause in approvals for those not yet begun construction to consider a wider environmental impact of LNG export projects. The graph below to the right is from RBN Energy showing projects that have reached FID hitting 22 Bcf/d of export capacity by 2030. One item to note as well is that most of these projects use natural gas to generate the power needed to liquify the gas and it is typically at least 10% so including the feedgas of those projects, over 24 Bcf/d of new supply is needed. Post 2025 the pipeline grid will be challenged to deliver the necessary supply on time from reserves to liquefaction sites.





In 2023, U.S. LNG exports averaged 12.0 Bcf/d and including fuel gas for refrigeration 13.0 Bcf/d with total capacity equal to just over 15 Bcf/d (the difference coming from planned maintenance or unexpected outages). EIA estimates for 2024 only marginally more than 2023's utilization rates. However, in 2025 the expectation is for exports to grow throughout that year and to average 14.4 Bcf/d, with total feedgas approaching 16 Bcf/d with two additional projects ramping up to full production. If high load factors can be maintained this demand continues to be the most significant contributor to a tight supply-demand balance in N.A. Imports and exports to/from Canada are not expected to grow or fall materially in the near-term time horizon as pipelines are operating at near capacity. However, STEO commentary cites an almost 1 Bcf/d increase in US exports to Mexico in 2024-25 as several expansion pipelines have not reached full service at this point in time.



Expectations for exports to Mexico during this outlook's horizon (5 years out or more) could see average exports to Mexico well exceed 7 Bcf/d from the current flows of 5-6 Bcf/d. This increased demand is mostly for LNG liquefaction for Pacific side exports which shorten LNG routes to Asia and lower transport costs by approximately $2 US/MMBtu. Costa Azul is likely the first Mexican LNG export project supplied via with TC Energy receiving FERC approval of its North Baja Xpress Project in Arizona accessing the Permian supply basin. LNG projects Golden Pass and Plaquemines publicly state commissioning in late 2024, start-ups are slow and specifically Plaquemines has stated a 2 year start up is expected.

https://www.eia.gov/todayinenergy/detail.php?id=60944

There are also LNG export projects to the Canadian Pacific Coast for Western Canadian Sedimentary Basin (WCSB) supply that are on track to begin commissioning in late 2024 and throughout 2025. LNG Canada's Phase 1 with two trains of 0.9 Bcf/d each is now expected to fully flow in late 2025 to early 2026. Next is Woodfibre at 0.3 Bcf/d, expected to begin service in 2027 (has not changed its start date). Cedar LNG's 0.4 Bcf/d project is now expected to flow in 2028-29 (delayed from 2027). The Ksi Lisims LNG 1.7 Bcf/d project has emerged on West Coast targeting flow by 2028-2029. This comes to a Canadian probable total of 4.2 Bcf/d by 2029, not including pipeline fuel gas and potential gas for power generation (depending on the project). As a result, we believe current forward pricing for calendar years 2025-2028 at AECO now over $4.00 CAD/GJ are also likely to persist. Other demand growth sectors have been mostly in AB in coal-fired generation retirements and in oil sands cogeneration of steam and power. Some oil sands production growth is likely as Trans Mountain Pipeline (TMP) comes into service mid-2024 leaving spare oil export capacity by rail. Coal-fired generation retirements are now complete with only 0.3 Bcf/d increase in average gas consumption expected as a result. Combined gas demand growth of oil sands and coal displacement generation could exceed 0.5 Bcf/d.

Finally, a new possible significant power demand that is emerging is for computer servers driving Artificial Intelligence (AI) development and subsequent data centers required. Estimates by experts range from 3 to 16 Bcf/d of gas-fired power generation depending on the mix of generation sources available to meet those growing needs. The timeframe for this demand growth is late in this decade and into the next.

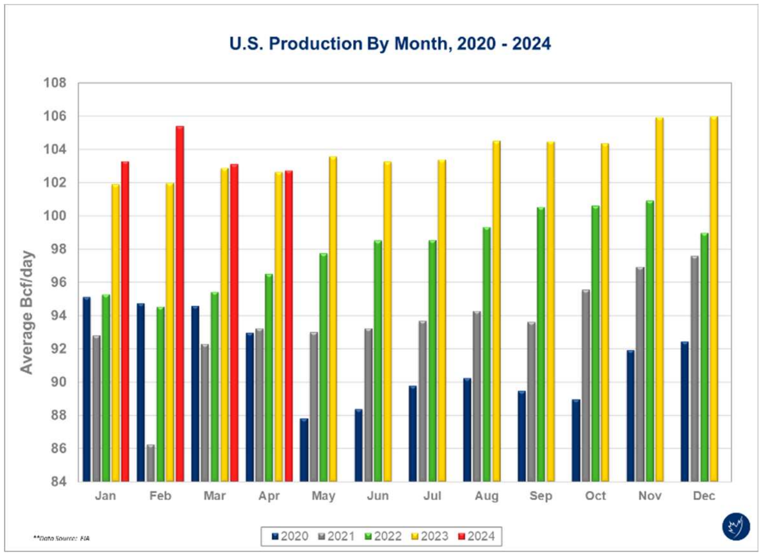
The US demand outlook for 2023 and beyond is for modest to no growth in domestic demand from R&C and industrial markets. Growth in the next 2 years in gas-fired power generation sectors offset by renewables driven by IRA funding but on a modest uptake. Demand growth will clearly come from significant LNG exports and associated feedgas for liquefaction cooling.

Supply Impact on pricing:

NYMEX and Dawn Near-term Very Bearish; Mid and Long-term Very Bullish

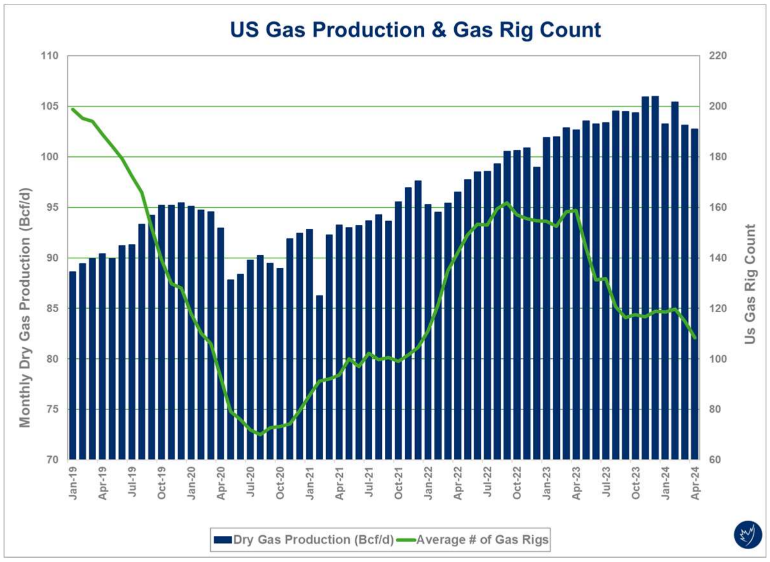
AECO Near-term Very Bearish; Mid and Long-term Mildly Bullish

U.S. dry gas production (supply) growth has been impressive since Q4 2023 and in early 2024 driven originally by high prices back in 2022 and LNG export projects expected to substantially flow in 2024. US production has impressively moved from an average of 103.7 Bcf/d in 2023 to an exit production in November and December 2023 of 106 Bcf/d. This production gain was halted by a brief but significant polar vortex storm that dropped daily production down (wellhead freeze-offs) to an estimated 87 Bcf/d before returning to over 105 Bcf/d by early February. Without this event it was likely that 4 consecutive months could have reached 106 Bcf/d.



As a result of a combination of 1) a significantly warmer than normal winter across NA, 2) new LNG project delays, 3) Freeport LNG ongoing production issues, 4) lower European LNG demand and 5) impressive US producer increases in supply, a significant drop in gas pricing was necessary. This price drop is necessary to drive a pullback on supply growth to balance the inventory surplus (exiting the winter).

The EIA is forecasting from April to October 2024 about 103 Bcf/d which is 1 Bcf/d less than last year for the same summer period. At this point in time that forecast appears realistic. In the first 4 months of 2024 several large producer announcements regarding 2024 CAPEX had similar themes of 1) oil directed drilling focus, 2) reduced overall CAPEX vs 2023, 3) expectation of increased “drilled-but-uncompleted” wells inventory which would lead to spare capacity for future production as prices recovered (as supply and demand return to balance). In other words, the messaging was that despite dropping rigs over the year, should the market need additional supply producers would respond relatively quickly. A final observation is that the supply community continues to produce more supply with less rigs (see chart below).



In the mid to longer term, new blocks of supply need to arrive on time to meet new LNG blocks of demand. Pipeline projects in Texas, Oklahoma and Louisiana appear to be on schedule with only modest headwinds. The challenge will be for adequate new supply to arrive on time or will portions come from existing markets thus driving up the price. Prolific reserves exist in Alberta and the US Northeast such that those more local markets do not rely on supply from Gulf of Mexico deposits. There is a possible scenario whereby new pipelines will be needed to move gas continentally north to south to fill the gap. These are the pipeline projects that will likely face stronger headwinds. This could lead to a higher NYMEX price that is not fully translated into the northern parts of North America. In other words, Dawn basis discounts to NYMEX may grow later in this decade as a result.

The Western Canadian Sedimentary Basin (WCSB) production has grown substantially in preparation for LNG Canada but also, higher oil sands demand (TMP start up) and Alberta power generation demand (complete phase out of coal-fired generation) and increased access to domestic and export markets through significant NGTL (Nova Gas Transmission) expansions completed. We continue to see evidence of significant supply growth in BC's prolific Montney shale formation as this is primarily the supply source for LNG Canada via TC Energy's Coastal GasLink.

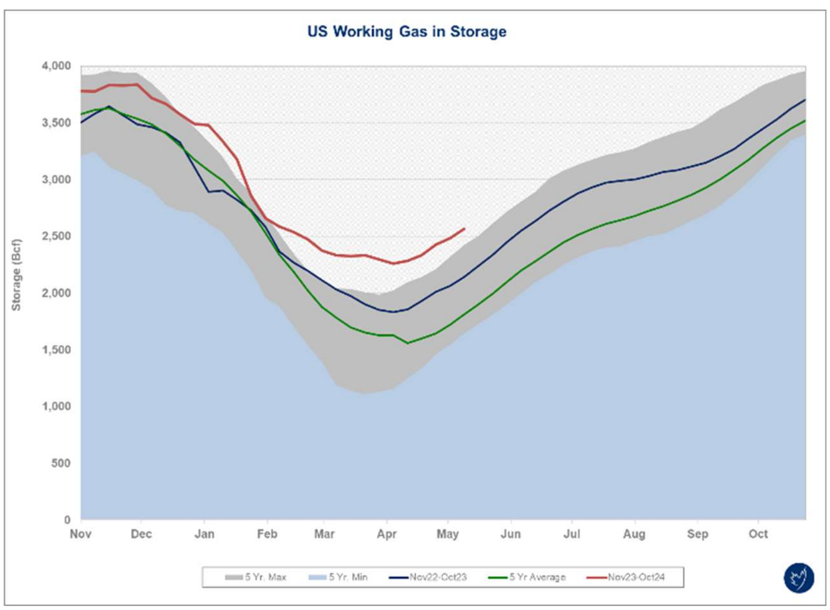
The supply response in the WCSB is expected to be quicker on a percentage basis compared to the U.S. however additional supply will be suppressed by limited pipeline capacity to the US and Eastern Canada to impact the NYMEX / US market. These constraints contribute to a significant above 5 year average storage level due to only modestly growing BC and AB demand which continues to drive the bearish sentiment in the short run. Mid and Long-term the sentiment moves towards bullish as LNG Canada begins circa mid-2025 into 2026 and then doubling by 2030 putting stress on supply and pipelines to deliver on time.

Storage Impact on pricing:

NYMEX and Dawn Near-term - Very Bearish; Mid and Longer Term – Mildly Bullish

Aeco Near-term - Very Bearish; Mid and Longer-term – Mildly Bullish

Total U.S. working inventories on April 5, 2024 ended well above the five-year average of 1.65 Tcf by approximately 630 Bcf (surplus). Most industry forecasters see the end of the 2024 injection season ending in a surplus to the five-year average but only between 150-300 Bcf, mostly due to physical limitations of storage (capacity and deliverability) and current sentiment that producers will curtail supply at prices persistently below $2.00 US/MMBtu. The U.S. Energy Information Administration estimates that natural gas in storage will end the injection season at a record 4,120 Bcf, or 10% above the five-year average. Demand side elasticity has been greatly reduced by coal plant retirements over the last 5 years to balance storage levels through the summer.



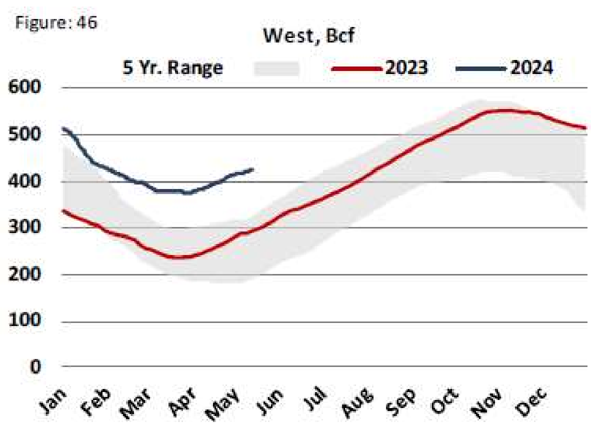
The table below from National Bank shows US withdrawals in Bcf/month per winter (Nov-Mar). It is not surprising that this year is the lowest for storage withdrawals in the last 9 years. (at the time this table was created Mar'24 withdrawals were not yet finalized and the 100 estimate below in red is likely overstated).

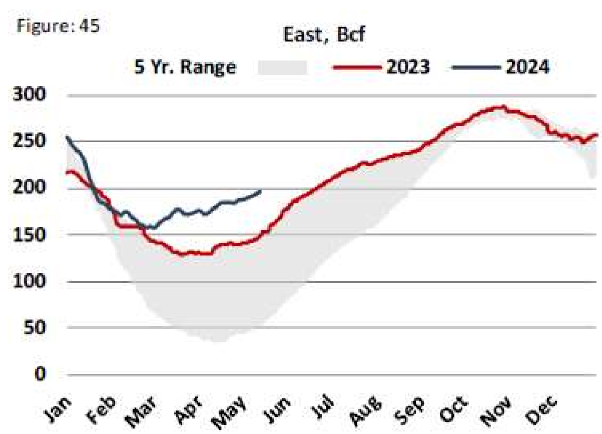
Bcf	24/23	23/22	22/21	21/20	20/19	19/18	18/17	17/16	16/15	Avg
Nov	5	-108	-84	21	-129	-186	-96	-43	52	-63
Dec	-302	-576	-429	-612	-431	-363	-748	-739	-367	-507
Jan	-785	-422	-894	-725	-493	-581	-809	-601	-717	-669
Feb	-268	-403	-631	-785	-532	-614	-484	-306	-392	-490
Mar	-100	-231	-183	-45	-150	-346	-285	-279	-34	-184
Total	-1,449	-1,739	-2,220	-2,145	-1,734	-2,090	-2,422	-1,967	-1,457	-1,913

EIA, S&P Global, NBC

A higher US storage balance means approximately 1-2 Bcf/d more supply available in the upcoming winter. Supply levels will need to rebound to 105 Bcf/d or more to balance the additional LNG export growth expected in 2025 and growing gas-fired power generation.

In Canada, storage at winter's end in Alberta (essentially the "West" graph below) is above the 5-year high, similar to storage at Dawn (essentially the "East" graph below) although different paths to get there.





Storage graphs from RBN Energy LLC 2021 on May 15, 2024.

All these current storage balances lead to a more bearish sentiment on summer gas pricing in 2024 and winter 2024/25 as a significant surplus to the 5-year average is carried into the winter (US and Western Canadian). In the Mid to Long Term, our sentiment appears to be moving into a Mildly Bullish realm simply due to the lack of storage capacity growth in proportion to the total market growth (including LNG exports) to offset the loss of market elasticity with emissions reducing coal-fired generation retirements and to a smaller extent industrial dual-fuel boiler retirements over the past 5-10 years.

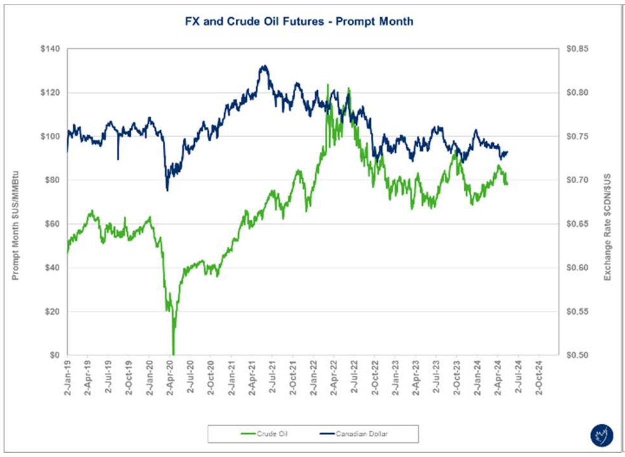
Crude Oil and Foreign Exchange Impact on pricing:

NYMEX and Dawn Near-term and Longer-term - Very Bearish

AECO Near-term – Neutral; Longer-term - Mildly Bullish

West Texas Intermediate (WTI) oil pricing in late 2023 and early 2024 has been moving between about $70 and $90 USD/b after reaching $120/b shortly after the war in Ukraine began in February 2022. The risk premium currently is more driven by the Israeli-Hamas (and Iran) and not as much by the ongoing Russia-Ukraine war. These ongoing wars should continue to incent a quicker pace to bring on more renewable energy sources. However, they continue to be impeded by higher cost of raw materials, interest rates and power grid infrastructure planning. The use of fossil fuels, mostly coal and oil continue to be used to bridge the timing gap and provide energy security during intermittent daily/weekly stretches in the long term. The previous EIA long term forecasts have not been updated since this Appendix was updated where the expectation of the US remaining a net exporter of petroleum products continues into the distant future (2050). Crude oil pricing continues to economically drive the supply of US oil especially from the Permian basin (Texas and Oklahoma) and the Baaken basin (North Dakota) resulting in associated natural gas supply which is predominantly the reason for our continuing bearish sentiment in this category. Regarding AECO, impact of crude pricing has not influenced a stronger Canadian dollar of late however, as TMP comes online at full output it will enable Western Canadian producers to realize much higher oil prices (less discounting to WTI) due to supply being restricted. When this happens, additional crude production will lead to additional gas demand for steam and power which is the primary driver to our Mildly Bullish sentiment in the long term at AECO. In the near term, crude oil market has little impact on FX or additional supply on WCSB supply so Neutral is our sentiment.

The next two graphs show WTI pricing with the U.S./Canadian foreign exchange (FX) and FX with the price of gas in the WCSB (AECO). It appears the Canadian dollar weakness has not contributed the AECO price fall since mid-2022 to the present.

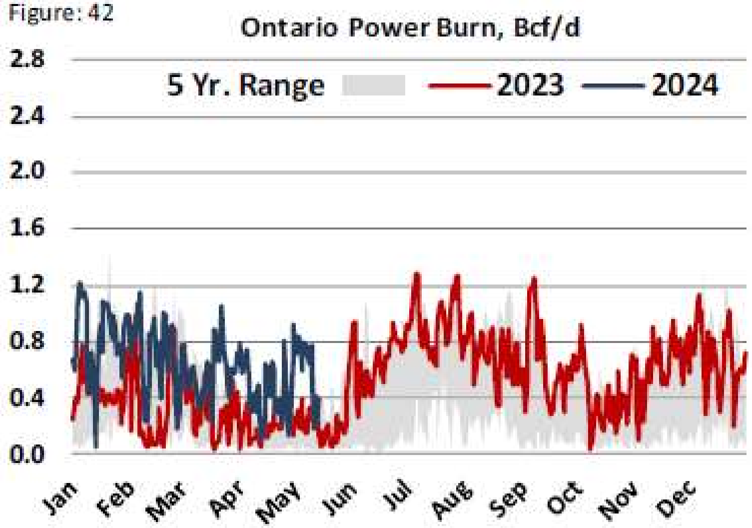


Dawn Market Hub Discussion

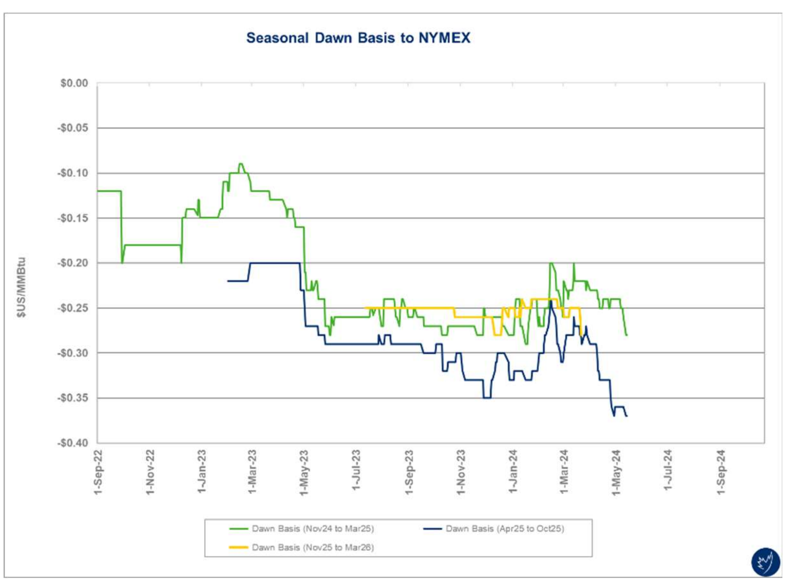
Natural gas primarily flows into the Dawn Hub ("Dawn") from the WCSB and from the U.S. Marcellus and Utica shale plays in the Appalachian region as well as from the Chicago Citygate (a market Hub with excess supply from WCSB, Baaken oil/gas shale formation, Rockies, Mid-Con and the Gulf of Mexico supply regions). There are no new supply pipeline projects expected in the Dawn connected infrastructure over the supply planning period that will shift the fundamental supply and demand dynamics to a degree that will impact the viability of the Supply Plan. With its multiple pipeline connections to the largest supply basins in N.A. providing supply reliability and access, the Dawn market can be vulnerable to pipeline contracting, renewals and long-term toll negotiations between pipelines and its shippers (suppliers, distribution utilities, marketers, and large industrial buyers). Within the next 5 years, some long-term contracts will expire or may be reopened and may not be renewed under the same terms. This change in contracting can alter the flow dynamics into and out of Dawn which will influence the price of gas there. Despite these potential undercurrents, the Gas Supply Plan is expected to be able to deliver on the guiding principles of cost-effectiveness, reliability, and security of supply.

Nearer term Dawn basis forward pricing curves are showing trends that are at a larger discount to NYMEX of late likely due to the excess storage gas remaining from the second consecutive warm winter at Dawn and at sites neighboring Midwest US (mostly Michigan). The mild weather in early 2024 again surprisingly did not lower demand from Ontario gas-fired power generation fleet and we expect similar-to-higher demand as was seen last summer to back up continuing nuclear refurbishments in Ontario plus supporting modest increased power demand year-over-year. Surprisingly the forward price curves at Dawn continue are trading only modestly narrower of a discount to NYMEX in winters and summers starting November 2025 likely due to only modest demand growth perceived low risk of long-term pipeline contracts to Ontario not being fully renewed. The results of the Independent Electricity System Operator's Expedited Long-Term RFP (E-LT1 RFP) due in mid-2023 resulted in just under 300 MW of gas-fired power generation additions to be connected within the risk horizon of this study. There have also been announcements by the Ontario Government of subsidizing new steelmaking technologies at Sault Ste. Marie and Hamilton that will likely increase either the power needs and/or the gas supply needs should these opportunities become be realized later in this decade. All these increases in demand amount to approximately 0.1-0.2 Bcf/d of new natural gas demand in Ontario.

Figure: 42



Ontario Power Burn from RBN Energy LLC 2021 on May 15, 2024.



The current Dawn basis market looks like good value however based on EPCOR's lack of interest in purchasing forward basis, which is in USD, there is no purchase opportunity (based on this index). However, there continues to be upside price risk in the Dawn market from modest demand growth, no new supply, and the low risk of supply (transport) non-renewals.

Summary table of market sentiments below.

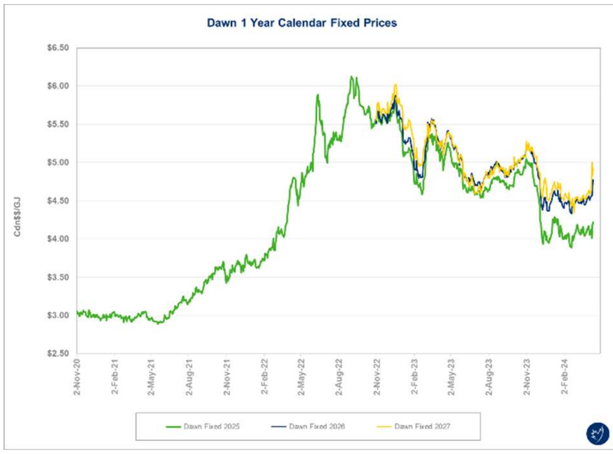
	NYMEX and Dawn		AECO	
Market Driver	**Near-term**	**Mid to Long-term**	**Near-term**	**Mid to Long-term**
Demand	Mildly Bullish	Very Bullish	Bearish	Bullish
Supply	Very Bearish	Very Bullish	Very Bearish	Mildly Bullish
Storage	Very Bearish	Mildly Bullish	Very Bearish	Mildly Bullish
Crude Oil & FX	Very Bearish	Very Bearish	Neutral	Mildly Bullish
Overall	**Mildly Bearish**	**Bullish**	**Very Bearish**	**Mildly Bullish**

Near-term Summary on pricing:

NYMEX and Dawn Mildly Bearish

AECO Very Bearish

In the next 1-2 years modestly growing LNG exports, increased gas-fired power generation demand, offset by high inventories at winter's end, with appear to be adequate year-over-year increases in supplies make for a continued well supplied short term market. As a result, NYMEX and Dawn price outlooks in the short term are likely to stay at historic lows until either sustained higher LNG exports resume over 15 Bcf/d and/or a normal winter does not provide the market with a supply surplus. The forward Dawn price for 2025 has upward volatility risk to the current forward prices shown in the graph below with normal winter weather scenario. AECO pricing is likely to stay suppressed with abundant storage inventories until LNG Canada flows at steady-state which will draw-down storage as new supply attempts to match the new block of demand. We are confident that the time needed for new supply to respond will be less than a year. Expected exports to the US will be modest as regional storage surpluses weigh on local Midwest US pricing. Current forward pricing history is found below.


Dawn 1 Year Calendar Fixed Prices
Cdn$$/GJ
Dawn Fixed 2025
Dawn Fixed 2026
Dawn Fixed 2027


Aeco 1 Year Term Prices
$CDN/GJ
Nov24-Oct25
Nov25-Oct26
Nov26-Oct27
Nov27-Oct28
Nov28-Oct29

Long-term Summary on pricing:

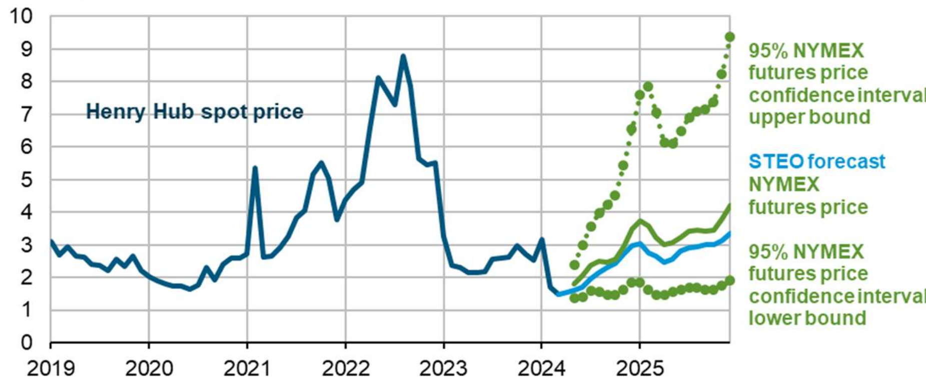
NYMEX and Dawn Bullish

AECO Mildly Bullish

Three to five years out, in the U.S. the expectation of significant growth in LNG exports, modest economic growth, continued fuel of choice in power generation and slow to arrive (on time) supply growth puts pressure on forward pricing to move upward. Local pipelines appear to be planned to match the supply needs of the coming LNG growth surge but there may be inadequate new supply from the local basins, causing the upward price risk. The lack of market elasticity accelerates price volatility (as we saw in 2022) to encourage new supply or to have LNG exports slow down to bring demand in balance with supply. The NA gas market will most likely be influenced by global LNG pricing before the end of the decade. Storage expansions may be necessary as well to meet the intermittent needs of natural gas-fired power generation as it supports renewable generation as supporting peak winter heating demands. US natural gas production can respond in the years ahead but there may be significant lags in pipeline capacity access to bring supply from north to south. The current forward landed cost of gas at Dawn currently resides around $5.00 CAD/GJ for the calendar years 2026-2029. This is good value as the cost of raw materials, labour and global energy prices are likely to persist and support this price in the mid to long-term. The AECO forward pricing volatility is limited to a shorter time frame with evidence of strong supply growth in 2023 coupled with high storage inventory ahead of Phase1 of LNG Canada start up. Supply access necessary to fill LNG Canada's start is capable, however, coordination timing could lead to intermittent daily and monthly discounts and/or premiums for several months until steady state is achieved. There continues to be lesser of a concern of WCSB supply meeting new upcoming Canadian LNG export expansion needs relative to the risk of US LNG expansion growth being met by timely supply.

The chart below speaks volumes to the range of future price outcomes (green dots) derived from options market data which in turn come from recent historical price volatility.

Henry Hub natural gas price and NYMEX confidence intervals
dollars per million British thermal units



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, April 2024, CME Group, and Refinitiv an LSEG Business

Note: Confidence interval derived from options market information for the five trading days ending April 4, 2024. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Appendix C – ECNG Credentials

ECNG Energy Group

ECNG Energy Group is Canada's largest full-service energy management consultant that works exclusively for the end-user in contracting for natural gas and electricity supply as well as delivery services. Further, we provide complete solutions ranging from energy conservation to electricity generation. We manage a volume of approximately 150,000 gigajoules per day of natural gas and 2.5 billion kilowatt hours annually on behalf of our clients, making ECNG the largest purchaser, other than the major utilities, in Canada. The advantages of retaining ECNG are access to specialized in-depth industry expertise, encompassing day-to-day market knowledge, utility rate options, existing regulatory framework, impending changes in these ground rules, and contact with a wide range of reliable gas suppliers.

ECNG's fees are fully transparent. At no time does ECNG take title to supply nor do we receive supplier kickbacks on any natural gas or electricity supply procurement transactions. The client always pays the true cost as offered by the supplier with zero margins being given back to ECNG. This ensures we always achieve the utmost competitive and transparent pricing while providing end-use consumers with objective and expert energy advice.

ECNG has been in business since 1987 and has built a large and loyal client base, including many of Canada's leading corporations, retailers, healthcare providers and associations. Our service to these clients includes over 21,000 end-use locations in all deregulated jurisdictions across the country. With this scale of operation, ECNG receives virtually every cost saving proposal from the supply and transportation communities. Finally, economies of scale and scope permit ECNG to provide its services at a fee that is a small fraction of the delivered cost of your energy. Additional information is available by visiting our web site www.ecng.com.

ECNG PRINCIPALS CVs

Angelo P. Fantuz – Director, Client Services

A Professional Engineer, Angelo brings 35 years of experience to his current role advising Canada's large commercial and industrial end-users about natural gas and electricity procurement and developing procurement strategies for clients. Angelo and his team are also responsible for monitoring regulatory development in order to ensure ECNG and its clients are prepared for what's ahead. Prior to joining ECNG in 2003, Angelo held senior roles at Eastern Pan Canadian/EnCana and Union Gas Limited. While at Union Gas he was a key sponsor in the development of Gas C.A.R.E. relational database to track, control and schedule the gas flow between Union Gas and its interconnected pipelines. He also testified at the Ontario Energy Board defending gas costs embedded in customer rates.

Dave Duggan – Director, Energy Supply & Market Risk

One of Canada's leading authorities on energy commodity purchasing and market fundamentals, Dave is a respected thought leader. He has shared his expertise and understanding of the Ontario and Alberta power markets and Eastern and Western Canada natural gas markets at various conferences presenting multiple times at EMC's Future of Manufacturing Conference, BOMA Canada's BOMEX – Canada's Building Excellence Summit and other conferences. Since 1995, he has held various senior leadership roles within ECNG and executed thousands of natural gas, power and transportation hedge purchases. He is currently responsible for setting market strategy and leading the Energy Commodity Supply and Price Risk Management team, which procures natural gas and electricity supply for utilities, institutional, commercial and industrial clients across Canada. Dave and the team collect and assess market intelligence and conduct fundamental analysis and financial modeling of risk management strategies for natural gas and electricity.

Paul Weingartner – Director, Client Services

Paul is both a Certified Energy Manager and Certified Energy Auditor with almost 20 years' experience building Canada's largest direct-purchase programs across multiple industries. He is a subject matter expert and speaker for organizations such as: the Canadian Healthcare Engineering Society, where he currently serves as Chair of its Corporate Advisory Council; the Independent Electricity System Operator; and Natural Resources Canada, among others. He joined ECNG Energy Group in 2008 after managing national energy programs for HealthPRO Procurement Services. Paul is responsible for managing ECNG's largest clients, developing and implementing customized multi-pronged commodity hedging strategies designed to meet their unique needs and bringing added value by identifying opportunities in the highly complex and volatile natural gas and electricity markets.

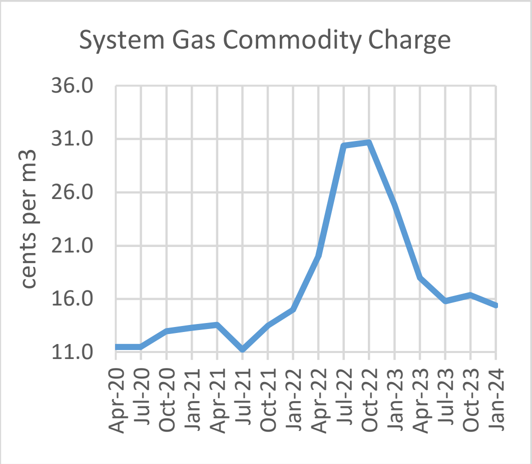
Steve Williams – Senior Energy Analyst, Supply & Risk Management

Steve has a deep understanding of the complex Canadian natural gas and power markets, from pricing to storage to logistics and more. He analyzes the markets to transact cost-effective natural gas and power deals in Ontario and Alberta. Steve's training as an accountant informs his detailed approach and helps ECNG's clients create impactful commodity strategies. He joined ECNG in 2007 after building his career in finance at Horizon Utilities and Burlington Hydro.

Althea Rothwell, Senior Consulting Analyst

Althea Rothwell has over 20 years of industry experience ranging from pipeline maintenance to operational controls. Working closely with utilities, pipelines and customers, Althea maintains high standards in meeting operation, supply and utility objectives. Drawing on past experience within the Accounting and Financial Trades sector, Althea provides detailed and accurate reporting to clients regarding contracted financial and volumetric balancing of natural gas.

Appendix D – EPCOR Southern Bruce Performance Scorecard

	Performance Categories	Intent of Measures	Measures	Sample	2021/22	2022/23	2023/24	3-yr Average
1. Cost Effectiveness	Policies & Procedures	Demonstrates consideration of timely pricing information and 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	C	n/a
			Transacting counterparties have met appropriate credit requirements	%	100%	100%	100%	100%
	Price Effectiveness	Demonstrates diversity of supply terms within procurement plan through a layers approach to contracting Illustrates Price Stability	Distribution of procurement terms:					
			1. < 1 Month	%	5.0%	11.0%	19.7%	11.9%
			2. Monthly	%	58.5%	48.9%	32.1%	46.5%
			3. Seasonal	%	36%	40.1%	48.1%	41.6%
			4. Annual	%	0%	0.0%	0.0%	0.0%
			5. Reference Price History					n/a

	Performance Categories	Intent of Measures	Measures	Sample	2021/22	2022/23	2023/24	3-yr Average
2. Reliability & Security of Supply	Design Day	Demonstrates ability to procure transportation assets required to meet design day demand	Acquired assets to meet design day	100%	100%	100%	100%	100%
	Storage	Demonstrates execution of storage inventory strategy	1. % of storage level Sept 30th	%	99%	100%	100%	100%
			2. % of storage level March 31st	%	16%	13%	34%	21%
	Coordination	Demonstrates ENGPL ability to invest in capital distribution required to meet design day demand	Monthly meetings between gas supply, engineering, operations	12/yr	12	12	12	12
	Communication	Ensure ongoing communications	Communication to ratepayers re material bill impacts	C	C	C	C	C
	Diversity	Demonstrate the diversity of the portfolio	1. % of contract vol. per delivery pt	%	Dawn: 100% AECO: 0%	Dawn: 100% AECO: 0%	Dawn: 100%	Dawn: 100% AECO: 0%
			2. # of unique counterparties	#	3	3	4	3.3
	Reliability	Demonstrate the reliability of the portfolio	1. Days failed to deliver to customers	#	0	0	0	0
			2.Days customer interrupted (1)	#	0	0	0	0
	Performance Categories	**Intent of Measures**	**Measures**	**Sample**	**2021/22**	**2022/23**	**2023/24**	**3-yr Average**
3. Public Policy	Supporting Policy	Reports public policy in ENGLP supply plan	1.Community expansion % customer converted (unlocked vs. CIP)	%	49.58%	86.37%	99.73%	78.56%
			2. FCC	C	C	C	C	N/A
			3. RNG	N/A	N/A	N/A	N/A	N/A
			4. DSM	N/A	N/A	N/A	N/A	N/A

Definitions

1. Years refers to planning years (April 1st to March 31st)
2. Cost Effectiveness: The gas supply plans will be cost-effect. Cost effectiveness is achieved by appropriately balancing the principles and in executing the supply plan in an economically efficient manner
3. 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 season gas delivery requirements
4. Public Policy: The gas supply plan will be developed to ensure that it supports and is aligned with public policy where appropriate