# EPCOR SOUTHERN BRUCE GAS SUPPLY PLAN: 2020-2023

JUNE 2020

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# 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. EPCOR Natural Gas Limited Partnership ("EPCOR") filed the Southern Bruce Supply Plan for the period 2019-2024 as part of the utility's cost of service application, in proceeding EB-2018-0336. In that proceeding, the OEB approved the resulting cost consequences of the plan.

EPCOR has developed the following update to the Southern Bruce Gas Supply Plan ("Supply Plan") 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 the Supply Plan are **flexibility** and a competitive price vis-à-vis alternative fuels. Southern Bruce is a new operation with no historical data; therefore, supply planning in the period covered by this plan must be done based on estimated consumption profiles. Thus, there is 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 June of 2020. The demand forecast was used as an input in determining the appropriate mix of gas supply purchases given contracted storage and transportation assets.

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 and Community Expansion.

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.

EPCOR is presenting this 3-year plan, including upcoming decisions in the plan, with the aim of being transparent and to enable meaningful consideration by the OEB. As the OEB pointed out in the Framework, "The responsibility for delivering reliable supply to customers in a prudent manner remains with the distributors. Distributors manage and execute their plans and adjust their activities to address changes to demand and supply conditions."

## 1.2. Process, Resources, Governance

EPCOR has developed an annual supply plan review process which is the starting point for the development of this Supply Plan. A number of variables are 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, M17 Limited Load Balancing (M17 LBA) balance).

The development of the Supply Plan 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 Gas Supply Plan is consistent with the Framework
    d. Ensure the Gas 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 Gas 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 D.

Gas supply procurement strategies and processes developed for this Supply Plan will be executed by EPCOR and ECNG in a cost-effective manner. In addition to the development of this Supply Plan, 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, assessed against the OEB guiding principles of cost-effectiveness, reliability and security of supply, and public policy. 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 additional to the monthly review, supply purchases decisions are made throughout the year to match changes in demand that deviates from the Supply Plan - for example, connection counts that deviates from the assumptions made in this Supply Plan, 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

As EPCOR begins the development of it franchise, significant distribution investment is required as well as upstream assets are required for security of supply and for balancing demand with supply. EPCOR required upstream firm transportation (from Dawn) and balancing from Enbridge Gas Inc. ("Enbridge"), as this is the most practical service provider to deliver such services. The EB-2019-0183 proceeding resulted in Enbridge providing M17 firm transportation and balancing services to EPCOR.

### 2.1.1. Supply Option

The options related to gas supply require availability at Dawn by suppliers or for EPCOR to consider reaching beyond Dawn to either supply basins or other market hubs like Chicago. 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 in the summer and a modest premium in the winter). Therefore, obtaining supply in supply basins or market hubs beyond Dawn is not necessary to achieve supply reliability for its 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.

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 four 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;
- Canadian Gas Price Reporter (CGPR) AECO Daily Index 5A plus Fixed Basis[3] in CAD/GJ; and
- CGPR AECO Monthly Index 7A plus in CAD/GJ Fixed Basis.

For this Supply Plan, EPCOR has chosen to transact with ICE NGX Union Dawn Day Ahead Index and CGPR 5A.

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

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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.

[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

[3] Fixed Basis is the fixed price transportation value between Alberta AECO and Dawn markets for the term of the contract at the time of transaction.

- The trading data is deeper than Gas Daily (more transactions, more volume used to arrive at the daily index market price).

CGPR 5A index is the preferred choice for the following reasons:

- While both 7A and 5A use the same popular NGX trading platform data as for Dawn providing depth of transactions and volume, 5A provides more of the same daily market price capture as that used in Dawn NGX day ahead index; and
- Over time there is little difference between the two prices (the 5A is an average of all the days trading as the month happens and the 7A is the average price of the days trading in the month before.)

### 2.1.2. Transportation Options

Upstream transportation to Dornoch has been secured in the EB-2019-0183 proceeding under the M17 rate for 10 years. 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 thinking as the Gas Supply Options section above. For the time horizon of this Supply Plan, 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's time horizon as discussed in the Market Outlook section.

### 2.1.3. Storage Options

As part of the EB-2019-0183 proceeding EPCOR was not offered cost-based storage and related daily balancing in T3 or M9 services available to other small gas utilities served by Enbridge in Ontario. The choice 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 reason 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 came with 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 are relatively small in the first 3 years of development.

### 2.1.4. Market-Based Commodity Solutions

There can be situations when a unique often short term need presents itself and the solution is not readily available through standard offers. These non-standard offers are made either solicited or unsolicited to solve a unique situation.

A popular example is a winter peaking service, which allows EPCOR to secure additional availability of gas from a supplier for a reservation fee during the winter, which allows EPCOR to nominate additional gas (at a discount up to the daily reserved volume) to meet winter demand when needed – for example, if demand on any given day is above the sum of the purchased volume plus gas available through storage withdrawal. In some cases, the cost of such a service can be more economical than holding upstream capacity or purchasing additional deliverability from storage. Another example is EPCOR contracts for a storage service where EPCOR buys gas 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.

## 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 in a more limited/indirect way crude oil and underlying currency foreign exchange. ECNG provided the market trending analysis (see Appendix C).

# 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")

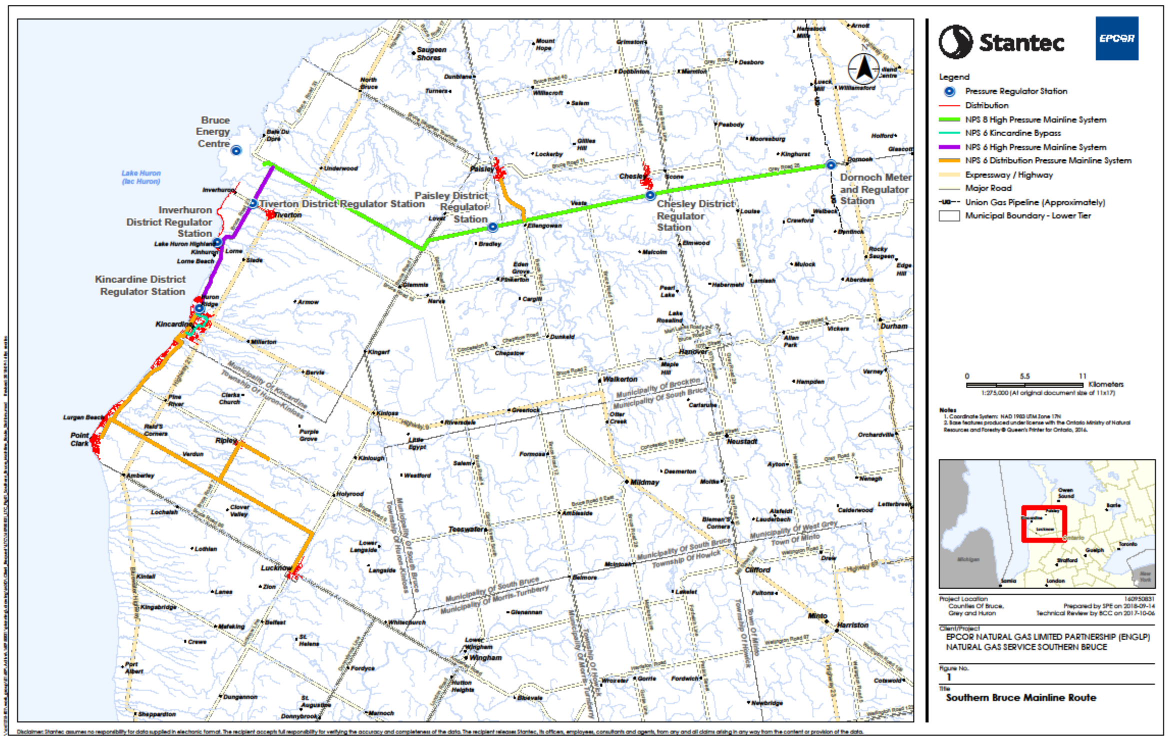



Figure 1 – Southern Bruce Distribution System Map

The utility will service main classes of customers: General Service and Contract Customers. Contract Customers make up 62% of EPCOR's demand profile by volume. There are currently two customers under this classification, and both will contract for their own natural gas supplies and their own storage assets to manage fluctuations in demand. As such, the consumption profile of these two customers is not included in the demand forecast and Supply Option Analysis. Direct Purchase, for other rate classes, is not taken into consideration in this Supply Plan.

General Service customers make up the remaining 38% of EPCOR's natural gas system, and are comprised of residential, commercial, and agricultural customers. Residential customers make up 60% of EPCOR's General Service demand profile, and commercial customers make up 31%. 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).

Agricultural customers, which make up the remaining 9% 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 difficult to forecast demand due to a lack of historical data.

The forecast captures year-on-year demand growth as more customers connect to the EPCOR distribution system. The previous Supply Plan assumed the annual increase in consumption volumes were based on the level of customer attachments EPCOR committed to during the CIP process. In June of 2019, EPCOR entered into a design build agreement with AECON Utilities to perform the design, engineering, procurement, construction, testing, purging, substantial completion and final completion of the Southern Bruce Facilities. This included a revised customer connection forecast which compressed the initial three year customer connection forecast into two years (note that the connection forecast is essentially the same as those in the CIP process by the end of 2021). This revised customer forecast was used for purposes of gas supply planning. Table 1 shows the changes in customer connection forecast between the three sources.

**Table 1 – Customer connection forecast comparison by source**

| | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|
| Original forecast in CIP application | 2,583 | 3,676 | 4,322 | 4,887 |
| CIP Revised forecast with delay | 1,292 | 3,676 | 4,322 | 4,887 |
| Revised forecast with AECON construction schedule | 2,285 | 3,677 | 4,331 | 4,887 |

## 3.1. Annual Demand

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 2020 to 2023. This first step ensures that EPCOR procures an efficient volume of natural gas commodity and storage assets. As EPCOR is servicing a new area where the rate base is expected to grow as customers switch from propane – the traditional heating fuel in the service area – to natural gas, the demand forecast must also sufficiently flexible to mitigate risks associated with a scenario where actual demand growth significantly deviates from the forecast.

The forecasted demand used to develop the Supply Plan is based on an annual forecast developed during the Common Infrastructure Plan ("CIP") process, based on expected customer connect numbers on a monthly basis, multiplied by monthly forecasted consumption for each customer type. Monthly consumption profiles for each customer types are derived from expected annual consumption profile consistent with the CIP, with the monthly breakdown of this annual volume consistent with the CIP and methodology applied in the Southern Bruce expansion applications.[4] For residential and commercial customers, the annual forecast was broken down 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 completed 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 forecasted average day volume per month broken down by each customer type is shown in Figure 2.

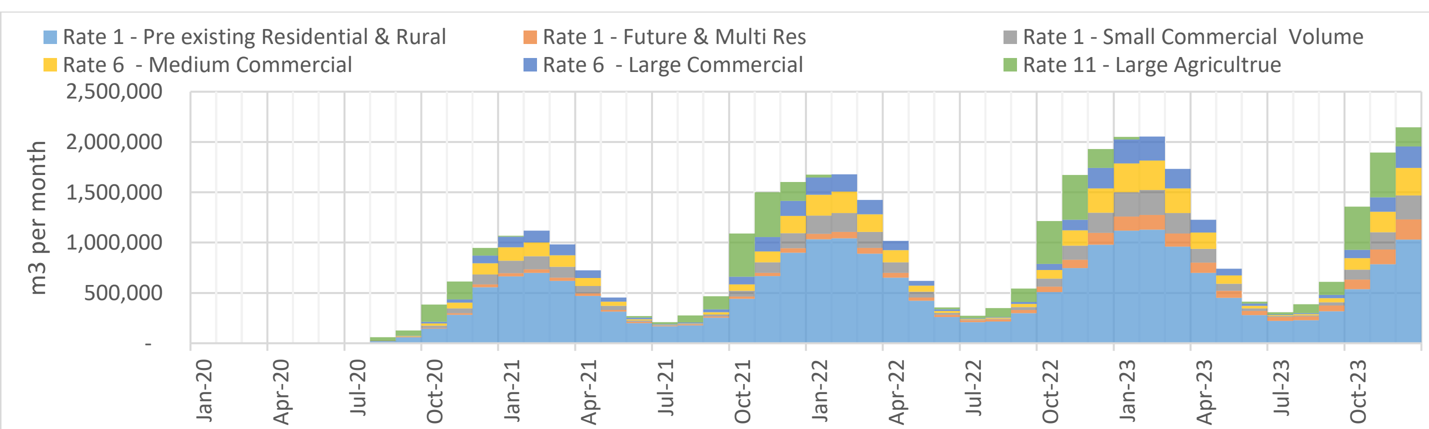



**Figure 2 - Forecast Monthly General Service Demand, by Customer Type**

[4] EB-2016-0137/EB-2016-0138/EB-2016-0139, Response to Board Staff Interrogatory #2, dated March 2, 2018.

## 3.2. Design Day Demand

EPCOR has procured sufficient transportation assets to meet customer demand within the planning horizon. EPCOR's Contract Demand under the M17 is based on the expected capacity required to meet peak day conditions in EPCOR's Year-10 gas flow, which is 141,085 $m^3$ per day (or 5,487 GJ per day) for General Service customers (an additional 86,827 $m^3$ per day (or 3,377 GJ per day) is currently reserved for Contract Customer that supplies their own gas and manages their own storage). Figure 3 below shows the expected average day demand compared against the M17 contract demand, and the portion of that contract demand apportioned to General Service customers.

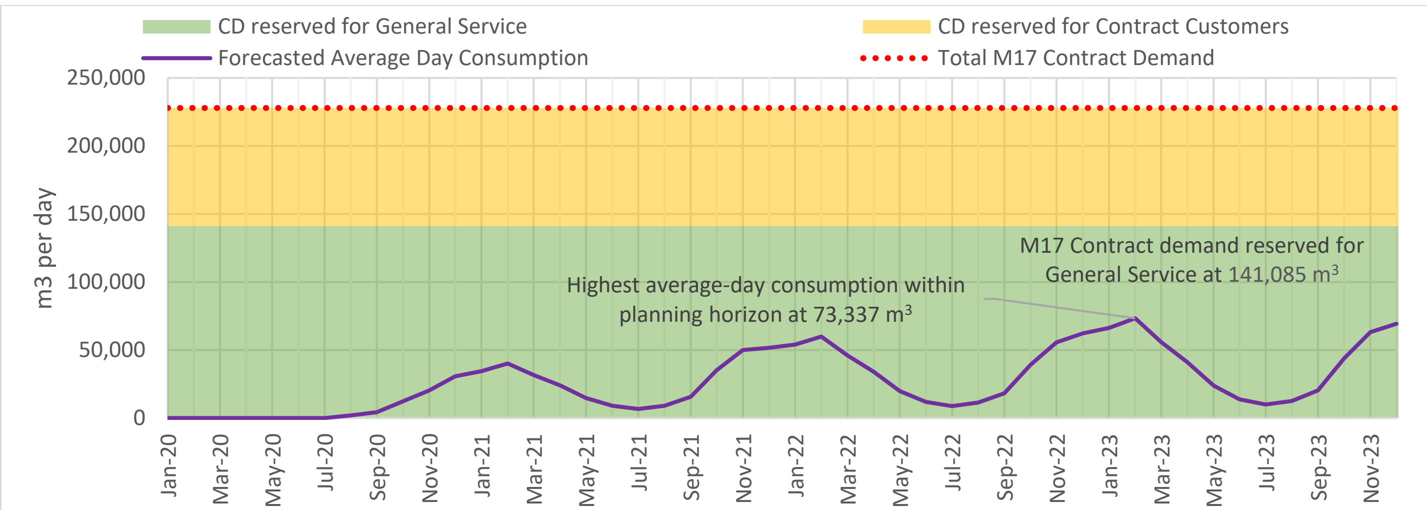



**Figure 3 - Forecast Average Day Consumption vs M17 Contract Demand**

Based on the demand forecast shown in Figure 3, EPCOR is not expecting to make full use of the Contract Demand in the three-year planning horizon covered by this Supply Plan. For example, peak day demand would need to be twice the forecasted daily demand volume in February 2023 to exceed the contract demand reserved for General Service customers. 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. EPCOR has contracted sufficient transportation capacity to service Southern Bruce within the planning horizon, and will review demand forecasts and utilization of the M17 contract demand on an annual basis to assess where additional capacity is needed and will contract accordingly.

## 3.3. COVID-related Demand Impacts

For the calendar year 2020, we have also modelled for potential demand impacts due to COVID-19. Specifically, shelter in place orders and the economic impact of these orders may reduce a customer's propensity to switch to natural gas, or delay site visits required to switch appliances to use natural gas. COVID-related impacts on demand are taken into considerations for the purposes of supply planning, and the considerations are discussed in further details in Section 6.1.4.

# 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. For the period covered by this Supply Plan, 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 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. 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.

## 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 September and October 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, 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.

## 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.

The three Supply Options reviewed in Section 5 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 to the Supply Plan 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, EPCOR does not expect all M17 transportation capacity to be fully utilized. 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 Gas/Union Gas 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 of this Supply Plan. 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. Supply Option Analysis

## 5.1. Design Day Analysis

As described in Sections 3.2 and 4.2, EPCOR has contracted sufficient transportation assets to service Southern Bruce within the planning horizon - The M17 Contract Demand reserved for General Service customers is approximately double the highest average-day demand forecasted in February 2023. 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 (additional gas can be drafted from the M17 LBA on peak days).

## 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 May 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 25 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 month to month or spot gas are purchased to satisfy demand. Withdrawals from storage and the M17 LBA are available to be used to supplement supply as needed on days with higher than expected demand.

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 withdrawal of 1,000 GJ/d during those months and maintaining 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.

Three Supply Options were considered and modeled for the Supply Plan to meet the guiding principles of cost-effectiveness and reliability and security of supply. Additional consideration include flexibility and burner-tip price competitiveness in order to address the start- up nature of the utility and to attract new customers. These options include:

**Option A:** Month to Month index purchases

**Option B:** A mix of month to month index purchases and annual baseload index purchase at AECO

**Option C:** A mix of month to month index purchases and seasonal baseload purchases (mixed of AECO index and Dawn fixed price)

Each of these options are analyzed below. It is important to note that all three options maximize contracted storage both by achieving firm storage injection in the summer and protecting maximum deliverability in the winter.

**Option A:** Month to month purchases 7-14 days prior to the start of the month, with procurement volume based on conservative average day demand forecast, taking into consideration storage withdrawal available during winter months, and injection requirements to fill storage during the summer months.

In October and November, the same purchasing strategy is used only there are no storage injections planned. For the December through March months, procurement volumes are made on a month-to-month basis to satisfy expected average day demand after considering storage withdrawal, with cash/spot purchases to fill the monthly demand shortfall and peak day demands not met by planned monthly storage withdrawals or drafting gas from the M17 LBA.

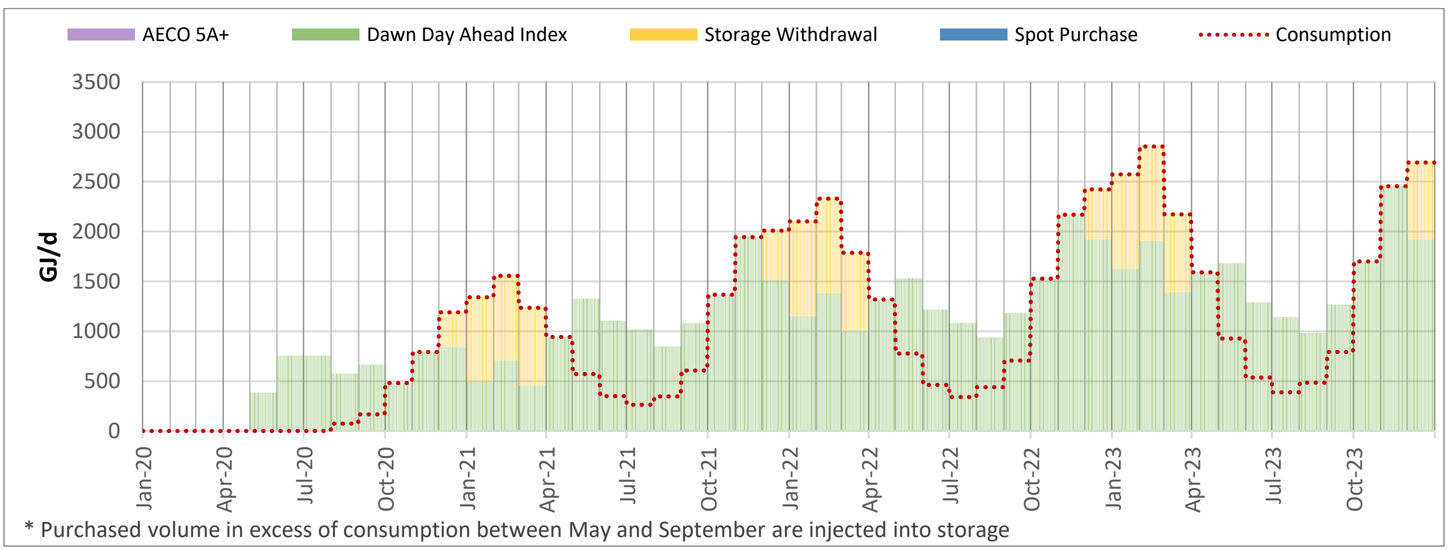



Figure 4 – OPTION A (Month to month Procurement) – Consumption vs. Delivery (GJ/Day)

| Risks | Opportunities |
|---|---|
| **Cost:** This Supply Option could potentially increase overall commodity cost as daily price volatility at Dawn historically occurs in the winter months.<br><br>**Diversity:** Least price diversity of the Options, more near term foreign exchange risk. | **Cost:** Cost may be reduced if warmer Ontario weather persists in the winter and pricing reflects reduced demand.<br><br>**Flexibility:** Due to the month to month nature of procurement there is ease of reducing purchases in the event of lesser connections vs forecast or a warmer than normal forecast as it is happening and, in the winter, especially relying on storage withdrawals. Reduces the risk of selling gas that cannot be used by the market or put into storage. |

Option A provides the most operational flexibility as all procurement volumes are determined on a monthly basis which allows EPCOR to quickly adjust procurement strategies to match near-term demand forecasts. However, since the entire procurement portfolio is priced at the Dawn Day Ahead Index, which have shown significant price volatility in past winters, this strategy does not allow for supply diversity and introduces high price risk.

**Option B:** Planned procured volume for each month is the same as Option A, with up to 50% of each planning year's average consumption (April to March) contracted in March prior to the planning year, at 5A Index plus a one-year fixed basis to Dawn in order to lock in the basis cost of the 5A index deal. Remaining monthly forecasted demand and peak day demand shortfall is met by planned monthly storage withdrawals, month-to-month purchases, and daily cash purchases.

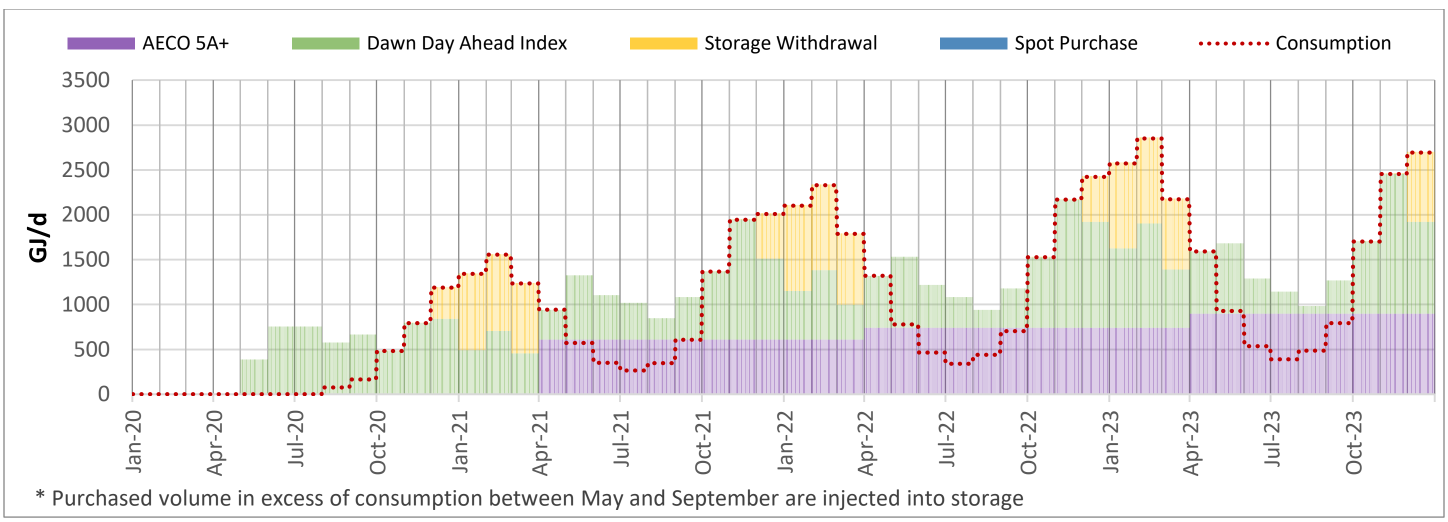



Figure 5 – OPTION B (50% Annual Baseload Procurement) – Consumption vs. Delivery (GJ/Day)

| Risks | Opportunities |
|---|---|
| **Cost:** Alberta market price dynamics may be different than Dawn (eg. Colder than normal vs Dawn being warmer than normal) leading to higher costs. Also, when the Fixed Basis is established for one year, this is transacted in mid-March and cannot reflect changing price dynamics at Dawn within the length of the contract.<br><br>**Flexibility:** Potential risk of east flexibility to react to lower than forecasted demands especially in the winter as the baseload amount is highest of the options. | **Cost:** Cost may be reduced if warmer either Alberta or Ontario weather persists in the winter and pricing reflects reduced demand.<br><br>**Flexibility:** Ample flexibility to react to lower than forecasted demands through buying less Month to month supplies as the demand signals<br><br>**Diversity:** Split between Dawn index and Alberta index dampens the winter Dawn price risk.<br><br>**Reliability:** This option increases reliability since a fixed annual quantity is committed to in advance. |

Option B introduces price diversity into the portfolio by pricing approximately 50% of a planning year's purchases at an AECO index with a fixed basis. This arrangement lowers risks of commodity cost spikes in the winter time in any particular markets driving up Southern Bruce's Weighted Average Cost of Gas (WACOG) – for example, as shown in Figure 6 below, the polar vortex that drove Dawn Day Ahead Index to very high level in Winter 2013/14 did not have the same impact on AECO 5A index. By introducing an AECO index pricing into the supply mix, it reduces the impact of price spikes on Southern Bruce's WACOG.

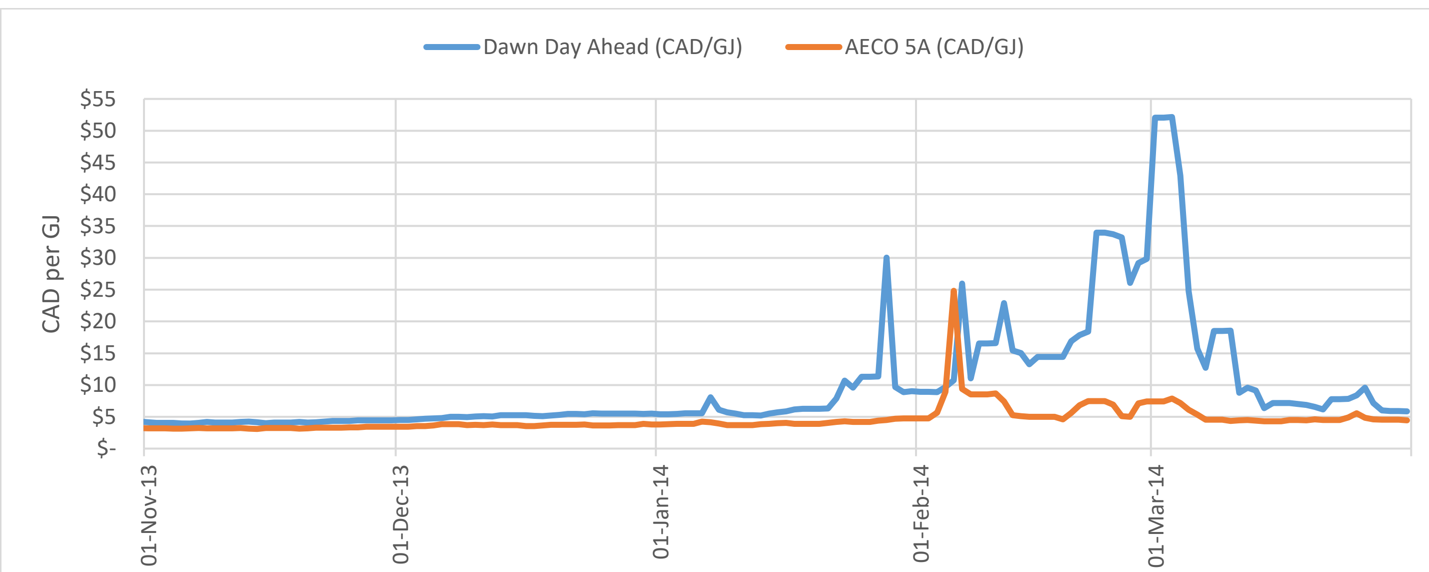



**Figure 6 – Dawn Day Ahead Index vs AECO 5A between Nov 1, 2013 to March 31, 2014**

A risk highlighted with this Option is the reduced flexibility in adjusting gas procurement volume to changes in average day customer demand in situations where customer demand is lower than forecasted at the time of entering into the 5A contract. This situation would leave little flexibility to react to lower than expected customer demand or a warmer than normal previous winter, leading to less days at full injection amounts to accept the committed supply, and may lead to an imbalance buildup in the LBA. This Supply Plan mitigates this risk by limiting the maximum amount of 5A procurement to no more than 50% of each planning year's average demand.

**Option C:** Planned procured volume for each month is the same as Option A, with up to 65% of each season's average consumption contracted prior to the start of the season at 5A Index plus a fixed basis to Dawn: 1) 65% of average consumption between April and September contracted in March at 5A Index plus a fixed basis to Dawn, and 2) 65% of average consumption between December to March priced using fixed priced at Dawn contracted in November each year. Remaining monthly forecasted demand and peak day demand shortfall is met by planned monthly storage withdrawals, month-to-month purchases, and daily cash purchases.

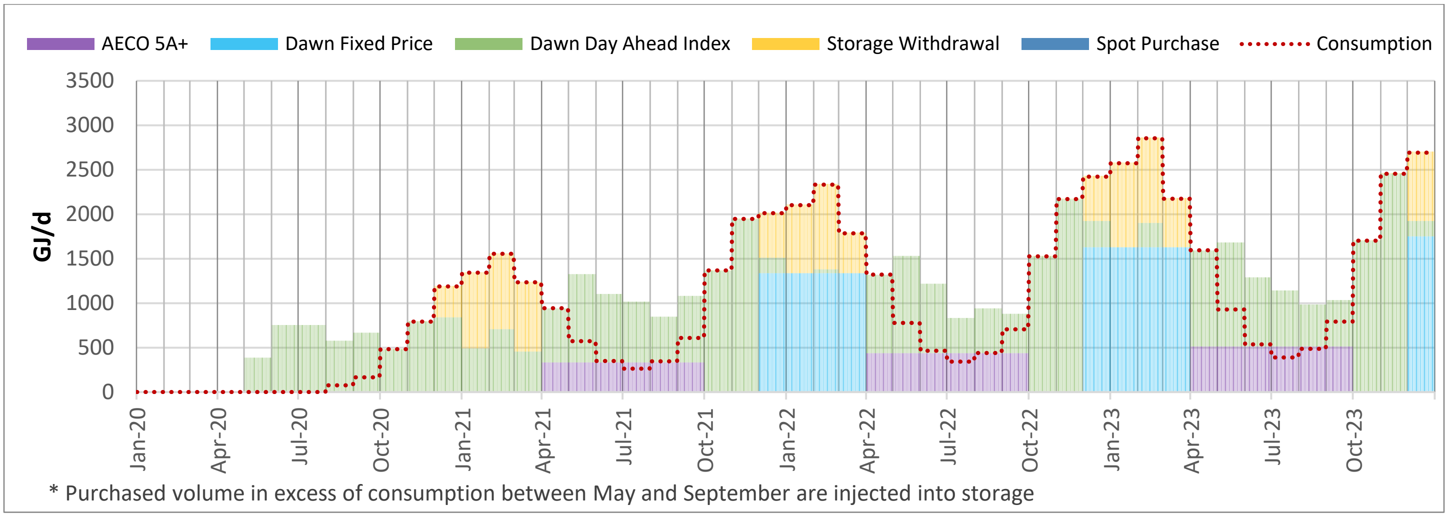



Figure 7 – OPTION C (65% Seasonal Baseload Procurement) – Consumption vs. Delivery (GJ/Day)

| Risks | Opportunities |
|---|---|
| **Cost:** Alberta market price dynamics may be different than Dawn leading to higher costs. Risk of fixed Dawn prices higher than index settles in the winter (low risk).<br><br>**Flexibility:** Lower than forecasted demands especially in the winter may cause utility to sell procured gas in excess of demand. | **Cost:** Cost risk reduced with a higher baseload quantity in the winter period.<br><br>**Diversity:** Increased price diversity through setting of Fixed Basis two times per year.<br><br>**Reliability:** This option has the highest reliability since it has the highest baseload winter quantity (committed to in advance of winter). |

Like Option B, Option C also introduces price diversity into the portfolio by pricing indexing a subset of gas supply transactions at AECO 5A. This arrangement also mitigates the price risk in a cost effective manner. Like Option B, this option can also be less flexible compared to Option A as a certain level of procurement volume is committed ahead of time. However, Option C is more flexible than Option B, in that:

- 5A strip volume over the summer months are lower, lowering the risk of over-contracting supply in these low consumption months compared to Option B.

- There two decision points through the planning year on setting these fixed volume term purchases, giving EPCOR more flexibility in adjusting these term volumes based on more up to date seasonal outlook and customer connection forecast.

Option C provides additional price stability by procuring a portion of its winter supply at fixed price, which reduces the risk of spikes in index prices driving up EPCOR's WACOG.

### 5.3. Summary of Supply Options

The associated guiding principles to help evaluate a gas supply plan of Cost, Diversity, Reliability and Flexibility are used in Table 2. The cost risks/opportunities are evaluated quantitatively in the supply options analysis (Section 6) where each option is subjected to an endogenous shocks of demand and pricing impacts.

**Table 2 - Supply Options Evaluation Summary**

| Supply Options | Reliability | Flexibility | Diversity | Price Stability |
|---|---|---|---|---|
| Option A:<br>Month to month Spot only | ↑ | ↑ | ↓ | – |
| Option B:<br>50 % 1Yr baseload, balance with month to month spot | ↑ | – | ↑ | ↑ |
| Option C:<br>65% Summer baseload,<br>65% Winter baseload, balance with month to month spot | ↑ | ↑ | ↑ | ↑ |

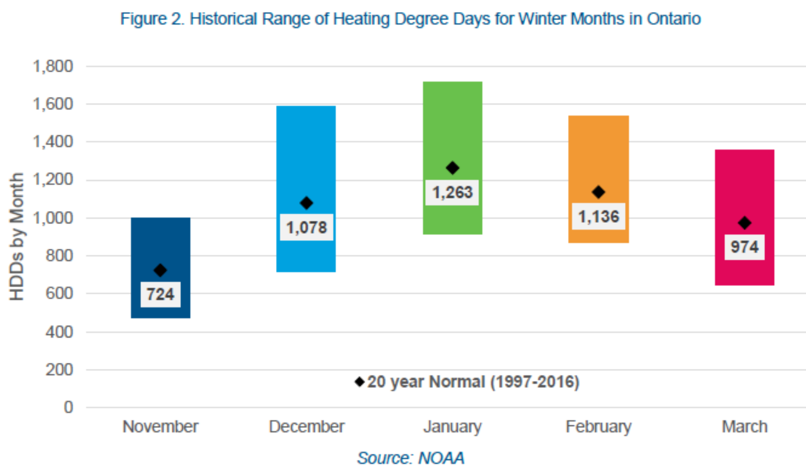
## 6. Risk Mitigation Analysis

### 6.1. Variation to Planned Assumptions

Variation analysis to gas supply plan execution is the existence of risk mitigation strategies. Key risks to the Supply Plan are weather, demand (both average day and design day) and price variation. These initial demand forecasts lack the benefit of history to analyze demand relative to weather effects, within rate class penetration of space and water heating, agricultural grain drying rate class differences in loading and moisture levels from year to year, etc. Due to the lack of detailed rate class historical data, rate class weather and consumption variances were not evaluated in the Supply Plan. As the utility collects this data it will incorporate in further supply plans.

#### 6.1.1. Weather Variation Risk

The demand forecast presented in this Supply Plan assumes normal weather. Each supply option assumes a normal winter weather. The figure below comes from the 2019 Enbridge Gas Supply Plan as prepared by ICF. It shows historical ranges of Heating Degree Days (HDD) over a 20-year period (1997-2016) by winter month for all of Ontario. In tabular form, and by average for November to March, the low end 20-year average is 30% below and the high end is 38% above. The gas Supply Options were tested with weather variations of 30% less HDD and 38% more HDDs driving heat sensitive forecasted demand estimates.




| 20 Years of data 1997-2016 | | | |
|---|---|---|---|
| HDD - ONTARIO | Low | Mean | High |
| Nov | 475 | 724 | 1,000 |
| Dec | 725 | 1,078 | 1,600 |
| Jan | 925 | 1,263 | 1,700 |
| Feb | 850 | 1,136 | 1,450 |
| Mar | 650 | 974 | 1,375 |
| | | | |
| % from Mean | Low | Mean | High |
| Nov | 34% | 724 | 38% |
| Dec | 33% | 1,078 | 48% |
| Jan | 27% | 1,263 | 35% |
| Feb | 25% | 1,136 | 28% |
| Mar | 33% | 974 | 41% |
| | 30% | | 38% |

Figure 8 – Ontario Heating Degree Day variation, 1997 to 2016

### 6.1.2. Demand Variation Risk – Average Day Demand

Demand Variation risk for EPCOR is largely due to its ability to forecast market growth measured by the number of new connections. Each rate class in its demand forecast are assumed to consume gas using the latest high efficiency-based equipment technologies therefore there is no variance analysis required due to demand side management. Demand assumptions within each rate class are not tested in this analysis. The greatest demand variation expected is the frequency of new connections. The supply options were tested against 30% more and 30% less connections to the forecast.

### 6.1.3. Demand Variation Risk – Design Day Demand

Design day demand risk is a test of the highest component of demand. At this time serving design day demand is of less concern since the size of the Southern Bruce distribution system is so much larger than the aggregated coincident demand of this first Supply Plan. The combination of excess M17 transportation capacity, staged monthly storage deliverability, LBA parameters, month to month supplies and spot purchases at Dawn are more than adequate to comfortably satisfy design day demand within the planning horizon. No winter peaking services are planned in any of the supply options analysis.

### 6.1.4. Demand Variation Risk – COVID-related Impacts

EPCOR was concerned that shelter in place orders and the associated economic impacts of COVID-19 pandemic ("COVID") of these orders may reduce a customer's propensity to switch to natural gas, or delay site visits required to switch appliances to use natural gas. While the situation is uncertain, EPCOR contracted with Innovative Research Group to conduct a phone survey of potential residential and commercial customers on COVID's impact on natural gas conversion. Innovative surveyed customers in Kincardine and Huron-Kinloss during the first two weeks of June. Based on the results of the survey, EPCOR determined that 96% of residential respondents and 84% of commercial respondents do not expect COVID to impact conversion decision or timeline of conversion. The survey results indicate to EPCOR that COVID's impact is negligible from a supply planning perspective – by ensuring that the Supply Plan is flexible enough to address the weather and demand variations outlined in Sections 6.1.1 and 6.1.2 (which presents a wider variation in demand than COVID-related impacts as indicated from the survey results), the plan will also be able to handle variations arising from COVID. Summary of survey results can be found in Appendix E. EPCOR will continue to monitor these fluid conditions.

### 6.1.5. Price Variation Risk

The price variation analysis shows potential cost outcomes on system gas customers in high and low price scenarios. One year of coincident prices at Dawn and AECO used to show realistic situations to test the supply options effects. For the high price scenario, the period April 2013 through March 2014 contains the coldest winter and highest prices seen at Dawn (and NYMEX) in several years. The prices chosen to present the low range is the most recent period of April 2019 through March 2020 as it presents the lowest Dawn (and NYMEX) winter price in the past several years.

## 6.2. Supply Interruption Risk

EPCOR has established a procurement policy which mandates contracting for supply from creditworthy suppliers and currently has three natural gas base contracts executed. Recently, EPCOR elected to procure its supply from Dawn instead of Kirkwall or Parkway in its M17 supply contract with Enbridge as this is the most liquid of the supply points to choose form. All of these form the basis for reducing the risk of supply interruption.

## 6.3. Transportation Interruption Risk

To minimize the transportation interruption risk, EPCOR has contracted for firm M17 upstream capacity to its franchise at Dornoch from a liquid supply point at Dawn. The amount of M17 capacity currently contracted is designed to serve its 10 years of forecasted growth, so there is excess capacity within the planning period. This excess capacity will minimize the risk of interruption in the event of a partial force majeure call on the main Owen Sound line in Enbridge's franchise area since its pro-rata share of existing excess capacity will be higher than if there was no excess capacity contracted.

## 6.4. Cost of Supply Options

From a cost perspective, all three supply options track relatively close to each other. Appendix A summarizes the expected cost of servicing each of the three options from May 2020 to December 2023. The gas cost ranges from $4.29/GJ in Supply Option C to $4.47/GJ in Supply Option B. The M17 Contract costs are based on the Contract Demand for General Service customers only (Contract Customers are excluded in the cost analysis since they are responsible for their own supply and storage).

Each of the Supply Options were shocked based on:

1) Warm, less connections: 30% less HDD and 30% less connections,
2) Cold, more connections: 38% more HDD and 30% more connection counts,
3) Low Price at planned demand volume (based on 2019/2020 Dawn and AECO index prices), and
4) High price at planned demand volume (based on 2013/2014 Dawn and AECO index prices)

Table 3 – Summary of WACOG impacts of each modeled scenarios for each Supply Option

| Supply Options | WACOG Impact for each Scenario against Base Scenario | | | |
|---|---|---|---|---|
| | Demand Shocks | | Price Shocks | |
| | Warm, less connections | Cold, more connections | Low price at planned demand volume | High price at planned demand volume |
| Option A | **16%** | **-9%** | **-13%** | **72%** |
| Option B | **20%** | **-8%** | **-9%** | **61%** |
| Option C | **25%** | **3%** | **-2%** | **38%** |

As Table 3 above shows, all supply options performed similar to each other in terms of managing demand shocks. With respect to protecting Southern Bruce's WACOG against price shocks, Option C performed the best due to the higher price diversification during the summer months and fixed price contracts in the winter months. In particular, under Option C it is possible for the Dawn fixed priced contract and storage withdrawal to meet demand during some winter months, limiting month to month or spot purchases required in situations when risk of elevated Dawn index prices are high.

## 6.5. Summary of Chosen Supply Option

Given the results of the risk mitigation analysis, EPCOR is choosing the following Supply Plan C. EPCOR will procure summer Baseload at AECO 5A plus a fixed basis, and winter baseload at fixed priced, and match the remaining monthly demand with month to month purchases at Dawn Day Ahead index, taking into account injection requirements in the summer months and withdrawal deliverability in the winter months.

Option C was chosen for the planning horizon due to superior price risk management compared to the other two Options, especially in scenarios like the Winter 2013/2014 polar vortex where Dawn Day Ahead Index saw very severe price spikes. Option C also allows for a good level of flexibility in the ability to adjust supply to actual demand – baseload volumes are relative to seasonal demand, meaning that they are low during low consumption months in the summer reducing the risk of over contracting. Higher baseload in the winter time also have a lower risk of over contracting as storage withdrawals can be readily adjusted down if demand is lower than expected – for example, due to warmer than normal temperatures).

# 7. Gas Supply Plan Execution

Once the Supply Plan has been established, EPCOR 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 Section 6.

To manage risk, EPCOR and ECNG maintains frequent communications on annual, seasonal, monthly, and weekly basis. EPCOR and ECNG have also co-developed a Gas Supply Planning Model specific which links demand forecasts, supply arrangements, price forecasts, storage injection and withdrawals, as well as LBA balance, all elements specific to the Southern Bruce operation, to produce an operational outlook for the period covered by this Supply Plan. The model will inform EPCOR of portfolio impacts of different supply arrangements given a set of demand and pricing assumptions. The model is also used to test EPCOR's natural gas portfolio against various demand and pricing scenarios, and forms the basis of risk analysis for supply planning purposes on a frequent and scheduled basis during the planning years.

On an annual and seasonal basis, EPCOR and ECNG will:

- Review historical average and peak day demand against forecasts made in the Gas Supply Plans, and adjust demand forecast for the upcoming year / season accordingly, based on updated connection forecast, ongoing regression analysis between local weather and consumption.

- Review performance and creditworthiness of suppliers.

- Review if additional suppliers, delivery points, storage asset, and transportation asset options are available to Southern Bruce, and analyze appropriateness of incorporating these additional considerations into gas supply planning based on OEB's guiding principles.

- Review historical utilization of storage and transportation assets, and determine if operational adjustments can be made to improve cost effectiveness, reliability of supply, or address new policy needs.

- Contract annual and seasonal supply arrangements based on the latest Board-approved Gas Supply Plan, taking into account any adjustments deemed appropriate based on the seasonal/annual review while remaining flexible to short term or seasonal changes in demand and potential operational considerations.

On a monthly basis:

- Review asset utilization, particularly storage and LBA balance.

- Review if prompt-month demand forecast adjustments are required based on updated short-term weather and connection counts forecasts.

- Make adjustments to supply if needed. For example, adjust additional gas supply required to more closely match updated demand for the prompt-month.

Outside of scheduled annual, seasonal, and monthly reviews, frequent meetings are held for EPCOR and ECNG to share any updates on operational items to flag any potential issues that arise on a week-to-week basis. Operational triggers have also been determined to prompt any action required outside the scheduled review timeframes. These scheduled review points and operational triggers allow EPCOR to be flexible to meet supply reliability needs and mitigate risks in a timely and cost-effective manner.

Southern Bruce's mix of storage and transportation asset is a new and unique arrangement for EPCOR. As EPCOR and ECNG gain more operational experience with Southern Bruce, gas supply planning and execution will continue to improve.

### 7.1. Procurement Process/Policy

EPCOR and ECNG are in the process of finalizing a Natural Gas Procurement Guideline and Procedures document which has formed and will continue to form 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 directs and authorizes 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 and determine how planned AECO index purchases have contributed to price stability. 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.

## 8. Historical Review

Southern Bruce is a new utility with no natural gas consumption and operational history. A historical review will be provided in the next Gas Supply Plan in 2024 and the annual Supply Plan updates.

## 9. Public Policy

### 9.1. 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.

### 9.2. 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 GGPPA, Part 1, effective April 1, 2019.

As part of EPCOR's compliance requirements with respect to the FCPP, the utility filed its 2020 FCPP application with the Board on May 1, 2020, and the OEB issued its Interim Decision and Order on May 21, 2020, authorizing on an interim basis, rates effective June 1, 2020.[5]

## 10. Performance Measurement

EPCOR has drafted a performance metric scorecard in order to measure the effectiveness of the Supply Plan. Please see Appendix F.

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.

EPCOR expects to commence service to customers in its Southern Bruce customer area in 2020. There may be opportunities to combine gas supply plans for both the Aylmer and Southern Bruce areas but EPCOR believes that at this time, this opportunity is beyond the scope of this gas supply planning period.

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[5] EB-2020-0076. EPCOR (Southern Bruce) is a greenfield utility, and it is expected that the first customer will not be connected until July 2020. Therefore, no application was made to request an update to rate schedules to reflect the charge effective April 1, 2019 per the GGPPA. The first two connections will both qualify as EITE emitters, and will have or are expected to file exemption certificates with the CRA and advising EPCOR.

# 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 – Scenario Analysis Results for Supply Plan Options A, B, and C

### Table 4 – Supply Option A Scenario Analysis: May 2020 to December 2023

| | Option A Base Scenario | Option A Warm, less connections | Option A Cold, more connections | Option A Low price at planned demand | Option A High price at planned demand |
|---|---|---|---|---|---|
| Commodity Cost (Baseload) | $0 | $0 | $0 | $0 | $0 |
| Commodity Cost (Month to Month) | $5,290,750 | $2,944,074 | $9,008,654 | $4,405,637 | $10,248,562 |
| Commodity Cost (Spot Gas) | $0 | $0 | $0 | $0 | $0 |
| Transportation Fuel Cost | $19,296 | $10,353 | $33,227 | $19,296 | $19,296 |
| Storage Costs | $344,148 | $343,950 | $344,084 | $344,148 | $344,148 |
| M17 LBA Charges | $0 | $0 | $0 | $0 | $0 |
| M17 Transportation Charges | $788,918 | $552,279 | $945,543 | $788,918 | $788,918 |
| Management Cost | $429,311 | $400,486 | $473,866 | $429,311 | $429,311 |
| Total Cost | **$6,874,443** | **$4,253,162** | **$10,807,393** | $5,989,330 | **$11,832,256** |
| $ per GJ of Demand | 4.466090 | 5.174943 | 4.081151 | 3.891063 | 7.687012 |
| ¢ per m3 of Demand | 17.368604 | 20.125399 | 15.871586 | 15.132325 | 29.894750 |

### Table 5 – Supply Option B Scenario Analysis: May 2020 to December 2023

| | Option B Base Scenario | Option B Warm, less connections | Option B Cold, more connections | Option B Low price at planned demand | Option B High price at planned demand |
|---|---|---|---|---|---|
| Commodity Cost (Baseload) | $2,128,272 | $1,714,948 | $2,512,716 | $1,926,356 | $3,776,309 |
| Commodity Cost (Month to Month) | $3,170,930 | $992,070 | $6,115,646 | $2,782,522 | $5,711,006 |
| Commodity Cost (Spot Gas) | $0 | $0 | - $86,267 | $0 | $0 |
| Transportation Fuel Cost | $19,296 | $9,615 | $31,864 | $19,296 | $19,296 |
| Storage Costs | $344,148 | $343,050 | $343,972 | $344,148 | $344,148 |
| M17 LBA Charges | $0 | $0 | $61 | $0 | $0 |
| M17 Transportation Charges | $788,918 | $552,279 | $945,543 | $788,918 | $788,918 |
| Management Cost | $429,311 | $397,628 | $468,524 | $429,311 | $429,311 |
| Total Cost | **$6,882,896** | **$4,011,609** | **$10,334,079** | $6,292,571 | **$11,071,008** |
| $ per GJ of Demand | $4.471582 | $5.346488 | $4.107851 | $4.088068 | $7.192455 |
| ¢ per m3 of Demand | $17.389959 | $20.792565 | $15.975428 | $15.898477 | $27.971423 |

## Table 6 – Supply Option C Scenario Analysis: May 2020 to December 2023

| | Option C Base Scenario | Option C Warm, less connections | Option C Cold, more connections | Option C Low price at planned demand | Option C High price at planned demand |
|---|---|---|---|---|---|
| Commodity Cost (Baseload) | $2,463,837 | $1,322,253 | $2,935,350 | $2,293,046 | $2,872,953 |
| Commodity Cost (Month to Month) | $3,107,507 | $1,461,893 | $6,478,818 | $2,623,370 | $4,718,046 |
| Commodity Cost (Spot Gas) | $0 | -$19,409 | -$23,414 | $0 | $0 |
| Transportation Fuel Cost | $19,293 | $9,631 | $31,924 | $19,293 | $19,293 |
| Storage Costs | $308,435 | $307,319 | $308,577 | $308,435 | $308,435 |
| M17 LBA Charges | $0 | $0 | $0 | $0 | $0 |
| M17 Transportation Charges | $428,206 | $552,279 | $945,543 | $789,312 | $788,918 |
| Management Cost | $271,797 | $397,633 | $468,550 | $429,297 | $429,297 |
| Total Cost | **$6,607,161** | **$4,033,620** | **$11,145,349** | **$6,464,774** | **$9,138,963** |
| $ per GJ of Demand | $4.29 | $5.375823 | $4.431138 | $4.199942 | $5.937271 |
| ¢ per m3 of Demand | 16.693302 | 20.90664923 | 17.2326907 | 16.333555 | 23.090019 |

## Appendix B – 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. |

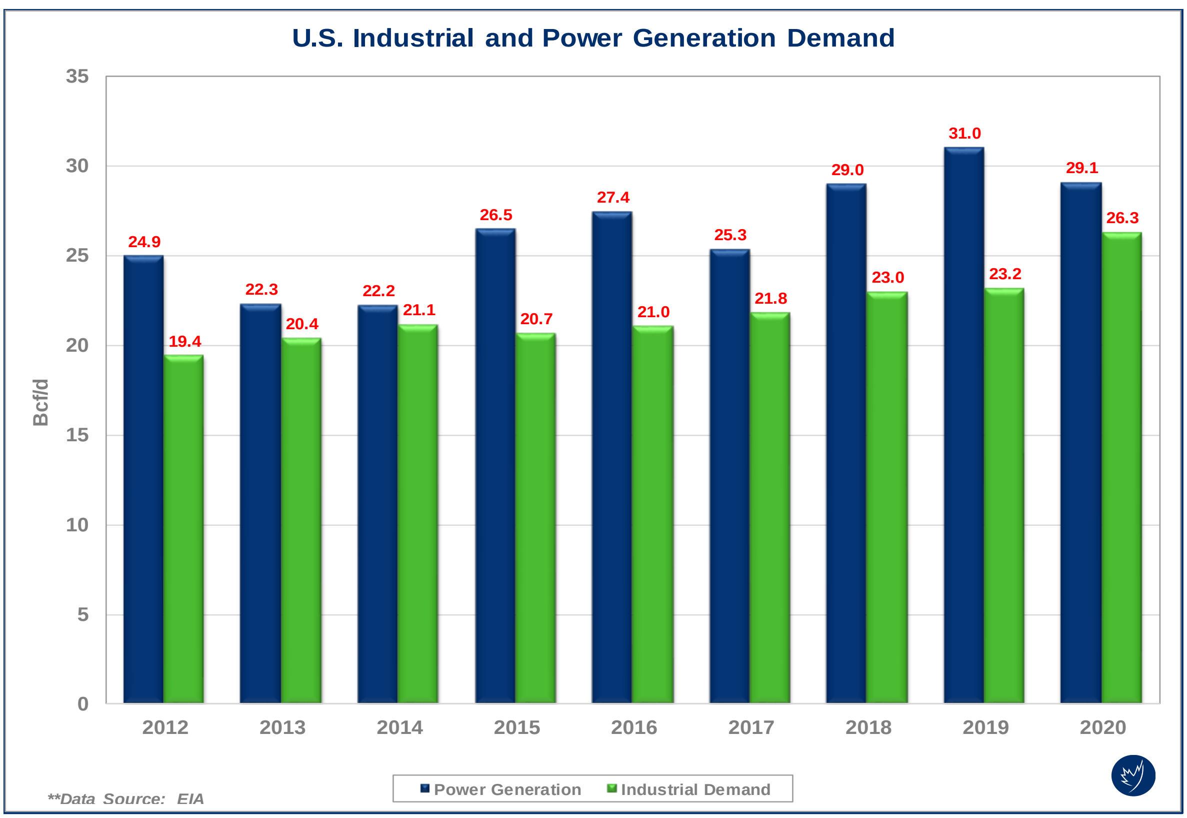
# Appendix C – Market Trends Analysis

## **Current and Future Market Trends Analysis**
## **Provided by ECNG**

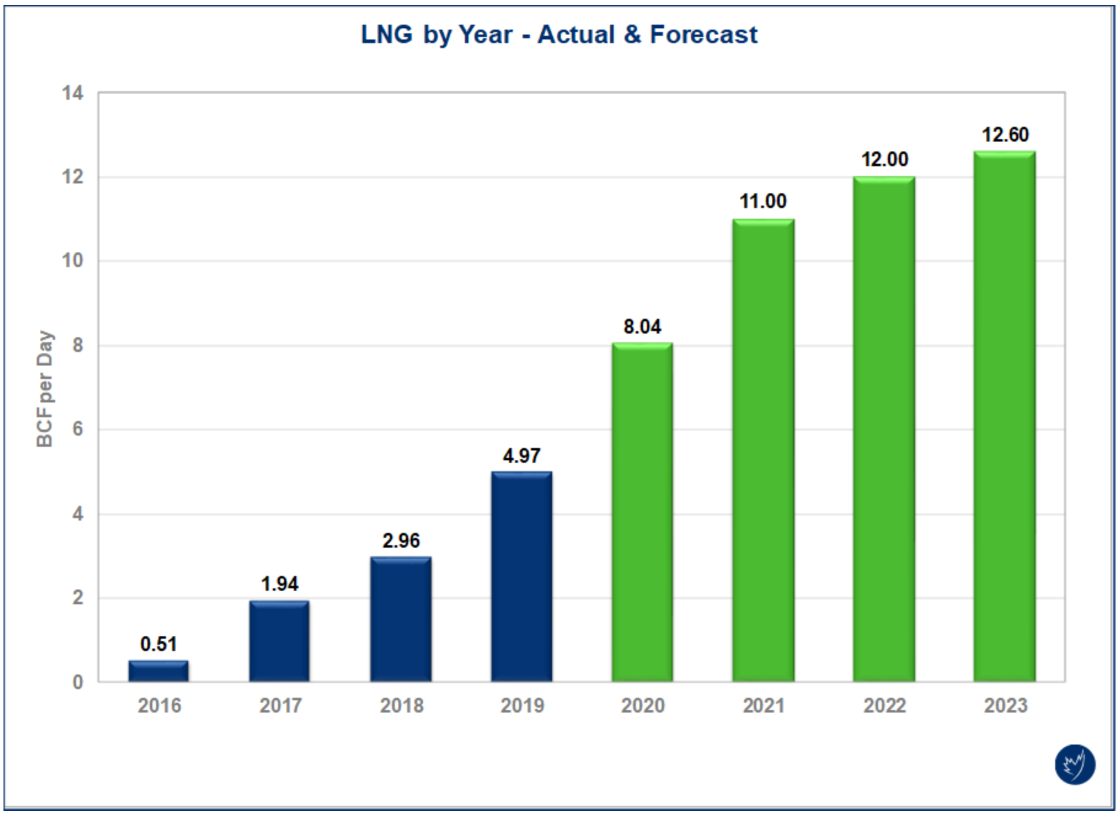
As an element of the risk mitigation strategy, the following overview of current and future trends is intended to inform EPCOR of any changes in natural gas market fundamentals which have the potential to impact its ability to execute the Supply Plan. The North American fundamental drivers for natural gas are demand, supply, storage and in a more limited/indirect way crude oil and underlying currency foreign exchange.

### Demand: Impact on pricing - Near term Mildly Bullish, midterm Mildly Bullish

While a mild winter across most of North America resulted in lower demand in the residential and commercial sectors, medium and long term demand growth continues to be seen. United States (U.S.) Industrial demand has grown on average +3% per year over the last 10 years. U.S. gas fired power generation demand shows much more growth (albeit erratic) has averaged 5.6% over the same 10-year period. This is expected to increase in the medium term as jurisdictions are running more baseload hours on natural gas pushing out coal and backing up wind (see figure below).



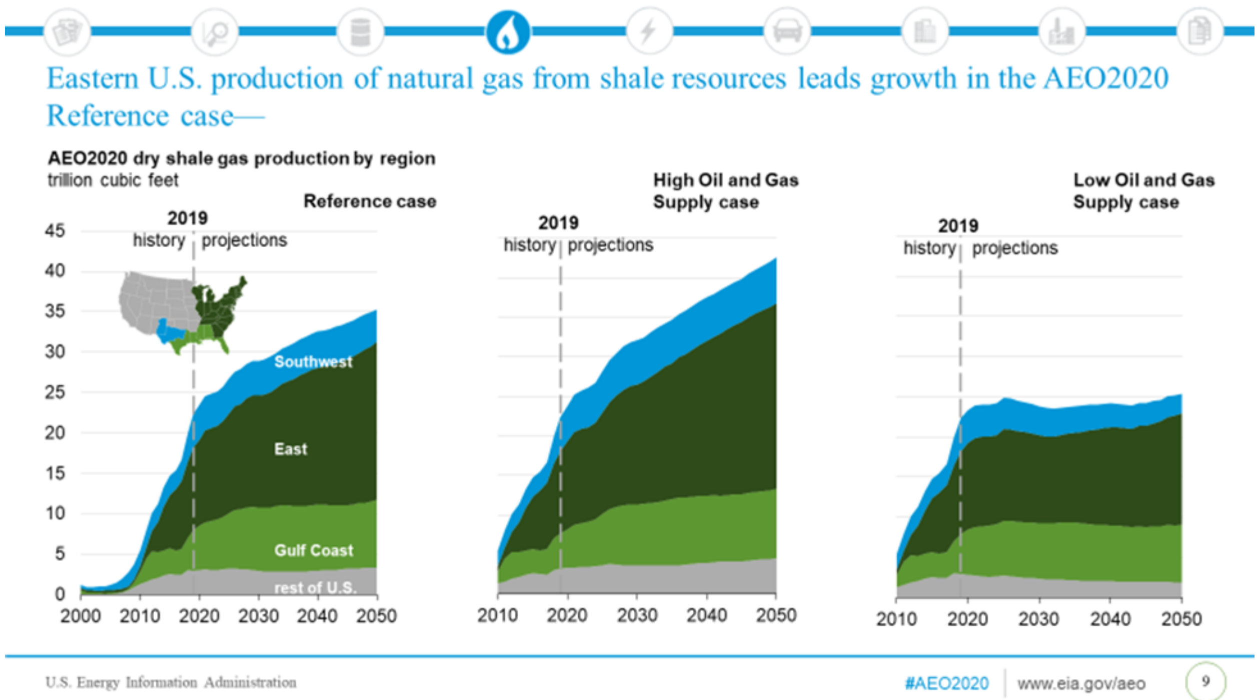
LNG exports are increasing by 3 Bcf/day from 5 Bcf/day in 2019 to 8 Bcf in 2020. The chart below shows U.S. LNG Exports since January 2016 when no natural gas was exported. The blue columns are actual volumes while the green columns are figures are an average of 3 LNG export forecasts prepared in January 2020 (see figure below).




Supply: Impact on pricing – Near-term Mildly Bearish (NYMEX) and Mildly Bullish (AECO); Longer-term Mildly Bearish (NYMEX) and Bearish (AECO)

While year over year U.S. dry gas production (supply) growth has been impressive the last two years (12% and 10%), the U.S. Energy Information Administration (EIA) is only forecasting 2020 growth of 3%.

Production in the Marcellus and Utica basins is expected to continue to grow in the three scenarios provided by the EIA keeping supply strong to fill Rover and Nexus pipelines feeding into Ohio, Michigan and Ontario and Tennessee, Empire and National Fuel Gas Pipelines at Niagara and Chippewa. See Figure ZZ, "East" portion of the growth curve as provided by the EIA in its Annual Energy Outlook 2020 released in January 2020. The "East" or the Appalachian region has been the key driver of gas production in U.S. over the last 10 years and is expected to continue for years to come.

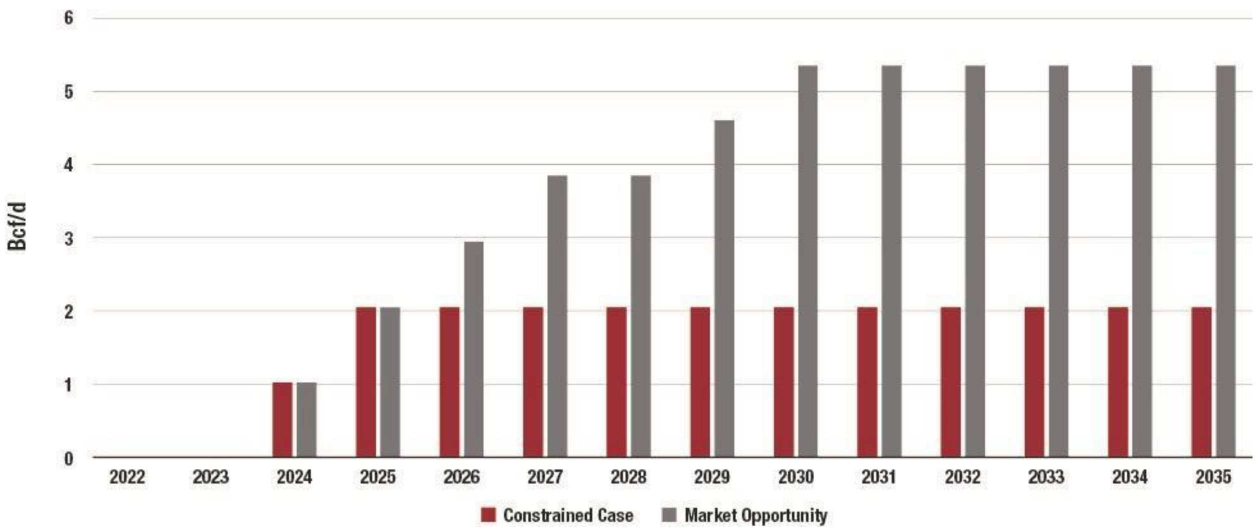



The Western Canadian Sedimentary Basin (WCSB) production has stagnated due to lack of demand growth or lack of economic access to North American (or world LNG) markets in the last decade however it is poised to grow to meet increased demand primarily via TransCanada Energy's (TCE) Mainline. Like in the U.S., WCBS shale reserves are prolific with deposits in North Montney and Duvernay in NE BC and NW AB resulting in supply that is connected to the Aeco Market via the Nova Gas Transmission Ltd. (NGTL), TCE's gathering and transmission network of pipelines in NE BC and Alberta including its most recent North Montney Mainline Project which gradually has come on-line during this past winter and in spring 2020. In total on NGTL, TCE is implementing a renovation and expansion program at a cost of $6.7 billion scheduled for completion in April 2022 which includes restoring capacity to Empress to primarily facilitate the refill of unused capacity at NGTL's Eastern Gate (TCE's Mainline inlet at Empress and Northern Border's Pipeline's inlet at McNeil).

The Canadian Association of Petroleum Producers (CAPP) in February 2020 released a report titled Canadian Natural Gas: Demand and Production Forecast and Scenario Modelling which identifies their view of WCSB capability to meet their Market Opportunity case to 2035 show significant confidence in growing production, see Figure WW.

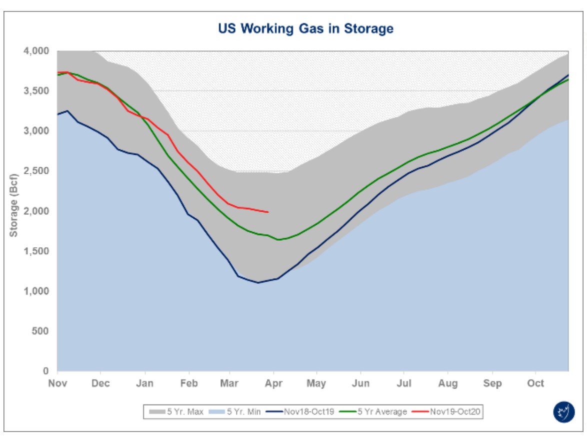
> *The 'Market Opportunity' case utilizes the same outlook for Canadian natural gas demand but incorporates a higher level of net exports to the U.S., that results from a more efficient regulatory framework being implemented that avoids protracted transportation bottlenecks and depressed prices.*

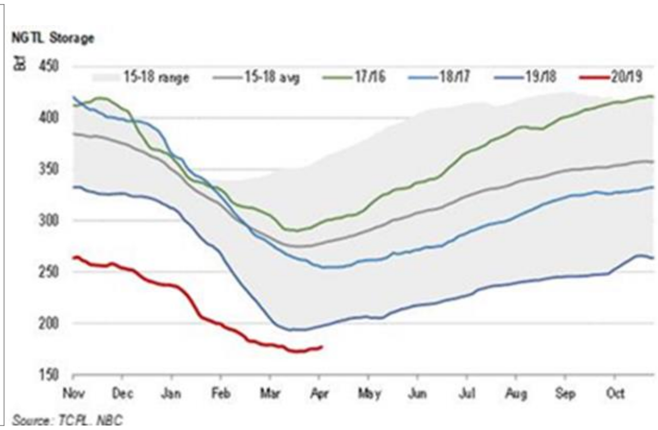
Figure WW – Canadian Natural Gas Production Forecast and Scenario Modelling

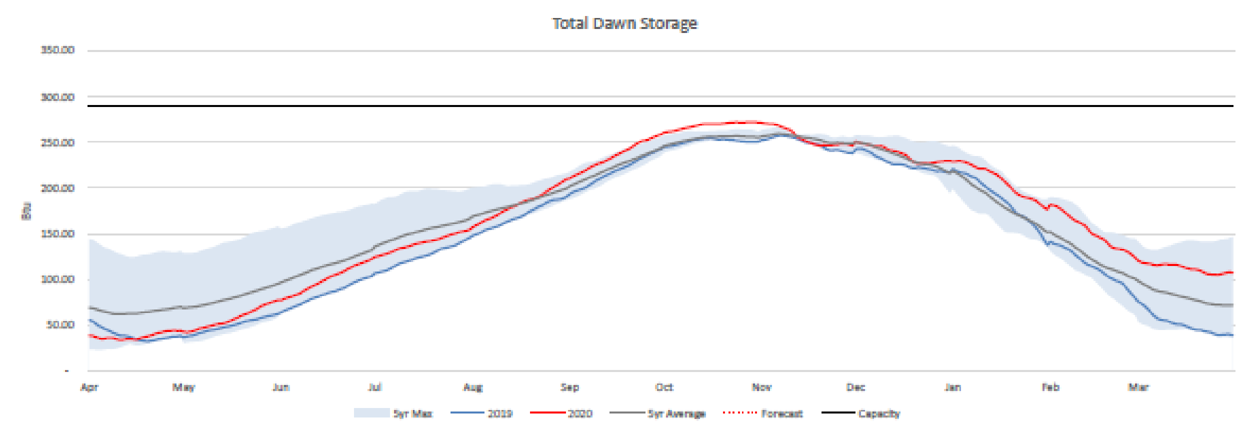



Storage: Impact on pricing – Near term Mildly Bearish (NYMEX and Dawn), Bullish (AECO)

Total U.S. working inventories at March ending fell just below 2.0 Tcf, 14% higher than the five-year average. In EIA's forecast, inventories rise by a total of 2.1 Tcf during the April through October injection season to reach 4.0 Tcf at October 31, which would be the highest end-of-October inventory level on record. In Canada, storage at winter's end in Alberta is setting the 5 year low, whereas storage at Dawn is closer to the 5 year high (see graphs below)

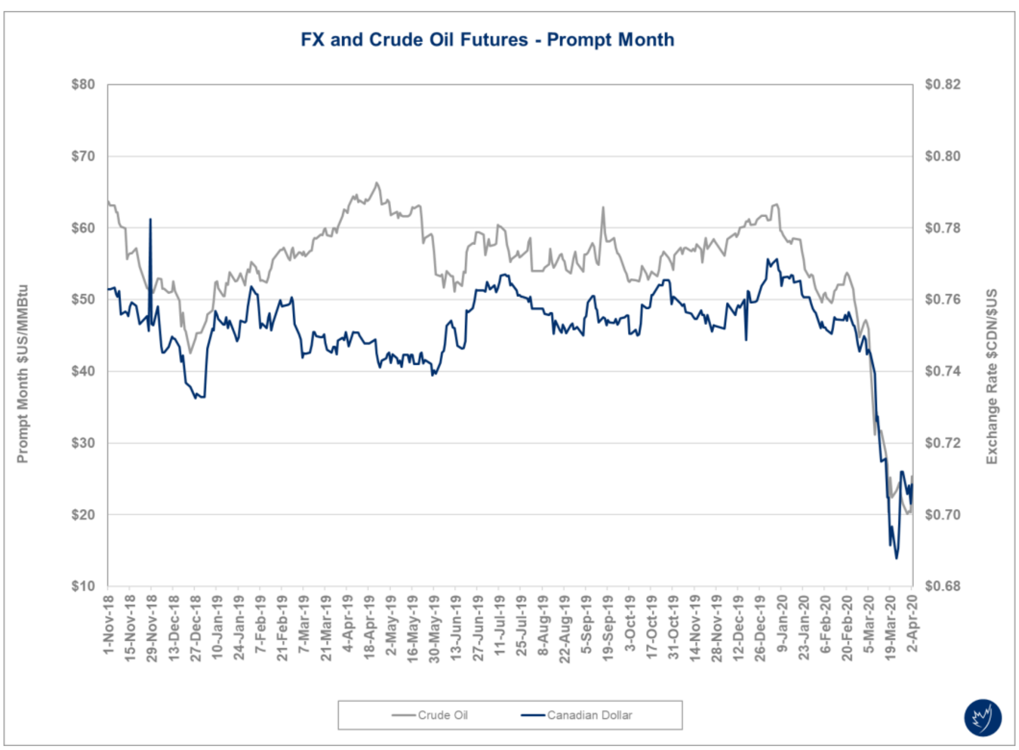


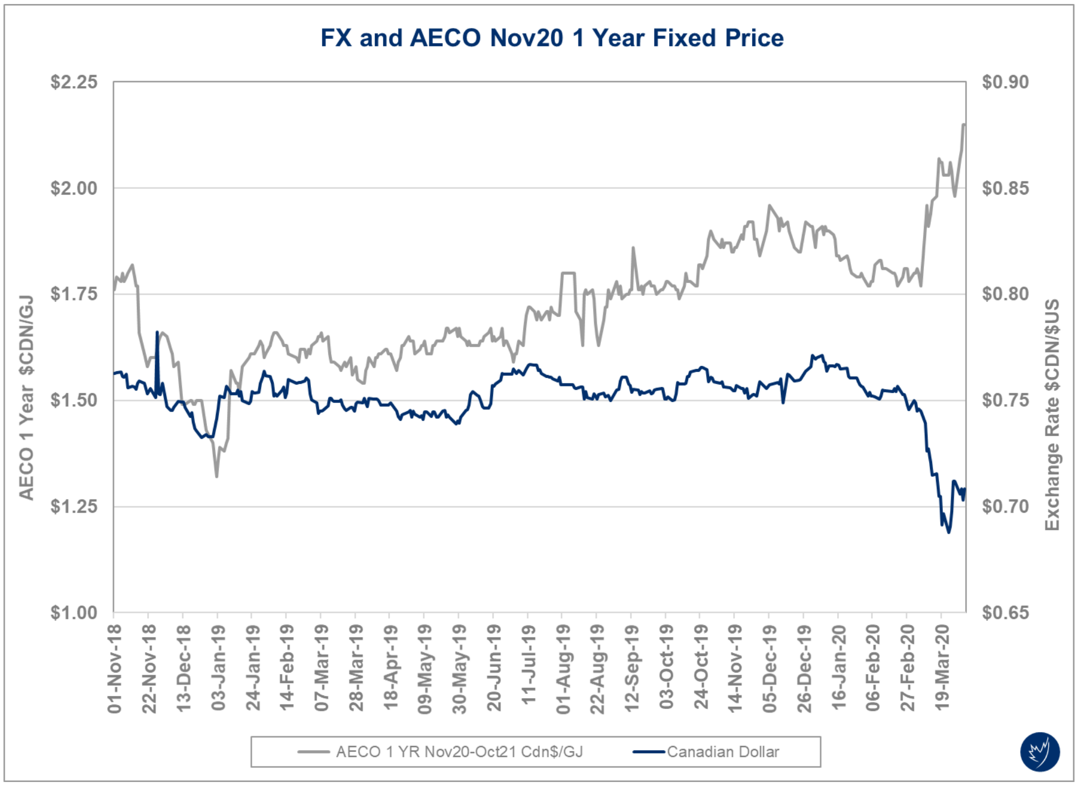






Crude Oil and Foreign Exchange: Impact on pricing – Near-term Mildly Bullish, Longer-term Neutral

The low oil pricing due to oversupply battle between Russia and Saudi Arabia should it continue throughout the summer will impact oil capital programs in the U.S. leading to lower associated gas supply. Also, for the Canadian buyer is to reduce its buying power and thus makes this price impact more bullish. The next two graphs show the impact of crude price drop on the U.S./Canadian foreign exchange and then the impact of the foreign exchange on the price of gas in the WCSB. Mid to long term the influence on natural gas pricing is expected to be minimal in the longer term as crude oil pricing has difficulty finding equilibrium in the $20-$30 U.S./MMBtu price levels.



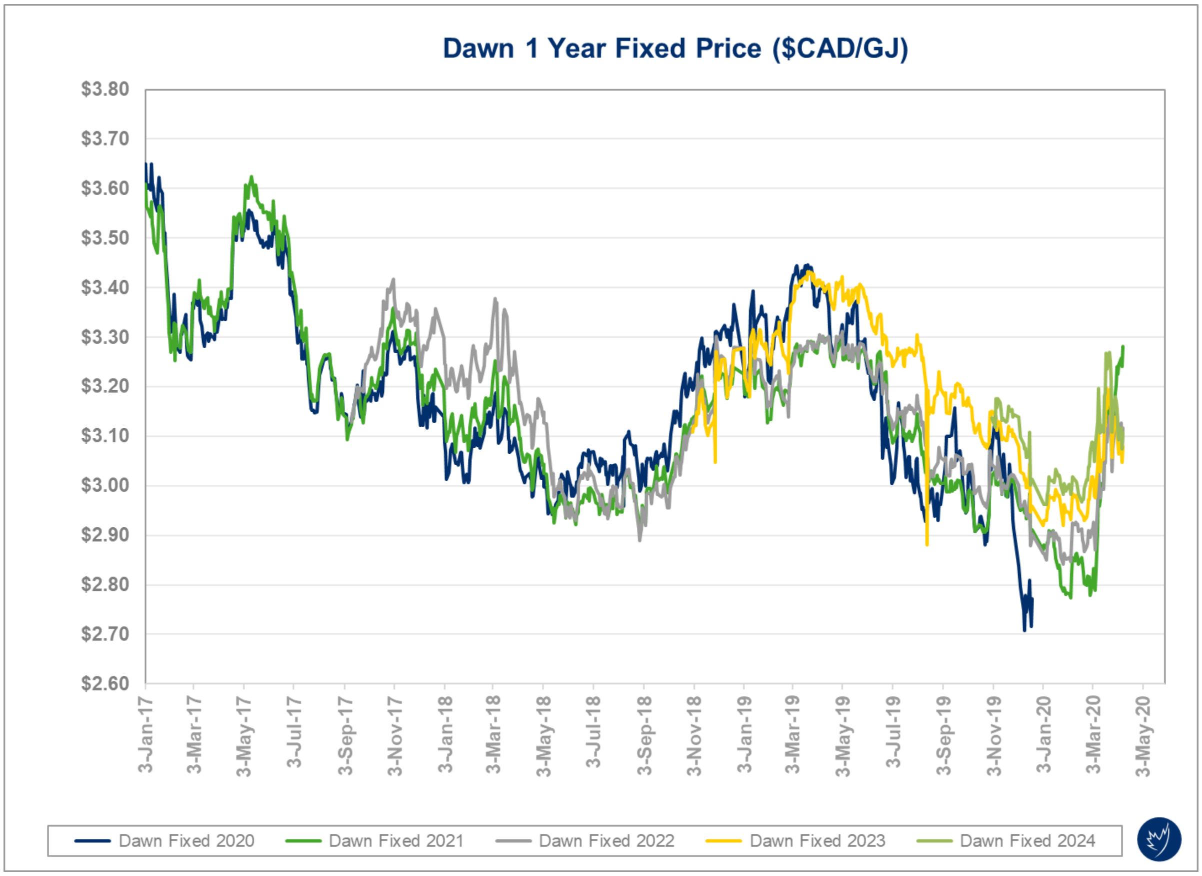



## Short Term Summary – Neutral / Bearish (NYMEX and Dawn), Bullish (AECO)

In the U.S., slowdowns in LNG exports, higher inventories (at Dawn as well) at winter's end, and strong shale supplies make NYMEX and Dawn price outlooks favourable in the near term. In the overall context of historical natural gas pricing, AECO term prices are strong which should continue to support investment in gathering and delivery infrastructure as well as supply exploration and development capital expenditures.

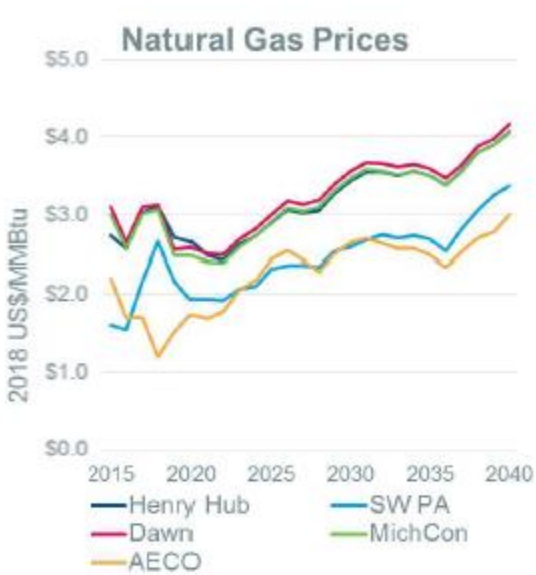
## Long Term Summary – Mildly Bullish (NYMEX and Dawn), Mildly Bearish (AECO)

With the expectation of strong LNG exports, continued growth in gas-fired power generation and slowdown of shale gas growth we expect pricing to move modestly upward. This view does not expect the COVID-19 economic slowdown to be long lasting. The landed cost of gas at Dawn is between $2.90 and $3.20 CAD/GJ for the next 4 gas years. This is good value and in a couple of years we do expect prices to be higher (up to 25%) unless U.S. natural gas production reverses its recent trend.




We are looking for AECO prices have the potential to fall as we head into 2021 with increased capacity infrastructure in WCSB on NGTL and TCE Mainline.

As presented in August 2019 at Enbridge's Annual Customer Meeting (found on its website) the below graph shows a forecast of various prices out to 2040 (in $US/MMBtu). It is interesting to note that Henry Hub (NYMEX) and Dawn are expected to follow closely downward in the early 2020's then upward from that point. AECO follows a similar trend post 2020.

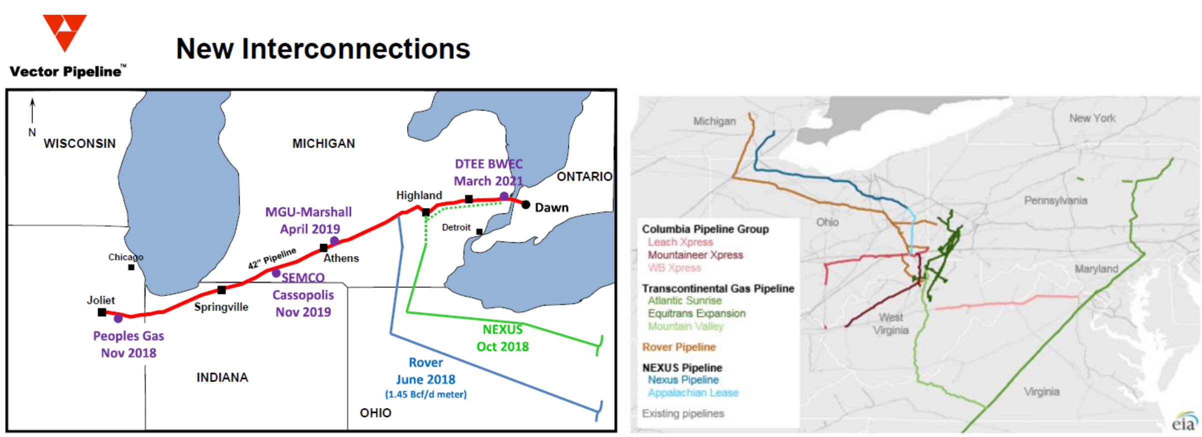


## Dawn Market Hub Discussion

Natural gas primarily flows into the Dawn Hub ("Dawn") from the WCSB and from the United States (U.S.) the Marcellus and Utica shale plays in the Appalachian region as well as from the Chicago Citygate (a market Hub with excess supply from WCSB and other U.S. supply regions)

Driven by its robust supply economics and proximity to the U.S. Northeast and Eastern Canadian markets, Appalachian supply now fulfills most of the gas demand in the U.S. Northeast, and had displaced most of the WCSB supply into that region, and in the last few years has made large inroads in Eastern Canada as well. The latter displacements primarily come from the reversal of the TCE's Niagara/Chippewa (N/C) export points in 2012 and 2015 respectively. This accounted for a greater than 2.0 Bcf/d swing in Ontario hydraulics changing from 1.0 Bcf/d of exports at N/C to over 1.0 Bcf/d of imports at N/C. In 2017 the expansion of the Vector pipeline (0.45 Bcf/day of incremental summer capacity) at Dawn has further increased capability to supply into Eastern Canada. This facilitated new pipeline projects such as Rover (3.25 Bcf/d) and Nexus (1.5 Bcf/d) in 2018 and 2019 respectively continue to bring new supplies into the U.S. Midwest and Dawn.

### Existing Pipelines Bringing Supply from Appalachia to Michigan

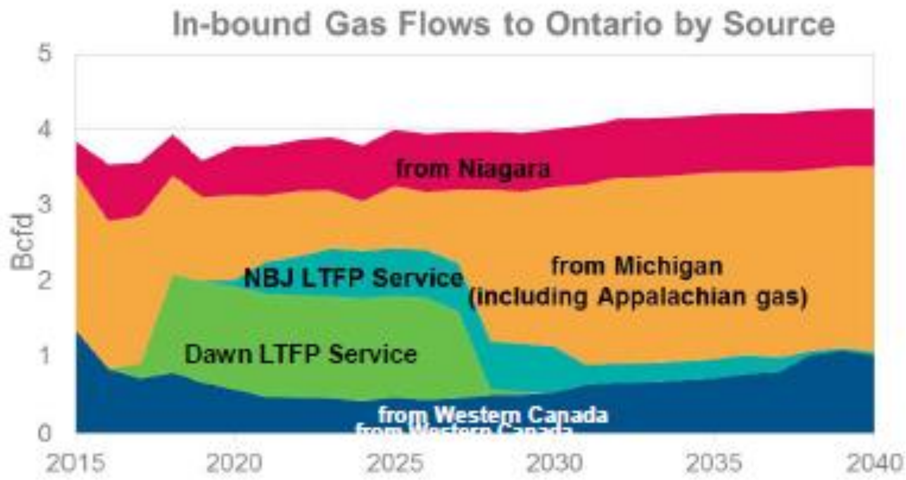



Source: EIA

The caveat to these pipeline developments is that Vector pipeline capacity is not increasing. The last expansion on Vector in 2017, pushed winter and summer capacity to 1.75 Bcf per day. Rover and Nexus will add incremental supply from the U.S. (displacing WCSB gas coming via Chicago supplied by Alliance Pipeline) that will have the potential to add further downward pressure on the Dawn gas price.

Historically, the WCSB has been the major gas supplier to markets in Eastern Canada, but the emergence and rapid development of Appalachian shale supply has significantly increased U.S. supply into Eastern Canada, displacing WCSB gas, however this trend has been dampened.

Effective November 1, 2018 and November 1, 2019 (predominantly) as a result of TCE's first successful Long Term (10 years) Fixed Price (LTFP) Empress to Dawn Open Season of 1.5 Bcf/day of new gas supply came into effect improving Dawn as a source of reliable and reasonable cost supply. Shortly thereafter TCE held another successful LTFP from Empress this time via North Bay Junction as it increased the access of WCSB gas by another 0.3 Bcf/d by 2022. The graph below shows the capacity being used to serve Eastern Canadian markets changing significantly between 2017 and 2019 and then in 2022 and beyond.




The significant aspect of this graph shows that there is excess capacity available to serve the Eastern Canadian markets.

Given the above market outlook and future trends analysis, there are no major changes expected in the North American natural gas market over the planning period that will shift the fundamental supply and demand dynamics to a degree that will impact the viability of the Supply Plan and its ability to deliver on the guiding principles of cost-effectiveness and reliability and security of supply.

## Appendix D – 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 Supply 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 E – Southern Bruce County COVID 19 Impact Survey Result

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# EPCOR Utilities Inc.| June 2020

## Southern Bruce County COVID-19 Impact Residential

EPCOR

June 9, 2020 | **DRAFT REPORT**



## Key Findings

**1** **Almost universal awareness of plan to bring NG to the region.**
97% are aware that EPCOR is working with the municipalities to bring natural gas service in.

**2** **A majority plan to switch to natural gas, and most want to move quickly.**
54% say they plan on switching to natural gas. Intent to switch is higher in Huron-Kinloss (65%). Most (58%) who plan on switching wish to do so as soon as possible.

**3** **Most (97%) had read, seen or heard something about NG coming to their area.**
Specific mentions include pipeline construction (9%), the location of the lines (7%) and the timeline (5%).

**4** **Learning about the plan to bring NG to the area does little to encourage switching.**
Cost is the main barrier. The COVID-19 outbreak is not cited as a barrier to switching.

**5** **COVID-19 is not a significant barrier.**
Only 2% say the outbreak impacted their decision to switch. They cite loss of income and disruption as their concerns – safety is not mentioned.

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# Survey Methodology

**Method:** Random digit dialing methodology, conducted via computer-assisted telephone interviewing.

**Sample Size:** n=304 in Kincardine and n=201 in Huron-Kinloss.

**Weighted Sample Size**: The overall survey sample of n=505 was weighted down to n=500 to ensure a proportionate representation of the targeted region. Huron-Kinloss was weighted down to n=170 and Kincardine weighted up to n=330.

**Margin of Error:** The margin of error for a sample of n=500 is ±4.4%, at the 95% confidence level. Subsamples will have higher margins of error.

**Field Dates:** Evenings and weekends between May 27th to June 5th, 2020.

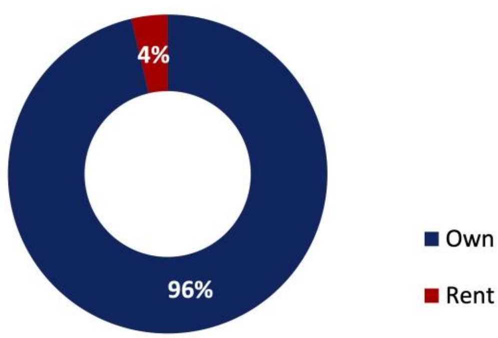
Innovative Research Group (**INNOVATIVE**) was commissioned by EPCOR Utilities, Inc. (EPCOR) to conduct a phone survey of **residents** in the municipalities of Kincardine and Huron-Kinloss, measuring attitudes about a switch to natural gas in their homes and determining whether or not COVID-19 is having any impact on their decision to switch.

**Note**: Graphs may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.

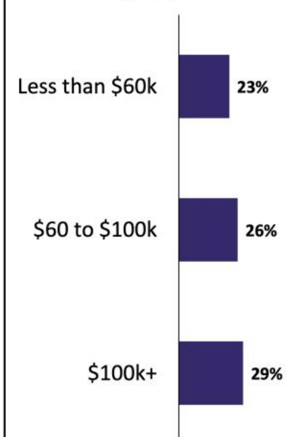


# Respondent Profile

**Own or Rent**




**Income**



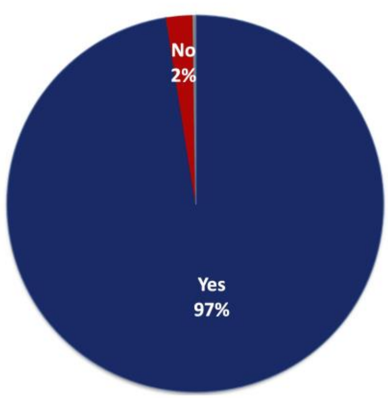

Note: Other Unspecified/Refuse (22%) not shown.

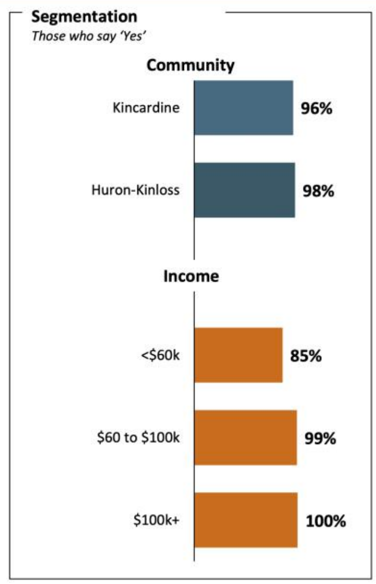
# Switching to Natural Gas

## Service Awareness: Almost all (97%) are aware that municipalities are working with EPCOR on bringing NG to the community

6

Q Are you aware that the municipalities in your area are working with EPCOR to bring natural gas service into your community?
[asked of all respondents; n=500]

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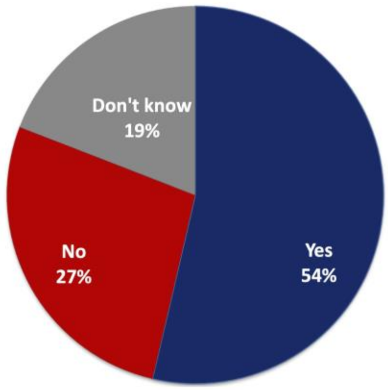
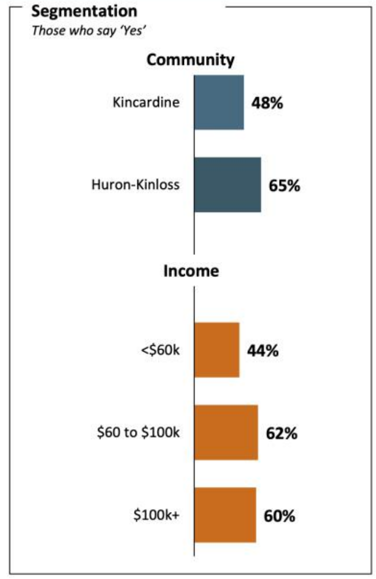
## **Plan to Switch:** Majority (54%) plan to switch to natural gas; those in Huron-Kinloss (65%) and mid/high income residents most likely to switch

7

Q Do you plan on switching any appliances or your heating system over to natural gas?
[asked of respondents aware of natural gas service; n=487]

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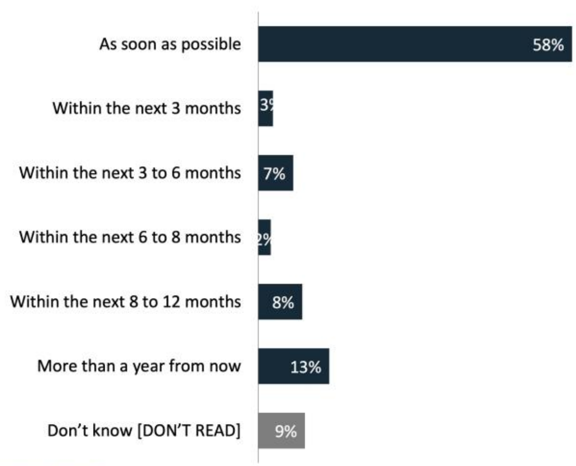
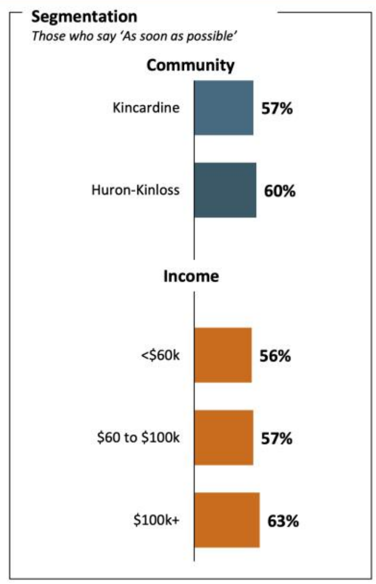
## **Timeline to Switch:** Nearly 6-in-10 (58%) intend to switch as soon as possible to natural gas

Q Which of the following best describes when you intend to switch over to natural gas?
[asked of respondents who plan to switch; n=261]

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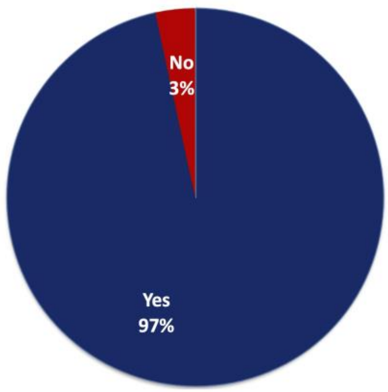
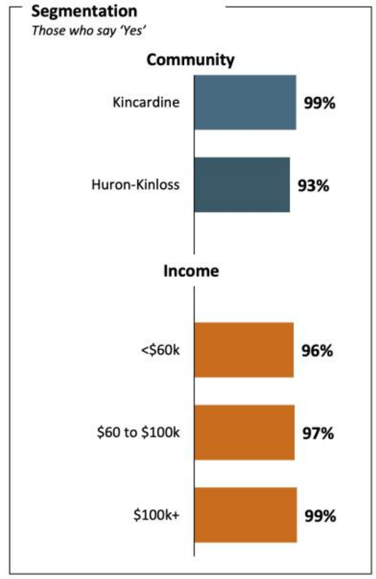
## **Recall of NG Coming:** 97% of respondents have read, seen, or heard about natural gas coming to their area

**Q** Before this survey, had you read, seen or heard anything about natural gas coming to your area?
[asked of all respondents; n=500]

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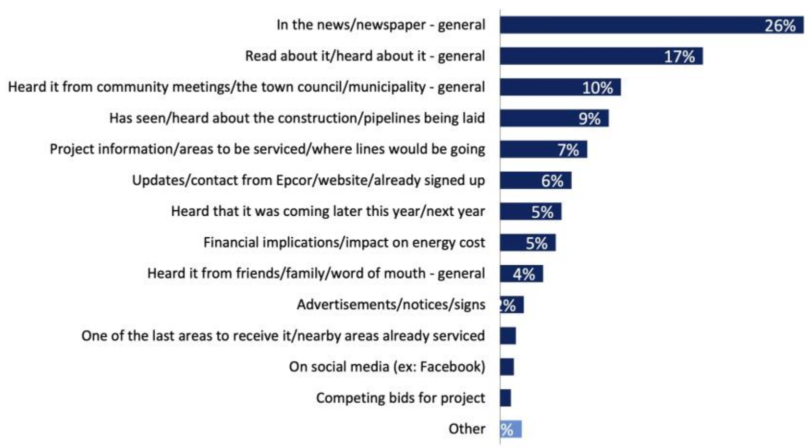
## **Recall:** Specific mentions include pipeline construction (9%), where the lines would be going (7%), and the timeline (5%) [10]

**Q** What, specifically did you read, see or hear? [OPEN]
[asked of respondents who have read, seen, or heard something; coded responses n=477]

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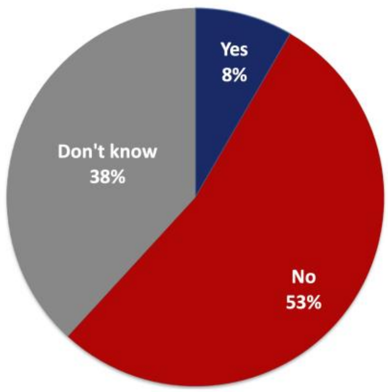
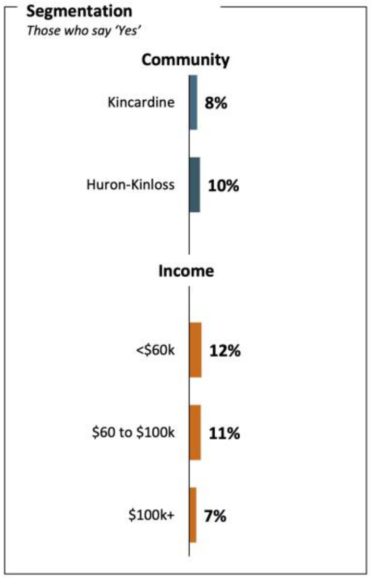
Note: 'None/Don't know ' (1%), 'Refused' (2%) not shown.

## **Reconsider Plan to Switch:** Roughly 1-in-10 (8%) of those without a plan to switch, having now heard about plan, would switch

Q Now that you know there is a plan to bring natural gas to your area, do you intend to switch over to natural gas?
[asked of respondents without a plan to switch; n=226]

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## **Timeline to Switch:** Of 19 respondents who would now switch, most would do so as soon as possible

Q Which of the following best describes when you intend to switch over to natural gas?
[asked of respondents who now plan to switch; n=19]


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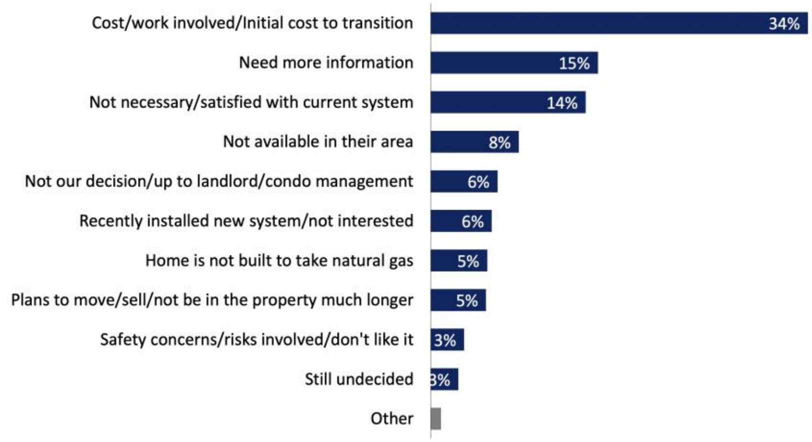
## **Barriers to Switching:** A plurality (34%) cite cost as the main reason not[13] to switch over to natural gas

Q What is the main thing holding you back from switching over to natural gas? [OPEN]
[asked of respondents who do not plan to switch or don't know; coded responses n=207]

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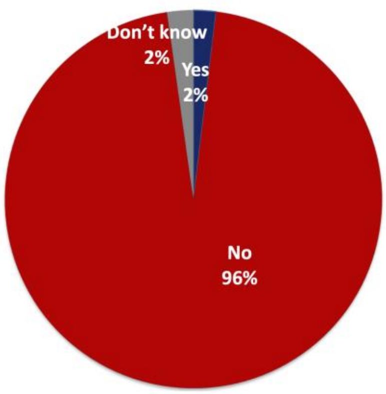
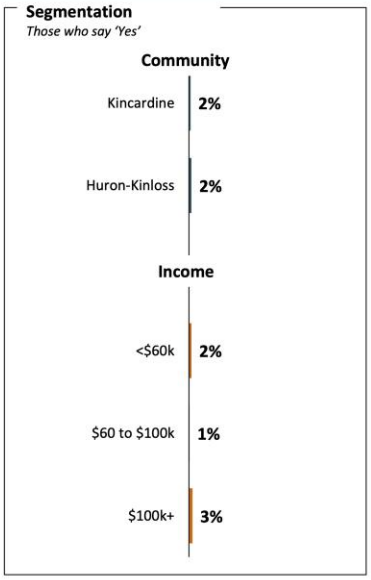
Note: 'Refused' (<1%) not shown.

## **COVID-19 Effect:** For nearly all respondents, COVID-19 has no effect on their decision to switch to natural gas

Q Does the current COVID-19 outbreak have any impact on your decision to switch to natural gas or when you plan on switching?
[asked of all respondents; n=500]

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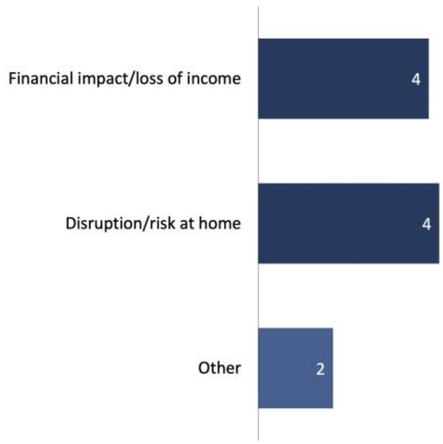
## **COVID-19 Concern:** Of the 10 respondents who say their decision is impacted by COVID-19, four concerned about loss of income



Q What, specifically is your concern? [OPEN]
[asked of respondents who say their decision is impacted by COVID-19; coded respondents n=10]

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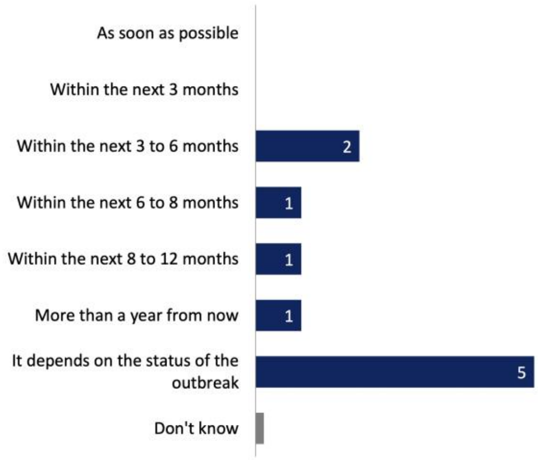
## **COVID-19 Delay Time:** Of 10 respondents who would delay, half say the timeline depends on the status of the outbreak

Q If you are delaying converting to natural gas due to the COVID-19 outbreak, which of the following best describes when you would consider switching to natural gas?
[asked of respondents who say their decision is impacted by COVID-19; n=10]

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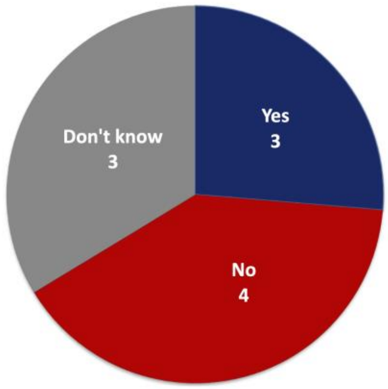
## **COVID-19 Restrictions:** Among 10 respondents who say their decision is impacted, three would reconsider decision to delay if protections lifted

Q If restrictions in place for health protection are lifted later this year, would you reconsider your decision to delay converting to natural gas?
[asked of respondents who say their decision is impacted by COVID-19; n=10]

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# EPCOR Utilities Inc.| June 2020

## Southern Bruce County COVID-19 Impact Business

June 9, 2020 | **DRAFT REPORT**

# Key Findings

**1** **Almost universal awareness of plan to bring NG to the region.**
95% are aware that EPCOR is working with the municipalities to bring natural gas service in.

**2** **A majority plan to switch to natural gas, and most want to move quickly.**
54% say they plan on switching to natural gas. Intent to switch is higher in Huron-Kinloss (65%). Most (58%) who plan on switching wish to do so as soon as possible.

**3** **Most (91%) had read, seen or heard something about NG coming to their area.**
Specific mentions include financial implications (4%) and the timeline (2%).

**4** **Learning about the plan to bring NG to the area does little to encourage switching.**
Cost and lack of necessity are the main barriers. The COVID-19 outbreak is not cited as a barrier to switching.

**5** **COVID-19 is not a significant barrier.**
One-in-ten say the outbreak impacted their decision to switch. They cite loss of income as their concerns – safety is not mentioned.

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# Survey Methodology

**Method:** Random digit dialing methodology, conducted via computer-assisted telephone interviewing.

**Sample Size:** n=93 in the municipalities of Kincardine (n=69) and Huron-Kinloss (n=24).

**Margin of Error:** The margin of error for a sample of n=93 is ±10.3%, at the 95% confidence level. Subsamples will have higher margins of error.

**Field Dates:** Evenings and weekends between May 27th to June 7th, 2020.

Innovative Research Group (**INNOVATIVE**) was commissioned by EPCOR Utilities, Inc. (EPCOR) to conduct a phone survey of **small businesses** in the municipalities of Kincardine and Huron-Kinloss, measuring attitudes about a switch to natural gas in their businesses and determining whether or not COVID-19 is having any impact on their decision to switch.

**Note**: Graphs may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.

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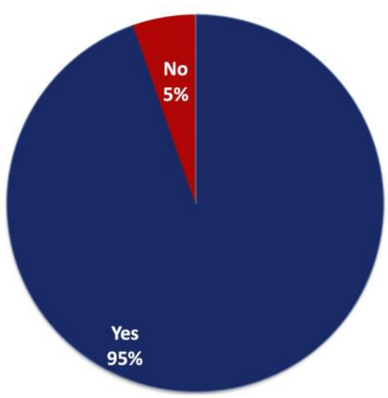
# Switching to Natural Gas

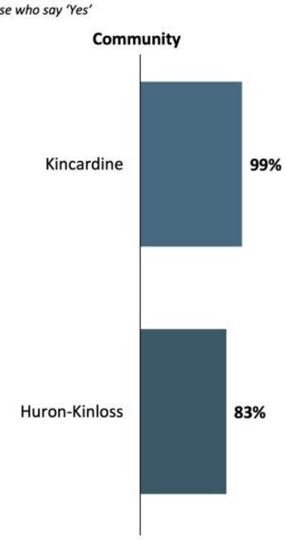
## **Service Awareness:** Almost all (95%) are aware that EPCOR is working with municipalities to bring natural gas service to their area

5

Q Are you aware that the municipalities in your area are working with EPCOR to bring natural gas service into your community?
[asked of all respondents; n=93]




**Segmentation**
*Those who say 'Yes'*

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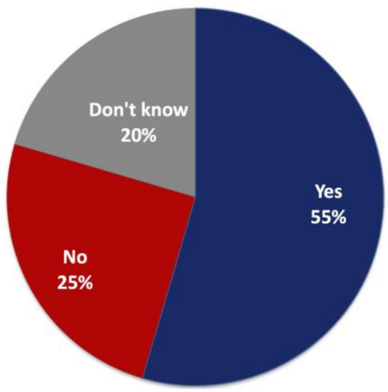
## **Plan to Switch:** Majority (55%) plan to switch to natural gas, 1-in-4 (25%) say they won't, and 2-in-10 (20%) are undecided

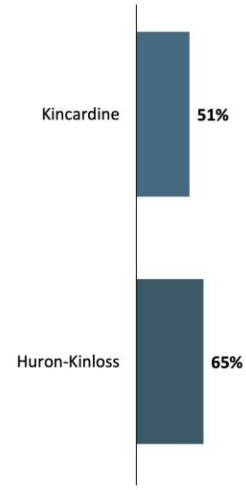
6

Q Do you plan on switching any of your business's appliances or heating system over to natural gas?
[asked of respondents aware of natural gas service; n=88]




**Segmentation**
*Those who say 'Yes'*

**Community**

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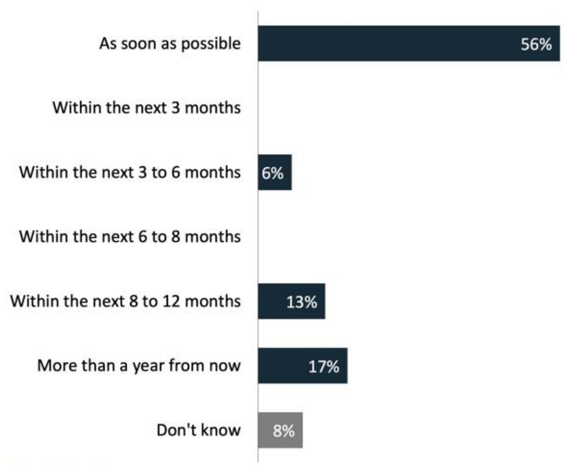
## **Timeline to Switch:** More than half (56%) of those who plan to switch intend to do so 'as soon as possible'

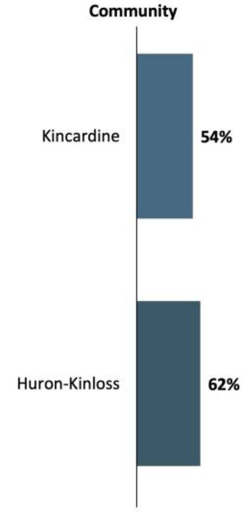
7

Q Which of the following best describes when you intend to switch over to natural gas?
[asked of respondents who plan to switch; n=48]




**Segmentation**
*Those who say 'As soon as possible'*

**Community**

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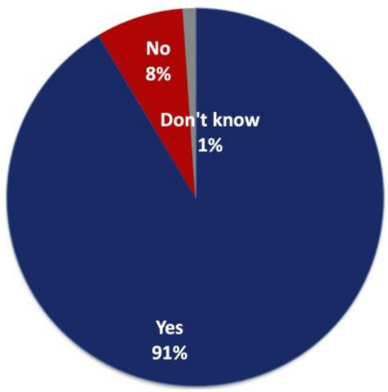
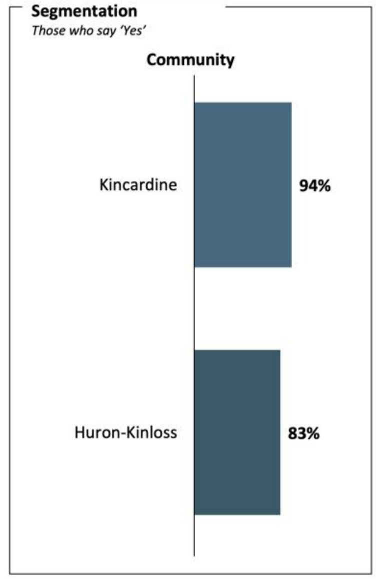
## **Recall of NG Coming:** 9-in-10 (91%) respondents have read, seen, or heard something about natural gas coming to their area

Q Before this survey, had you read, seen or heard anything about natural gas coming to your area?
[asked of all respondents; n=93]

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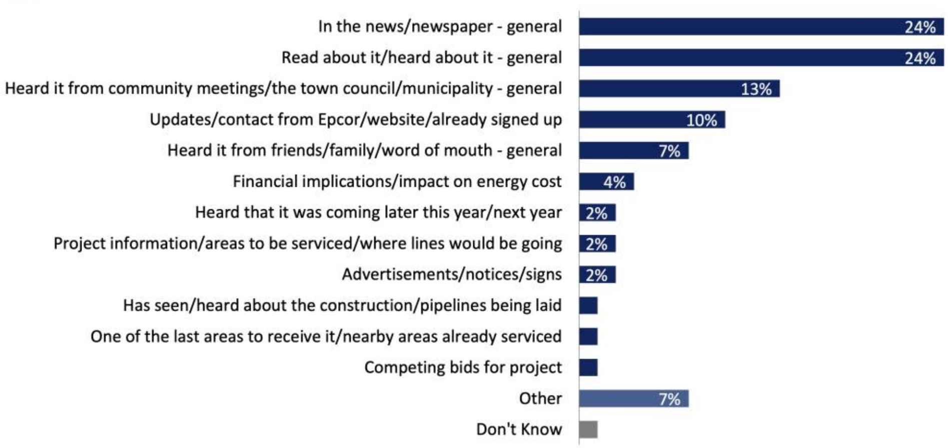
9

## **Recall:** Specific mentions include financials (4%) and timeline (2%)

Q What, specifically did you read, see or hear? [OPEN]
[asked of respondents who have read, seen, or heard something; coded responses n=84]

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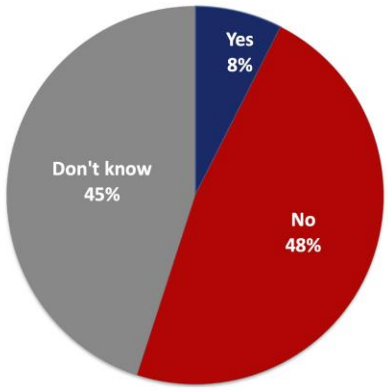
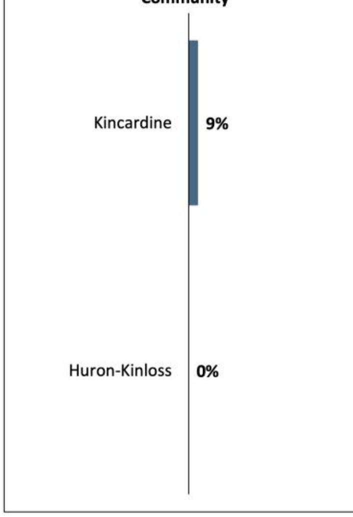
## **Aided Plan to Switch:** Three respondents who did not have a plan to switch would do so now, all from Kincardine

Q Now that you know there is a plan to bring natural gas to your area, do you intend to switch over to natural gas?
[asked of respondents without a plan to switch; n=40]

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## **Aided Timeline to Switch:** The three respondents who now plan to switch would do so more than a year from now

Q Which of the following best describes when you intend to switch over to natural gas?
[asked of respondents who plan to switch, aided; n=3]


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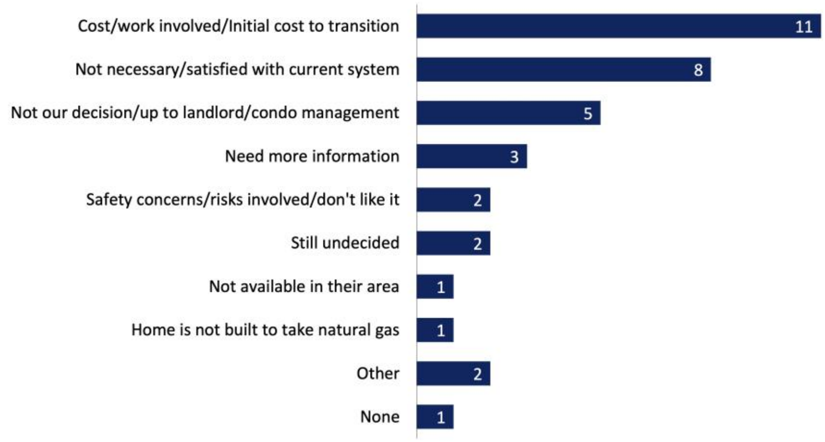
## **Barriers:** 11 of the 36 respondents who do not plan to switch cite the cost and work involved

12

Q What is the main thing holding you back from switching over to natural gas? [OPEN]
[asked of respondents who do not plan to switch or don't know; n=36]

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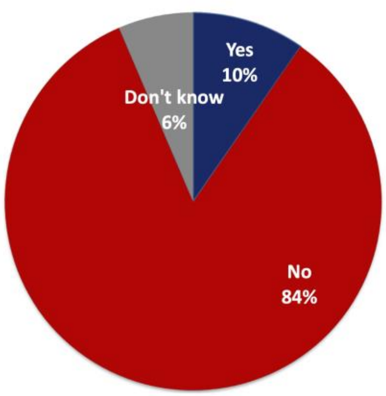
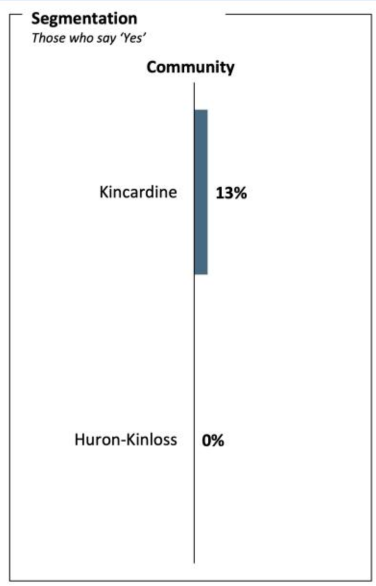
## **COVID-19 Effect:** 1-in-10 (10%) say the COVID-19 outbreak has impacted their decision to switch to natural gas

Q Does the current COVID-19 outbreak have any impact on your decision to switch to natural gas or when you plan on switching?
[asked of all respondents; n=93]

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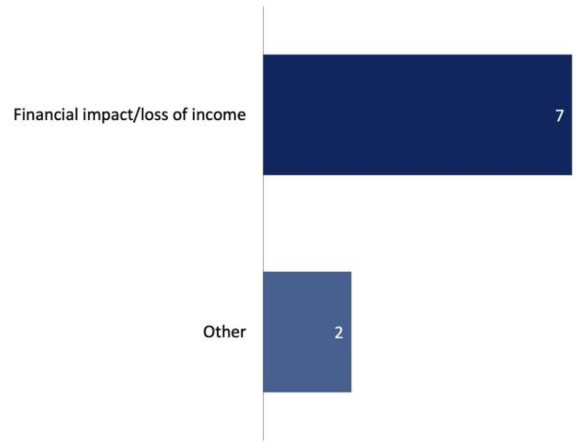
## COVID-19 Concern: Of the nine respondents who feel their decision is impacted by COVID-19, seven cite financial issues

14

Q What, specifically is your concern? [OPEN]
[asked of respondents who say their decision is impacted by COVID-19; coded respondents n=9]

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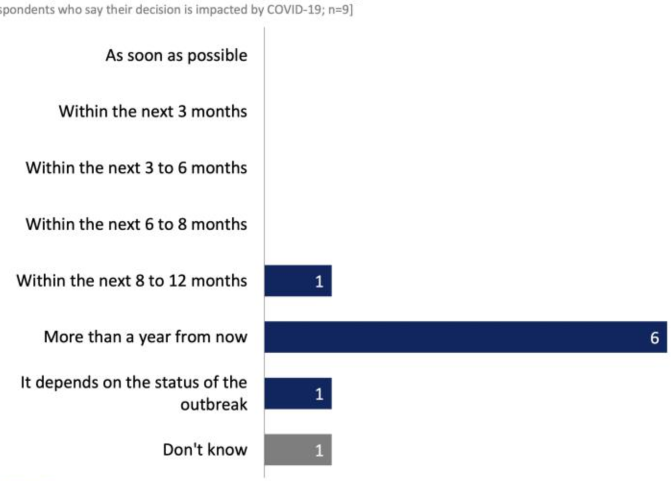
## COVID-19 Delay Time: Six out of nine respondents who say their decision is impacted by COVID-19 would delay more than a year

Q If you are delaying converting to natural gas due to the COVID-19 outbreak, which of the following best describes when you would consider switching to natural gas?
[asked of respondents who say their decision is impacted by COVID-19; n=9]

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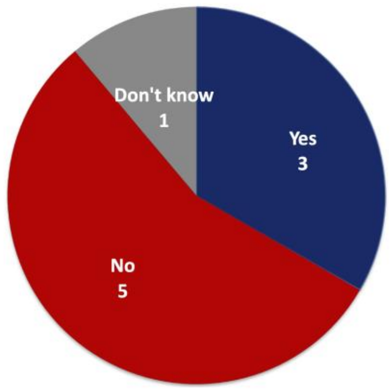
## **COVID-19 Restrictions:** Of nine respondents whose decision is impacted, three would reconsider delay if health protections are lifted

Q If restrictions in place for health protection are lifted later this year, would you reconsider your decision to delay converting to natural gas?
[asked of respondents who say their decision is impacted by COVID-19; n=9]

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(416) 642-6341
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**Building Understanding.**

## Appendix F – EPCOR Southern Bruce Performance Scorecard

| 1. Cost Effectiveness | Performance Categories | Intent of Measures | Measures | Sample | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|
| | 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<br><br>Transacting counterparties have met appropriate credit requirements | C<br><br>100% | | | | | |
| | Price Effectiveness | Demonstrates diversity of supply terms within procurement plan through a layers approach to contracting<br><br>Illustrates Price Stability | Distribution of procurement terms:<br>Less than 1 month<br>Monthly<br>Seasonal<br>Annual<br>Reference price history | Inserts %<br>Reference price graph | | | | | |
| **2. Reliability & Security of Supply** | **Performance Categories** | **Intent of Measures** | **Measures** | **Sample** | **2020** | **2021** | **2022** | **2023** | **2024** |
| | Design Day | Demonstrates ability to procure transportation assets required to meet design day demand | Acquired assets to meet design day | 100% | | | | | |
| | Storage | Demonstrates execution of storage inventory strategy | % of actual storage contract Nov 1 to plan<br><br>% of storage target at March 31 to plan | 100%<br><br>100% | | | | | |
| | Coordination | Demonstrates ENGPL ability to invest in capital distribution required to meet design day demand | Monthly meetings between gas supply & engineering operations | 12/yr | | | | | |
| | Communication | Ensure ongoing communications | Communication to ratepayers re: material bill impacts | C | | | | | |
| | Diversity | Demonstrate the diversity of the portfolio | 1. % of contract tied to various pricing basins<br><br>2. # of unique counterparties | %<br><br># | | | | | |
| | Reliability | Demonstrate the reliability of the portfolio | 1. Days failed to deliver to customers<br><br>2.Days customer interrupted | #<br><br># | | | | | |
| **3. Public Policy** | **Performance Categories** | **Intent of Measures** | **Measures** | **Sample** | **2020** | **2021** | **2022** | **2023** | **2024** |
| | Supporting Policy | Reports public policy in EPCOR supply plan | Plan addresses:<br><br>1.Community expansion<br><br>2. FCC | % of customer converted versus CIP<br><br>C | | | | | |

Notes : C= Compliant

**Definitions:**

1. 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

2. Reliability and Security of Supply: The gas supply plans will ensure the reliable and secure supply of gas. Reliability and security of supply is achieved by ensuring gas supply to various receipt points to meet planned peak day and season gas delivery requirements

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