EPCOR Natural Gas Limited Partnership

2022 Annual Gas Supply Plan Update
(2020-2024 Gas Supply Plan)

Aylmer

EB-2022-0141

Date Filed: April 29, 2022

1. Contents

2. Introduction

On October 25, 2018, the Ontario Energy Board ("Board") issued its Report of the Ontario Energy Board: Framework for the Assessment of Distributor Gas Supply Plans ("Framework") 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 ("ENGLP") filed the Gas Supply Plan (Supply Plan) for the period 2019-2024 as part of the utility's cost of service application, in proceeding EB-2018-0336. In the phase 1 decision, the OEB approved the settlement proposal between the applicant and the intervenors in its entirety, including ENGLP's five-year GSP, including the resulting cost consequences of the plan.

On May 1, 2020, ENGLP filed its 2020 annual update to the Supply Plan, in proceeding EB-2020-05-01. This document is the third Annual Update to the Supply Plan (the "Annual Update").

ENGLP has developed the 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.

Guiding Principles for the Assessment of Gas Supply Plans

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.

To satisfy the Framework requirements, ENGLP developed a demand forecast that reflects its expected annual load profile over the five year rate period starting January 2022. The demand forecast was used as an input in determining the appropriate mix between supply obtained from the Enbridge Gas system and local production.[1] To reliably meet forecasted Peak Day, seasonal, and annual demand, the supply strategy relies on the procurement of gas supply from local production as well as Enbridge Gas.

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 ENGLP'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, Renewable Natural Gas, and Community Expansion.

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[1] Local production has been described in detail through ENGLP's QRAM and other proceedings. Local production refers to gas produced within ENGLP's franchise area or adjacent Lake Erie, i.e., onshore well gas, lake gas, or onshore renewable natural gas.

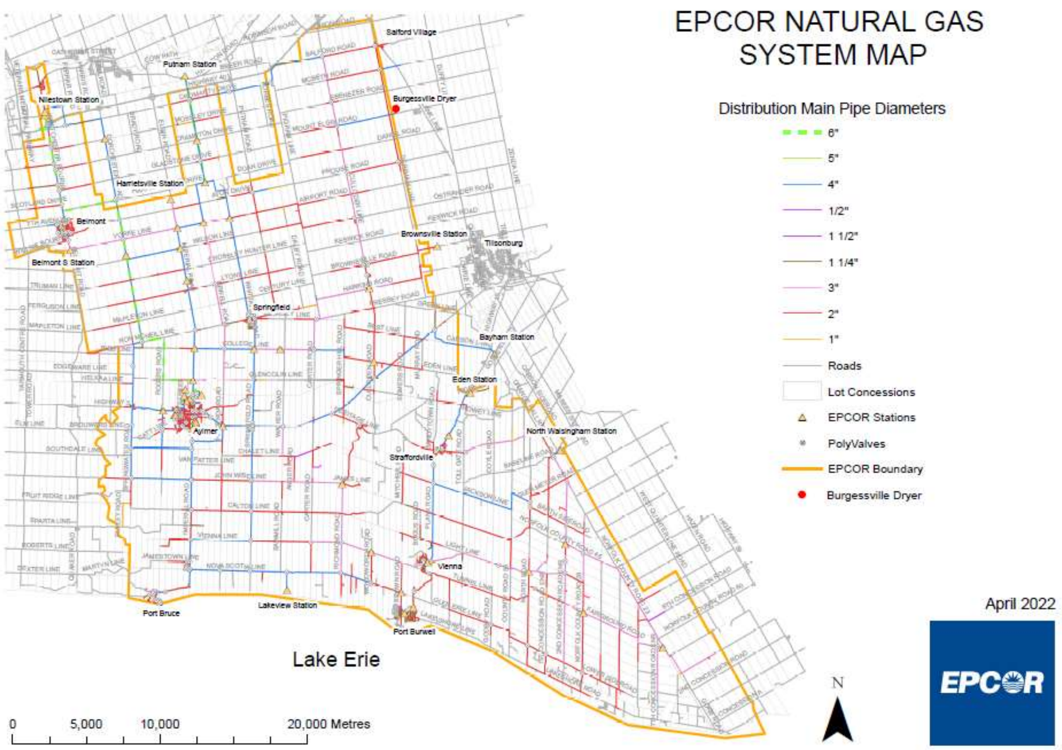
The Supply Plan is intended to provide strategic direction that will guide ENGLP's ongoing decisions related to its natural gas portfolio such that the utility is able to meet Peak Day, seasonal, and annual demand throughout the winter and summer periods for General Service Customers and Contract Customers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

ENGLP is presenting this Annual Update, including upcoming decisions in the Supply Plan, with the aim of transparency 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." Furthermore, ENGLP understands the Board's clarification in the Framework that "the assessment of the gas supply plans will not result in a decision on the costs or cost recovery. That would be the subject of related applications."[2] Accordingly, ENGLP understands that the Board's assessment of the Annual Update will not be an assessment of prudency, or an assessment of the cost consequences of the plan.

2.1. Summary of Service Area

The map below provides a summary of ENGLPs service territory which is current as of April 2022. Key changes, relevant to the Supply Plan, include the addition of the Village of Salford and the South West Oxford Burgessville dryer. The consumption profile for these additions are included in the demand forecast and capacity discussion as well.

[2] EB-2017-0129, *Report of the Board*, dated October 25, 2018, at page 2.



2.2. Significant Changes

Two major significant changes are introduced in this gas supply plan update

Section	Significant changes
4. Supply Options	Introduction of a third local supply source (Production D) expected October 2022
4.1.1 Transportation	Shifting a portion of the System Supply Contract Demand (SA1550) to the Direct Purchase Contract Demand (SA25050), to account for the introduction of the Lakeview contract demand and related gas supply in December 2019.

3. Demand Forecast

To develop a natural gas supply portfolio, ENGLP first constructed a demand forecast. The demand forecast for this Supply Plan is based on the values provided by Elenchus Research Associates Inc. ("Elenchus") in its Weather Normalization and Distributions System Load Forecast (EB-2018-0336, Exhibit 3, Tab 2, Schedule 1). This analysis was updated by Elenchus on April 17, 2021 for purposes of this gas supply plan. The forecast methodology can be found at the end of this section.

The utility will service three main classes of customers: General Service, Seasonal and Contract customers. These customers fit under six rate classes that include:

- **General Service Customers:** Rate 1 (General Service Rate) and Rate 4 (General Service Peaking),
- **Seasonal Customers:** Rate 2, and
- **Contract Customers:** Rate 3 (Special Large Volume Contract Rate), Rate 5 (Interruptible Peaking Contract Rate) and Rate 6 (Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility).

General Service Customers

General Service customers (residential, commercial, and industrial) are forecasted to make up approximately 30.6% of ENGLP's demand profile in 2022.

Residential customers comprise the majority (68.5%) of the General Service demand profile. While the residential segment is expected to have the highest growth in terms of customer numbers (from 9,070 to 9,393), weather normalized demand is expected to remain relatively flat in 2022 compared to 2021.

Commercial customers make up approximately 20.6% of the General Service demand profile. In 2022, 593 customers are forecasted to be under this segment. 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). Industrial customers have an interruptible (Rate 4) and non-interruptible (Rate 1) component and make up approximately 14.1% of the General Service demand profile. There are 81 non-interruptible and 50 interruptible industrial customers in the ENGLP natural gas system forecasted for 2022.

Contract Customers

Contract customers are forecasted to make up approximately 68.3% of ENGLP's demand profile in 2021. There are currently 11 customers under this classification and no change in customer numbers are forecasted in 2022. At this time, Contract Customers contract for their own natural gas supply. Contract customer Rates 3 and 5 have an interruptible component and on average make up approximately 2.42% of ENGLP's demand profile by volume.

Seasonal Customers

Seasonal customer are forecasted to make up the remaining 1.05% of ENGLP's demand profile in 2022. There are 48 customers under this rate class and that consist mainly of tobacco framing and curing customers (non-interruptible).

The following tables provide ENGLP's Customer Connection Forecast and Annual Customer Service Demand Forecast by Rate Class. The forecasted 2021 values are provided by Elenchus Research Associates Inc. ("Elenchus") in their Weather Normalization and Distributions System Load Forecast (EB-2018-0336, Exhibit 3, Tab 2, Schedule 1) and updated for purposes of this Annual Update. The updated Elenchus report can be found in Appendix D.

Table 1-1
Forecast of Customer Connections

	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
R1 Residential	9070	9353	9644	9945	10,254	10,574
R1 Industrial	76	79	81	84	87	90
R1 Commercial	559	575	593	610	628	647
R2 Seasonal	51	49	48	47	46	45
R3	6	6	6	6	6	6
R4	46	48	50	52	54	57
R5	4	4	4	4	4	4
R6	1	1	1	1	1	1
Total	9,812	10,115	10,427	10,750	11,081	11,424

Table 1-2
Forecast Annual Customer Service Demand, by Rate Class

	2021 Actual	2021 Normalized	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
R1 Residential	17,299,257	18,272,944	18,607,331	19,257,743	19,930,528	20,626,443	21,346,276
R1 Industrial	2,226,121	2,736,619	2,220,366	2,333,411	2,451,644	2,575,289	2,704,581
R1 Commercial	5,306,940	5,648,018	5,876,510	6,078,753	6,287,803	6,503,888	6,727,238
R2 Seasonal	829,096	829,096	962,031	940,348	919,154	898,437	878,187
R3	1,372,372	1,414,518	1,358,859	1,301,078	1,249,451	1,202,977	1,160,868
R4	1,793,580	1,793,580	1,806,683	1,889,798	1,976,737	2,067,675	2,162,797
R5	791,530	791,530	757,724	757,724	757,724	757,724	757,724
R6	60,410,748	60,410,748	61,336,401	61,336,401	61,336,401	61,336,401	61,336,401
Total	90,029,645	91,897,053	92,925,905	93,895,256	94,909,441	95,968,834	97,074,072

Methodology

The forecasted annual customer service demand for R1 Residential, R1 Commercial, R1 Industrial and R3 rate classes were determined through multivariate regressions. Consumption of the three R1 rate classes were forecasted using a base load and excess consumption methodology wherein average monthly consumption per customer was first calculated for each class. The amounts were then reduced by the base load consumption, which is considered the average consumption in the summer months of July and August. The remaining consumption is considered the weather-sensitive load (or “excess” load).

The excess load was regressed by the actual heating degree days in each month to determine the impact of cold weather on average consumption. A time-series (Prais-Winsten) regression was used to determine the coefficient, consistent with the methodology used in prior NRG throughput forecasts. Actual heating degree days were then multiplied by the coefficients and base load consumption was added back to determine the average predicted consumption in each month. Predicted total consumption of a class was determined by multiplying this sum by the actual number of customers. Similar methodology was used for the R3 rate class; however, the base load was removed from the regression.

Consumption of the remaining four rate classes (R2 Seasonal, R4, R5 and R6) were not weather- sensitive and did not exhibit sensitivity to the explanatory variables. Total and monthly volumes fluctuate from year-to-year and as such, a 5-year rolling average was used to forecast monthly consumption for each of these classes, with the exception of R4 in which a trend is also applied.

The customer connections count was forecasted by applying the geometric mean annual growth rate from 2011 to 2021 to the 2021 average customer count.

4. Supply Options

4.1. Key Assumptions

The appropriate balance of system gas supply and local gas production are considered for the procurement of natural gas commodity in order to meet the demand forecast established in Section 3. The chart below provides an analysis of the supply sources for the 2021 calendar year, including incremental local production.

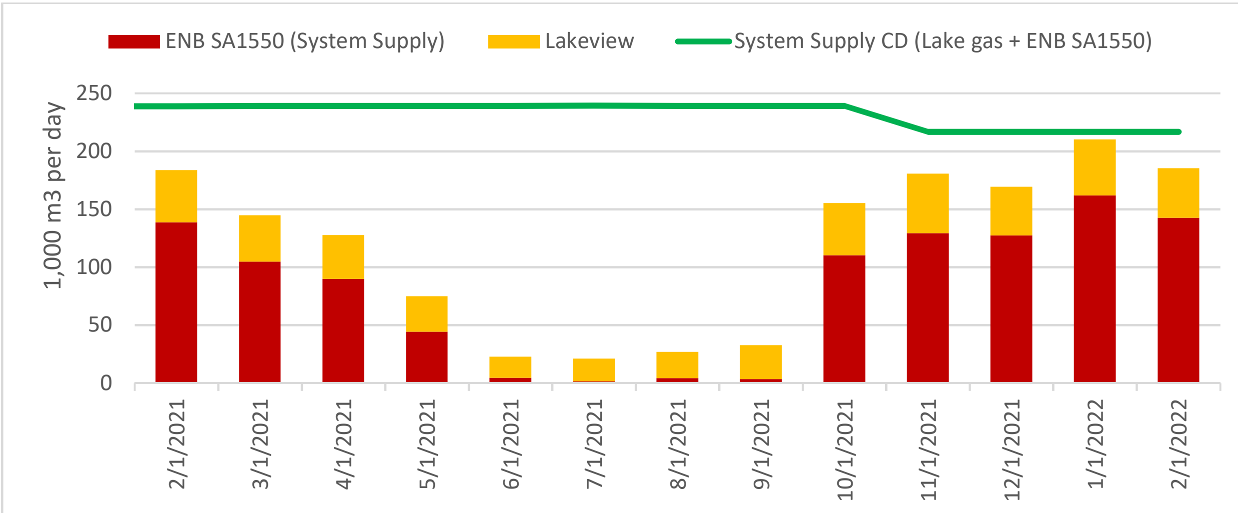
Three changes are made:

1) Well Gas volumes are not considered for the analysis related to Contract Demand and capacity. The well gas contract does not have associated contract demand. While the local production volumes from these wells play an important role in system pressure and system reliability, they have an overall minor impact on contract demand utilization.

2) A shift of a portion of the SA1550 System Supply Contract Demand to SA25050 Direct Purchase Contract Demand, to account for the introduction of the Lakeview contract demand and related increase in local supply in December 2019. Note the overall capacity contracted with Enbridge (sum of SA1550 and SA25050) remains the same.

3) Introduction of a third local supply source (Production D) expected October 2022, which is discussed in Section 4.1.3

Table 3-1
Max Daily Demand each Month by Source vs Contract Demand,
Feb 2021 to Feb 2022



While the demand forecast serves as the primary input used to develop the Supply Options, the following base assumptions also underpin each option:

4.1.1. **Peak Day/Hour**

ENGLP engaged Cornerstone to review and predict system conditions under the current peak gas demand and predict future peak demands. Based on the study, the biggest difficulty in establishing an accurate model for the distribution system was the loading throughout the system. Gas is not metered using district meter stations for each of the towns the system serves, which necessitates that a peak hour consumption estimate be developed for each town center. With the town loads making up a large majority of the consumption, based on the number of customers located in the towns compared to the distributed customers, this introduced a large unknown.

In previous analyses of this system's integrity, the month of November had days that were considered the peak scenario of gas consumption. In November, seasonal agricultural loads are still active and drawing gas from the system. The seasonal agricultural loads, however, are largely interruptible and therefore ENGLP focused on the January 2018 peak load, when seasonable interruptible customers were not using gas.

January 30, 2019 had the highest gas consumption for the historical data provided and the goal was to construct the base case model to reflect the gas meter readings that each Union station was seeing, as well as the pressure recordings at the stations and at the several other points in the system. The modelling was set up with flows in m^3/hour, so a peak hour was chosen for January 5, 2019 based on the hour with the largest meter readings (9:00 a.m.). The total meter readings for the 8:00-9:00 a.m. hour were 9,747 m^3/h, thus all loads had to equal that number.

This work provided ENGLP with a demand day road map in order to assist in determining the required Peak Day and firm Contract Demand requirements from its gas supply sources. The roadmap was updated in this Annual Update to include 2021 actual peak demand and a forecast for 2026.

Table 3-2
Actual & Forecast Demand Requirements

	ACTUAL / FORECAST	Actual and Forecast Peak Demand (Cornerstone)*	Actual and Forecast CD (Enbridge)	Lakeview CD (1,200 GJ/d)	Total CD
2017	ACTUAL	197,278	177,234		177,234
2018	ACTUAL	208,650	208,429		208,429
2019	ACTUAL	241,670	208,429	30,856	239,285
2020	ACTUAL	187,720	208,429	30,856	239,285
2021	ACTUAL	213,131	186,100	30,856	216,956
2022	FORECAST	217,394	189,822	30,856	220,678
2023	FORECAST	221,742	193,618	30,856	224,474
2024	FORECAST	226,177	197,491	30,856	228,347
2025	FORECAST	230,700	201,441	30,856	232,297
2026	FORECAST	235,314	205,469	30,856	236,325

*assume 2% growth YOY as per Cornerstone

In 2021, the highest system gas peak day demand recorded was 213,131 m3 on November 3rd, 2021. ENGLP will continue to monitor the system's consumption and growth pattern and increase contract demand from either Enbridge or Lakeview as needed.

4.1.2. **Weather**

ENGLP retained Elenchus to provide a Weather Normalized Distribution System Load Forecast. A copy of this report is provided in Appendix D.

4.1.3. **Commodity**

ENGLP receives the majority of its commodity under the bundled M9 rate which is based on Enbridge Gas' OEB approved WACOG application. ENGLP currently has three M9 Large Wholesale Service Contracts; SA1550 (System Gas) with a contract demand of 186,100 m^3, SA25050 (Direct Purchase) with a contract demand of 35,695 m^3 and SA8936 (IGPC) with a contract demand of 208,800 m^3.

The balance of ENGLP's commodity requirements are sourced from local production. In the fall of 2022, ENGLP Aylmer is expecting another source of local supply to the distribution system through the introduction of renewable natural gas (Production D). The facility is expected to increase supply to the distribution system by approximately 4,577 m3 14,000 m3 per day. While the source of this supply is from a renewable natural gas facility, ENGLP is only purchasing the commodity and not the environment attributes. Therefore, ENGLP Aylmer will treat the natural gas produced by the facility as another source of local supply, with a pricing structure similar to other Aylmer local supply contracts at the Enbridge commodity rate minus a 5% discount. Note that ENGLP is expecting to finalize the supply contract in during the summer 2022.

4.1.4. **Transportation**

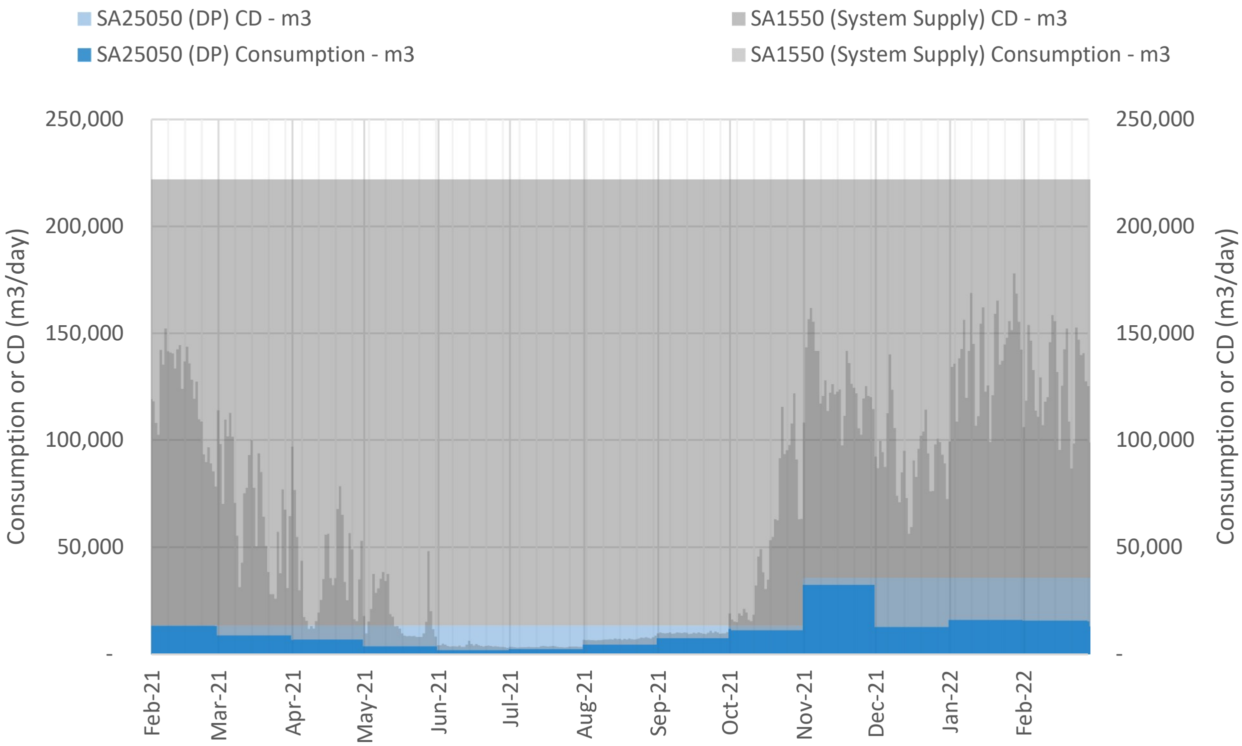
ENGLP incurs gas transportation costs (to/from Enbridge Gas) for storage, load balancing, and transportation across Enbridge Gas' system to ENGLP's distribution system. These costs are recovered in ENGLP's delivery charges as reflected in the EB-2018-0336 cost of service rate filing.

ENGLP currently contracts for an annual Contract Demand in the amount of 191,683 m^3 for its System Gas customers. This is approximately 11% lower than the CD in

2020/2021.

ENGLP evaluates its Contract Demand requirements with Enbridge Gas on an annual basis and will balance the need to maximize its usage and minimize over run charges under this contract. For the November 2021 renewal, Enbridge proposed lowering the Contract Demand for SA1550 (for system gas customers) by 22,329 m3 and increasing the Contract Demand for SA25050 (for direct purchase customers) by an equivalent amount. This is due to the introduction of the Lakeview local supply in 2019, which displaced the volumes purchased from Enbridge's SA1550 contract and also lowering the peak day consumption from SA1550. The higher CD allocated to SA25050 allows ENGLP to lower the risk of triggering overrun charges from SA25050 in high consumption months for DP customers, which is often the highest in the grain drying season in October to November. Table 3-3 below shows the daily consumption profile for SA25050 and SA1550 between February 2021 and February 2022 – note the change in the Contract demand on November 1, 2021. The reduced contract demand for SA1550 proved to provide sufficient capacity for Aylmer system gas customers in January 2022. The new source of local supply in 2022 will further displace Enbridge volumes, which will allow for lower consumption from the SA1550 contract from Enbridge during peak day and lowering the risk of consuming above Enbridge's contract demand.

Table 3-3
Daily Consumption of SA25050 and SA1550 vs Contract Demand,
Feb 2021 to Feb 2022



4.1.5. **Storage**

ENGLP relies on its contract with Enbridge Gas for storage, load balancing and transportation.

4.1.6. **Daily Balancing Management**

ENGLP is not required to Daily Balance its gas supply as that service is provided by Enbridge Gas under the M9 service agreement.

4.1.7. **Direct Purchase Program**

ENGLP has Direct Purchase Customers in its system whereby these customers arrange for gas supply and/or upstream transmission services directly with Enbridge Gas or ENGLP's distribution service to deliver gas to end-user locations. Currently, approximately 1% of ENGLP customers are on direct purchase compared to system sales and represent approximately 11.7% of ENGLP's demand profile by volume.

ENGLP relies on the Direct Marketer to deliver the volumes to Enbridge Gas. In accordance with the Bundled T-Service Receipt Contract between ENGLP and the Direct Marketer, if on any Day, for any reason, including an instance of Force Majeure, the Direct Purchase Customer fails to deliver gas then such event shall constitute a "Failure to Deliver" and the Failure to Deliver clause (Section 3.01) in the this contract will take effect. The Direct Marketer will indemnify and hold ENGLP harmless with respect to the excess of any costs and expenses incurred by ENGLP in acquiring such Gas and transportation capacity.

4.1.8. **Long-Term Contracts**

There are no changes to existing long-term supply agreements that was discussed in the 2021 Gas Supply Plan Update (EB-2021-0146).

At the time of writing this Gas Supply Plan Update, the local supply contract with the RNG producer is still being finalized. An update will be provided in the next Gas Supply Plan once the contract is finalized.

4.1.9. **Diversity of Supply**

Diversity of supply was identified as a key consideration in the Supply Plan. The introduction of incremental local production in the form of RNG in addition to existing local supply further diversifies the portfolio as demonstrated in the analysis below:

Table 3-4
Supply Source Breakdown – Forecast and Actual

Supply Source Breakdown-Forecast					
	Enbridge	Production A & B	Production C	Production D	Total
2026	69.0%	1.2%	24.1%	5.7%	100%
2025	67.8%	1.5%	24.9%	5.9%	100%
2024	66.5%	1.8%	25.7%	6.1%	100%
2023	66.3%	2.1%	26.5%	5.0%	100%
2022	69.0%	2.6%	27.3%	1.1%	100%

Supply Source Breakdown-Historical					
	Enbridge	Production A & B	Production C	Production D	Total
2021	67.5%	2.7%	29.8%	0%	100%
2020	67.3%	3.3%	29.4%	0%	100%
2019	94.9%	4.6%	0.5%	0%	100%
2018	96.5%	3.5%	0.0%	0%	100%
2017	94.3%	5.7%	0.0%	0%	100%

5. Gas Supply Plan Recommendations

Given ENGLP's limited size and resources, the utility recommends it continue its strategy of contracting with Enbridge Gas for the M9 rate, including system supply. Local production, in particular the introduction of gas from Lake Erie, will augment Enbridge Gas' system supply in order to ensure reliability of the ENGLP system. Specifically, this incremental lake gas addresses historical low pressure issues and allows ENGLP to displace fixed price local production.

ENGLP is also developing the Southern Bruce natural gas franchise and as ENGLP gains operational experience and measures consumption data associated with this system, it will evaluate potential synergies between the two systems including the M9 system supply option for the Aylmer operation. ENGLP is mindful that should it elect to not take service under the M9 rate for the Aylmer operation, the rate will no longer be available to ENGLP.

6. Gas Supply Plan Execution & Risk Mitigation

6.1. Procurement Processes and Policies

Leading into each contract year (July for IGPC and November for Direct Purchase and System Gas customers), ENGLP will evaluate its current demand, its forecasted growth and direct purchase demand. This will help establish the annual Contract Demand with Enbridge Gas under each of the M9 contracts (System Gas Customers, Direct Purchase Customers and IGPC). ENGLP will also consider the amount of local production it is purchasing on both a firm and interruptible basis when establishing its Contract Demand with Enbridge Gas.

ENGLP has established a monthly review process with its System Gas and Direct Purchase Customers under Rates 3 and 5 to ensure provisions are in place for these customers to not exceed the established Firm Contract Demand. This will ensure the customers consume within the established Firm Contract Demand in the same manner that ENGLP has to operate within the limits set by Union. ENGLP established an annual review of its Rates 3 and 5 customers to ensure they are meeting the Minimum Annual Volume Requirements during each contract year as specified in the rate class descriptions.

Further ENGLP continues to review customer consumption to determine the appropriate rate class for each customer i.e. if their consumption is large enough to qualify for a contract rate. This review will also be conducted if there is a significant change in consumption (volume or profile) of an existing customer.

ENGLP completed an annual review of the Residential accounts at the end of December 2020 and re-classified those customers that should have classified as commercial or industrial.

6.2. Evaluation of Procurement Process and Policies

ENGLP purchases the majority of its commodity from Enbridge Gas. ENGLP does not directly enter into upstream transportation, daily balancing, and seasonal storage or third party commodity agreements and therefore does not establish contracting policies with respect to these services.

ENGLP procures a number of other gas related services including consulting services such as those provided by ECNG Energy LP. These other services are initiated through a Request for Proposals (RFP) process provided through a Shared Services Agreement with EPCOR Water Services Inc. (EWSI), an Edmonton-based corporation. The RFP process is governed by a Procurement Document which provides guiding principles; non-competitive procurement procedures; approvals and limits; roles and responsibilities; and compliance.

As part of its Annual Distribution Capital Planning Process[3], ENGLP reviews the system's peak day requirements and ensures it has sufficient assets and contracting flexibility in order to meet these requirements. These capital plans are filed as part of the EB-2018-0336 Cost of Service rate filing.[4] Contract considerations include:

- The amount of firm Contract Demand capacity required from Enbridge and local producers; and
- The amount of interruptible capacity contracted for under Rate 5 – Interruptible Peaking Contract.

6.3. Risk Mitigation Strategy

A key aspect of the execution of this Gas Supply Plan is the identification of risks and the adoption of risk mitigation strategies.

[3] This process is subsumed within the "Utility System Plan" evidence of the EB-2018-0336 Cost of service rate filing.
[4] EB-2018-0336, Application and Pre-filed Evidence, Exhibit 2, Tab 3, Schedule 1, at page 2.

6.4. Description

The risk identified is that the M9 Rate will not be offered by Enbridge in the future.

6.5. Evaluation

M9 Rate no longer being offered

ENGLP is aware that Enbridge Gas has an approved new M17 rate designed to provide transmission service to embedded distribution utilities. ENGLP's view is that this new rate is unfavorable as compared to the M9 rate and does not intend to subscribe to this service. The OEB recently ruled that any embedded distributor who elects to move to an M17 rate will be precluded from returning to its former M9 rate. However, as the Board indicated in its decision on Enbridge's M17 application, ENGLP understands that Enbridge will continue to offer the M9 rate to ENGLP (Aylmer). As discussed in this Gas Supply Plan, ENGLP (Aylmer) intends to remain on the M9 rate. In the Staff Report on the 2021 Gas Supply Plan Update (EB-2021-0146), OEB Staff considers that purchasing gas under the M9 rate is appropriate as it is less expensive and provides security of supply, reliability, and is less onerous to administer.

7. Public Policy Objectives

7.1. Renewable Natural Gas (RNG)

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

In the fall of 2022, ENGLP is expecting to start receiving RNG into it's distribution system. However, ENGLP is not the ultimate buyer of the RNG – the RNG producer have a contract with a buyer outside of Ontario for the RNG volume as well as the environmental attributes. As such, ENGLP will purchase the RNG as another source of local supply, and will not take ownership of the environmental attributes generated from the production of RNG.

Even though ENGLP will not be taking ownership of the environmental attributes resulting from the RNG production, this arrangement ultimately allows for development of RNG production within Ontario. It also provides ENGLP a learning opportunity on how to transact and procure RNG without significant cost impact to the rate base.

7.2. Demand Side Management (DSM)

ENGLP is in process of developing a commercial DSM pilot within its Aylmer or South Bruce territories. In 2021 and 2022, ENGLP had a number of conversations with OEB staff as well as a number of consultants to develop an initial program. The DSM program is now expected to be filed in 2023. If proved to be successful, ENGLP would look to expand the DSM offerings into other rate classes. ENGLP has been working with OEB staff to better understand the DSM framework and budgetary expectations. Customer rate impacts and uptake will be key drivers of the success of the pilot and future DSM program.

7.3. Community Expansion

ENGLP has been actively working to bring secure, reliable and affordable natural gas to unserved communities. A number of customers have requested service and ENGLP has pro-actively responded to those requests and they are considered as part of the 2022 demand forecast. There are no updates for this Gas Supply Plan Update.

7.4. Federal Carbon Pricing Program

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,* with the following features:

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

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

ENGLP continues to file annual applications for FCPP rates and recoverable costs, effective April 1, most recently EB-2021-0268.

8. Current and Future Market Trends Analysis

ENGLP engaged ECNG to perform a "Current and Future Market Trends Analysis". This analysis can be found in Appendix "A".

In summary, the Current and Future Market Trends Analysis, concludes 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.

9. Performance Metrics

ENGLP has drafted a performance metric scorecard in order to measure the effectiveness of the Supply Plan. Please see Appendix F for details. There are no major changes compared to the version in the 2021 Gas Supply Plan Annual Update.

As discussed in the OEB Staff Report to the Ontario Energy Board - Review of 2021 Annual Update to EPCOR Natural Gas Limited Partnership Natural Gas Supply Plan [EB-2021-0146], performance metrics and targets for RNG and DSM are not established as part of a gas supply annual update.

10. Continuous Improvement Strategies

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

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

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

11. Appendix A – Market Trends Analysis April 2022 Update

Current and Future Market Trends Analysis
Provided by ECNG

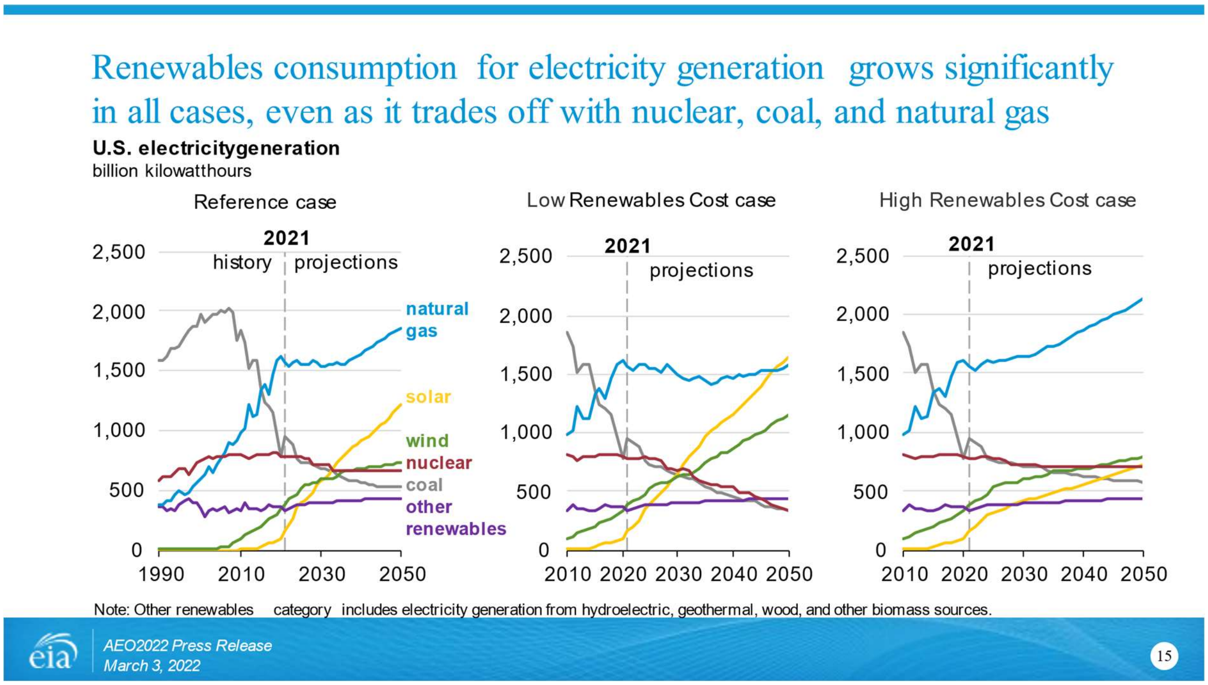
As an element of the risk mitigation strategy, the following overview of current and future trends is intended to inform EPCOR of any changes in natural gas market fundamentals which have the potential to impact its ability to execute the Supply Plan. The North American fundamental drivers for natural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

Unique to this outlook is the unexpected war in Ukraine which has led to unprecedented global free-world unification regarding economic sanctions against the Russian economy and oligarchs. This in turn has led to a plan to phase out European imports of Russian oil, natural gas, coal and steel and resulting surge in prices of these and related commodities alternatively sourced around the globe.

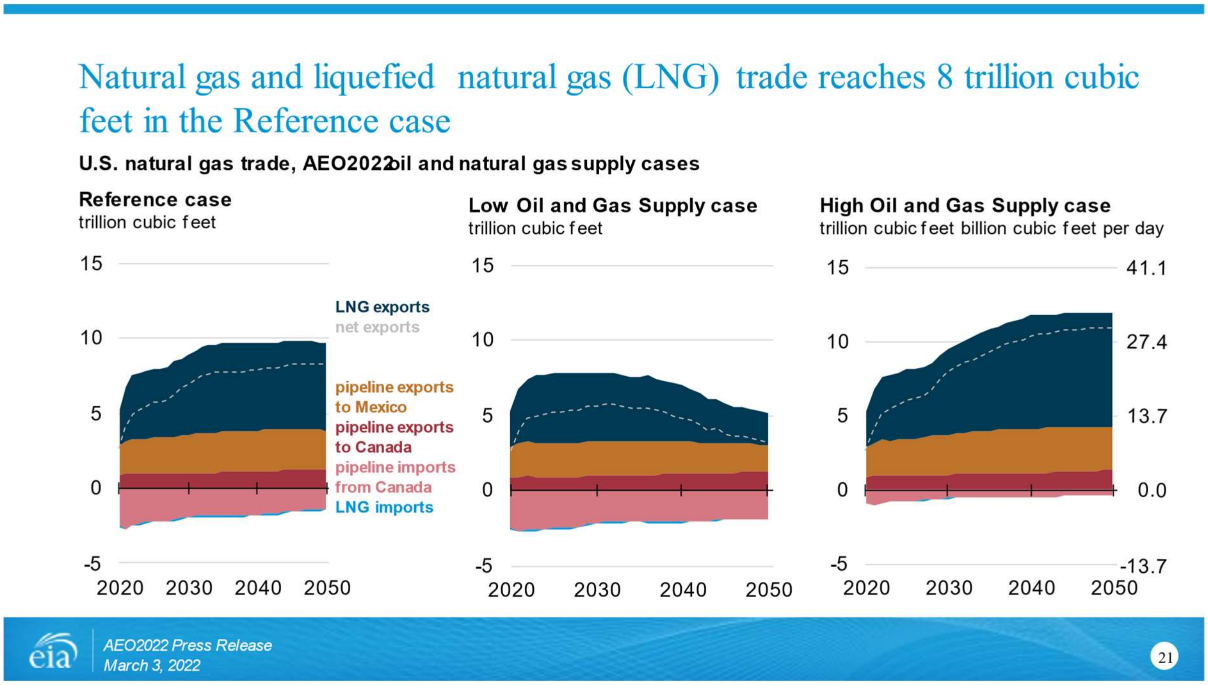
Demand: Impact on pricing – Near-term Bullish, Mid and Long-term Bullish

The 2021/2022 Winter weather overall, across most of North America (N.A.) resulted in average to more than average demand in the residential, commercial (R&C) and industrial sectors. Mid-term and Long-term gas demand growth is largely expected by most forecasters in the United States (U.S.) in industrial and gas fired power generation demand sectors. At the time of this writing, near term N.A gas pricing is approximately $4 US/MMBtu higher than last year. Coal-fired power generation retirements continue in favour of gas-fired generation. Also, gas fired generation will likely continue running more baseload hours not only due to attrition of the coal fired fleet but due to the surge in coal pricing making it higher priced than gas as coal supply is pulled to Europe. This is offset by the increase in solar generation expected to be added of 20 Gigawatts (GW) and 24 GW in 2022 and 2023 respectively forecasted by the U.S. Energy Information Administration's (EIA) Short Term Energy Outlook 2022 (April 2022). In December 2021 the International Energy Agency (IEA) forecasted 200 GW of renewable additions by 2026 (split 150 GW solar and 50 GW wind). Not accounting for load growth this could cut the power sector burn by over the next 5 years which is approximately 8% of current U.S. domestic demand.

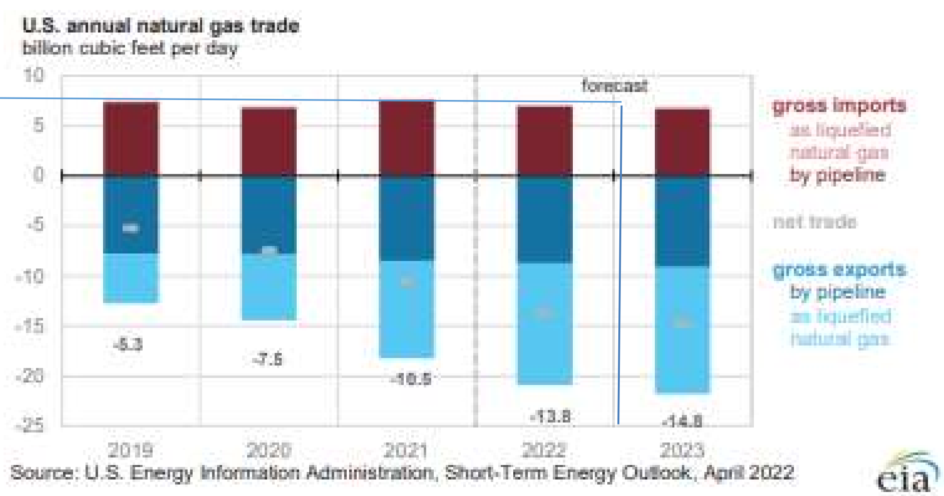
The EIA in its latest Annual Energy Outlook (AEO2022) cites an expectation of generally unchanged consumption of natural gas for power generation to the end of 2030 with coal fired generation dropping at the expense of renewables.



The single largest increase in demand is in exports of liquified natural gas (LNG) in the next 5 years. All the scenarios in the graphic below identify that by 2025 approximately 7,500 Tcf/yr (20.5 Bcf/d on average) is expected. This is an increase of nearly 10 Bcf/d from 2021 average of 10.7 Bcf/d.



U.S. LNG exports including fuel gas for refrigeration are now operating at capacity between 13 and 14 Bcf/day in early in Q2 2022 (except for planned maintenance or unexpected outages). EIA estimates on average 14.8 Bcf/d will be exported in 2023 which is realistic if high load factors can be maintained. This will continue to be the most significant contributor to a tight supply-demand balance in N.A.



U.S. natural gas R&C sector consumption in 2021 rebounded from a pandemic influenced lower demand in the sector (weather normalized) the previous year showing increasing demand closer to pre-pandemic levels. Industrial demand however appears to have grown by 1-2 Bcf/d from pre- pandemic levels.

Expectations for exports to Mexico during this outlook's horizon could see average exports to Mexico well exceed 7 Bcf/d from the current flows of 5-6 Bcf/d. This increased demand is mostly for LNG liquefaction for Pacific side exports which shorten LNG routes to Asia and lower transport costs by approximately $2 US/MMBtu. Costa Azul is likely the first Mexican LNG export project supplied via with TC Energy receiving FERC approval of its North Baja Xpress Project in Arizona accessing the Permian supply basin (Texas and Oklahoma). There are another 3 LNG export projects that have not yet reached FID (Final Investment Decision) which will require supply via U.S. pipeline also likely from the Permian basin which would increase U.S. exports to Mexico post 2024.

The U.S. demand outlook for 2023 and beyond is for modest growth in domestic demand from R&C, industrial and gas fired power generation sectors and those sectors combined growth is not nearly as significant as LNG exports (including exports to Mexico).

Supply: Impact on pricing – Near-term Bullish (NYMEX) and Bullish (AECO); Mid and Long-term Mildly Bullish (NYMEX) and Neutral (AECO)

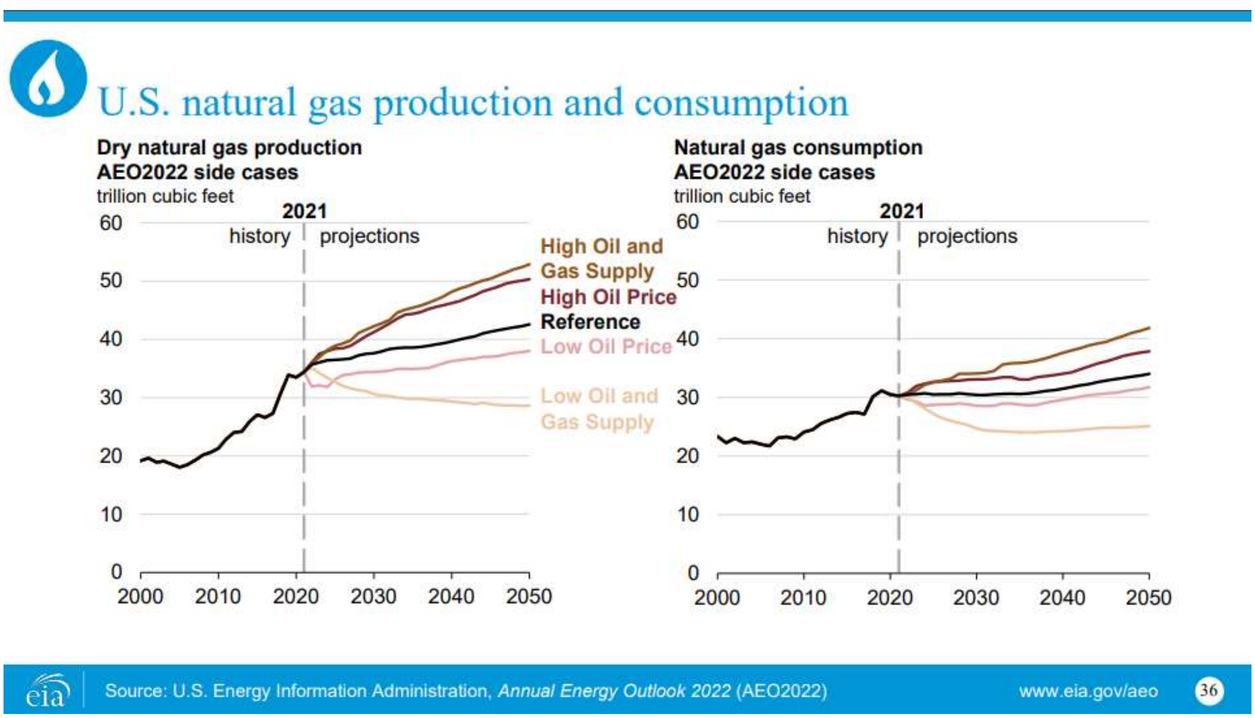
While year over year U.S. dry gas production (supply) growth has been impressive in 2018 and 2019, 2020 was setback mostly due to the pandemic - uncertainty in demand led to prompt month's price softening which then led to reduced investment by producers. Since then, consistent reporting of U.S. producer sentiment regarding supply growth has been of disciplined sustainable expansion due to more focus related to producer financial health, shareholder dividends and growth in stock price. This has also been met with labour shortages, higher labour and raw material costs and a global shortage of drilling rigs as the free world searches for alternative fossil fuel production to replace Russian supplies. Although production to date in 2022 appears to be nearly 3 Bcf/d higher YoY this is not enough to meet the growth of LNG exports confidently expected in 2022 and early 2023. (Table below data from S&P Global Platts)

UNITED STATES Supply & Demand	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022 YTD	Y / Y
Dry Production	50.5	55.7	58.9	60.7	64.8	68.5	67.7	70.3	80.5	88.5	87.5	89.1	92.7	4%
Canadian Imports	6.5	5.6	5.1	5.0	5.1	5.3	5.7	5.4	5.3	4.6	4.3	5.1	5.8	
LNG Imports	1.1	0.7	0.5	0.3	0.1	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.3	
Total Supply	**58.1**	**62.0**	**64.5**	**66.0**	**70.0**	**74.0**	**73.7**	**75.9**	**86.0**	**93.3**	**92.0**	**94.4**	**98.8**	
Power Burn	20.3	20.9	24.7	22.6	22.6	26.4	27.1	25.5	29.0	30.9	31.8	31.0	27.4	
Industrial	18.9	19.2	19.7	20.3	20.9	20.6	21.2	21.8	22.8	23.0	22.4	22.5	24.6	
Res/Comm	23.7	23.2	21.7	25.4	26.5	24.4	23.2	23.6	26.9	27.3	24.7	24.6	40.4	
Mexican Exports	0.8	1.3	1.7	1.8	2.0	2.9	3.7	4.3	4.6	5.1	5.4	6.0	5.7	
LNG Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.6	2.2	3.4	5.7	7.3	10.7	12.5	17%
Pipe Loss	1.8	1.8	1.9	1.9	2.0	2.0	2.0	2.0	2.3	2.3	2.3	2.2	2.6	
Total Demand	**65.5**	**66.4**	**69.7**	**72.0**	**74.0**	**76.3**	**77.8**	**79.4**	**89.0**	**94.3**	**93.9**	**97.0**	**113.2**	

Updated March 29, 2022 All figures in BCF per day Strong Growth Flat Growth Significant Item

Note: 2022 is only Year to date so some numbers are not relevent.

The EIA's High Oil and Gas Supply is forecasting for 2023 37.0 Tcf (101 Bcf/d) vs 34.4 TCF (94.0 Bcf/d) 2021 actual for an increase in 7 Bcf/d. At this point in time that appears optimistic return to grow 2021 supply levels by that much, even in the reality of high pricing driven by high overall demand growth. The EIA also expects supply to be able to satisfy growing demand at current prices.

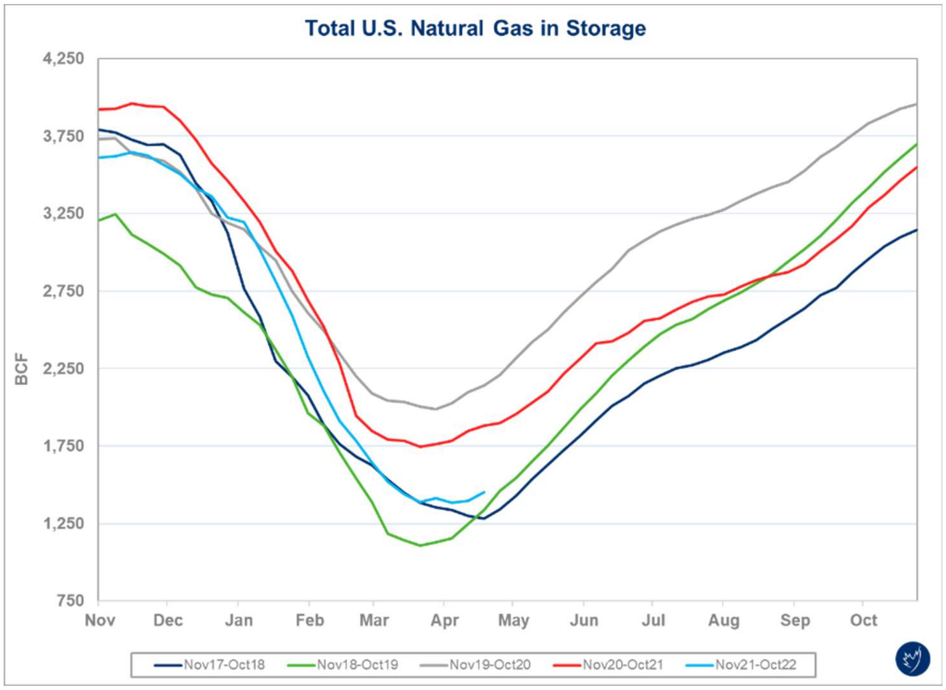


The Western Canadian Sedimentary Basin (WCSB) production has grown substantially in response to the confluence of higher AECO pricing, higher oil sands and Alberta power generation demand (continued phase out of coal fired generation) and increased access to domestic and export markets through significant NGTL (Nova Gas Transmission Limited) expansion nearing full completion. The NGTL expansion Drilling activity is robust in Alberta resulting in growth of supply exceeding 17.5 Bcf/d in April 2022. Unfortunately, British Columbia production has not grown to the same extent due entirely to lack of new BC licenses being issued since July 2021. A new resolution framework for resource development is required between the BC provincial government and the Blueberry River First Nation before any new licenses can be issued. On June 29, 2021 a historic BC's Supreme Court ruling determined the Treaty 8 rights of the Blueberry River First Nations had been breached by development authorized by the BC government over many years. The BC government has decided not to appeal the decision, has begun negotiations and an initial agreement has been reached for existing permit holders to manage current business. We are optimistic that a final settlement will be reached in 2022 such that growth in BC supply will begin growing again.

At current elevated forward NYMEX prices relative to last year, the supply response in the WCSB will be quicker on a percentage basis compared to the U.S. however there will not be enough to materially increase exports and meet growing regional demand. This sentiment is driving the bullish sentiment in the short run. Mid and Long-term there is little disagreement that there are ample N.A. reserves to meet the demand forecasts.

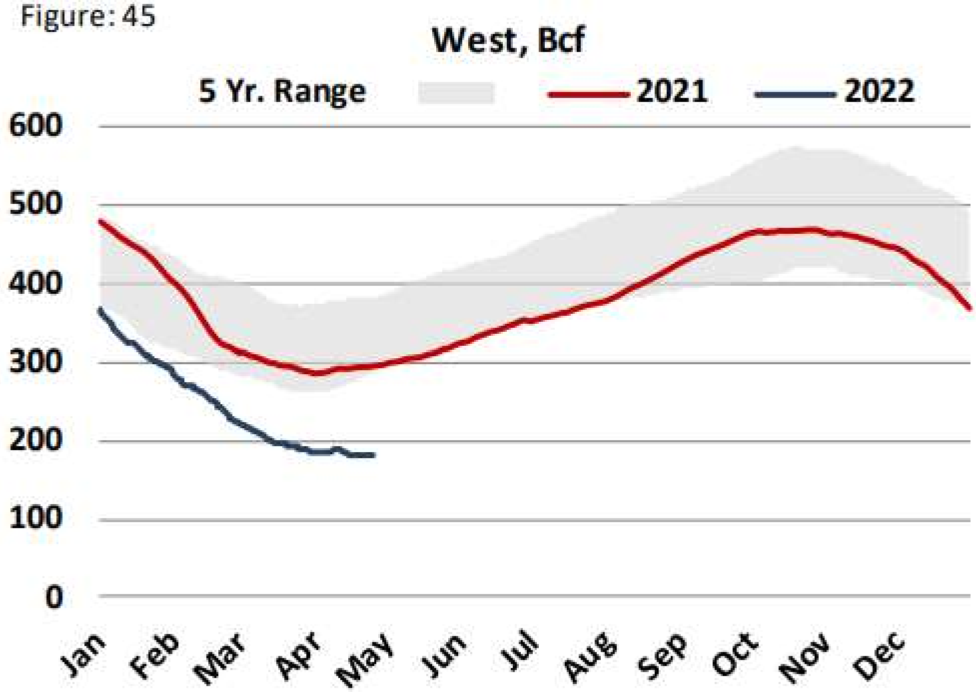
Storage: Impact on pricing – Near term mildly Bullish (NYMEX and Dawn), Very Bullish (AECO); Mid and Longer-term No Impact on price

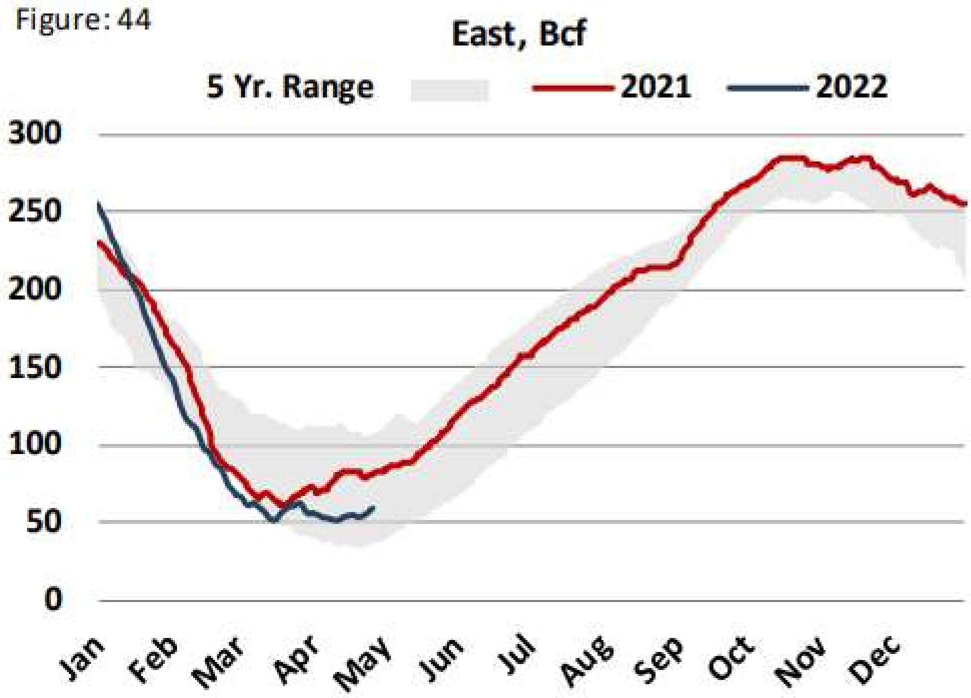
Total U.S. working inventories on March 31, 2022 fell below the five-year average of 1.67 Tcf by 284 Bcf (deficit). Most industry forecasters see end of the 2022 injection season ending significantly less than 2021's value of nearly 3.65 Tcf mostly as a result of increased LNG exports and slow to arrive supply growth. The likely outcome has storage filling approximately 150 Bcf less than last year or about 1 Bcf/d less supply available in the upcoming winter. This may also lead to an inventory level at the end of the upcoming winter season significantly less than the 5 year average and possibly reaching a new 5 year low. (Data for graph below is from the EIA.)



In Canada, storage at winter's end in Alberta (essentially the "West" graph below) is much below last year's 5 year low, whereas storage at Dawn (essentially the "East" graph below) is between the 5 year low and average.

Figure: 45



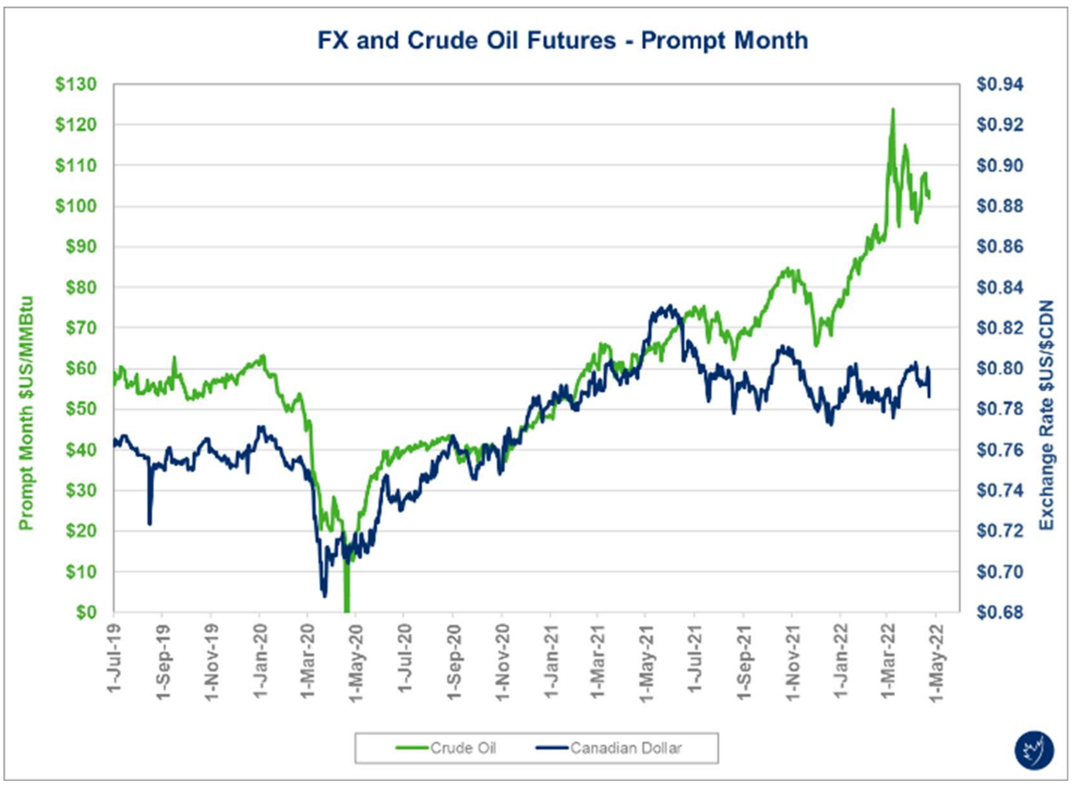


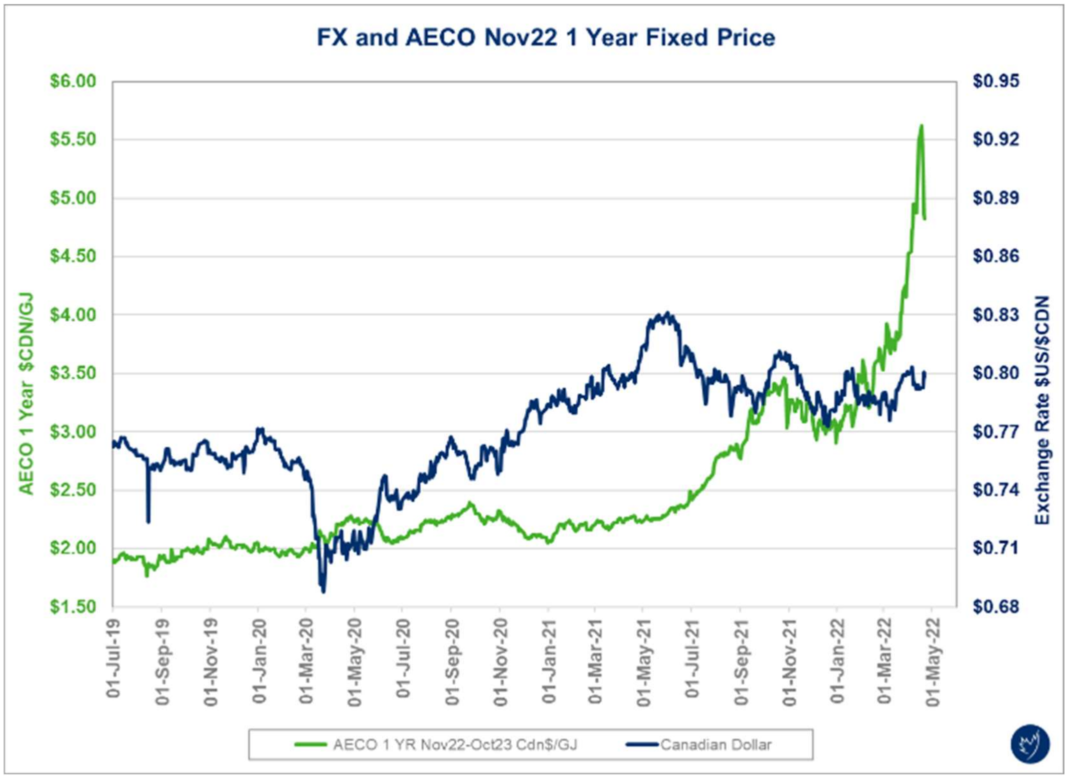
Storage graphs from RBN Energy LLC 2021 at April 26, 2022.

All these current storage balances lead to a more bullish sentiment on gas pricing year over year as it either increases summer demand (U.S. and Eastern Canadian) or maintains demand (Western Canadian) to refill.

Crude Oil and Foreign Exchange: Impact on NYMEX and Dawn pricing – Near-term Mildly Bearish, Longer-term Neutral; Impact on AECO pricing Neutral Near and Longer-term

World oil pricing in early 2022 has remained well supported over $90 USD/barrel price with the war in Ukraine leading to a world shortage of non-Russian supply to meet world demand. The U.S. planned release of a significant amount of its Strategic Petroleum Reserve (1 MMBbl/d April-September 2022) and a COVID new wave in China suppressing its demand has helped to dampen crude prices in the short run. It is difficult to forecast the end and outcome of the Ukraine war especially regarding world use of Russian oil over the next few years. However, this current event has increased the world's pace to bring on more renewable energy sources and to reduce the use of fossil fuels, mostly coal and oil. Increased U.S. supply of oil especially from the Permian basin results in associated natural gas supply which is predominantly the reason for our bearish sentiment in this category. A persistent high oil price and/or incentive to move to more renewable power generation has a bearish effect on gas fired power generation demand as well. Historically with higher oil pricing the Canadian buyer should enjoy a stronger dollar which will offset the higher price of NYMEX priced gas (which mostly drives Dawn pricing) however, since 2022 start, the correlation appears to have de-linked likely due to the increased planned Canadian government expenditures and/or uncertainty related to the Ukrainian war support from North America. The next two graphs show the relationship of crude oil pricing and the U.S./Canadian foreign exchange (FX) and FX on the price of gas in the WCSB (AECO). It appears the Canadian dollar value has not contributed the AECO price run up since mid-2021.



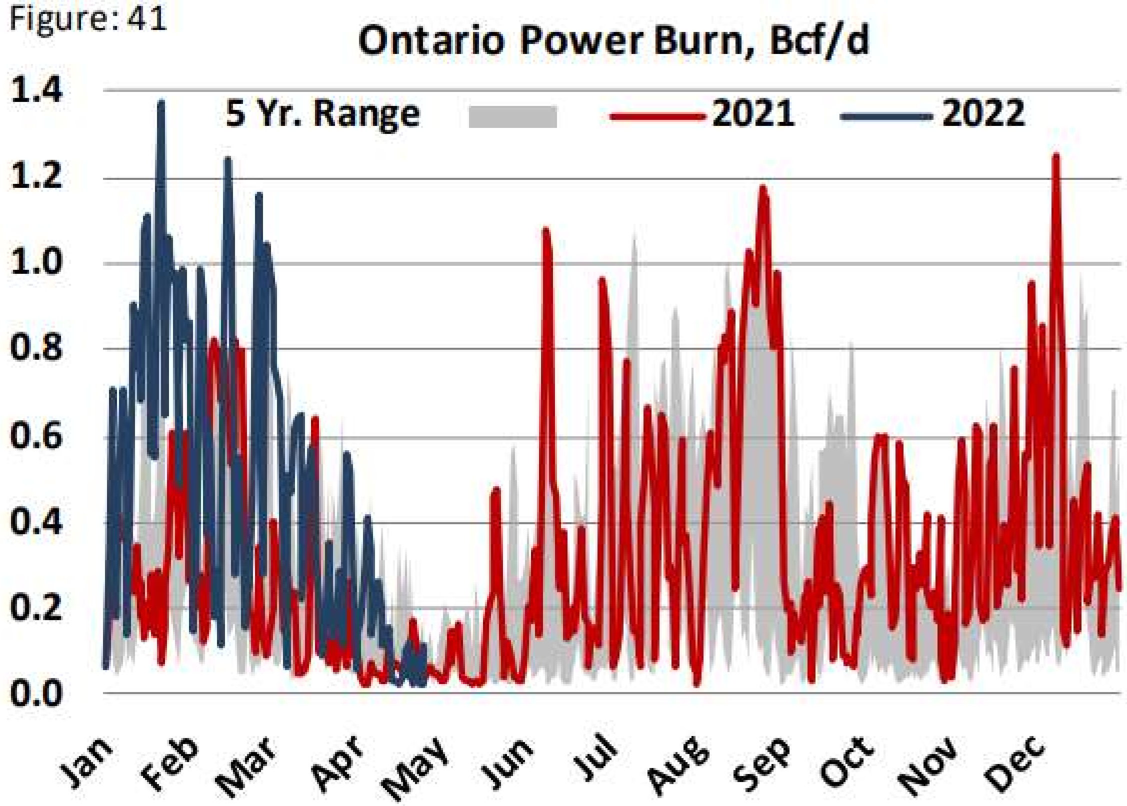


Dawn Market Hub Discussion

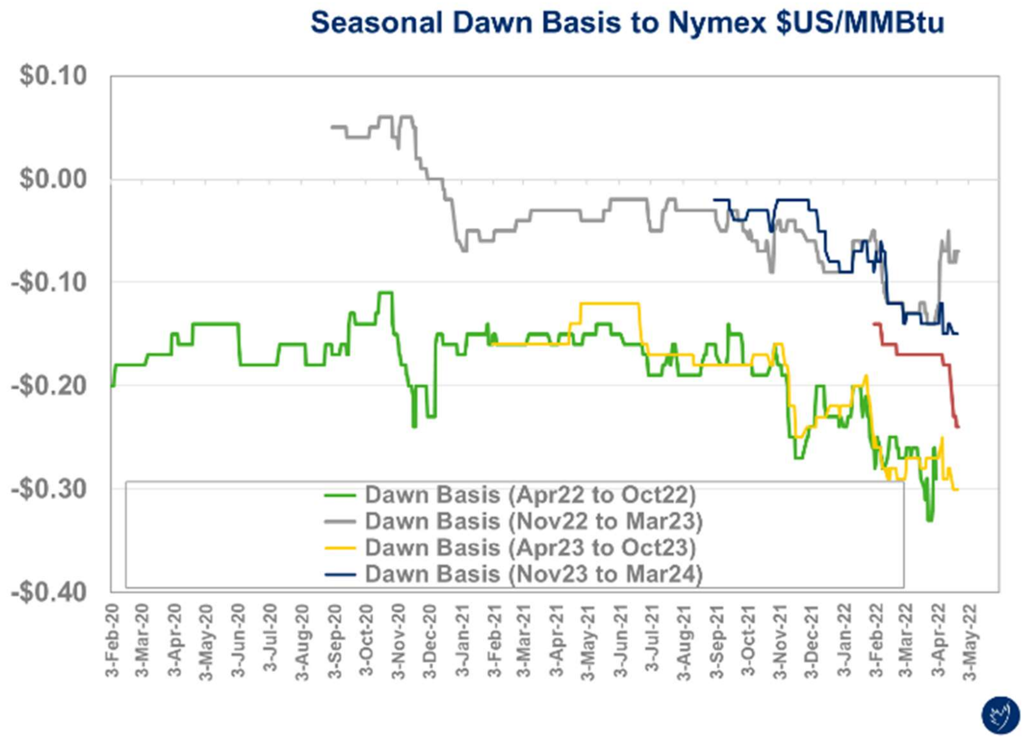
Natural gas primarily flows into the Dawn Hub ("Dawn") from the WCSB and from the U.S. Marcellus and Utica shale plays in the Appalachian region as well as from the Chicago Citygate (a market Hub with excess supply from WCSB and other U.S. supply regions). There are no new projects expected in the Dawn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

Nearer term Dawn basis forward pricing are showing trends that are a larger discount to NYMEX of late as seen in the basis graph below. This is despite a higher Ontario gas fired power generation demand seen last summer as nuclear refurbishments continue in Ontario coupled with higher YoY overall power demand. Further forward curves are trading at a lesser discount in winters and summers starting November 2026 likely due to slow demand growth and or risk of long term pipeline contracts not being fully renewed.

Figure: 41



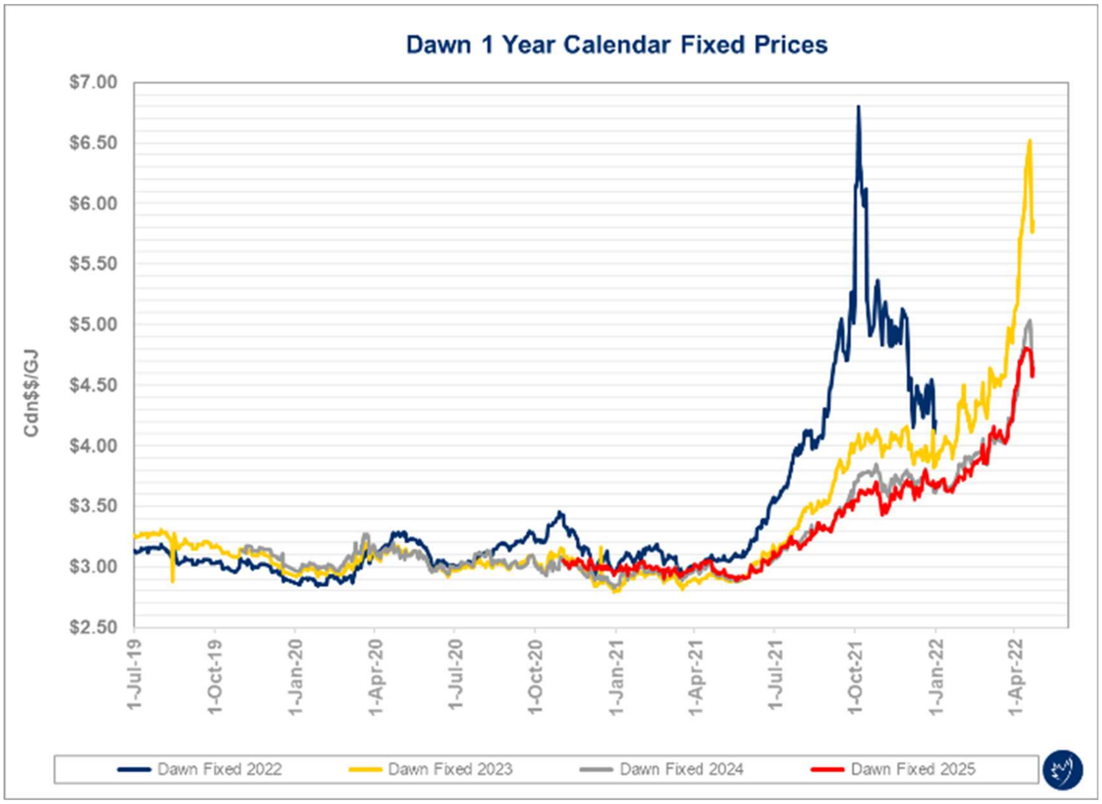
Ontario Power Burn from RBN Energy LLC 2021 at April 26, 2022.



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

Near-term Summary – Bullish (NYMEX and Dawn), Bullish (AECO)

In summary, in N.A. strong and growing LNG exports, increased gas fired power generation demand, low inventories at winter's end, with only marginal increase in supplies relative to 2021 make for a continued tightly supplied market moving forward for the next few years. As a result, NYMEX and Dawn price outlooks in the short term are at likely to remain at elevated levels until supply growth is proven and sustained. The forward Dawn price for 2022 has much high volatility risk to the forward prices seen in 2021 price shown in the graph below. AECO pricing is expected to stay strong and move with or go narrower to NYMEX with a higher demands year over year from oil sands, local power generation, expected U.S. exports and regional storage deficits supporting its pricing. Current forward pricing history is found below.


Dawn 1 Year Calendar Fixed Prices
Cdn$$/GJ
$7.00
$6.50
$6.00
$5.50
$5.00
$4.50
$4.00
$3.50
$3.00
$2.50
1-Jul-19
1-Oct-19
1-Jan-20
1-Apr-20
1-Jul-20
1-Oct-20
1-Jan-21
1-Apr-21
1-Jul-21
1-Oct-21
1-Jan-22
1-Apr-22
Dawn Fixed 2022
Dawn Fixed 2023
Dawn Fixed 2024
Dawn Fixed 2025


Aeco 1 Year Term Prices
$CDN/GJ
$6.00
$5.50
$5.00
$4.50
$4.00
$3.50
$3.00
$2.50
$2.00
$1.50
1-Jul-19
1-Sep-19
1-Nov-19
1-Jan-20
1-Mar-20
1-May-20
1-Jul-20
1-Sep-20
1-Nov-20
1-Jan-21
1-Mar-21
1-May-21
1-Jul-21
1-Sep-21
1-Nov-21
1-Jan-22
1-Mar-22
1-May-22
Nov22-Oct23
Nov23-Oct24
Nov24-Oct25
Nov25-Oct26
Nov26-Oct27

Mid to Long-term Summary – Mildly Bullish (NYMEX and Dawn), Mildly Bullish (AECO)

In the U.S. the expectation of continued strong LNG exports, continuing economic growth, continued fuel of choice in power generation and a return to shale gas supply growth (including supply from oil production) we expect pricing to move modestly upward. The current forward landed cost of gas at Dawn exceeds $4.50 CAD/GJ for calendar years 2024-2027. This is good value as the cost of raw materials, labour and global energy prices are likely to persist and support this price over the next year. Also supporting this view and not mentioned previous is the potential for existing pipeline capacity in N.A. to be closer to capacity in moving supply basin gas to markets. Greenfield pipelines are exceedingly difficult to be built due to environmental opposition and the likelihood that 30 – 40 year amortizations will not be accepted by regulators going forward. Capacity expansions may be limited to new capital of compression only and safety related “lift and replace” pipeline segments. N.A. natural gas production may be able to respond in the years ahead but there may not be sufficient growth in pipeline capacity access. AECO pricing follows the same sentiment as above only pipeline access from field zone to AECO appears to continue to be approved and implemented in reasonable timeframes however downstream of AECO there are limitations to accessing traditional downstream markets as mentioned above. Also not mentioned earlier are persistent LNG export projects to the Canadian Pacific coast for WCSB supply for LNG Canada (1.0 Bcf/d flow in 2024, delayed from 2023) and Woodfibre (0.3 Bcf/d flow in 2027) and Cedar LNG (0.4 Bcf/d flow in 2027). As a result, we believe current forward pricing for calendar years 2024-2027 at AECO of about $3.70 CAD/GJ are also likely to persist and support this price over the next year.

12. Appendix B – ECNG Credentials

ECNG Energy Group

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

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

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

ECNG PRINCIPALS CVs

Angelo P. Fantuz – Director, Client Services

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

Dave Duggan – Director, Energy Supply & Market Risk

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

Paul Weingartner – Director, Client Services

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

Steve Williams – Senior Energy Analyst, Supply & Risk Management

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

Althea Rothwell, Senior Consulting Analyst

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

13. Appendix C - DETAILED SUPPLY/ DEMAND FORECAST

SUPPLYFORECASTANALYSIS

Production A and Production B (Formerly NRG now owned by Lagasco)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2026	37,819	37,315	36,818	36,327	35,842	35,364	34,893	34,428	33,969	33,516	33,069	32,628	421,987
2025	44,429	43,837	43,252	42,676	42,107	41,545	40,991	40,445	39,905	39,373	38,848	38,330	495,740
2024	52,194	51,498	50,812	50,134	49,466	48,806	48,156	47,513	46,880	46,255	45,638	45,030	582,382
2023	61,317	60,499	59,692	58,896	58,111	57,336	56,572	55,818	55,073	54,339	53,615	52,900	684,168
2022	70,125	75,140	70,125	69,190	68,268	67,357	66,459	65,573	64,699	63,836	62,985	62,145	805,902
												Decline Rate	16%

Enbridge (Supply)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2026	4,117,191	3,619,930	2,980,072	1,939,558	770,792	270,984	388,358	498,541	354,230	1,914,129	3,834,233	3,508,962	24,196,980
2025	3,953,109	3,480,876	2,842,865	1,824,800	719,798	230,782	348,778	462,343	315,803	1,817,993	3,659,425	3,385,884	23,042,455
2024	3,793,945	3,345,669	2,709,786	1,713,692	669,597	191,131	309,746	426,747	278,263	1,724,751	3,490,960	3,265,851	21,920,139
2023	3,721,059	3,280,973	2,641,788	1,658,674	676,085	151,811	271,041	391,535	241,399	1,664,738	3,347,644	3,169,085	21,215,831
2022	3,751,869	3,289,001	2,680,817	1,682,048	754,243	184,939	308,279	430,560	343,206	1,622,127	3,268,181	3,135,368	21,450,639

Production D (RNG Supply)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2026	234,586	192,255	214,187	172,546	183,589	71,894	76,495	76,495	140,913	183,589	220,475	234,586	2,001,610
2025	234,586	192,255	214,187	172,546	183,589	71,894	76,495	76,495	140,913	183,589	220,475	234,586	2,001,610
2024	234,586	192,255	214,187	172,546	183,589	71,894	76,495	76,495	140,913	183,589	220,475	234,586	2,001,610
2023	152,991	125,383	152,991	119,824	127,492	71,894	76,495	76,495	140,913	152,991	201,304	214,187	1,612,960
2022	-	-	-	-	-	-	-	-	-	101,994	119,824	127,492	349,310

Production C (Lakeside Production owned by Lagasco)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2026	956,784	864,192	956,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,470,104
2025	956,784	864,192	956,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,470,104
2024	956,784	864,192	956,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,470,104
2023	956,784	864,192	956,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,470,104
2022	956,784	864,192	956,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,470,104

Total Supply – Production A + B (Formerly NRG) + Enbridge Gas + Production C (Lakeshore) + Production D (RNG)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2026	5,346,380	4,713,692	4,187,861	2,804,351	1,468,615	841,202	799,578	909,296	1,185,031	3,088,017	5,013,697	4,732,960	35,090,681
2025	5,188,908	4,581,159	4,057,089	2,695,942	1,423,886	807,182	766,096	879,115	1,152,541	2,997,739	4,844,669	4,615,584	34,009,909
2024	5,037,509	4,453,614	3,931,568	2,592,293	1,381,044	774,791	734,229	850,588	1,121,976	2,911,379	4,682,994	4,502,251	32,974,235
2023	4,892,150	4,331,047	3,811,255	2,493,314	1,340,081	744,001	703,940	823,680	1,093,305	2,828,852	4,528,482	4,392,955	31,983,063
2022	4,778,778	4,228,333	3,707,726	2,407,158	1,300,903	715,256	674,570	795,965	1,063,825	2,744,741	4,376,909	4,281,790	31,075,955

DEMAND FORECAST ANALYSIS

Total Demand

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2026	5,346,380	4,713,692	4,187,861	2,804,351	1,468,615	841,202	799,578	909,296	1,185,031	3,088,017	5,013,697	4,732,960	35,090,681
2025	5,188,908	4,581,159	4,057,089	2,695,942	1,423,886	807,182	766,096	879,115	1,152,541	2,997,739	4,844,669	4,615,584	34,009,909
2024	5,037,509	4,453,614	3,931,568	2,592,293	1,381,044	774,791	734,229	850,588	1,121,976	2,911,379	4,682,994	4,502,251	32,974,235
2023	4,892,150	4,331,047	3,811,255	2,493,314	1,340,081	744,001	703,940	823,680	1,093,305	2,828,852	4,528,482	4,392,955	31,983,063
2022	4,778,778	4,228,333	3,707,726	2,407,158	1,300,903	715,256	674,570	795,965	1,063,825	2,744,741	4,376,909	4,281,790	31,075,955

Weather Normalized Growth Rate: 3%

14. Appendix D – KEY TERMS

Balancing Gas:	The volume of gas purchased for the purpose of clearing the Cumulative or Daily Operating Imbalance.
Baseload Gas:	The minimum amount of natural gas delivered or contracted over a given period of time at a steady rate or price structure.
Cap and Trade:	Ontario’s cap and trade program is a market-based system that sets a hard cap on greenhouse gas emission. The cap is lowered over time and participants in the program must procure compliance instruments (e.g. emissions allowances, offset credits) to cover their annual emissions.
Clean Fuel Standard:	A performance-based approach to reducing the carbon intensity of fossil fuels that would incent the use of a broad range of low carbon fuels, energy sources and technologies, such as electricity, hydrogen, and renewable fuels, including renewable natural gas. It would establish lifecycle carbon intensity requirements separately for liquid, gaseous and solid fuels, and would go beyond transportation fuels to include those used in industry and buildings.
Contract Customers:	The maximum volume or quantity of gas that ENGLP 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 ENGLP 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.

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 Day:	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.
Production A&B	Local gas production wells located within the ENGLP franchise area. These wells are owned by Lagasco and were formerly owned by NRG. The wells were sold at the time EPCOR Utilities Inc. purchased NRG distribution system on November 1, 2017and are currently under contract to ENGLP until September 30, 2020.
Production C	Local gas production wells located offshore in Lake Erie. ENGLP entered into a 5 year term contract effective October 3, 2019 in order to purchase firm gas deliveries from these wells
Production D	Local gas production from an Renewable Natural Gas (RNG) facility within the Aylmer Distribution Area. The gas is purchased as local supply, expected to start production in the fall of 2022
Rate 1– General Service Rate:	Includes residential, commercial and industrial customers that constitute majority of the customer base in the ENGLP natural gas system
Rate 2– Seasonal Service:	Includes mainly tobacco farming and curing customers (non-interruptible) that consume gas during the months of August and September. These customers are charged a different Delivery Charge for gas consumed between the months of April 1 through October 31 and November 1 through March 31.

Rate 3 – Special Large Volume Contract Rate:	Includes customers who enter into a contract for the purchase or transportation of gas: • for a minimum term of one year; • that specifies a combined daily contracted demand for firm and interruptible service of at least 700 m^3; • a qualifying annual volume of at least 113,000 m^3.
Rate 4 – General Service Peaking:	Include primarily industrial customers whose operations can readily accept interruption and restoration of gas service within 24 hours' notice. These customers are charged a different Delivery Charge for gas consumed between the month of April 1 through December 31 and January 1 through March 31.
Rate 5 – Interruptible Peaking Contract Rate:	Includes customers who enter into a contract for the purchase or transportation of gas: • for a minimum term of one year; • that specifies a daily contracted demand for interruptible service of at least 700 m3 • a qualifying annual volume of at least 50,000 m3.
Rate 6 - Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility:	Rate specific to the IGPC ethanol production facility located in the Town of Aylmer.
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.

15. Appendix E - Elenchus Weather Normalized Distribution System Throughput Forecast: 2022-2026

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Weather Normalized Distribution System Throughput Forecast: 2022-2026

Report prepared by
Elenchus Research Associates Inc.

Prepared for:
EPCOR Natural Gas LP

23 April 2022

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1 INTRODUCTION

This report outlines the results of, and methodology used to derive, the 2022 to 2026 weather normal throughput forecast (or "load forecast") prepared for EPCOR Natural Gas Limited Partnership ("ENGLP").

The methodology outlined in this report is virtually unchanged from the methodology used in ENGLP's 2020-24 load forecast update dated April 17, 2020 and 2021-25 load forecast updated dated April 23, 2021. The methodology is largely consistent with the methodology used in ENGLP's 2020 COS application (EB-2018-0336) and the methodology used by Natural Gas Resources Limited ("NRG") in previous rates applications. Parties agreed to the results of the 2020 throughput forecast in settlement and the overall methodology was last approved in EB-2010-0018. Alternate methods were tested but generally found to be inferior to the previously approved methodology.

The regression equations used to normalize and forecast ENGLP's weather sensitive load use monthly heating degree days as measured at Environment Canada's London CS weather station to take into account temperature sensitivity. This location is the closest weather station to ENGLP's service territory with strong historical weather data. ENGLP experiences peak loads in winter months, though certain rate classes are not weather sensitive. Environment Canada defines heating degree days as the difference between the average daily temperature and 18°C for each day. Heating degree days is 0 when the average temperature is above 18°C. New to this forecast, Elenchus considered heating degree day data with alternate temperature thresholds other than 18°C, consistent with changes to the OEB's electricity distributor load forecast filing requirements.

ENGLP serves six rate classes, R1 to R6, one of which (R1) contains three sub-classes: Residential, Commercial, and Industrial. Each R1 sub-class and the R3 class are weather-sensitive. Consumption of the R2, R4, R5, and R6 rate classes are not correlated to heating degree days. Consumption per customer forecasts for the R1 sub-classes use a baseload and excess consumption methodology to examine the impact of temperature on consumption. The R3 class's baseload consumption has fluctuated in historic years so the regression for this uses total consumption with a time trend.

Forecasts for non-weather sensitive classes are derived with average consumption per customer figures in recent years, consistent with previously approved forecasts. The number of years used on the average consumption per customer calculations is reassessed in each load forecast to account for changes in consumption patterns over time. Consumption forecasts for non-weather sensitive classes is further described in Section 6 of this report.

In addition to the weather variables, other variables such as economic variables, time trend variable, number of days and number of working days in each month, number of customers, and month of year variables, have been examined for weather sensitive rate classes. A COVID variable and COVID/weather interaction variables were considered for weather-sensitive classes but found not to be statistically significant. More details on the individual class specifications are provided in the next section.

ENGLP does not have a DSM plan so no adjustments were made to the class forecasts to account for DSM savings.

1.1 Summarized Results

The following table summarizes the historic and weather normalized consumption.

Normal Forecast

	2019 Actual	2020 Actual	2021 Actual	2021 Normal	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
R1 Residential	18,000,452	16,837,081	17,299,257	18,272,944	18,607,331	19,257,743	19,930,528	20,626,443	21,346,276
R1 Industrial	2,461,420	2,067,358	2,226,121	2,736,619	2,220,366	2,333,411	2,451,644	2,575,289	2,704,581
R1 Commercial	5,890,482	5,028,438	5,306,940	5,648,018	5,876,510	6,078,753	6,287,803	6,503,888	6,727,238
R2 Seasonal	1,279,499	784,724	829,096	829,096	962,031	940,348	919,154	898,437	878,187
R3	1,510,164	1,361,184	1,372,372	1,414,518	1,358,859	1,301,078	1,249,451	1,202,977	1,160,868
R4	1,953,378	1,534,283	1,793,580	1,793,580	1,806,683	1,889,798	1,976,737	2,067,675	2,162,797
R5	927,203	554,438	791,530	791,530	757,724	757,724	757,724	757,724	757,724
R6	62,525,354	59,599,950	60,410,748	60,410,748	61,336,401	61,336,401	61,336,401	61,336,401	61,336,401
Total	**94,547,953**	**87,767,455**	**90,029,645**	**91,897,053**	**92,925,905**	**93,895,256**	**94,909,441**	**95,968,834**	**97,074,072**

Table 1 Consumption Forecast by class

The following table summarizes the historic and forecast customer/connections for 2019-2026:

Customers / Connections

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
R1 Residential	8657	8839	9070	9353	9644	9945	10,254	10,574
R1 Industrial	73	75	76	79	81	84	87	90
R1 Commercial	536	535	559	575	593	610	628	647
R2 Seasonal	49	48	51	49	48	47	46	45
R3	6	6	6	6	6	6	6	6
R4	37	40	46	48	50	52	54	57
R5	4	4	4	4	4	4	4	4
R6	1	1	1	1	1	1	1	1
Total	**9,363**	**9,548**	**9,812**	**10,115**	**10,427**	**10,750**	**11,081**	**11,424**

Table 2 Customer Forecast for 2019-2026

Forecasts of 2022 consumption by tier, for the classes billed based on volume tiers, is provided below.

2022 Tier Forecast

kW	Period	Tier 1	Tier 2	Tier 3	Total
R1 Residential		18,492,197	115,133		18,607,331
R1 Industrial		520,770	1,699,596		2,220,366
R1 Commercial		2,781,738	3,094,773		5,876,510
Seasonal	Apr-Oct	64,054	535,030	102,213	701,296
Seasonal	Nov-Mar	49,709	197,942	13,084	260,735
R4	Jan-Mar	28,308	5,731		34,039
R4	Apr-Dec	148,280	1,624,364		1,772,644

Table 3 2022 Consumption Forecast by Tier

2 METHODOLOGY

Energy use for R1 Residential, R1 Industrial, R1 Commercial and R3 rate classes are forecast with multivariate regressions. Regressions were not selected for R2 Seasonal, R4, R5 and R6 rate classes as these classes do not exhibit sufficient sensitivity to the explanatory variables available for a statistical regression approach.

2.1 CONSUMPTION OF WEATHER SENSITIVE CLASSES

Consumption of the three R1 rate classes are forecast using a base load and excess consumption method. Average monthly consumption per customer is first calculated for each class. The amounts are then reduced by the base load consumption, which is considered the average consumption in the summer months of July and August. The remaining consumption is considered the weather-sensitive load (or “excess” load). A baseline trend is applied to certain classes that have ongoing increasing consumption per customer that is not related to heating.

The excess load is regressed by the actual heating degree days in each month to determine the impact of cold weather on average consumption. A time-series (Prais-Winsten) regression is used to determine the coefficient, consistent with the methodology used in prior NRG throughput forecasts. A simple Ordinary Least Squares (“OLS”) model is not appropriate as the errors exhibit a high level of autocorrelation (as demonstrated by Durbin-Watson statistics close to, or below, 1).

Alternate heating degree days data were also considered for each weather-sensitive class. Elenchus considered heating degree day figures for a range of reference temperatures from 10°C to 20°C. Using alternate HDD temperatures considers the possibility that classes, on average, begin consuming natural gas for their heating load at temperatures other than 18°C.

Actual heating degree days are then multiplied by the coefficients and base load consumption is added back to determine the average predicted consumption in each month. Predicted total consumption of a class is determined by multiplying this sum by the actual number of customers.

The methodology is similar for the R3 class, but the base load is not removed before the regression. While the calculated base load consumption is generally consistent from year to year for the R1 classes, the base load appears to have declined in historic years. As a consequence of higher base load consumption in earlier years, the calculated base load is higher than consumption in 25 of the 120 sample months and over double the volume of consumption in the most recent summer months.

To forecast 2022-2026 consumption, forecast heating degree days figures, as described in section 4, are used in place of actual heating degree days. Weather normalized consumption in historic years is determined by removing the deviations from average weather from consumption. This is done by multiplying the coefficients by the difference between actual and average heating degree days and applying the difference to actual consumption.

A set of interaction COVID/Weather variables were considered for the weather-sensitive classes but found to be not statistically significant. The values for this variable were set to 0 in all months before March 2020 and set equal to the applicable heating degree day variable for the months of March 2020 to December 2021. This variable was intended to capture potential incremental heating load for the Residential class, and reduced heating load for non-residential classes, resulting from people staying and working from home. This indicates that COVID did not have a material impact on heating load. A COVID variable, equal to 1 from March 2020 to December 2021 and 0 in all other months, was also tested and found not to be statistically significant.

2.2 Consumption of Non-Weather Sensitive Classes

Consumption of four rate classes (R2 Seasonal, R4, R5 and R6) are not weather-sensitive and do not exhibit sensitivity to the explanatory variables. Total and monthly volumes fluctuate from year to year, so a rolling average is used to forecast monthly consumption for these classes, with the exception of R4 in which a trend is also applied. The number of years used in the average calculations is explained in Section 6.

2.3 Customer Counts

Annual customer counts for 2022-2026 are forecast by applying the geometric mean annual growth rate from 2010 to 2021 to the 2021 average customer count. Calculations for each class are provided in section 5 and 6 of this report. Monthly customer counts are derived by applying equal percentage increases in each month such that the annual average of monthly forecasts is equal to the annual forecast.

2.4 CONSUMPTION TIERS

The R1 classes, R2 Seasonal Class, and R4 classes are billed according to consumption tiers (also known as volume blocks). Historic tiered data from January 2017 to November 2018 was used to derive weather-normal tiered forecasts. The allocation from total class throughput to tiered throughput has not been updated for this forecast.

The R1 classes are billed different rates on consumption above and below a 1,000 m^3 threshold. As these classes are weather-sensitive, the share of energy consumed in each tier is determined by adjusting actual consumption in each month for each individual customer to weather normal consumption. This method allows a class's forecast consumption to be consistent with the weather normalized total volume while maintaining the consumption profile of the rate classes. The weather-normalized consumption split between Tier 1 and Tier 2 in historic years is determined for each month and used to forecast the monthly splits in the forecast months. When two years of data was available, an average of the 2017 and 2018 splits was used. The R2 Seasonal and R4 classes are not weather-sensitive so the average of 2017 and 2018 tier splits were applied to total annual consumption.

3 CLASS SPECIFIC CONSUMPTION REGRESSIONS

3.1 R1 RESIDENTIAL

For the R1 Residential Class consumption the equation was estimated using 144 observations from 2010:01 to 2021:12. The natural logarithm of heating degree days at 18°C for the months of September to June were used, as measured at the London CS weather station as described in the introduction.

Several other variables were examined and found to not show a statistically significant relationship to energy usage. Those included alternate reference temperatures, economic indicators of full-time employment and GDP, days in each month, workdays in each month, a time trend, a COVID binary variable, and COVID/weather interaction variables.

A baseload trend was used to remove from 31.45m^3 in 2010 to 39.0m^3 in 2021 from the average consumption variable in each month. This amount is added back to the predicted values.

The following table outlines the resulting regression model:

Model 2: Prais-Winsten, using observations 2010:01-2021:12 (T = 144)				
Dependent variable: ExLNResAverageTrend				
rho = 0.206192				
	coefficient	std. error	t-ratio	p-value
const	0.21788	0.0563	3.87	1.7E-04
LNHDDJanuary18	0.83933	0.0140	59.90	4.3E-98
LNHDDFebruary18	0.83459	0.0142	58.62	6.9E-97
LNHDDMarch18	0.83123	0.0147	56.63	5.7E-95
LNHDDApril18	0.79945	0.0158	50.65	8.3E-89
LNHDDMay18	0.77246	0.0184	41.88	1.8E-78
LNHDDJune18	0.54440	0.0255	21.33	9.1E-45
LNHDDSeptember18	0.43137	0.0201	21.44	5.4E-45
LNHDDOctober18	0.73448	0.0166	44.20	2.2E-81
LNHDDNovember18	0.80291	0.0151	53.06	2.3E-91
LNHDDDecember18	0.83510	0.0144	57.91	3.2E-96
Statistics based on the rho-differenced data				
Mean dependent var	3.74373	S.D. dependent var	2.022	
Sum squared resid	8.12044	S.E. of regression	0.24710	
R-squared	0.98611	Adjusted R-squared	0.98506	
F(10, 121)	672.43688	P-value(F)	0.00000	
rho	-0.00261	Durbin-Watson	2.00340	

Table 4 R1 Residential Regression Model

In the above table, and all regression results tables in the section, LN denotes natural logarithm, HDD denotes heating degree days, the month name denotes a dummy variable representing 1 in the labeled month and 0 in all other months, and the ‘18’ denotes the reference HDD temperature of 18°C. The values within the LNHDDJanuary variable, for example, includes the natural logarithm of the number of heating degree days for each January, and 0 in all other months. The label for the dependent variable includes “Ex” denoting the values of this variable are the excess consumption above the class's base load.

Using the above model coefficients, we derive the following:

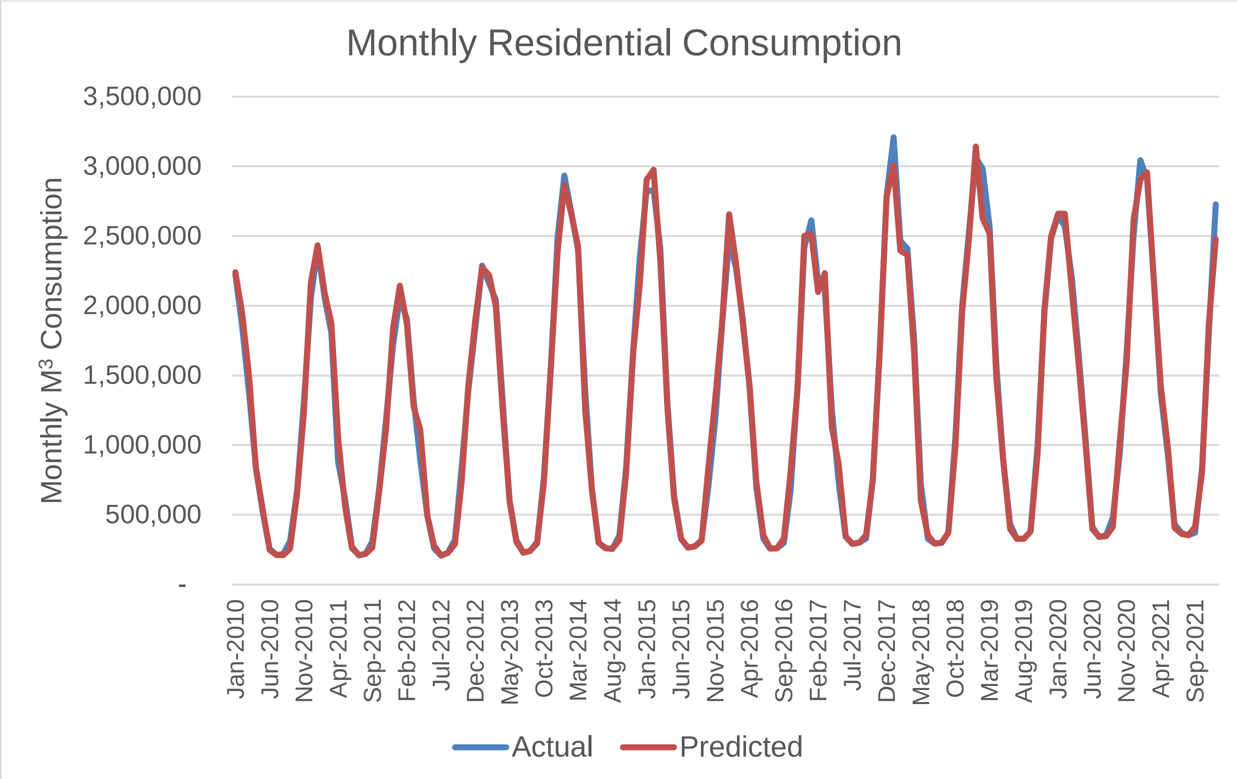

Figure 1 R1 Residential Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 2.1%. The MAPE calculated monthly over the period is 4.5%.

	Residential		Absolute
Year	**Actual**	**Predicted**	**Error (%)**
2011	12,393,486	12,611,688	1.8%
2012	11,751,822	11,963,989	1.8%
2013	14,287,143	14,077,166	1.5%
2014	16,127,158	15,631,550	3.1%
2015	14,948,329	15,321,787	2.5%
2016	14,417,053	14,950,349	3.7%
2017	15,400,135	15,358,194	0.3%
2018	17,442,260	16,758,461	3.9%
2019	18,000,452	17,519,555	2.7%
2020	16,837,081	16,758,636	0.5%
2021	17,299,257	17,115,095	1.1%
Total	**168,904,177**	**168,066,469**	**0.5%**

Mean Absolute Percentage Error (Annual)	2.1%
Mean Absolute Percentage Error (Monthly)	4.5%

Table 5 R1 Residential model error

3.2 R1 Industrial

For the R1 Industrial Class consumption the equation was estimated using 144 observations from 2010:01 to 2021:12. The natural logarithm of heating degree days at 16°C for the months from August to June were used, as measured at the London CS weather station.

Several other variables were examined and found to not show a statistically significant relationship to energy usage. Those included alternate reference temperatures, economic indicators of full-time employment and GDP, days in each month, workdays in each month, and a time trend.

A baseload trend was used to remove from 373.20m^3 in 2010 to 768.83m^3 in 2021 from the average consumption variable in each month. This amount is added back to the predicted values.

The following table outlines the resulting regression model:

Model 3: Prais-Winsten, using observations 2010:01-2021:12 (T = 144)				
Dependent variable: ExLNR1AverageTrend				
rho = 0.224137				
	coefficient	std. error	t-ratio	p-value
const	0.57718	0.2734	2.11	3.7E-02
LNHDDJanuary16	1.10713	0.0666	16.64	3.4E-34
LNHDDFebruary16	1.09883	0.0676	16.24	2.8E-33
LNHDDMarch16	1.12297	0.0701	16.02	9.7E-33
LNHDDApril16	1.15177	0.0763	15.09	1.6E-30
LNHDDMay16	1.15874	0.0930	12.45	5.0E-24
LNHDDJune16	0.27230	0.1639	1.66	9.9E-02
LNHDDAugust16	1.89409	0.4713	4.02	9.8E-05
LNHDDSeptember16	1.21571	0.1137	10.69	1.3E-19
LNHDDOctober16	1.44145	0.0819	17.60	1.9E-36
LNHDDNovember16	1.32167	0.0726	18.19	8.8E-38
LNHDDDecember16	1.16255	0.0687	16.92	7.5E-35
Statistics based on the rho-differenced data				
Mean dependent var	5.64798	S.D. dependent var	3.101	
Sum squared resid	167.63238	S.E. of regression	1.12692	
R-squared	0.87806	Adjusted R-squared	0.86790	
F(11, 120)	61.31425	P-value(F)	0.00000	
rho	-0.02046	Durbin-Watson	2.04069	

Table 6 R1 Industrial Regression Model

Using the above model coefficients we derive the following:

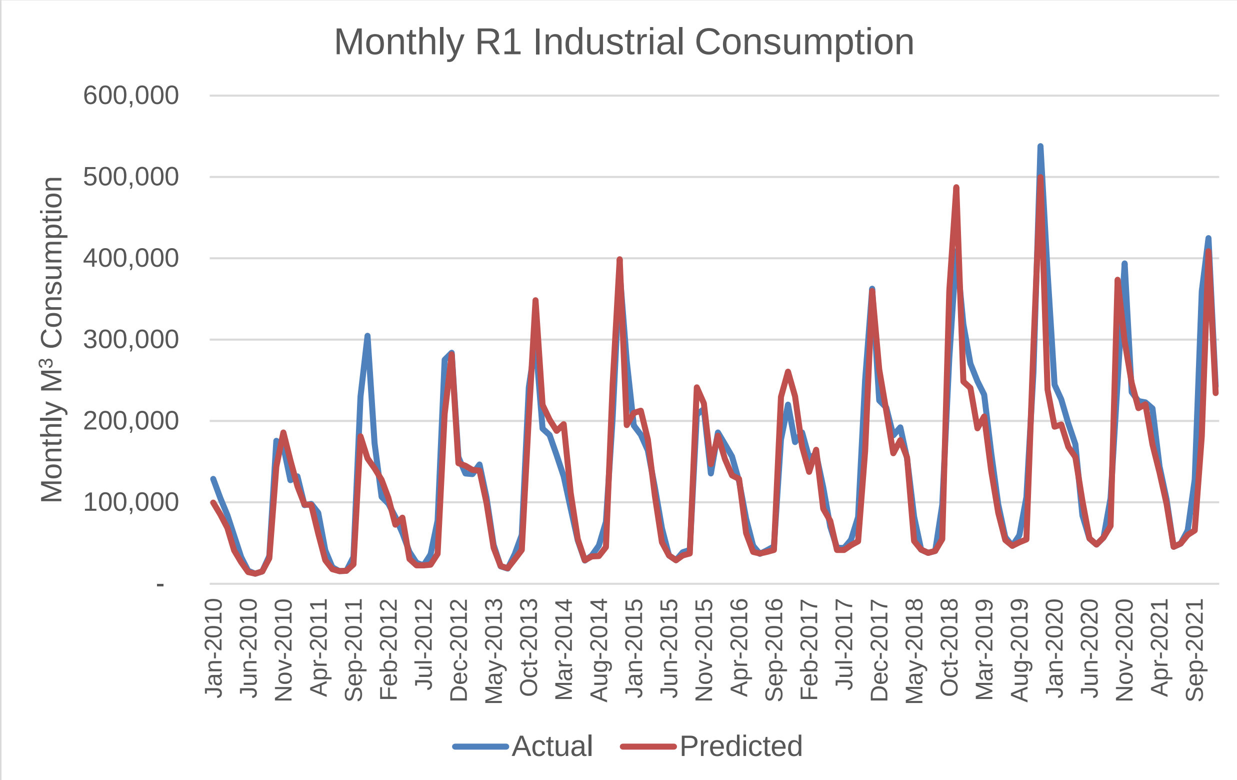

Figure 2 R1 Industrial Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 8.3%. The MAPE calculated monthly over the period is 18.5%.

	R1 Industrial		Absolute
Year	Actual	Predicted	Error (%)
2011	1,247,376.0	955,074.6	23.4%
2012	1,265,913.0	1,162,815.3	8.1%
2013	1,436,592.0	1,452,758.9	1.1%
2014	1,666,209.0	1,732,930.6	4.0%
2015	1,430,900.0	1,505,370.4	5.2%
2016	1,462,707.0	1,538,068.7	5.2%
2017	1,752,123.4	1,610,215.4	8.1%
2018	2,050,371.1	2,028,673.3	1.1%
2019	2,461,420.1	2,099,488.3	14.7%
2020	2,067,357.8	1,965,416.0	4.9%
2021	2,226,121.1	1,887,126.8	15.2%
Total	19,067,090	17,937,938	5.9%
Mean Absolute Percentage Error (Annual)			8.3%
Mean Absolute Percentage Error (Monthly)			18.5%

Table 7 R1 Industrial model error

3.3 R1 COMMERCIAL

For the R1 Commercial Class consumption the equation was estimated using 144 observations from 2010:01 to 2021:12. The natural logarithm of heating degree days at 18°C for the months from September to June were used, as measured at the London CS weather station.

Several other variables were examined and found to not show a statistically significant relationship to energy usage. Those included alternate reference temperatures, economic indicators of full-time employment and GDP, days in each month, workdays in each month, and a time trend.

A baseload trend was used to remove from 180.64m^3 in 2010 to 228.08m^3 in 2021 from the average consumption variable in each month. This amount is added back to the predicted values.

The following table outlines the resulting regression model:

Model 4: Prais-Winsten, using observations 2010:01-2021:12 (T = 144)				
Dependent variable: ExLNComAverageTrend				
rho = 0.178664				
	coefficient	std. error	t-ratio	p-value
const	1.24666	0.1713	7.28	2.7E-11
LNHDDJanuary18	0.92918	0.0430	21.63	2.2E-45
LNHDDFebruary18	0.92735	0.0436	21.25	1.4E-44
LNHDDMarch18	0.92035	0.0450	20.45	6.9E-43
LNHDDApril18	0.89198	0.0484	18.41	2.1E-38
LNHDDMay18	0.86237	0.0568	15.19	7.7E-31
LNHDDJune18	0.58732	0.0794	7.40	1.4E-11
LNHDDSeptember18	0.59899	0.0626	9.57	7.8E-17
LNHDDOctober18	0.82413	0.0512	16.11	4.7E-33
LNHDDNovember18	0.89180	0.0464	19.20	3.6E-40
LNHDDDecember18	0.92162	0.0442	20.84	1.0E-43
Statistics based on the rho-differenced data				
Mean dependent var	5.20105	S.D. dependent var	2.322	
Sum squared resid	77.78975	S.E. of regression	0.76478	
R-squared	0.89915	Adjusted R-squared	0.89157	
F(10, 121)	88.62763	P-value(F)	0.00000	
rho	-0.03268	Durbin-Watson	2.06511	

Table 8 R1 Commercial Regression Model

Using the above model coefficients we derive the following:

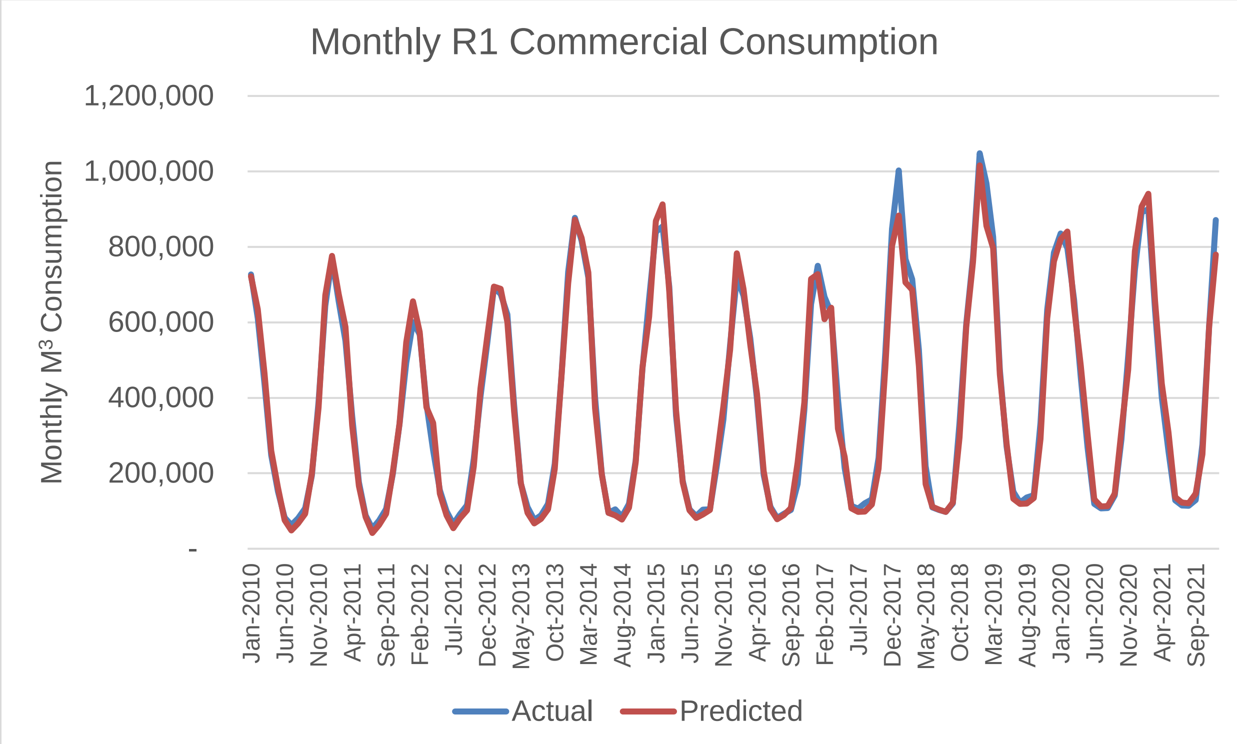

Figure 3 R1 Commercial Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 3.2%. The MAPE calculated monthly over the period is 7.2%.

	R1 Commercial		Absolute
Year	Actual	Predicted	Error (%)
2011	3,846,511.0	3,895,980.2	1.3%
2012	3,526,397.0	3,615,432.8	2.5%
2013	4,352,319.0	4,238,513.0	2.6%
2014	4,788,282.0	4,690,033.3	2.1%
2015	4,420,443.0	4,524,717.2	2.4%
2016	4,117,374.0	4,341,403.3	5.4%
2017	4,734,212.7	4,451,277.5	6.0%
2018	5,363,287.7	5,008,229.0	6.6%
2019	5,890,482.0	5,579,567.8	5.3%
2020	5,028,437.6	5,167,836.6	2.8%
2021	5,306,939.8	5,395,213.8	1.7%
Total	51,374,686	50,908,204	0.9%
Mean Absolute Percentage Error (Annual)			3.2%
Mean Absolute Percentage Error (Monthly)			7.2%

Table 9 R1 Commercial model error

3.4 R3

For the R3 Class consumption the equation was estimated using 144 observations from 2010:01 to 2021:12. The natural logarithm of heating degree days at 20°C for the months from September to May were used, as measured at the London CS weather station. A natural log of a time trend is also included, beginning at ln(10) in January 2010 (increasing to ln(153) in December 2021) is used as this class exhibits declining average consumption over time.

The R3 class's customer count declined from 6 to 4 from October 2009 to June 2010, which had a clear impact on average consumption per customer, as shown on the below chart. A dummy variable is used for this period (denoted d2009), set at 1 for the months October 2009 to May 2010 and 0.5 in June 2010, the month the customer count fell to 4. A dummy variable for June was included as consumption in June was typically greater than what was expected based on the weather in that month. A dummy variable for the shoulder months of March, April, May, September, October, and November was also used to reflect lower consumption in those months than could be explained by heating degree days.

Several other variables were examined and found to not show a statistically significant relationship to energy usage. Those included alternate weather variables, economic indicators of full-time employment and GDP, days in each month, and work days in each month.

The following table outlines the resulting regression model:

Model 7: Prais-Winsten, using observations 2010:01-2021:12 (T = 144)				
Dependent variable: LNContractR3Average				
rho = 0.652409				
	coefficient	std. error	t-ratio	p-value
const	11.76531	0.3636	32.36	4.7E-64
LNHDDJanuary20	0.26195	0.0154	17.01	7.4E-35
LNHDDFebruary20	0.25241	0.0157	16.08	1.1E-32
LNHDDMarch20	0.63527	0.1194	5.32	4.4E-07
LNHDDApril20	0.61279	0.1273	4.81	4.0E-06
LNHDDMay20	0.61182	0.1457	4.20	5.0E-05
LNHDDSeptember20	0.06558	0.0144	4.56	1.2E-05
LNHDDOctober20	0.58752	0.1345	4.37	2.5E-05
LNHDDNovember20	0.61803	0.1233	5.01	1.7E-06
LNHDDDecember20	0.24057	0.0153	15.68	9.3E-32
lnTrend	-0.59848	0.0839	-7.13	6.1E-11
d2009	-1.07601	0.2400	-4.48	1.6E-05
Shoulder	-2.50196	0.7631	-3.28	1.3E-03
June	0.20433	0.0681	3.00	3.2E-03
Statistics based on the rho-differenced data				
Mean dependent var	10.12214	S.D. dependent var	0.779	
Sum squared resid	6.08624	S.E. of regression	0.21637	
R-squared	0.92992	Adjusted R-squared	0.92291	
F(13, 118)	69.16274	P-value(F)	0.00000	
rho	0.02113	Durbin-Watson	1.94448	

Table 10 R3 Regression Model

Using the above model coefficients we derive the following:

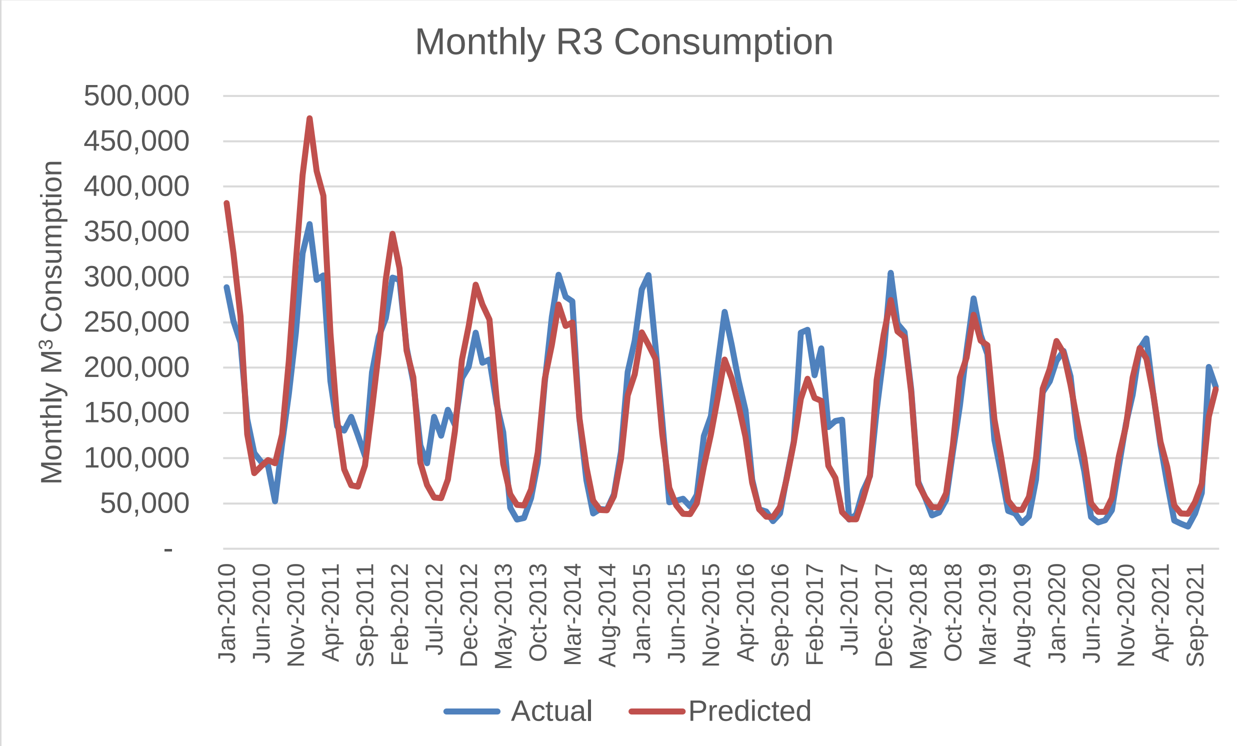

Figure 4 R3 Predicted vs Actual observations

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 9.0%. The MAPE calculated monthly over the period is 21.6%. The MAPEs are relatively high for this class but more variance can be expected in a class with only 4 to 6 customers.

	R3		Absolute
Year	Actual	Predicted	Error (%)
2011	2,464,687.0	2,650,359.3	7.5%
2012	2,161,705.0	2,004,057.8	7.3%
2013	1,644,742.0	1,816,443.4	10.4%
2014	1,792,006.0	1,656,867.0	7.5%
2015	1,692,328.0	1,425,517.7	15.8%
2016	1,492,346.0	1,272,777.2	14.7%
2017	1,653,466.4	1,351,372.1	18.3%
2018	1,711,012.7	1,715,883.6	0.3%
2019	1,510,163.8	1,629,201.7	7.9%
2020	1,361,183.7	1,481,391.9	8.8%
2021	1,372,372.2	1,381,119.4	0.6%
Total	18,856,013	18,384,991	2.5%
Mean Absolute Percentage Error (Annual)			9.0%
Mean Absolute Percentage Error (Monthly)			21.6%

Table 11 R3 model error

4 WEATHER NORMALIZATION

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells "average" out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. While there are several different approaches to determining an appropriate weather normal, ENGLP has adopted the 10-year trend of 10-year monthly degree day averages.

Various methods were analysed to determine the most appropriate methodology to forecast monthly heating degree days from 2022 to 2026. A 5-year average, 10-year average, 20-year trend, 5-year weighted average, 10-year trend of 5 year averages, 10-year trend of 10-year averages, and the midpoint of the 10-year average and 20-year trend were considered.

Data from 1982 to 2021 was used to evaluate each method's predicted heating degree days against the actual heating degree days for each month since January 2001. Data from Environment Canada's London Airport weather station was used for the period from 1982 to 2002. London Airport's temperature data is only provided until 2002, which is approximately when temperature data for London CS begins. Data from the London A weather station (another London Airport weather station with temperature data as of March 2012) is used in place of London CS when data from that station is unavailable.

Each method was ranked according to the magnitude of the deviations between predicted and actual heating degree days, with 1 being the closest predicted value and 7 being the furthest. The rankings were done on monthly and annual bases. The following table shows the annual rankings, average annual and monthly rankings, and variance of the deviations on monthly and annual bases.

Year	5-Year Average	10-Year Average	20-Year Trend	Weighted 5-Year Average	10-Year Trend (5MA)	10-Year Trend (10MA)	10-Yr Avg & 20-Yr Trend Midpoint
2002	2	5	1	4	7	6	3
2003	7	2	5	6	4	1	3
2004	6	2	5	4	7	1	3
2005	4	3	6	2	7	1	5
2006	6	2	4	7	1	5	3
2007	2	4	6	3	7	1	5
2008	1	4	6	3	7	2	5
2009	1	2	6	3	4	7	5
2010	3	5	2	7	6	1	4
2011	1	6	5	4	7	2	3
2012	5	6	1	4	7	3	2
2013	4	3	7	6	1	2	5
2014	4	2	7	6	3	1	5
2015	4	2	5	1	7	6	3
2016	6	3	5	7	1	2	4
2017	2	4	6	7	1	3	5
2018	1	5	2	7	6	3	4
2019	1	6	4	7	2	3	5
2020	1	3	5	6	7	2	4
2021	1	5	3	2	7	6	4
Average Rank							
Monthly	3.98	3.90	4.14	4.19	4.02	3.85	3.93
Annual	3.10	3.70	4.55	4.80	4.95	2.90	4.00
Variance between Predicted and Actual							
Monthly	4,072	3,650	4,100	4,402	3,971	3,605	3,835
Annual	67,711	59,711	69,038	77,181	67,488	54,182	63,406

Table 12 HDD Rankings and Variance

The rankings and variance analysis reveals that the 10-year trend of the 10-year average is the best methodology for predicting future heating degree days. On a monthly and annual basis, the predicted heating degree days using this methodology is closest to actual heating degree days and the deviations from actual weather have the lowest variance among the methods analysed.

For clarity, the 10-year trend of the 10-year moving average is the annualized trend of one 10-year period to the next 10-year period. For example, the 2002 predicted value uses the trend from the average heating degree days from 1982 and 1991 to the average from 1992 and 2001.

This method is the best predictive method as it accounts for trends in heating degree days over time without being over-reliant on data of any one year. Simple averages do not consider weather trends over time and typical trend forecasts can be significantly impacted by single data points.

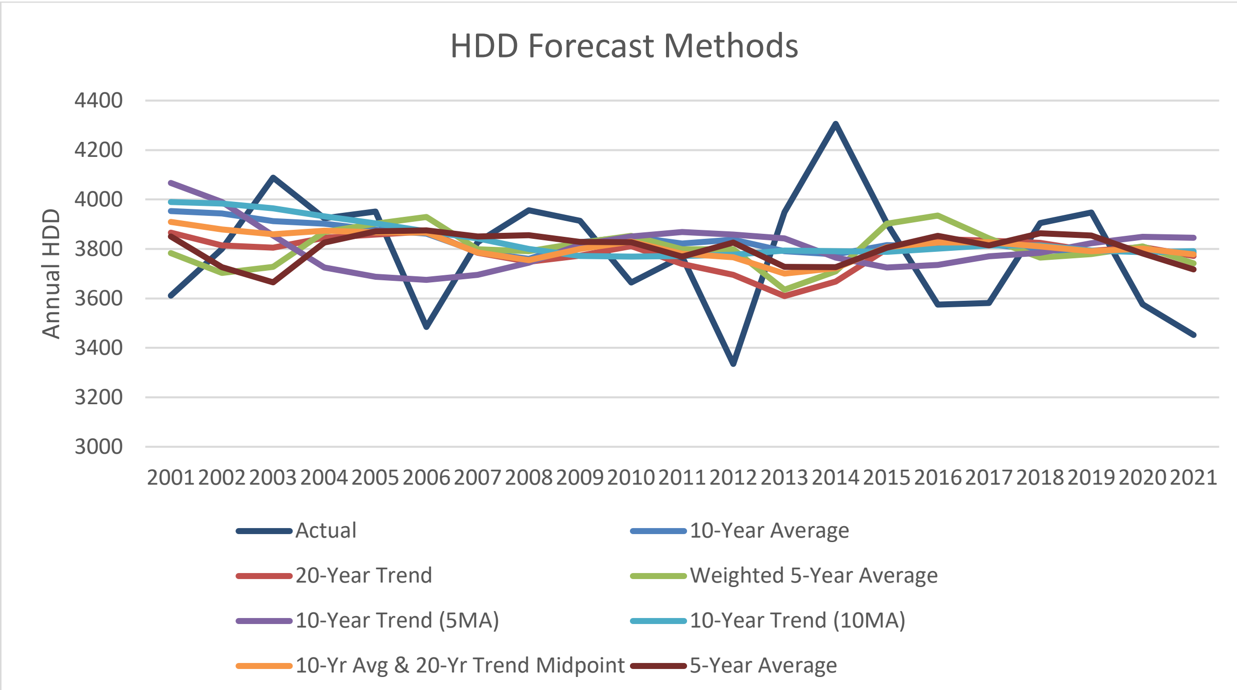

Figure 5 Weather Forecast for Various Methods

The monthly predicted and forecast heating degree days are detailed in the following tables for heating degree days at 18°C.

18°C	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	**Total**	**Actual**
2012	722	651	549	311	162	33	6	11	67	257	404	633	**3,806**	**3,335**
2013	721	655	545	310	157	32	6	11	69	254	408	632	**3,799**	**3,949**
2014	719	661	546	312	153	30	6	10	71	251	415	630	**3,806**	**4,306**
2015	721	671	549	314	147	29	7	11	73	250	420	620	**3,812**	**3,904**
2016	725	676	548	318	142	29	7	11	73	248	422	614	**3,813**	**3,575**
2017	726	672	547	318	137	30	7	11	73	245	422	612	**3,801**	**3,582**
2018	730	666	547	324	131	30	7	11	73	243	425	608	**3,796**	**3,905**
2019	732	661	549	330	128	29	6	11	72	241	431	605	**3,796**	**3,947**
2020	729	656	551	338	129	29	6	10	71	241	434	598	**3,792**	**3,577**
2021	722	652	549	343	134	29	5	10	69	239	438	592	**3,783**	**3,452**
2022	721	649	551	352	131	29	5	10	67	236	445	583	**3,777**	
2023	721	647	552	357	129	28	4	9	66	234	448	579	**3,774**	
2024	720	645	552	361	128	28	4	9	66	233	451	574	**3,771**	
2025	720	643	553	366	126	28	4	9	65	231	454	570	**3,768**	
2026	719	641	554	370	125	28	4	9	64	229	458	565	**3,765**	

Table 13 Forecast HDD 18°C

5 WEATHER-NORMALIZED CLASS FORECASTS

5.1 R1 RESIDENTIAL

Incorporating the normalized and forecast heating degree days the following weather corrected consumption and forecast values are calculated:

R1 Residential						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2011	6,609	1,876	12,400,852	12,393,486	1,885	12,460,549
2012	6,896	1,705	11,756,626	11,751,822	1,893	13,041,075
2013	7,181	1,990	14,289,175	14,287,143	1,954	14,021,948
2014	7,470	2,162	16,150,603	16,127,158	2,002	14,949,679
2015	7,726	1,938	14,974,492	14,948,329	1,900	14,671,276
2016	7,956	1,813	14,425,323	14,417,053	1,886	14,995,391
2017	8,110	1,892	15,347,218	15,400,135	1,977	16,078,869
2018	8,400	2,075	17,426,321	17,442,260	2,050	17,235,055
2019	8,657	2,083	18,035,211	18,000,452	2,033	17,562,537
2020	8,839	1,904	16,828,057	16,837,081	1,992	17,616,719
2021	9,070	1,907	17,299,680	17,299,257	2,015	18,272,944
2022	9,353				1,994	18,607,331
2023	9,644				2,001	19,257,743
2024	9,945				2,009	19,930,528
2025	10,254				2,016	20,626,443
2026	10,574				2,023	21,346,276

Table 14 Actual vs Normalized R1 Residential

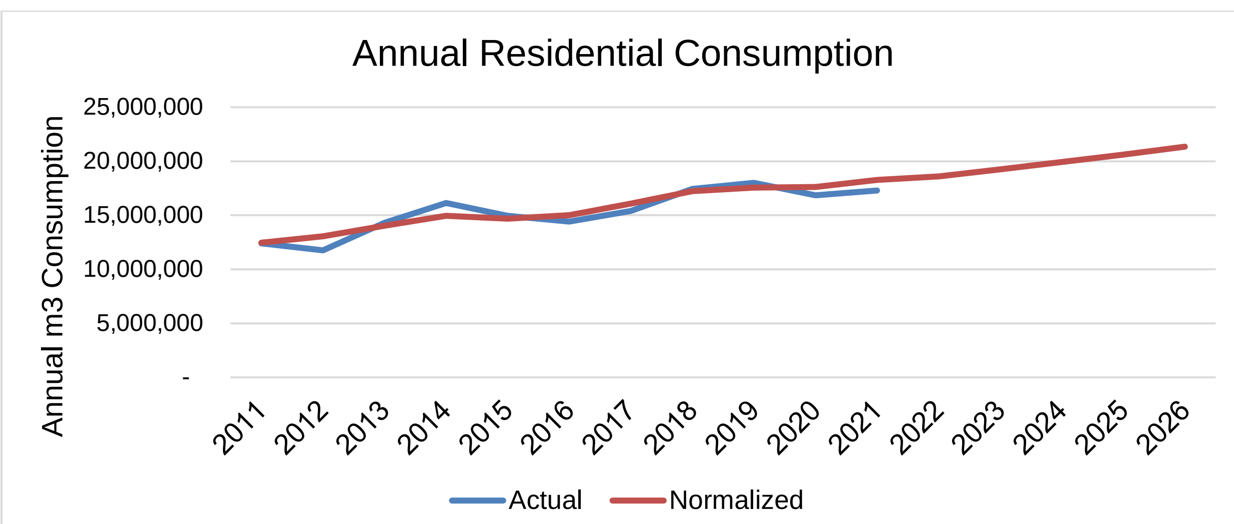

Figure 6 Actual vs Normalized R1 Residential

A tiered forecast was produced using actual individual customer data adjusted to weather-normal consumption.

	R1 Residential		
	Tier 1	**Tier 2**	**Total**
2020	16,736,013	101,069	16,837,081
2021	17,190,340	108,917	17,299,257
2022	18,492,197	115,133	18,607,331
2023	19,138,839	118,905	19,257,743
2024	19,807,729	122,799	19,930,528
2025	20,499,624	126,819	20,626,443
2026	21,215,305	130,971	21,346,276

Table 15 Forecasted R1 Residential Tiered Consumption

The Geometric mean of the annual growth from 2010 to 2021 was used to forecast the growth rate from 2022 to 2026.

Year	Residential Customers	Percent of Prior Year
2010	6,472	
2011	6,609	102.1%
2012	6,896	104.3%
2013	7,181	104.1%
2014	7,470	104.0%
2015	7,726	103.4%
2016	7,956	103.0%
2017	8,110	101.9%
2018	8,400	103.6%
2019	8,657	103.1%
2020	8,839	102.1%
2021	9,070	102.6%
2022	9,353	103.1%
2023	9,644	103.1%
2024	9,944	103.1%
2025	10,254	103.1%
2026	10,574	103.1%

Table 16 Forecasted R1 Residential Customer Count

5.2 R1 INDUSTRIAL

Incorporating the normalized and forecast heating degree days the following weather corrected consumption and forecast values are calculated:

R1 Industrial						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2011	43	28,608	1,225,376	1,247,376	31,232	1,372,395
2012	51	24,350	1,252,019	1,265,913	26,371	1,369,217
2013	58	24,752	1,429,444	1,436,592	24,071	1,396,675
2014	63	26,306	1,659,456	1,666,209	24,071	1,525,376
2015	62	23,186	1,439,435	1,430,900	24,316	1,496,325
2016	65	22,433	1,461,881	1,462,707	24,586	1,604,009
2017	66	26,620	1,752,499	1,752,123	29,539	1,944,061
2018	68	29,425	2,005,771	2,050,371	28,133	1,956,516
2019	73	33,281	2,440,611	2,461,420	33,204	2,449,929
2020	75	27,629	2,067,592	2,067,358	29,813	2,231,524
2021	76	29,179	2,220,030	2,226,121	35,858	2,736,619
2022	79				28,170	2,220,366
2023	81				28,618	2,333,411
2024	84				29,067	2,451,644
2025	87				29,516	2,575,289
2026	90				29,966	2,704,581

Table 17 Actual vs Normalized R1 Industrial

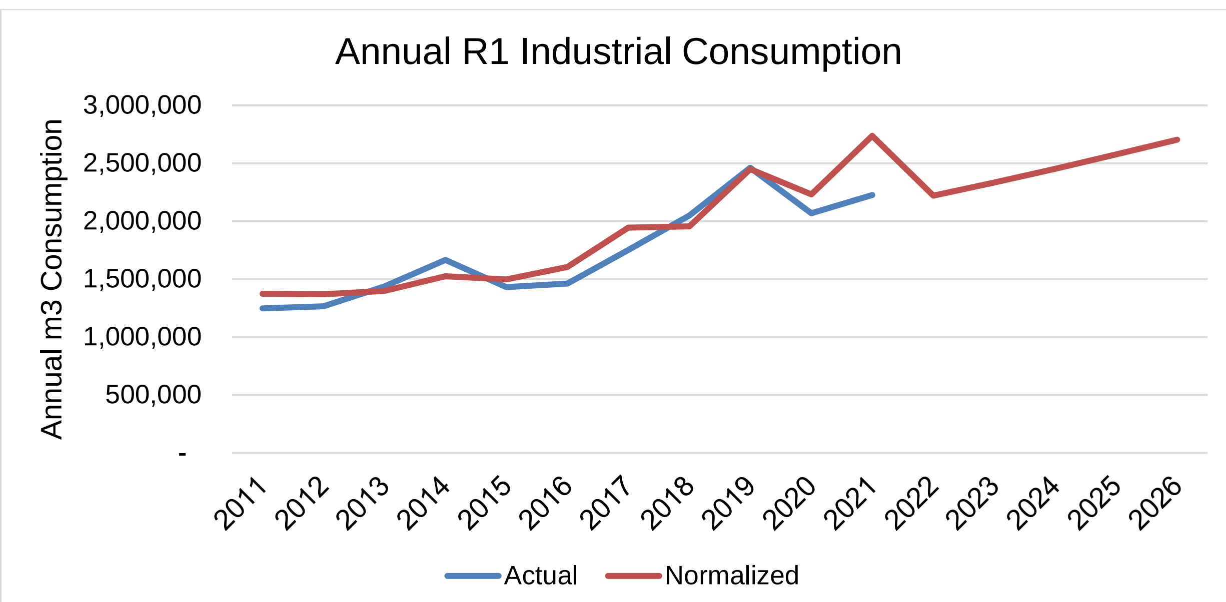

Figure 7 Actual vs Normalized R1 Industrial

A tiered forecast was produced using actual individual customer data adjusted to weather-normal consumption.

	R1 Industrial		
	Tier 1	**Tier 2**	**Total**
2020	486,972	1,580,386	2,067,358
2021	513,443	1,712,679	2,226,121
2022	520,770	1,699,596	2,220,366
2023	549,743	1,783,668	2,333,411
2024	580,101	1,871,542	2,451,644
2025	611,905	1,963,384	2,575,289
2026	645,219	2,059,362	2,704,581

Table 18 Forecasted R1 Industrial Tiered Consumption

The Geometric mean of the annual growth from 2016 to 2021 was used to forecast the growth rate from 2022 to 2026. The number of customers in this class grew significantly from 2009 to 2016 so the growth rates from these years was excluded as they do not reflect the current customer growth trend.

The following table includes the customer Actual / Forecast customer count on this basis:

Year	R1 Industrial Customers	Percent of Prior Year
2010	43	
2011	43	99.8%
2012	51	120.0%
2013	58	112.3%
2014	63	109.2%
2015	62	98.4%
2016	65	105.0%
2017	66	101.0%
2018	68	103.5%
2019	73	107.6%
2020	75	102.0%
2021	76	101.7%
2022	79	103.4%
2023	81	103.4%
2024	84	103.4%
2025	87	103.4%
2026	90	103.4%

Table 19 Forecasted R1 Industrial Customer Count

5.3 R1 COMMERCIAL

Incorporating the normalized and forecast heating degree days the following weather corrected consumption and forecast values are calculated:

R1 Commercial						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2011	405	9,477	3,833,380	3,846,511	9,522	3,863,954
2012	415	8,515	3,533,844	3,526,397	9,528	3,943,192
2013	424	10,227	4,336,095	4,352,319	10,012	4,260,086
2014	437	10,964	4,795,706	4,788,282	10,077	4,402,353
2015	445	9,935	4,421,983	4,420,443	9,711	4,323,556
2016	453	9,065	4,102,131	4,117,374	9,448	4,290,469
2017	462	10,219	4,716,893	4,734,213	10,733	4,968,796
2018	487	10,958	5,332,657	5,363,288	10,824	5,295,344
2019	536	10,970	5,880,685	5,890,482	10,691	5,741,454
2020	535	9,378	5,017,149	5,028,438	9,960	5,341,100
2021	559	9,469	5,292,354	5,306,940	10,078	5,648,018
2022	575				10,234	5,876,510
2023	593				10,282	6,078,753
2024	610				10,330	6,287,803
2025	628				10,377	6,503,888
2026	647				10,425	6,727,238

Table 20 Actual vs Normalized R1 Commercial

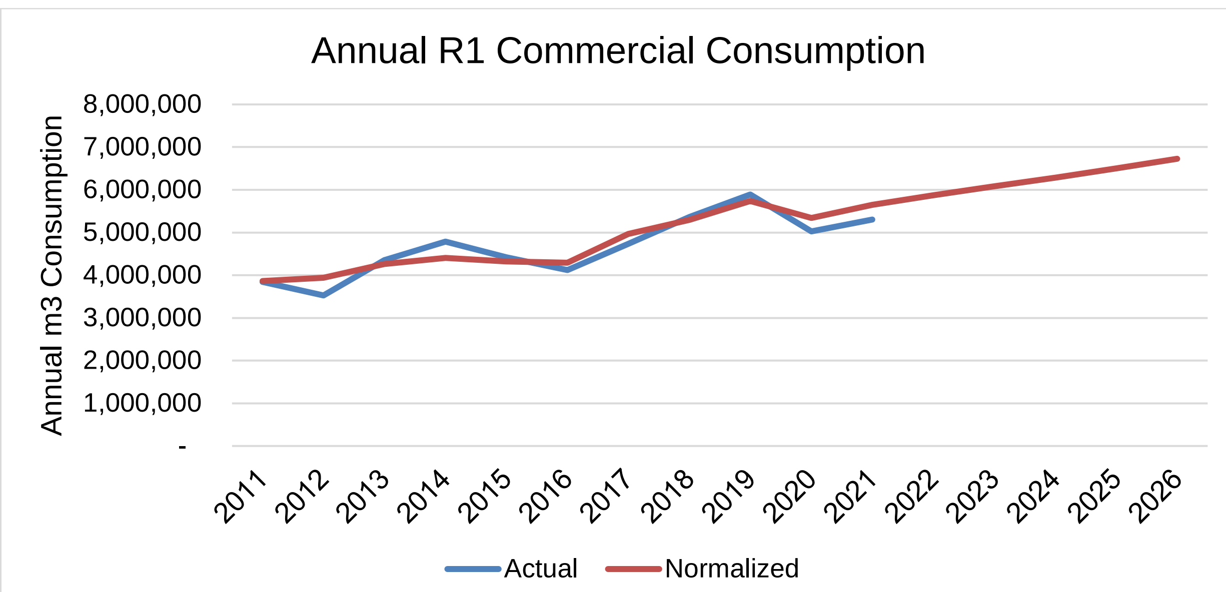

Figure 8 Actual vs Normalized R1 Commercial

A tiered forecast was produced using actual individual customer data adjusted to weather-normal consumption.

	R1 Commercial		
	Tier 1	**Tier 2**	**Total**
2020	2,391,122	2,637,316	5,028,438
2021	2,503,888	2,803,052	5,306,940
2022	2,781,738	3,094,773	5,876,510
2023	2,879,860	3,198,893	6,078,753
2024	2,981,345	3,306,458	6,287,803
2025	3,086,307	3,417,581	6,503,888
2026	3,194,861	3,532,377	6,727,238

Table 21 Forecasted R1 Commercial Tiered Consumption

The Geometric mean of the annual growth from 2010 to 2021 was used to forecast the growth rate from 2022 to 2026.The following table includes the customer Actual / Forecast customer count on this basis:

Year	R1 Commercial Customers	Percent of Prior Year
2010	405	
2011	405	99.8%
2012	415	102.6%
2013	424	102.2%
2014	437	103.2%
2015	445	101.8%
2016	453	101.7%
2017	462	102.0%
2018	487	105.4%
2019	536	110.2%
2020	535	99.8%
2021	559	104.5%
2022	575	103.0%
2023	593	103.0%
2024	610	103.0%
2025	628	103.0%
2026	647	103.0%

Table 22 Forecasted R1 Commercial Customer Count

5.4 R3

Incorporating the normalized and forecast heating degree days, continuing time trend and calendar dummy variables, the following weather corrected consumption and forecast values are calculated:

R3						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2011	4	616,172	2,464,687	2,464,687	621,678	2,486,712
2012	4	540,426	2,161,705	2,161,705	570,119	2,280,477
2013	4	411,186	1,644,742	1,644,742	407,454	1,629,818
2014	4	448,002	1,792,006	1,792,006	427,015	1,708,062
2015	4	423,082	1,692,328	1,692,328	420,923	1,683,691
2016	4	373,087	1,492,346	1,492,346	380,354	1,521,417
2017	5	375,566	1,690,049	1,653,466	380,399	1,671,154
2018	6	285,169	1,711,013	1,711,013	280,148	1,680,888
2019	6	251,694	1,510,164	1,510,164	244,504	1,467,022
2020	6	226,864	1,361,184	1,361,184	230,461	1,382,767
2021	6	228,729	1,372,372	1,372,372	235,753	1,414,518
2022	6				226,476	1,358,859
2023	6				216,846	1,301,078
2024	6				208,242	1,249,451
2025	6				200,496	1,202,977
2026	6				193,478	1,160,868

Table 23 Actual vs Normalized R3

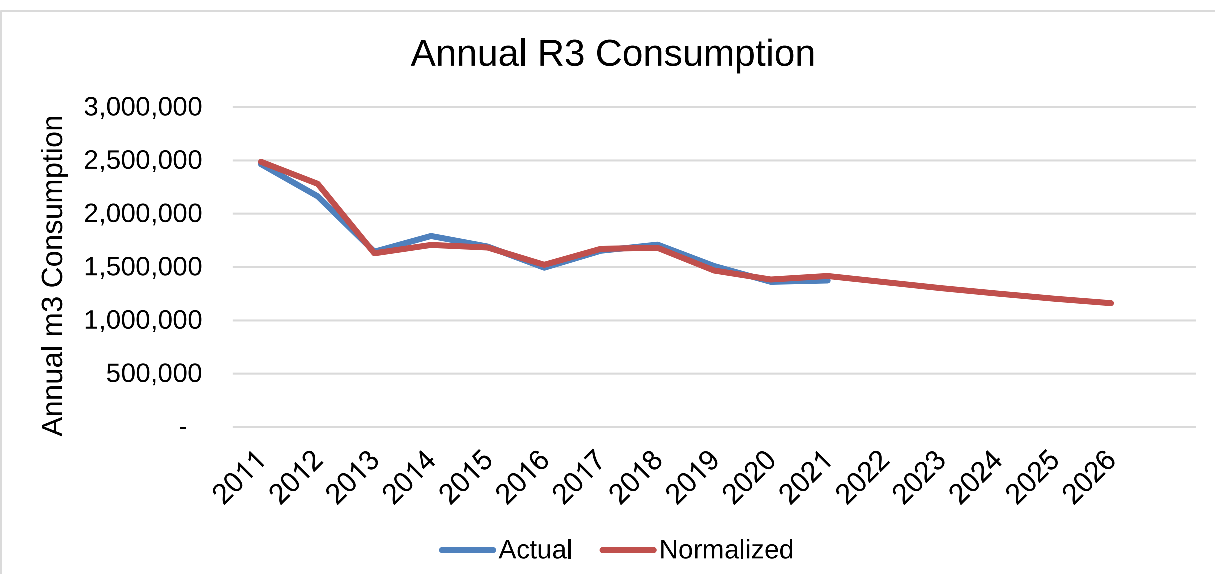

Figure 9 Actual vs Normalized R3

The R3 class has fluctuated between 4 and 6 customers since 2009. The current count of 6 customers is expected to continue through 2022-2026.

6 Non-Weather Sensitive Class Forecasts

6.1 R2 Seasonal

Monthly consumption is forecast using a three-year average of consumption per customer in each month. The sum of monthly forecast values per customer are used to calculate annual total consumption as follows:

R2 Seasonal						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2011	65	27,387	1,768,757	1,849,679		
2012	66	28,174	1,868,851	1,885,826		
2013	64	28,302	1,820,741	1,844,495		
2014	65	30,594	1,980,940	1,988,124		
2015	63	20,017	1,256,038	1,242,867		
2016	59	23,524	1,382,013	1,394,132		
2017	55	26,211	1,435,062	1,410,653		
2018	54	28,488	1,526,500	1,520,647		
2019	49	25,819	1,267,264	1,279,499		
2020	48	16,202	781,723	784,724		
2021	51	16,595	839,456	829,096		
2022	49				19,539	962,031
2023	48				19,539	940,348
2024	47				19,539	919,154
2025	46				19,539	898,437
2026	45				19,539	878,187

Table 24 Actual vs Normalized R2 Seasonal

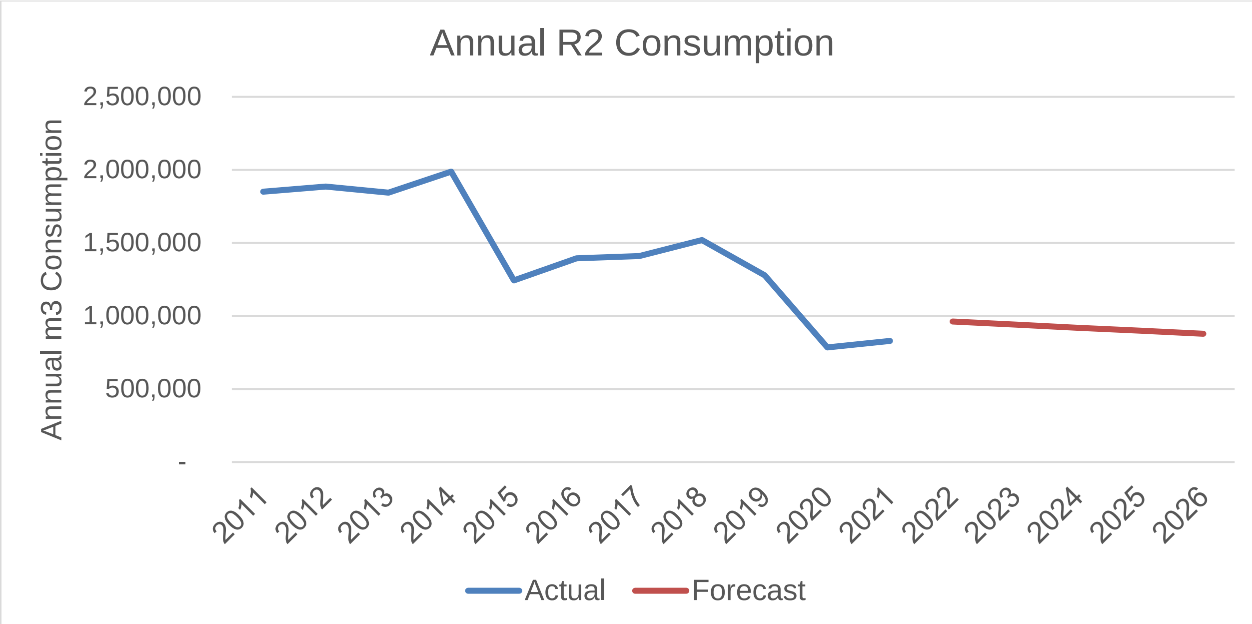

Figure 10 Actual vs Normalized R2 Seasonal

An average of tiered consumption shares in 2017 and 2018 was used to forecast tiered consumption in future years. The R2 seasonal class has three tiers with different rates in April to October and November to March. Tier 1 consumption is consumption up to 1,000 m^3, tier 2 applies to consumption between 1,000 m^3 and 25,000 m^3, and all consumption above 25,000 m^3 is considered Tier 3.

R2 Seasonal							
	April 1 to Oct 31			Nov 1 to Mar 31			
	Tier 1	Tier 2	Tier 3	Tier 1	Tier 2	Tier 3	Total
2020	52,248	436,421	83,374	40,547	161,461	10,672	784,724
2021	55,203	461,098	88,089	42,840	170,590	11,276	829,096
2022	64,054	535,030	102,213	49,709	197,942	13,084	962,031
2023	62,610	522,971	99,909	48,588	193,481	12,789	940,348
2024	61,199	511,184	97,657	47,493	189,120	12,500	919,154
2025	59,819	499,662	95,456	46,423	184,858	12,219	898,437
2026	58,471	488,400	93,304	45,377	180,691	11,943	878,187

Table 25 Forecasted R2 Seasonal Tiered Consumption

The Geometric mean of the annual growth from 2010 to 2021 was used to forecast the growth rate from 2022 to 2026. The following table includes the customer Actual / Forecast customer count on this basis:

Year	R2 Seasonal Customers	Percent of Prior Year
2010	65	
2011	65	99.4%
2012	66	102.7%
2013	64	97.0%
2014	65	100.6%
2015	63	96.9%
2016	59	93.6%
2017	55	93.2%
2018	54	97.9%
2019	49	91.6%
2020	48	98.3%
2021	51	104.8%
2022	49	97.7%
2023	48	97.7%
2024	47	97.7%
2025	46	97.7%
2026	45	97.7%

Table 26 Forecasted R2 Seasonal Customer Count

6.2 R4

Consumption per R4 customer is not consistent over time and the 5-year average does not accurately reflect current consumption for the class. Consumption per customer has been consistent in 2020 and 2021 so the 2022 forecast is based on a 2-year average.

R4						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2011	23	21,688	487,988	477,633		
2012	25	23,036	575,898	678,458		
2013	32	26,175	831,059	861,111		
2014	33	39,661	1,318,721	1,345,169		
2015	34	29,232	996,339	994,710		
2016	35	25,140	888,266	904,160		
2017	36	31,238	1,119,348	1,124,029		
2018	37	35,029	1,278,561	1,327,953		
2019	37	50,232	1,841,844	1,953,378		
2020	40	37,145	1,501,271	1,534,283		
2021	46	37,805	1,720,128	1,793,580		
2022	48				37,475	1,806,683
2023	50				37,475	1,889,798
2024	52				37,475	1,976,737
2025	54				37,475	2,067,675
2026	57				37,475	2,162,797

Table 27 Actual vs Forecast R4

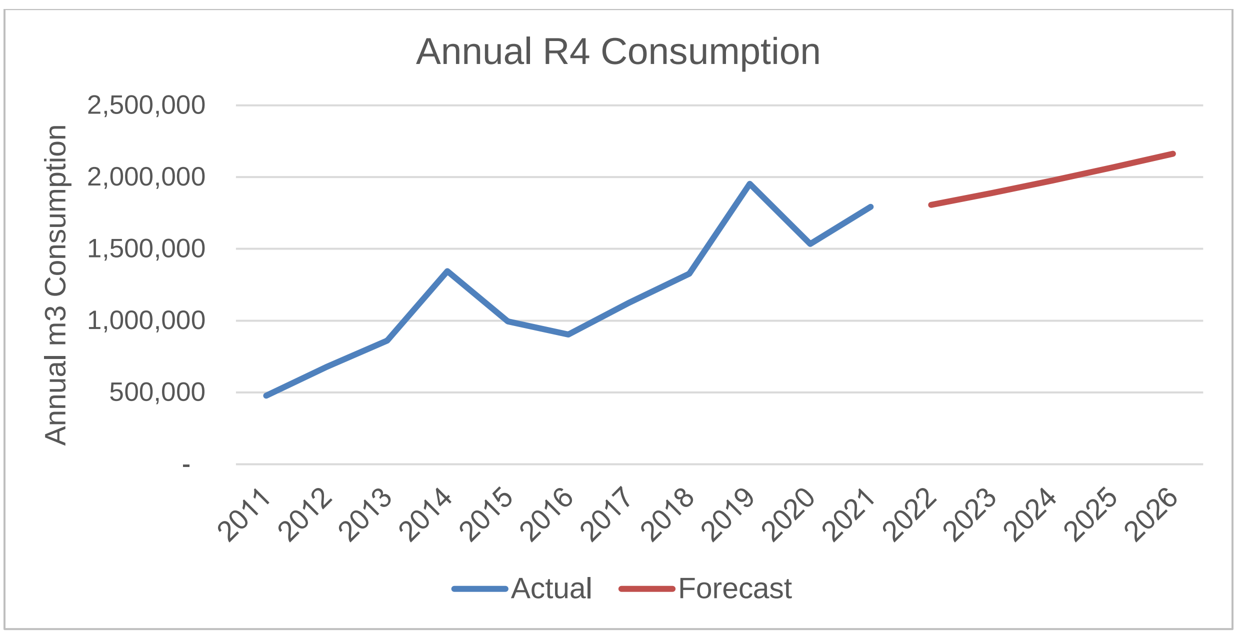

Figure 11 Actual vs Normalized R4

An average of tiered consumption shares in 2017 and 2018 was used to forecast tiered consumption in future years. The R4 class has two tiers with different rates in January to

March and April to December. Tier 1 consumption is consumption up to 1,000 m^3 and all consumption above 1,000 m^3 is considered tier 2.

	R4				
	Jan 1 to Mar 31		Apr 1 to Dec 31		
	Tier 1	Tier 2	Tier 1	Tier 2	Total
2020	24,040	4,867	125,923	1,379,453	1,534,283
2021	28,103	5,689	147,205	1,612,584	1,793,580
2022	28,308	5,731	148,280	1,624,364	1,806,683
2023	29,610	5,995	155,102	1,699,092	1,889,798
2024	30,973	6,270	162,237	1,777,257	1,976,737
2025	32,397	6,559	169,700	1,859,019	2,067,675
2026	33,888	6,861	177,507	1,944,541	2,162,797

Table 28 Forecasted R4 Tiered Consumption

The Geometric mean of the annual growth from 2014 to 2021 was used to forecast the growth rate from 2022 to 2026. The number of customers in this class grew significantly from 2010 to 2013 so the growth rates from these years was excluded as they do not reflect the current customer growth trend.

The following table includes the customer Actual / Forecast customer count on this basis:

Year	R4 Customers	Percent of Prior Year
2010	23	
2011	23	96.8%
2012	25	111.1%
2013	32	127.0%
2014	33	104.7%
2015	34	102.5%
2016	35	103.7%
2017	36	101.4%
2018	37	101.9%
2019	37	100.5%
2020	40	110.2%
2021	46	112.6%
2022	48	104.6%
2023	50	104.6%
2024	52	104.6%
2025	54	104.6%
2026	57	104.6%

Table 29 Forecasted R4 Customer Count

6.3 R5

Consumption per R5 customer has fluctuated considerably since 2011. The 2022-2026 forecast is based on a 3-year average from 2019 to 2021, which is in line with average consumption per customer per year since 2012.

R5						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2011	5	222,975	1,114,874	1,114,874		
2012	5	177,350	886,748	886,748		
2013	5	203,326	1,016,630	1,016,630		
2014	5	225,771	1,147,669	1,128,958		
2015	5	134,524	672,622	672,622		
2016	5	112,572	562,860	562,860		
2017	5	186,530	870,472	753,900		
2018	4	149,492	610,424	624,337		
2019	4	231,801	927,203	927,203		
2020	4	138,609	554,438	554,438		
2021	4	197,882	791,530	791,530		
2022	4				189,431	757,724
2023	4				189,431	757,724
2024	4				189,431	757,724
2025	4				189,431	757,724
2026	4				189,431	757,724

Table 30 Actual vs Forecast R5

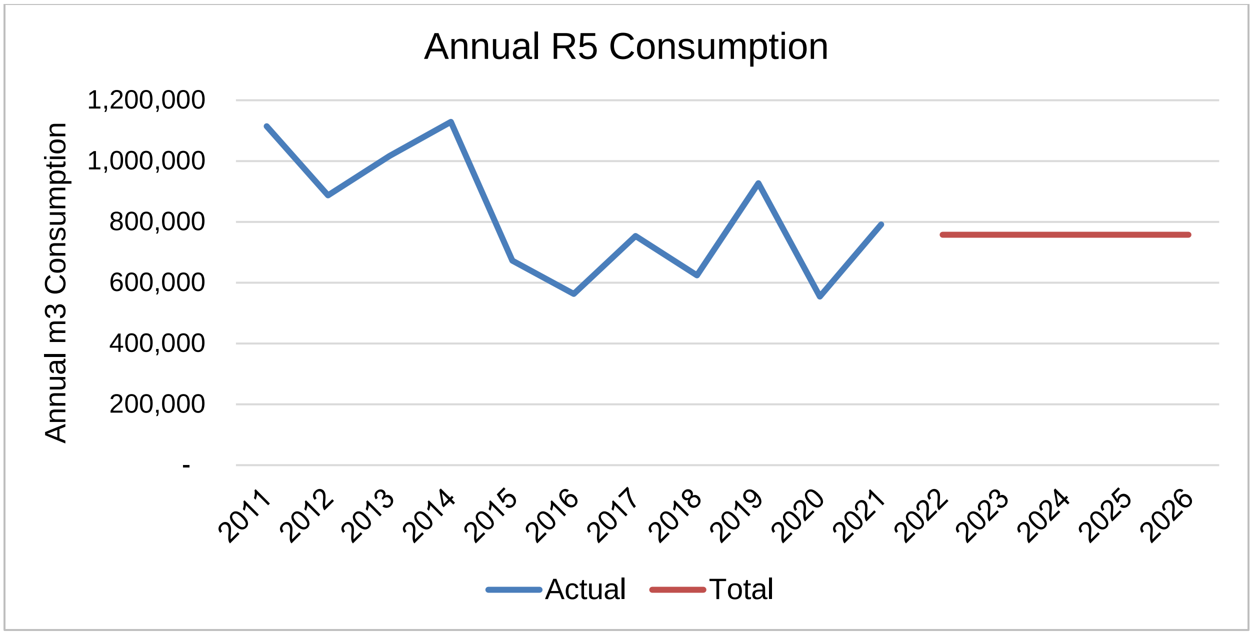

Figure 12 Actual vs Normalized Large Use R5

The R5 class had 5 customers from 2009 to 2017 and had 4 customers from 2018 to 2021. It is expected to maintain 4 customers through 2022 to 2026.

6.4 R6

R6 consumption increased significantly in 2019 over historic volumes. The 2022-2026 forecast uses average 2019-2021 consumption as forecast consumption in each year. Volumes in February and October 2021 were anomalously high and low, respectively, so these months are excluded from the average calculation.

R6						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
2011	1	30,758,504	30,758,504	30,758,504		
2012	1	31,628,262	31,628,262	31,628,262		
2013	1	31,582,423	31,582,423	31,582,423		
2014	1	31,735,774	31,735,774	31,735,774		
2015	1	34,710,609	34,710,609	34,710,609		
2016	1	40,074,176	40,074,176	40,074,176		
2017	1	36,485,139	36,485,139	36,485,139		
2018	1	40,205,243	40,205,243	40,205,243		
2019	1	62,525,354	62,525,354	62,525,354		
2020	1	59,599,950	59,599,950	59,599,950		
2021	1	60,410,748	60,410,748	60,410,748		
2022	1				61,336,401	61,336,401
2023	1				61,336,401	61,336,401
2024	1				61,336,401	61,336,401
2025	1				61,336,401	61,336,401
2026	1				61,336,401	61,336,401

Table 31 Actual vs Forecast R6

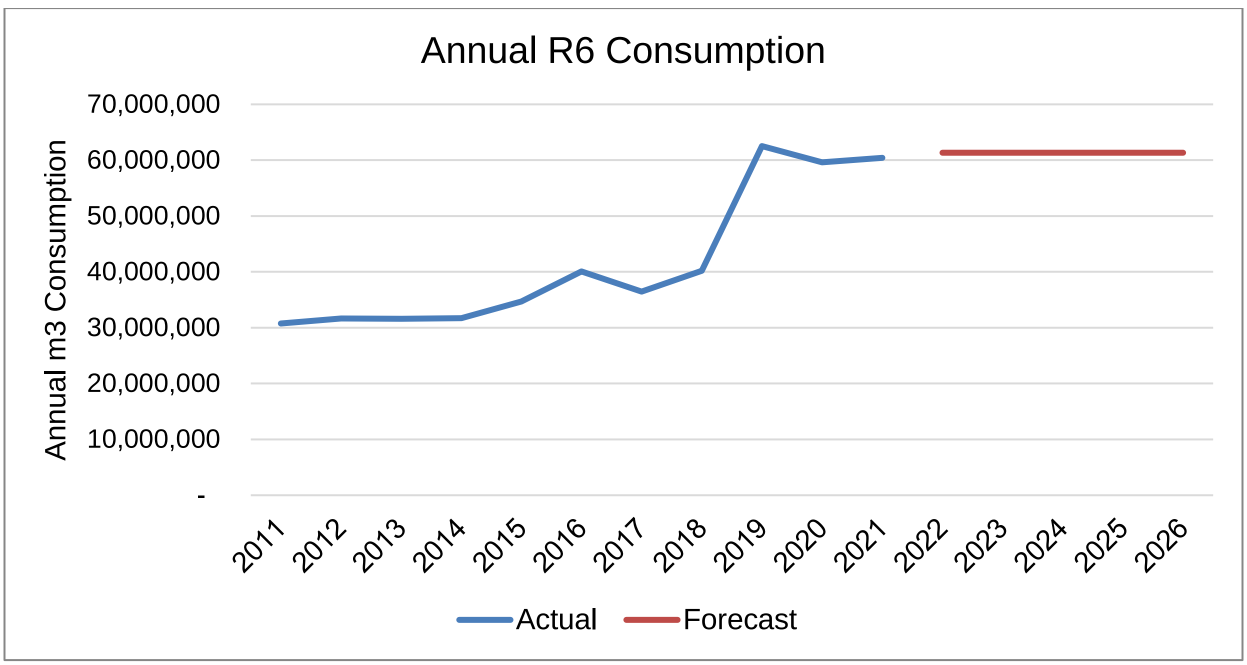

Figure 13 Actual vs Normalized R6

The R6 class has one customer and is expected to persist with one customer through 2026.

7 WEATHER SENSITIVITY

This section provides alternate low forecasts for scenarios with mild winters and high forecasts for cold winters. The low forecast uses the warmest winter in the past 10 years, which was 3,335 HDD (at 18°C) in 2012. The high forecast uses the coldest winter in the past 10 years, 4,306 HDD in 2014. The derived 18°C HDD forecast temperatures from 2022 to 2026 are provided with the normal forecast for reference. Forecast and actual HDDs from 2012 to 2021 are provided in Table 13.

Low Forecast	HDD	3,335.0	3,335.0	3,335.0	3,335.0	3,335.0
	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
R1 Residential	17,299,257	17,235,043	17,850,374	18,487,317	19,146,622	19,829,065
R1 Industrial	2,226,121	1,989,872	2,095,208	2,205,441	2,320,785	2,441,460
R1 Commercial	5,306,940	5,417,303	5,608,423	5,806,112	6,010,592	6,222,091
R2 Seasonal	829,096	962,031	940,348	919,154	898,437	878,187
R3	1,372,372	1,304,387	1,248,677	1,198,904	1,154,101	1,113,509
R4	1,793,580	1,806,683	1,889,798	1,976,737	2,067,675	2,162,797
R5	791,530	757,724	757,724	757,724	757,724	757,724
R6	60,410,748	61,336,401	61,336,401	61,336,401	61,336,401	61,336,401
Total	**90,029,645**	**90,809,443**	**91,726,953**	**92,687,789**	**93,692,337**	**94,741,234**

Table 32 Low HDD Forecast

Normal Forecast	HDD	3,782.8	3,776.9	3,773.9	3,771.0	3,768.0
	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
R1 Residential	17,299,257	18,607,331	19,257,743	19,930,528	20,626,443	21,346,276
R1 Industrial	2,226,121	2,220,366	2,333,411	2,451,644	2,575,289	2,704,581
R1 Commercial	5,306,940	5,876,510	6,078,753	6,287,803	6,503,888	6,727,238
R2 Seasonal	829,096	962,031	940,348	919,154	898,437	878,187
R3	1,372,372	1,358,859	1,301,078	1,249,451	1,202,977	1,160,868
R4	1,793,580	1,806,683	1,889,798	1,976,737	2,067,675	2,162,797
R5	791,530	757,724	757,724	757,724	757,724	757,724
R6	60,410,748	61,336,401	61,336,401	61,336,401	61,336,401	61,336,401
Total	**90,029,645**	**92,925,905**	**93,895,256**	**94,909,441**	**95,968,834**	**97,074,072**

Table 33 Normal HDD Forecast

High Forecast	HDD	4,306.0	4,306.0	4,306.0	4,306.0	4,306.0
	2021 Actual	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**	**2026 Forecast**
R1 Residential	17,299,257	20,203,895	20,911,727	21,644,054	22,401,715	23,185,577
R1 Industrial	2,226,121	2,504,341	2,627,412	2,755,992	2,890,314	3,030,623
R1 Commercial	5,306,940	6,413,188	6,633,806	6,861,867	7,097,618	7,341,315
R2 Seasonal	829,096	962,031	940,348	919,154	898,437	878,187
R3	1,372,372	1,426,955	1,366,013	1,311,563	1,262,552	1,218,146
R4	1,793,580	1,806,683	1,889,798	1,976,737	2,067,675	2,162,797
R5	791,530	757,724	757,724	757,724	757,724	757,724
R6	60,410,748	61,336,401	61,336,401	61,336,401	61,336,401	61,336,401
Total	**90,029,645**	**95,411,218**	**96,463,228**	**97,563,491**	**98,712,435**	**99,910,770**

Table 34 High HDD Forecast

The graph below displays total forecast consumption for the three scenarios. The majority of consumption is not weather-sensitive so the range does not vary considerably on a total consumption basis.

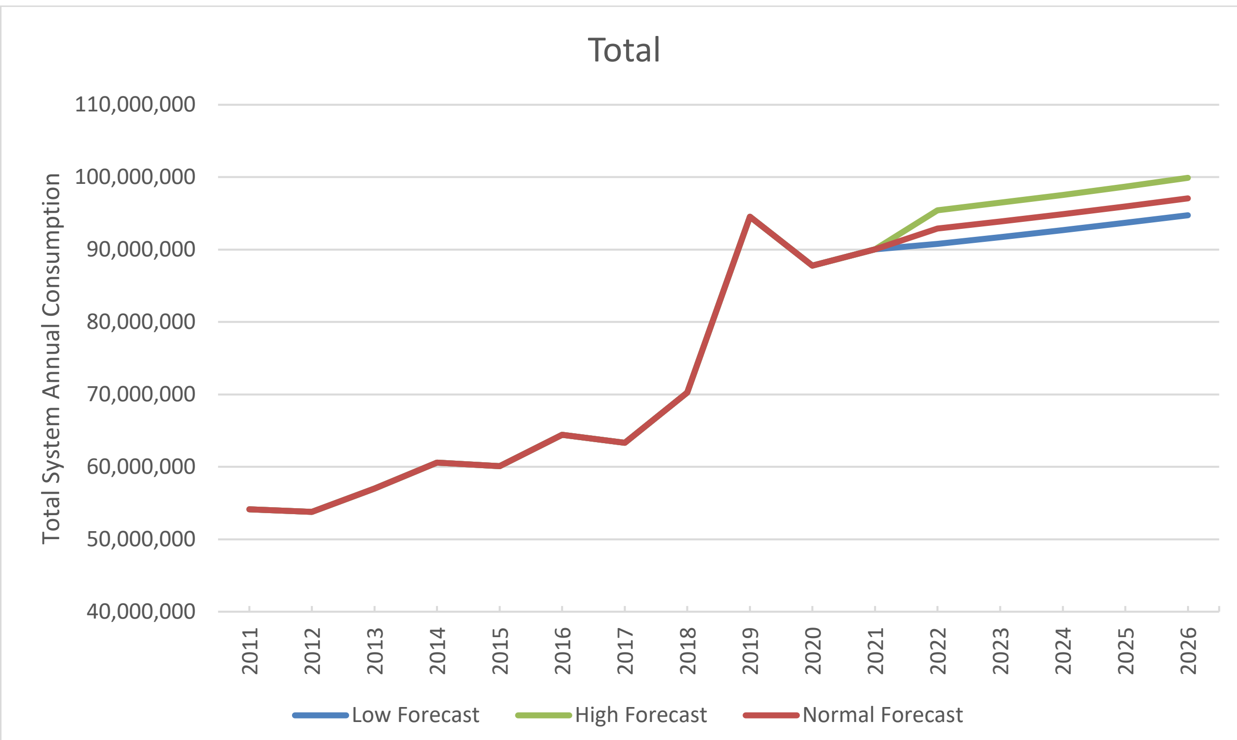

Figure 14 Weather Sensitivity – Total Consumption

Consumption forecasts for only largest weather-sensitive class, R1 Residential, are displayed in the following graph. Note the y-intercept is non-zero in each graph.

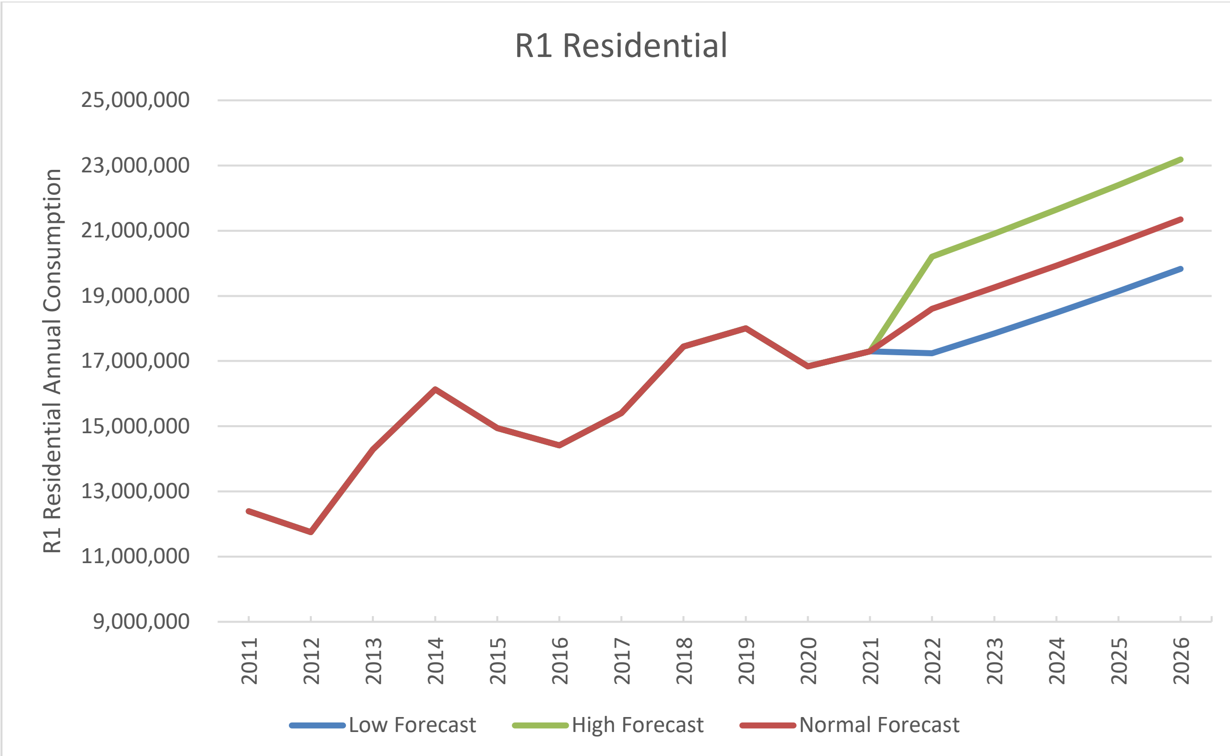

Figure 15 Weather Sensitivity – R1 Residential

16. Appendix F - ENGLP Aylmer Performance Metrics Scorecard

	Performance Categories	Intent of Measures	Measures	Sample	2020	2021
1. Cost Effectiveness	Policies & Procedures	Demonstrates consideration of alternate Enbridge rates	Annual rate review	C	C	C
	Price Effectiveness	Demonstrates local production a competitive option	Premium to system gas alternative	+/-%	Well gas: +80% Lake gas: -5%	Well gas: -5% Lake gas: -5%
	Performance Categories	Intent of Measures	Measures	Sample	2020	2021
2. Reliability & Security of Supply	Design Day	Demonstrates ENGPL ability to procure transportation assets required to meet design day demand	1. Acquired assets to meet design day	%	100%	100%
			2. Enbridge Overrun Charges	$	$0	$0
	Coordination	Demonstrates ENGPL ability to invest in capital distribution required to meet design day demand	Monthly meetings between gas supply & engineering operations	12/yr	4	12
	Communication	Ensure ongoing communications	Communication to ratepayers re material bill impacts	C	C	C
	Diversity	Demonstrate the diversity of the portfolio	1. % Firm local gas flow	%	95%	97%
			2. Local production as % of system gas	%	37.08%	37.01%
	Reliability	Demonstrate the reliability of the portfolio	1. Days failed to deliver to customers	#	0	0
			2.Days customer interrupted	#	0	0
	Performance Categories	Intent of Measures	Measures	Sample	2020	2021
3. Public Policy	Supporting Policy	Reports public policy in ENGLP supply plan	1.Community expansion	C	C	C
			2. FCC	C	C	C
			3. RNG	C	N/A	N/A
			4. DSM	C	N/A	N/A