EPCOR Natural Gas Limited Partnership

2023 Annual Gas Supply Plan Update

(2020-2024 Gas Supply Plan)

Aylmer

EB-2023-0111

Contents

1. Introduction

On October 25, 2018, the Ontario Energy Board ("Board") issued its Report of the Ontario Energy Board: Framework for the Assessment of Distributor Gas Supply Plans ("Framework") which set out a new requirement for all rate-regulated natural gas distributors in the Province of Ontario to file five year gas plans in January 2019. EPCOR Natural Gas Limited Partnership ("EPCOR" or "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 EPCOR's five-year Supply Plan, including the resulting cost consequences of the plan.

This document is the third Annual Update to the Supply Plan (the "Annual Update").

EPCOR 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, EPCOR has developed a demand forecast that reflects its expected annual load profile over the next five year rate period starting January 2023. The demand forecast was used as an input in determining the appropriate mix between supply obtained from the Enbridge 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.

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

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

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

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

Grant.

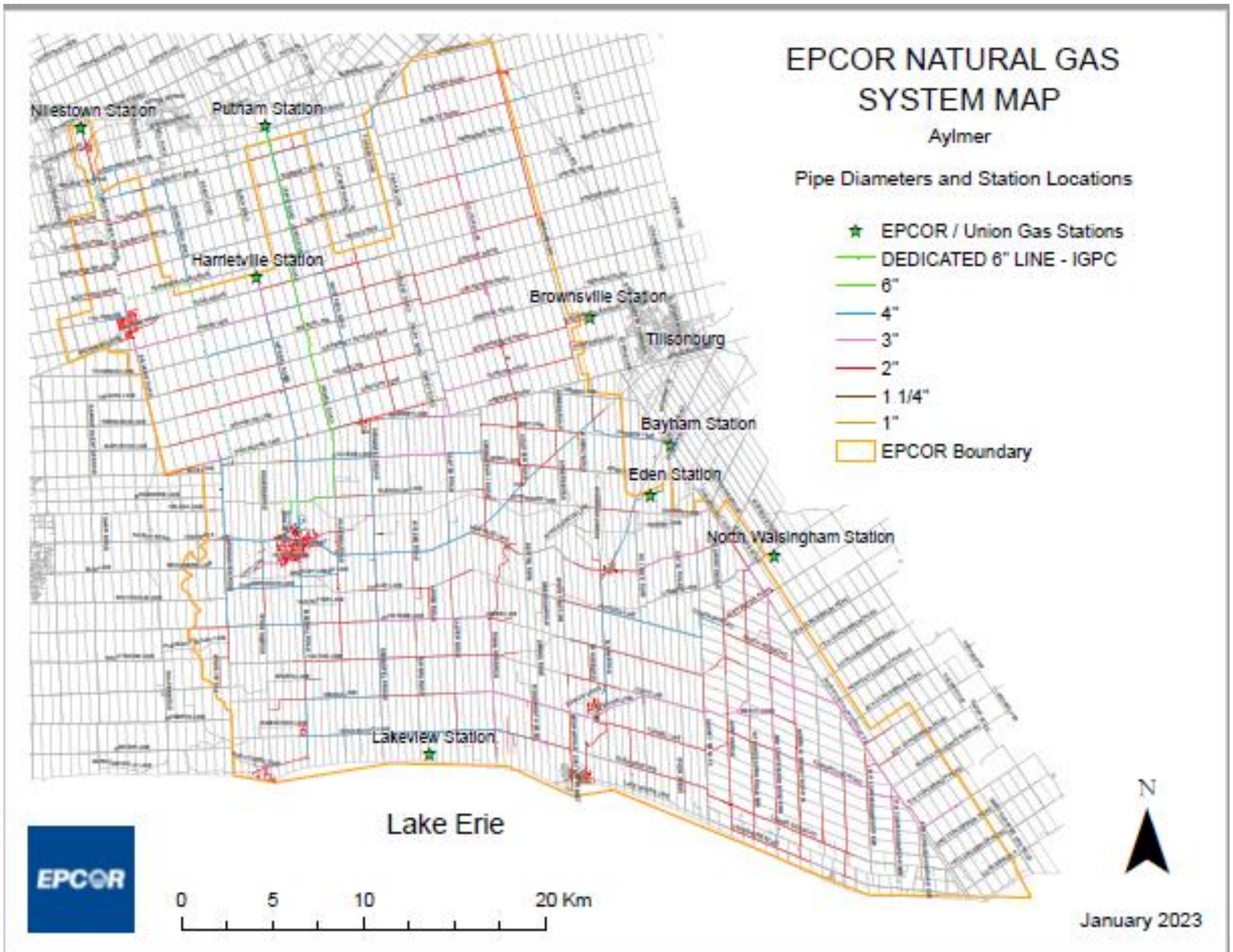
The Supply Plan is intended to provide strategic direction that will guide EPCOR's ongoing decisions related to its natural gas portfolio such that the utility is able to meet Peak Day, seasonal, and annual demand throughout the winter and summer periods for General Service Customers and Contract Customers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

EPCOR is presenting this 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, EPCOR 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, EPCOR 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.

1.1. Summary of Service Area

The map below provides a summary of EPCOR's service territory which is current as of January 2023. There are no major changes compared to the 2022 Annual Update.

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


EPCOR NATURAL GAS SYSTEM MAP
Aylmer
Pipe Diameters and Station Locations
EPCOR / Union Gas Stations
DEDICATED 6" LINE - IGPC
6"
4"
3"
2"
1 1/4"
1"
EPCOR Boundary
Nilestown Station
Putnam Station
Harrietsville Station
Brownsville Station
Tillsonburg
Bayham Station
Eden Station
North Walsingham Station
Lakeview Station
Lake Erie
EPCOR
0
5
10
20 Km
N
January 2023

1.2. Significant Changes

One significant change is introduced in this Annual Update.

Section	Significant changes
4. Supply Options	Introduction of a third local supply source (Production D) expected May 2023
Appendix F – ENGLP Aylmer Performance Metrics Scorecard	Added 3-year average view to scorecard

2. Demand Forecast

To develop a natural gas supply portfolio, EPCOR 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 14, 2023 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),
- **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), and
- **Seasonal Customers:** Rate 2.

2.1. General Service Customers

General Service customers (residential, commercial, and industrial) are forecasted to make up approximately 31.26% of EPCOR's demand profile in 2023.

Residential customers comprise the majority (64.45%) of the General Service demand profile. While the residential segment is expected to have the highest growth in terms of customer numbers (from 9,123 to 9,340), weather normalized demand is expected to remain relatively flat in 2023 compared to 2022.

Commercial customers make up approximately 20.76% of the General Service demand profile. In 2023, 585 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 14.79% of the General Service demand profile. There are 79 non-interruptible and 43 interruptible industrial customers in the EPCOR natural gas system forecasted for 2023.

2.2. Contract Customers

Contract customers are forecasted to make up approximately 67.73% of EPCOR's demand profile in 2023. There are currently 10 customers under this classification and no change in customer numbers are forecasted in 2023. 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% of EPCOR's demand profile by volume.

2.3. Seasonal Customers

Seasonal customer are forecasted to make up the remaining 1% of EPCOR's demand profile in 2023. There are 50 customers under this rate class and that consist mainly of tobacco framing and curing customers (non-interruptible).

The following tables provide EPCOR's Customer Connection Forecast and Annual Customer Service Demand Forecast by Rate Class. The forecasted 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

	2022 Actual	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
R1 Residential	9,132	9,340	9,547	9,755	9,962	10,170
R1 Industrial	77	79	81	83	86	88
R1 Commercial	567	585	604	624	644	665
R2 Seasonal	52	50	49	48	47	46
R3	5	5	6	6	6	7
R4	41	43	44	45	47	48
R5	4	4	4	4	4	4
R6	1	1	1	1	1	1
Total	9,878	10,107	10,336	10,566	10,797	11,029

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

	2022 Actual	2022 Normalized	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
R1 Residential	18,758,836	18,633,571	18,779,614	19,275,421	19,776,619	20,281,194	20,789,326
R1 Industrial	2,367,680	2,399,540	2,259,047	2,358,149	2,461,008	2,567,756	2,678,530
R1 Commercial	6,146,717	6,979,306	6,048,327	6,278,022	6,516,256	6,763,341	7,019,600
R2 Seasonal	838,908	838,908	933,892	911,088	888,840	867,136	845,962
R3	1,551,993	1,554,954	1,219,400	1,324,601	1,285,943	1,374,744	1,638,793
R4	1,601,181	1,601,181	2,051,464	2,132,436	2,196,351	2,262,182	2,329,986
R5	585,954	585,954	643,974	643,974	643,974	643,974	643,974
R6	62,040,423	62,040,423	61,267,873	61,267,873	61,267,873	61,267,873	61,267,873
Total	93,891,693	94,633,837	93,203,592	94,191,565	95,036,865	96,028,200	97,214,044

2.4. 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 not 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.

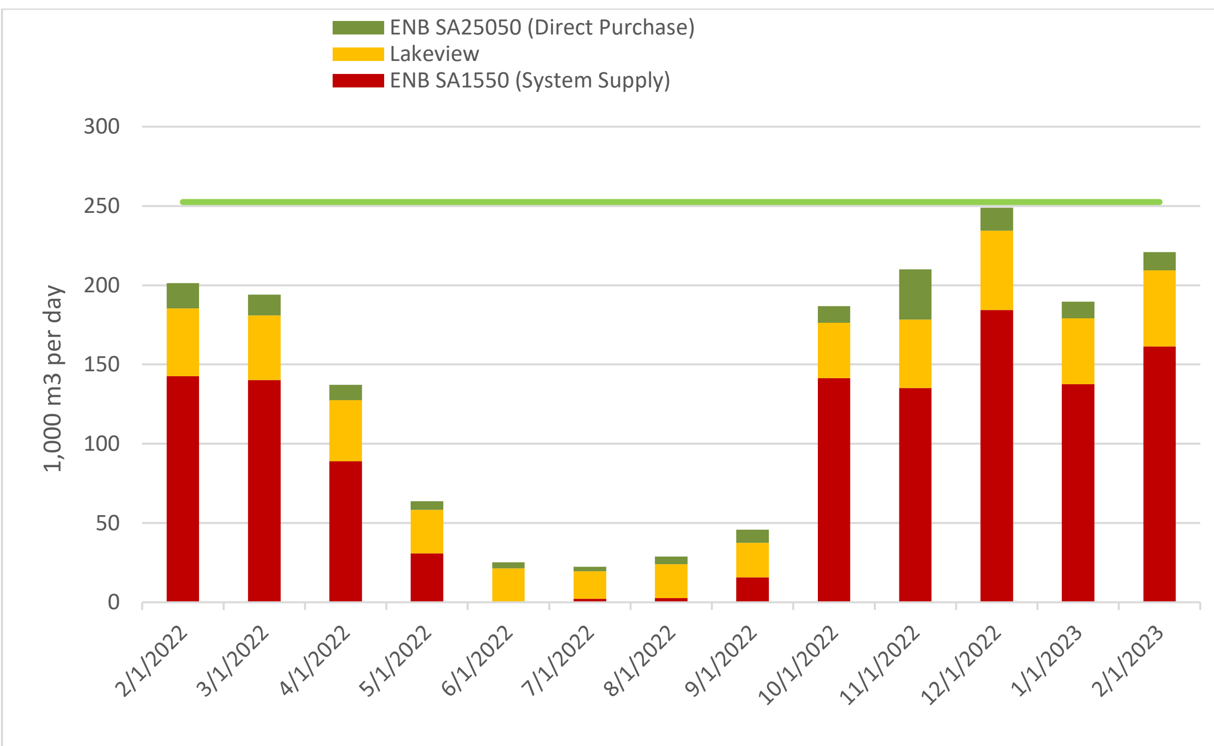
The customer connections count was forecasted by applying the geometric mean annual growth rate from 2011 to 2022 to the 2022 average customer count.

3. Supply Options

3.1. 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 2022 calendar year, including incremental local production. In this Annual Update, the peak day consumption are compared against compared the Contract Demand of Enbridge Gas System Supply Contract (ENB SA1550), Enbridge Gas Direct Purchase Contract (ENB SA25050), Lagasco Lakeview Contract.

Figure 3-1
Max Daily Demand each Month by Source vs Contract Demand,
Feb 2022 to Feb 2023



The 2022 Contract Demand were sufficient to meet peak day consumption of the three contracts.

No major changes were made compared to the 2022 Annual Update. However, the introduction of a third local supply source (Production D) that was expected October 2022 (discussed in Section 4.1.3) is now expected May 2023. Production D volumes now also reflect expected RNG production volumes from a new local RNG facility.

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

3.1.1.Peak Day/Hour

EPCOR 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 EPCOR 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 EPCOR 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 2022 actual peak demand and a forecast for 2023 to 2027.

Table 3-2
Actual & Forecast Demand Requirements

	ACTUAL / FORECAST	Actual and Forecast Peak Demand (Cornerstone)*	Actual and Forecast Contract Demand (Enbridge)		Lakeview Contract Demand	Total CD
			Sys Gas	Direct Purchase		
2017	ACTUAL	197,278	177,234			177,234
2018	ACTUAL	208,650	208,429			208,429
2019	ACTUAL	241,670	208,429	13,366	30,856	252,651
2020	ACTUAL	187,720	208,429	13,366	30,856	252,651
2021	ACTUAL	213,131	186,100	35,695	30,856	252,651
2022	ACTUAL	248,955	186,100	35,695	30,856	252,651
2023	FORECAST	253,934	186,100	35,695	32,139	253,934
2024	FORECAST	259,013	186,100	35,695	37,218	259,013
2025	FORECAST	264,193	186,100	35,695	42,398	264,193
2026	FORECAST	269,477	186,100	35,695	47,682	269,477
2027	FORECAST	274,866	186,100	35,695	53,071	274,866

*assume 2% growth YOY as per Cornerstone on Lakeview CD (Enbridge remains the same)

EPCOR will continue to monitor the system's consumption and growth pattern and increase Contract Demand from either Enbridge or Lakeview as needed.

3.1.2. Weather

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

3.1.3. Commodity

EPCOR receives the majority of its commodity under the bundled M9 rate which is based on Enbridge's OEB approved WACOG application. EPCOR 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 EPCOR's commodity requirements are sourced from local production. In the spring of 2023, EPCOR Aylmer is expecting another source of local supply to the distribution system through the introduction of renewable natural gas (Production D) injected into the system by a new local RNG facility. This volume was previously expected by the fall of 2022 but commissioning of the RNG facility has been delayed to Q2 2023 due to supply chain issues. The facility is expected to increase supply to the distribution system by approximately 3,000 m3 to 13,500 m3 per day, which will be offset by a decrease in volume from other supply sources. While the source of this supply is from a renewable natural gas facility, EPCOR is only purchasing the commodity and not the environmental attributes. Therefore, EPCOR 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. EPCOR finalized the supply contract with the RNG producer during the winter of 2022.

3.1.4. Transportation

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

EPCOR currently contracts for an annual Contract Demand in the amount of 216,956 m^3 for its System Gas customers.

EPCOR evaluates its Contract Demand requirements with Enbridge on an annual basis and will balance the need to maximize its usage and minimize over run charges under this contract. For the November 2022 renewal, Enbridge proposed no changes to the Contract Demand for SA1550 (for system gas customers) and SA25050 (for direct purchase customers). EPCOR plans to increase the Contract Demand with the Lakeview contract in 2023 to meet expected system gas peak day requirements.

3.1.5. Storage

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

3.1.6. Daily Balancing Management

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

3.1.7. Direct Purchase Program

EPCOR has Direct Purchase Customers in its system whereby these customers arrange for gas supply and/or upstream transmission services directly with Enbridge or EPCOR's distribution service to deliver gas to end-user locations. Currently, approximately 1% of EPCOR customers are on direct purchase compared to system sales and represent approximately 3.83% of EPCOR's demand profile by volume.

EPCOR relies on the Direct Marketer to deliver the volumes to Enbridge. In accordance with the Bundled T-Service Receipt Contract between EPCOR 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 EPCOR harmless with respect to the excess of any costs and expenses incurred by EPCOR in acquiring such Gas and transportation capacity.

3.1.8. Long-Term Contracts

There are no changes to existing long-term supply agreements that was discussed in the 2022 Annual Update (EB-2021-0146).

In December 2022, EPCOR finalized the local supply contract with a local RNG producer.

The RNG producer is expected to generate approximately 11% to 12% of total system demand by 2024.

3.1.9. 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
2027	64.8%	1.2%	22.8%	11.3%	100%
2026	63.3%	1.4%	23.6%	11.7%	100%
2025	62.0%	1.7%	24.3%	12.0%	100%
2024	60.7%	2.1%	24.9%	12.3%	100%
2023	64.8%	2.6%	25.5%	7.1%	100%

Supply Source Breakdown-Historical					
	Enbridge	Production A & B	Production C	Production D	Total
2022	70.3%	2.6%	27.1%	0%	100%
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%

4. Gas Supply Plan Recommendations

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

EPCOR is also developing the Southern Bruce natural gas franchise and as EPCOR 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. EPCOR 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 EPCOR.

5. Gas Supply Plan Execution & Risk Mitigation

5.1. Procurement Processes and Policies

Leading into each contract year (July for IGPC and November for Direct Purchase and System Gas customers), EPCOR will evaluate its current demand, its forecasted growth and direct purchase demand. This will help establish the annual Contract Demand with Enbridge under each of the M9 contracts (System Gas Customers, Direct Purchase Customers and IGPC). EPCOR 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.

EPCOR 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 EPCOR has to operate within the limits set by Enbridge. EPCOR 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 EPCOR 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.

EPCOR 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.

5.2. Evaluation of Procurement Process and Policies

EPCOR purchases the majority of its commodity from Enbridge. EPCOR 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.

As part of its Annual Distribution Capital Planning Process[3], EPCOR 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

[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.

local producers; and

- The amount of interruptible capacity contracted for under Rate 5 – Interruptible Peaking Contract.

5.3. 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.

5.3.1. Description

The risk identified is that the M9 Rate will not be offered by Enbridge in the future. EPCOR has reviewed Enbridge's proposed Rate E72 in their 2024 Rebasing application (EB-2022-0200), which is not expected to have material impact to the way EPCOR will manage Aylmer's gas supply under the new rate.

6. Public Policy Objectives

6.1. Renewable Natural Gas (RNG)

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

In Q2 of 2023, EPCOR is expecting to start receiving RNG into its distribution system. However, EPCOR is not purchasing the environmental attributes of this RNG gas. As such, EPCOR 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 EPCOR 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 EPCOR a learning opportunity on how to transact and procure RNG without significant cost impact to the rate base.

One of the key learnings to date is that RNG projects tend to have relatively steady production volumes throughout the year, which presents a challenge to system operations during the summer period when consumption is low, especially for systems like Aylmer where it is not possible for the RNG to physically leave the system. This limits the size and the number of RNG projects to be considered and implemented in the Aylmer system. EPCOR will provide further updates in future Gas Supply Plans and Annual updates once the RNG volume has been introduced into the Aylmer system.

6.2. Demand Side Management (DSM)

As per Broad Staff's recommendation in their Review of the 2022 Annual Update, EPCOR plans to submit a DSM proposal in its next cost of service filing for Aylmer (or in a separate standalone proceeding, where the plan, the financial impacts and ratemaking implications can be addressed. At this time there are no further updates to DSM related to EPCOR South Bruce and its implication to the Supply Plan.

6.3. Community Expansion

EPCOR has been actively working to bring secure, reliable and affordable natural gas to unserved communities. A number of customers have requested service and EPCOR has pro-actively responded to those requests and they are considered as part of the 2023 demand forecast. There are no updates for this Annual Update.

6.4. Minister of Energy Letter of Direction

On October 21, 2022, Todd Smith, Minister of Energy, provided a letter of direction of Richard Dicerni, Chair of the Ontario Energy Board. This letter highlighted the Minister's near-term priorities for the energy portfolio focusing on continuance of energy transition and the OEB modernization. These priorities include:

- Supporting the Electrification and Energy Transition Panel

- Regulatory Framework
- Distribution Sector Resiliency, Responsiveness and Cost Efficiency
- Electric Vehicles
- Strengthen the Performance Measurement Framework
- Red Tape Reduction

The letter also addressed other priorities including Conservation and Demand Management/Demand-Side Management (CDM/DSM). The letter stated: "*I am looking to the OEB to ensure Ontario natural gas ratepayer interests are protected and that Ontario takes every opportunity to generate deeper retrofits, more natural gas savings and greater emissions reductions".*

EPCOR will continue to support the Minister's priorities and monitor the impacts on the Supply Plan, including plans for DSM/retrofit rollout and collaboration as noted further in this section (Section **Error! Reference source not found.**). There are no direct impacts from the Minister's letter on this filing.

6.5. 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.

EPCOR continues to file annual applications for FCPP rates and recoverable costs, effective April 1, most recently EB-2022-0245. EPCOR will continue to monitor and assess the potential impact of the FCPP on future customer consumption and conversion decisions.

6.6. Integrated Resource Planning

This Annual Update does not include potential impacts of future IRP projects. As per the OEB Staff Report for the Review of the 2022 Annual Update, consideration of IRP alternatives to facility projects are not properly part of a Supply Plan review and EPCOR should not provide information with respect to options for IRP implementation in its Supply Plans. There are currently no plans to implement IRPs in Aylmer.

6.7. Canada Green Homes Grant

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

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

7. Current and Future Market Trends Analysis

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

8. Performance Metrics

EPCOR has drafted a performance metric scorecard in order to measure the effectiveness of the Supply Plan. Please see Appendix F for details. In the Staff Report to EB-2022-0141, OEB staff recommended that EPCOR provide details regarding its consideration of scorecard improvements (including potentially adding targets) at the time of its next five-year Supply Plan for the Aylmer service area. As such there are no changes considered in this Annual Update compared to the version in the 2022 Gas Supply Plan Annual Update. To align with the Southern Bruce 3-Year Supply Plan, EPCOR have included the 3-year average in the Scorecard starting with this Annual Update.

9. Continuous Improvement Strategies

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

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

EPCOR commenced 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 EPCOR believes that at this time, this opportunity is beyond the scope of this gas supply planning period.

10. Appendices

Appendix A – Market Trends Analysis April 2023 Update

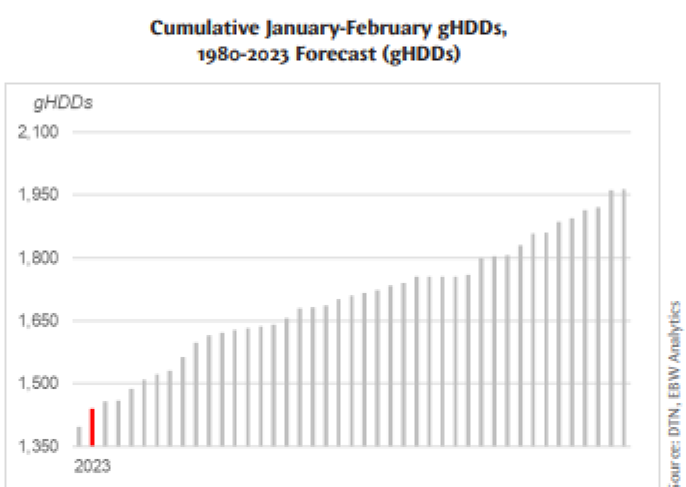
Current and Future Market Trends Analysis Provided by ECNG

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.

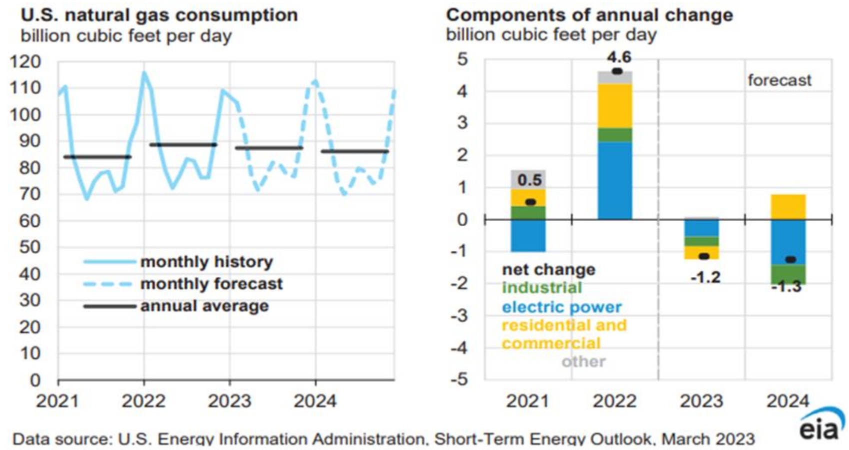
Continuing in this outlook is the war in Ukraine and global free-world unification regarding economic sanctions against the Russian economy and oligarchs. The phase out European imports of Russian oil, natural gas, coal, and steel initially resulted in a surge in prices of these and related commodities alternatively sourced around the globe. The prices of these and related commodities have stabilized and pulled back largely due to warm winter weather in both Europe and N.A. in early 2023.

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

US natural gas R&C sector consumption in 2022 continued to rebound from pandemic lows of 2020. The EIA forecasts a modest drop in R&C demand for 2023 largely influenced by the start of 2023 with January and February combined marking the second warmest since 1980 resulting in 7.9 Bcf/d below 10-year normal demand.

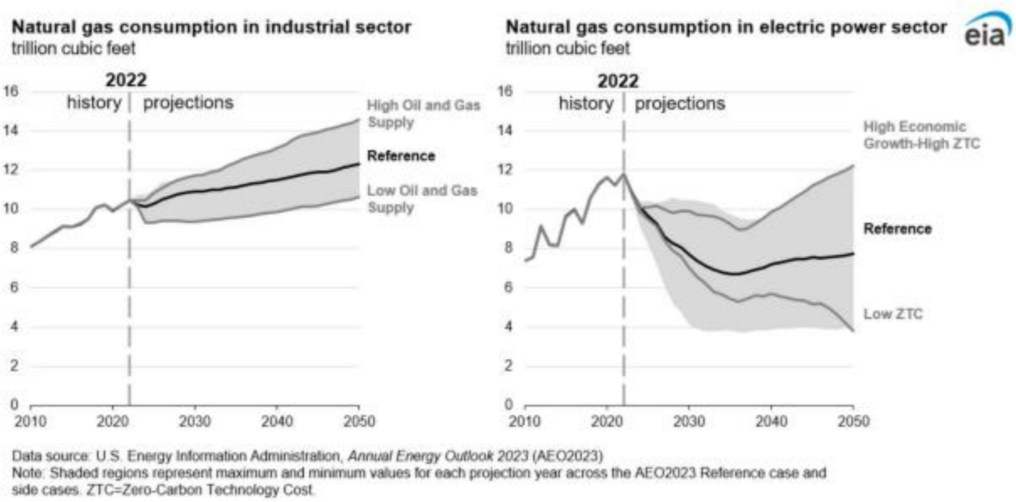


Industrial demand, however, appears to have grown by 1-2 Bcf/d from pandemic lows however have flattened in the forecast in EIA's most recent Short Term Energy Outlook 2023 - April 2023 (STEO 2023).

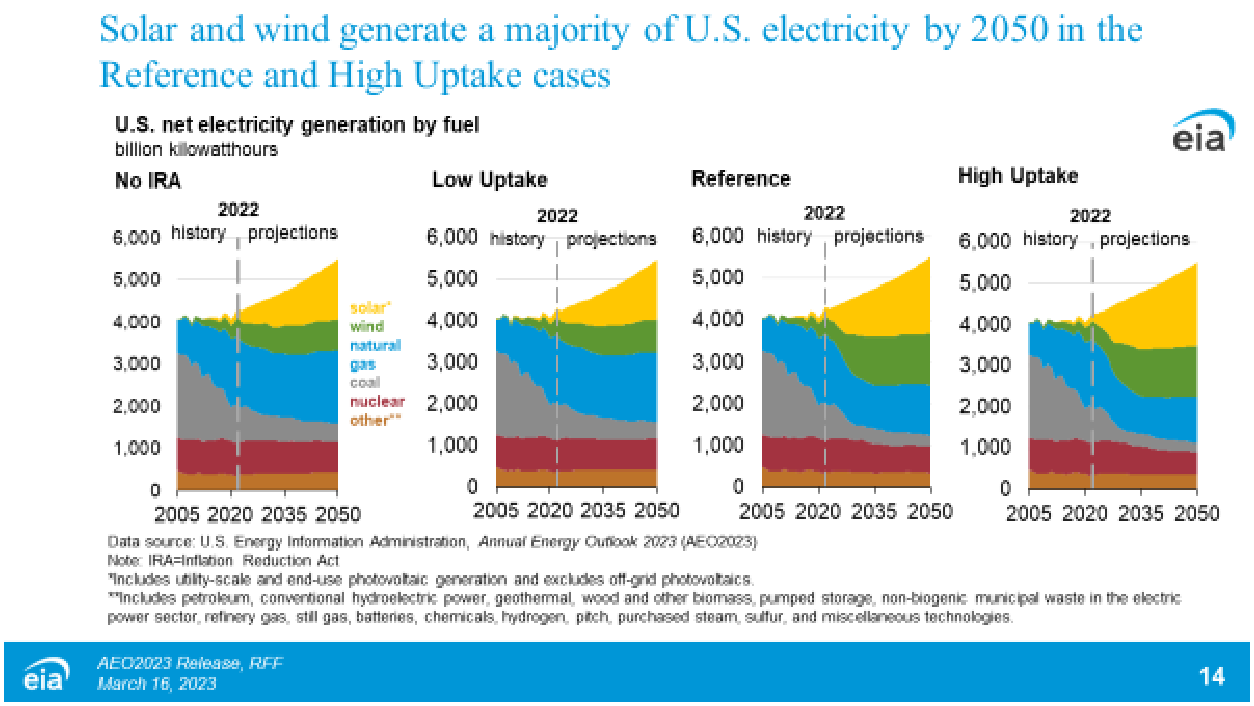


Mid-term and Long-term gas demand growth is largely expected by most forecasters in the United States (U.S.) in industrial and gas fired power generation demand sectors. At the time of this writing, near term N.A gas pricing is approximately $4 US/MMBtu higher than last year. Coal-fired power generation retirements 11 Gigawatts (GW) in 2023 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 dramatic drop in gas pricing making it cheaper than coal. Growth in gas-fired power generation is expected to be offset by the increase in solar capacity of 27 GW in 2023, up 38% from last year. Solar and wind generation of a combined 77 GW is expected to be installed from Dec 2022 to the end of 2024 as forecasted in STEO 2023. In the industrial sector significant divergence is shown in the High and Low Oil and Gas Supply cases in the EIA forecasts. It is difficult to surmise such a divergence in just a few years out from 2022 as industry consumption of natural gas is not so elastic as to be able to fuel switch other than the petroleum refinery sector. No recession type drivers are expected in this forecast. In our opinion, Industrial demand forecast variation is not as material as gas fired power generation and/or LNG feedgas for exports discussed later.

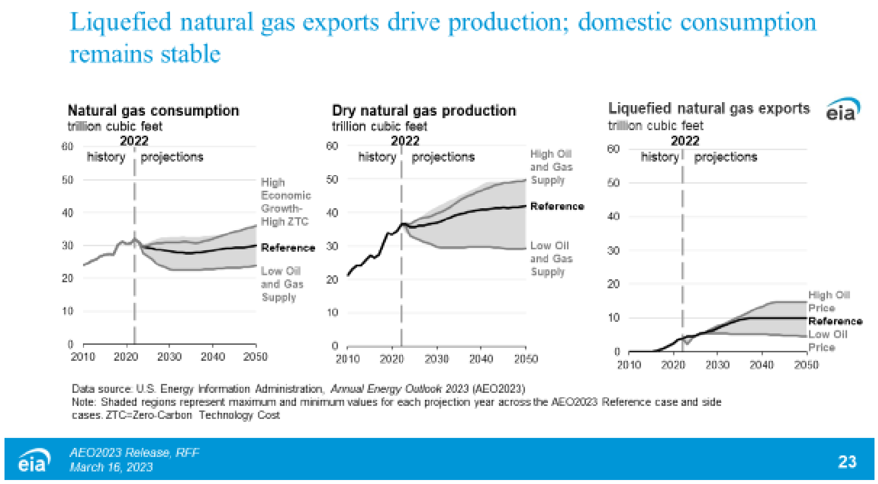
Figure 15.



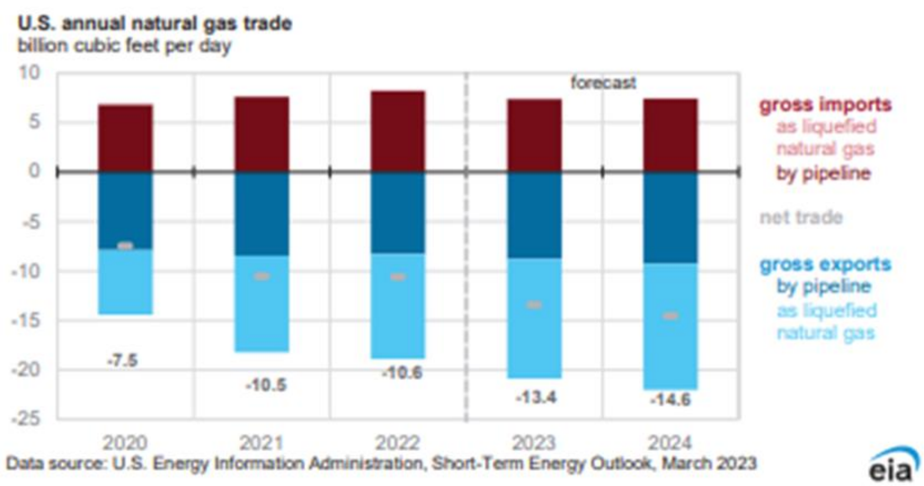
The EIA in its latest Annual Energy Outlook (AEO2023) cites in its Reference Case a modest drop of natural gas for power generation to the end of 2030 at the expense of renewables. In its High Uptake Case (high uptake of renewables driven by federal government funding Inflation Reduction Act) natural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



The single largest increase in demand is in exports of liquified natural gas (LNG) in the next 5 years. Each of the scenarios in the rightmost graphic below identifies that by 2025 approximately 7,500 Tcf/yr (20.5 Bcf/d on average) is expected based on regulatory approved projects. This is an increase of nearly 10 Bcf/d from 2022 average of 10.7 Bcf/d.



U.S. LNG exports including fuel gas for refrigeration are now operating near capacity between 14 and 15 Bcf/day in early in Q2 2023 (except for planned maintenance or unexpected outages). EIA estimates on average 13.4 Bcf/d will be exported in 2023 (not including fuel which is approximately 10%) which is realistic if high load factors can be maintained continue to be the most significant contributor to a tight supply-demand balance in N.A. Imports and exports to/from Canada and Mexico are not expected to grow or fall materially in the near-term time horizon as pipelines are operating at near capacity.



Expectations for exports to Mexico during this outlook's horizon (5 years out or more) could see average exports to Mexico well exceed 7 Bcf/d from the current flows of 5-6 Bcf/d. This increased demand is mostly for LNG liquefaction for Pacific side exports which shorten LNG routes to Asia and lower transport costs by approximately $2 US/MMBtu. Costa Azul is likely the first Mexican LNG export project supplied via with TC Energy receiving FERC approval of its North Baja Xpress Project in Arizona accessing the Permian supply basin. 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 US exports to Mexico post 2025.

There are also LNG export projects to the Canadian Pacific Coast for Western Canadian Sedimentary Basin (WCSB) supply that continue to be delayed and with much higher costs. LNG Canada's 0.9 Bcf/d project is now expected to flow in 2026 (delayed from 2024) and Cedar LNG's 0.4 Bcf/d project is now expected to flow in 2028-29 (delayed from 2027). Only Woodfibre 0.3 Bcf/d, expected to flow in 2027 has not changed its start date. The Ksi Lisims LNG project, 2 Bcf/d has emerged on West Coast targeting flow by 2028-2029 as is LNG Canada's 1.8 Bcf/d Train 2. As a result, we believe current forward pricing for calendar years 2025-2028 at AECO now over $4.00 CAD/GJ are also likely to persist. Other demand growth sectors have been mostly in AB in coal fired generation retirements and in oil sands cogeneration of steam and power. Very little oil sands production growth is forecasted, and the coal fired generation retirements will be complete at the end of 2023 with only 0.3 Bcf/d increase in average gas consumption expected as a result.

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

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

U.S. dry gas production (supply) growth has been impressive since Q4 2022 and so far in Q1 2023 driven by high prices in 2022 and eventual reinvestment by producers. US producer sentiment continues to show supply growth driven by disciplined sustainable expansion balancing producer financial health (paying down debt) and shareholder value (dividends). The issues of early to mid-2022 labour shortages, higher labour and raw material costs and a global shortage of drilling rigs seems to have subsided. The free world has been fortuitous with warm winter weather in Europe and the US coincident with lower energy demand from China (due to COVID resurgence) increasing inventories and dropping fuel prices. Although production to date in 2023 appears to be nearly 2.5 Bcf/d higher YoY the question is whether it is sustainable at current and near term forward natural gas prices of approximately $3.00 US/MMBtu. The EIA is forecasting for 2023 101 Bcf/d an increase of 3% over 2022. At this point in time that forecast appears realistic.

UNITED STATES Supply & Demand	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023 YTD	Y / Y
Dry Production	57.3	61.8	64.7	65.4	70.0	73.2	71.8	74.1	83.6	92.2	90.6	93.6	97.6	100.4	2.9%
Canadian Imports	6.5	5.6	5.1	5.0	5.1	5.3	5.7	5.4	5.3	4.6	4.3	5.0	5.6	5.1	
LNG Imports	1.1	0.7	0.5	0.3	0.1	0.2	0.3	0.2	0.2	0.2	0.1	0.1	0.2	0.2	
Total Supply	**64.9**	**68.1**	**70.3**	**70.7**	**75.2**	**78.7**	**77.8**	**79.7**	**89.1**	**97.0**	**95.0**	**98.7**	**103.4**	**105.7**	
Power Burn	20.2	20.8	24.6	22.6	22.7	26.4	27.1	25.5	28.9	30.9	31.7	31.0	33.3	30.1	-9.6%
Industrial	18.9	19.2	19.7	20.3	20.9	20.6	21.2	21.8	22.8	23.0	22.4	22.8	23.1	24.3	
Res/Comm	22.7	22.3	20.3	23.8	24.7	22.8	21.5	21.4	23.2	23.5	21.5	21.9	23.0	35.2	
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	5.8	5.6	
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	11.8	12.9	9.3%
Pipe Loss	4.7	4.8	5.1	5.6	5.4	5.5	5.4	5.6	6.2	7.0	6.9	7.4	7.8	8.0	
Total Demand	**67.3**	**68.5**	**71.5**	**74.2**	**75.7**	**78.1**	**79.5**	**80.8**	**89.2**	**95.2**	**95.1**	**99.9**	**104.8**	**116.1**	

Updated April 1, 2023 All figures in BCF per day

Strong Growth

Flat Growth

Source: Platts; Recalibrated by Platts March 27, 2023

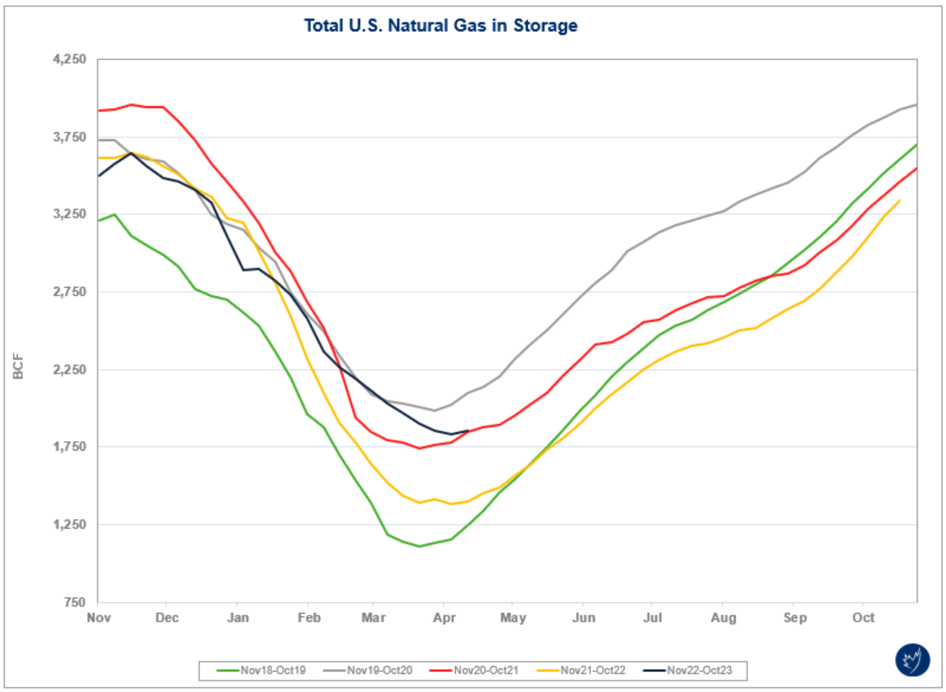
Note: 2023 is only Year to date so some numbers are not relevent.

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) expansion nearing full completion. The NGTL facilities expansion continues in 2023 supporting drilling activity in Alberta resulting in growth of supply exceeding 18.5 Bcf/d consistently in April 2022. British Columbia production has also grown as well despite new BC licenses being issued as of A new resolution framework for resource development was announced January 26, 2023 between the BC provincial government and the Blueberry River First Nation enabling new licenses to be issued. Subsequently in the days following, four other Treaty 8 Nations signed similar agreements. We are optimistic that a growth in BC supply will resume in the prolific Montney formation in 2023.

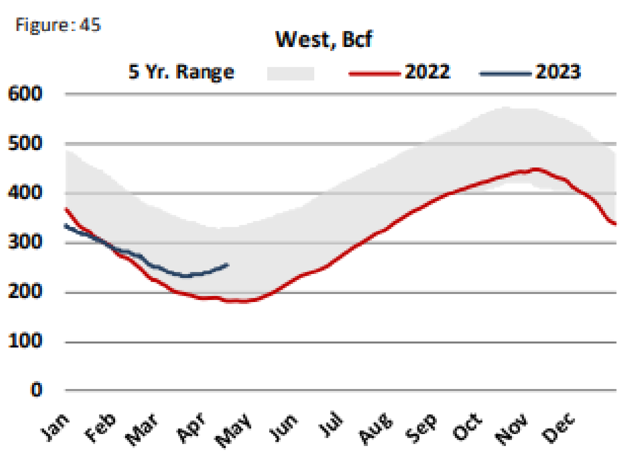
The supply response in the WCSB will be quicker on a percentage basis compared to the U.S. however additional supply will be suppressed by limited pipeline capacity to the US and Eastern Canada to impact the NYMEX / US market. These constraints along with healthy storage levels and only modestly growing BC and AB demand are driving the bearish sentiment in the short run. Mid and Long-term the sentiment moves towards bullish as LNG Canada begins circa 2026.

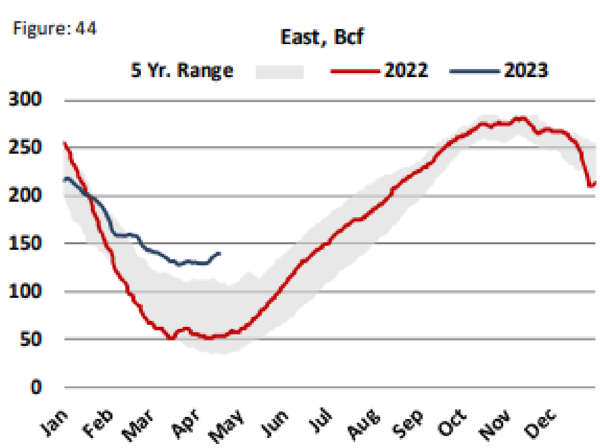
Storage: Impact on pricing – Near term Very Bearish (NYMEX and Dawn), Bearish (AECO); Mid and Longer-term No Impact on price

Total U.S. working inventories on March 31, 2023 ended well above the five-year average of 1.53 Tcf by approximately 300 Bcf (surplus). Most industry forecasters see the end of the 2023 injection season ending in a surplus to the five-year average but only between 1-200 Bcf, mostly due to increased LNG exports and waning supply growth (due to surprisingly low gas prices). The likely outcome is that storage filling about 100-150 Bcf more than last year or about 1 Bcf/d more supply available in the upcoming winter. Unless supply levels continue to grow to meet rebounding LNG exports and growing gas fired power generation this may lead to an inventory level at the end of the upcoming winter season significantly less than the 5-year average. US storage graph using EIA weekly data up to April 7, 2023.



In Canada, storage at winter's end in Alberta (essentially the "West" graph below) has dramatically recovered and is now near the 5-year average, whereas storage at Dawn (essentially the "East" graph below) is above the 5-year high.



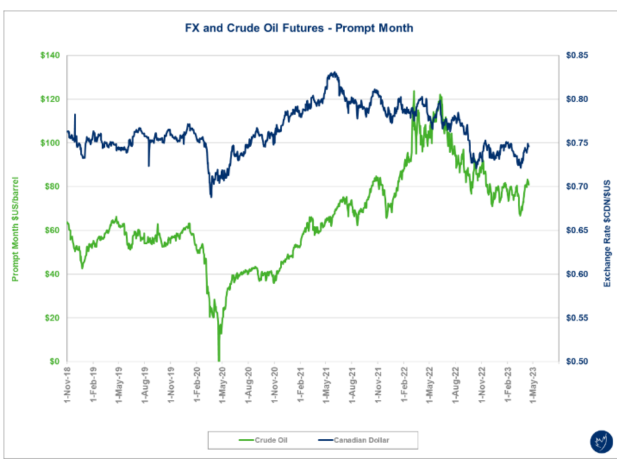


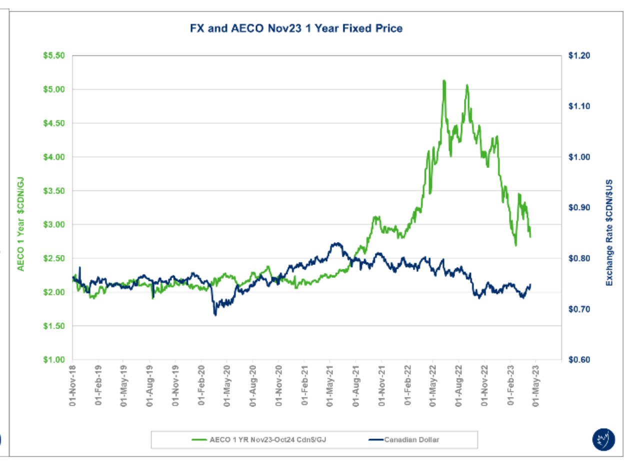
Storage graphs from RBN Energy LLC 2021 on April 18, 2023.

All these current storage balances lead to a more bearish sentiment on summer gas pricing in 2023 with less storage fill demand (US, Eastern and Western Canadian).

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

West Texas Intermediate oil pricing in early 2023 has remained range bound between $70 - $85 USD/b after reaching $120/b shortly after the war in Ukraine began a year ago. It fell back below $100/b as world demand faded (mostly China due to COVID relapse) and with OPEC actions to right size supply and the end of US Strategic Petroleum Reserve release ending in late 2022 the market seems to have settled for the time being. It continues to be 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 ongoing war has increased the world's pace to bring on more renewable energy sources and to continue to use of fossil fuels, mostly coal and oil to bridge the timing gap. The EIA forecasts the expectation of the US remaining a net exporter of petroleum products in the distant future (2050). Supply of oil especially from the Permian basin (Texas and Oklahoma) and the Baaken basin (N. Dakota) results in associated natural gas supply which is predominantly the reason for our continuing bearish sentiment in this category. A persistent oil price above $70/b (helped by President Biden's promise to buyback oil at this price) keeps US producers investing in E&P. Historically strong world oil prices have helped the Canadian buyer with a stronger dollar (offsetting the higher price of NYMEX priced gas (which mostly drives Dawn pricing). However, since mid-2022, the correlation appears to have brought the Canadian dollar down as WTI has fallen. The next two graphs show WTI pricing with the U.S./Canadian foreign exchange (FX) and FX with the price of gas in the WCSB (AECO). It appears the Canadian dollar value has not contributed the AECO price run up or fall since mid-2021 to the present.

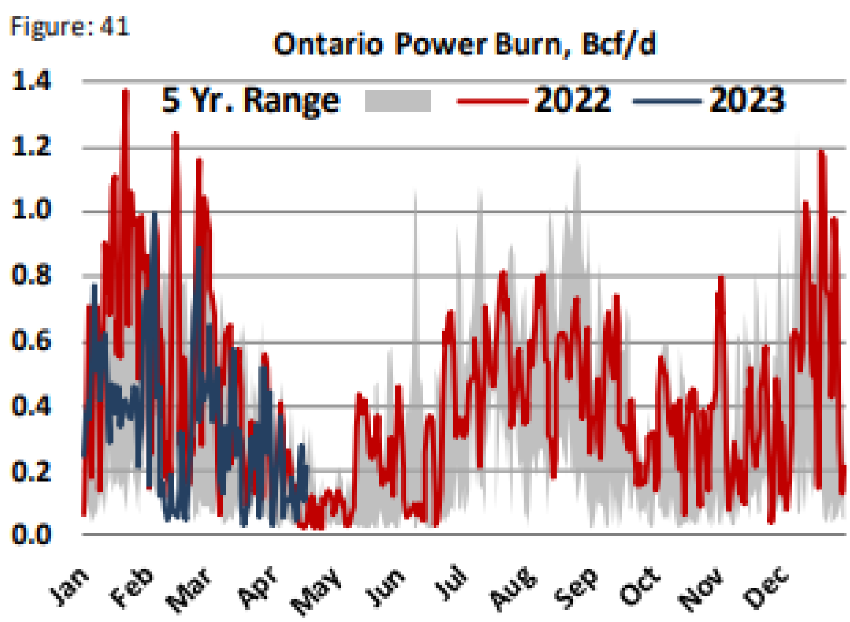




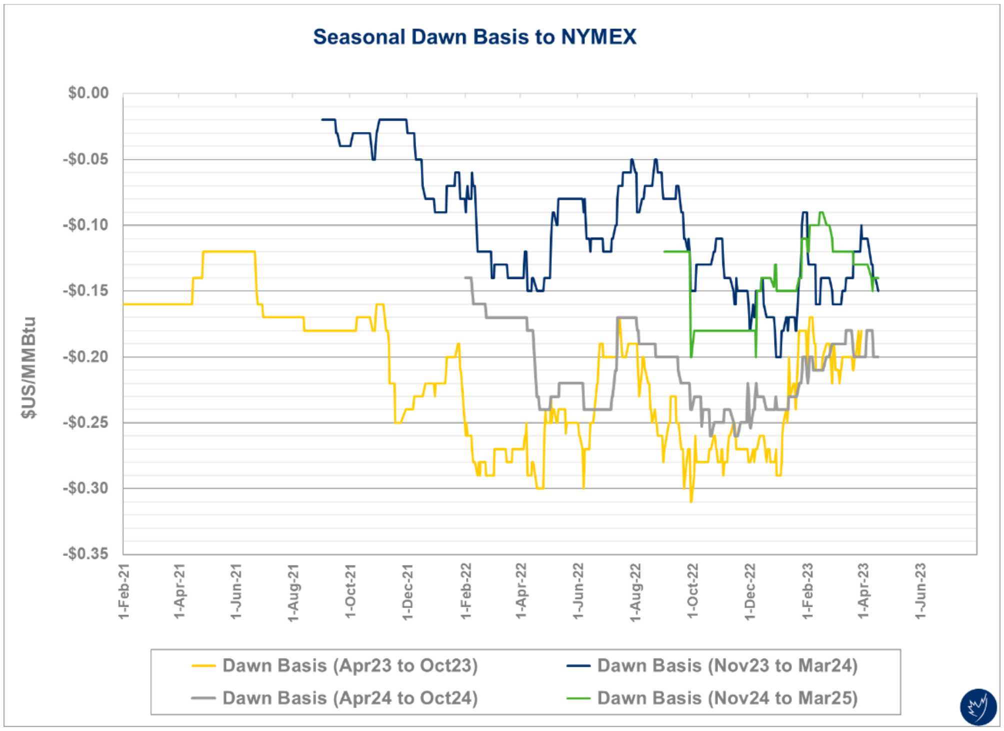
Dawn Market Hub Discussion

Natural gas primarily flows into the Dawn Hub ("Dawn") from the WCSB and from the U.S. Marcellus and Utica shale plays in the Appalachian region as well as from the Chicago Citygate (a market Hub with excess supply from WCSB, Baaken oil/gas shale formation, Rockies, Mid-Con and the Gulf of Mexico supply regions). There are no new pipeline 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 alter the flow dynamics into and out of Dawn which will influence the price of gas there. Despite these potential undercurrents, the Gas Supply Plan is expected to be able to deliver on the guiding principles of cost-effectiveness, reliability, and security of supply.

Nearer term Dawn basis forward pricing curves are showing trends that are at a larger discount to NYMEX of late likely due to the excess storage gas remaining from the winter at Dawn and at sites neighboring Midwest US (mostly Michigan). The mild weather in early 2023 also resulted in lower demand from Ontario gas fired power generation fleet however, we expect similar-to-higher demand as was seen last summer to back up continuing nuclear refurbishments in Ontario plus supporting modest increased power demand year-over-year. The forward price curves at Dawn continue to trade at a lesser discount to NYMEX in winters and summers starting November 2026 likely due to modest demand growth and/or risk of long-term pipeline contracts not being fully renewed.



Ontario Power Burn from RBN Energy LLC 2021 on April 18, 2023.



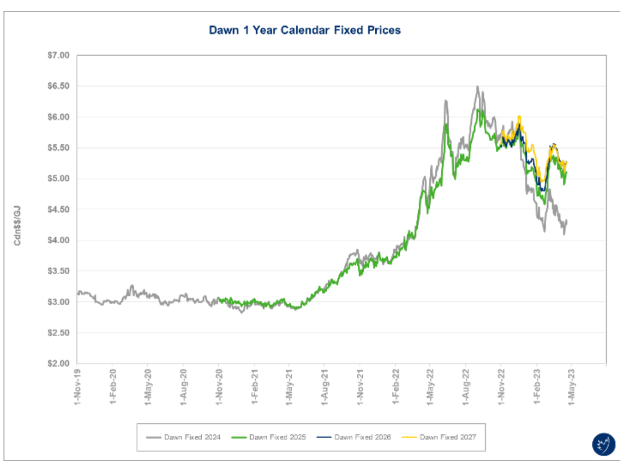
The current Dawn basis market looks like good value however based on EPCOR's lack of interest in purchasing forward basis, which is in USD, there is no purchase opportunity (based on this index). However, there continues to be upside price risk in the Dawn market from modest demand growth, no new supply,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

Summary table of market sentiments below.

	NYMEX and Dawn		AECO	
Market Driver	Near-term	Mid to Long-term	Near-term	Mid to Long-term
Demand	Mildly Bullish	Bullish	Bearish	Bullish
Supply	Bullish	Very Bullish	Bearish	Mildly Bearish
Storage	Very Bearish	n/a	Bearish	n/a
Crude Oil	Mildly Bearish	Mildly Bearish	Neutral	Neutral
Overall	Mildly Bullish	Bullish	Bearish	Mildly Bullish

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

In the next 1-2 years modestly growing LNG exports, increased gas fired power generation demand, offset by high inventories at winter's end, with difficult to sustain year-over-year increases in supplies (at such low prices) make for a continued tightly supplied market moving forward. As a result, NYMEX and Dawn price outlooks in the short term are likely to move upward until supply growth is proven and sustained. The forward Dawn price for 2023 has upward volatility risk to the current forward prices shown in the graph below. AECO pricing could stay suppressed as storage fills and abundant supply continues to outpace new pipeline facility additions despite higher demands year-over-year from local power generation. Expected exports to the US will be modest as regional storage surpluses weigh on local Midwest US pricing. Current forward pricing history is found below.



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

In the U.S. the expectation of continued growth in LNG exports, modest economic growth, continued fuel of choice in power generation and slow to arrive supply growth (including supply from oil production) we expect pricing to move upward. The current forward landed cost of gas at Dawn exceeds $5.00 CAD/GJ for the calendar years 2025-2028. This is good value as the cost of raw materials, labour and global energy prices are likely to persist and support this price in the mid-term. Also supporting this view and not mentioned previously is the potential for existing pipeline capacity in NA to be closer to capacity in moving supply basin gas to all markets. Greenfield pipelines are exceedingly difficult to build due to environmental opposition and the likelihood that 30-to-40-year amortizations will not be accepted by regulators going forward. Capacity expansions may be limited to new capital for compression only and safety related “lift and replace” pipeline segments with larger diameter capacities increasing costs and longer in-service dates. Storage expansions may be necessary as well to meet the intermittent needs of natural gas fired power generation as it supports increasing grid support to renewables as well as supporting peak winter heating demands. US natural gas production can respond in the years ahead but there may be significant lags in pipeline capacity access. 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. Supply access necessary to fill LNG Canada’s start is capable, however, coordination timing could lead to intermittent daily and monthly discounts and/or premiums for several months until steady state is achieved. There is lesser of a concern of WCSB supply meeting LNG Canada’s needs relative to the risk of US LNG expansion growth being met by timely supply.

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.

Appendix C – DETAILED SUPPLY/ DEMAND FORECAST

SUPPLY FORECAST ANALYSIS

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

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2027	38,170	37,661	37,159	36,663	36,174	35,692	35,216	34,747	34,283	33,826	33,375	32,930	425,896
2026	44,841	44,243	43,653	43,071	42,497	41,930	41,371	40,819	40,275	39,738	39,208	38,685	500,331
2025	52,678	51,975	51,282	50,599	49,924	49,258	48,602	47,954	47,314	46,683	46,061	45,447	587,776
2024	61,884	61,059	60,245	59,442	58,649	57,867	57,096	56,335	55,583	54,842	54,111	53,390	690,505
2023	80,380	71,731	70,775	69,831	68,900	67,981	67,075	66,180	65,298	64,427	63,568	62,721	818,867
												Decline Rate	16%

Enbridge (Supply)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2027	4,036,470	3,546,031	3,191,952	1,835,399	776,831	177,353	283,197	369,120	179,416	1,774,281	3,785,044	3,324,008	23,279,105
2026	3,834,298	3,373,278	3,022,006	1,693,808	703,090	126,804	235,659	324,478	130,599	1,699,206	3,645,708	3,229,892	22,018,826
2025	3,701,109	3,262,587	2,909,208	1,592,310	652,329	89,682	199,108	290,853	96,583	1,598,262	3,465,640	3,082,373	20,940,045
2024	3,569,215	3,152,478	2,797,490	1,492,200	601,515	52,310	162,319	257,058	62,505	1,524,787	3,331,528	2,988,614	19,992,017
2023	3,822,541	3,415,702	3,075,410	1,777,466	690,243	6,595	119,592	217,417	20,863	1,451,905	3,199,880	2,895,079	20,692,692

Production D-(RNG Supply)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2027	417,871	390,911	417,871	404,391	296,007	209,523	216,507	216,507	288,682	369,533	404,391	417,871	4,050,065
2026	417,871	390,911	417,871	404,391	296,007	209,523	216,507	216,507	288,682	369,533	404,391	417,871	4,050,065
2025	417,871	390,911	417,871	404,391	296,007	209,523	216,507	216,507	288,682	369,533	404,391	417,871	4,050,065
2024	417,871	390,911	417,871	404,391	296,007	209,523	216,507	216,507	288,682	369,533	404,391	417,871	4,050,065
2023					143,988	209,523	216,507	216,507	288,682	369,533	404,391	417,871	2,267,002

Production C-(Lakeside Production owned by Lagasco)

	January	February	March	April	May	June	July	August	September	October	November	December	Total
	31	28	31	30	31	30	31	31	30	31	30	31	
2027	956,784	864,192	677,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,191,104
2026	956,784	864,192	677,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,191,104
2025	956,784	864,192	677,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,191,104
2024	956,784	864,192	677,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,191,104
2023	937,519	849,510	677,784	655,920	478,392	462,960	299,832	299,832	655,920	956,784	925,920	956,784	8,157,157

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
2027	5,449,295	4,838,795	4,324,766	2,932,374	1,587,405	885,528	834,752	920,206	1,158,302	3,134,424	5,148,731	4,731,593	35,946,170
2026	5,253,793	4,672,624	4,161,314	2,797,190	1,519,987	841,217	793,369	881,636	1,115,477	3,065,261	5,015,228	4,643,232	34,760,327
2025	5,128,442	4,569,666	4,056,145	2,703,220	1,476,652	811,423	764,049	855,146	1,088,500	2,971,263	4,842,012	4,502,475	33,768,991
2024	5,005,754	4,468,641	3,953,390	2,611,953	1,434,563	782,660	735,753	829,731	1,062,691	2,905,946	4,715,951	4,416,658	32,923,692
2023	4,840,441	4,336,943	3,823,969	2,503,217	1,381,522	747,059	703,005	799,936	1,030,764	2,842,649	4,593,759	4,332,454	31,935,718

DEMAND FORECAST ANALYSIS

Total Demand

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2027	5,449,295	4,838,795	4,324,766	2,932,374	1,587,405	885,528	834,752	920,206	1,158,302	3,134,424	5,148,731	4,731,593	35,946,170
2026	5,253,793	4,672,624	4,161,314	2,797,190	1,519,987	841,217	793,369	881,636	1,115,477	3,065,261	5,015,228	4,643,232	34,760,327
2025	5,128,442	4,569,666	4,056,145	2,703,220	1,476,652	811,423	764,049	855,146	1,088,500	2,971,263	4,842,012	4,502,475	33,768,991
2024	5,005,754	4,468,641	3,953,390	2,611,953	1,434,563	782,660	735,753	829,731	1,062,691	2,905,946	4,715,951	4,416,658	32,923,692
2023	4,840,441	4,336,943	3,823,969	2,503,217	1,381,522	747,059	703,005	799,936	1,030,764	2,842,649	4,593,759	4,332,454	31,935,718

* for forecasting purposes e.g. 2023 onward, Enbridge gas supply is a formula based on total demand less Production A, B, C, and D

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 EPCOR is obligated to deliver in any one day to a customer under all services or, if the context so requires, a particular service at the consumption point.
Contract Demand ("CD"):	Means the maximum volume or quantity of Gas that Union is obligated to deliver in any one Day to EPCOR under all Services or, if the context so requires, a particular Service at the Consumption Point
Contract Year:	Means a period of twelve consecutive Months beginning on the Day of First Delivery and each anniversary date thereafter unless mutually agreed otherwise.
Dawn:	Located southeast of Sarnia, Ontario, Dawn is referred to as a Hub as it represents the point where Enbridge supply, storage and transmission systems meet. A number of other pipeline systems (e.g. TCPL, Vector) are interconnected to Enbridge Gas' distribution system at Dawn.

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 EPCOR 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 EPCOR until September 30, 2020.
Production C	Local gas production wells located offshore in Lake Erie. EPCOR 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 EPCOR 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.

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Appendix E – Elenchus Weather Normalized Distribution System Throughput Forecast: 2023-2027

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Weather Normalized Distribution System Throughput Forecast: 2023-2027

Report prepared by Elenchus Research Associates Inc.

Prepared for:
EPCOR Natural Gas LP

17 April 2023

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1 INTRODUCTION

This report outlines the results of, and methodology used to derive, the 2023 to 2027 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, the 2021-25 load forecast update dated April 23, 2021, and the 2022-2026 load forecast dated April 23, 2022. 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 by the OEB 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. 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

	2020 Actual	2021 Actual	2022 Actual	2022 Normaliz	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
R1 Residential	16,837,081	17,299,257	18,758,836	18,633,571	18,779,614	19,275,421	19,776,619	20,281,194	20,789,326
R1 Industrial	2,067,358	2,226,121	2,367,680	2,399,540	2,259,047	2,358,149	2,461,008	2,567,756	2,678,530
R1 Commercial	5,028,438	5,306,940	6,146,717	6,979,306	6,048,327	6,278,022	6,516,256	6,763,341	7,019,600
R2 Seasonal	784,724	829,096	838,908	838,908	933,892	911,088	888,840	867,136	845,962
R3	1,361,184	1,372,372	1,551,993	1,554,954	1,219,400	1,324,601	1,285,943	1,374,744	1,638,793
R4	1,534,283	1,793,580	1,601,181	1,601,181	2,051,464	2,132,436	2,196,351	2,262,182	2,329,986
R5	554,438	791,530	585,954	585,954	643,974	643,974	643,974	643,974	643,974
R6	59,599,950	60,410,748	62,040,423	62,040,423	61,267,873	61,267,873	61,267,873	61,267,873	61,267,873
Total	**87,767,455**	**90,029,645**	**93,891,693**	**94,633,837**	**93,203,592**	**94,191,565**	**95,036,865**	**96,028,200**	**97,214,044**

Table 1 Consumption Forecast by class

The following table summarizes the historic and forecast customer/connections for 2020-2027:

Customers

	2020 Actual	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
R1 Residential	8,805	8,983	9,132	9,340	9,547	9,755	9,962	10,170
R1 Industrial	75	75	77	79	81	83	86	88
R1 Commercial	535	552	567	585	604	624	644	665
R2 Seasonal	48	50	52	50	49	48	47	46
R3	6	6	5	5	6	6	6	7
R4	40	41	41	43	44	45	47	48
R5	4	4	4	4	4	4	4	4
R6	1	1	1	1	1	1	1	1
Total	**9,514**	**9,712**	**9,878**	**10,107**	**10,336**	**10,566**	**10,797**	**11,029**

Table 2 Customer Forecast for 2020-2027

Forecasts of 2023 consumption by tier, for the classes billed based on volume tiers, is provided below.

2023 Tier Forecast

	Period	Tier 1	Tier 2	Tier 3	Total
R1 Residential		18,654,216	125,397		18,779,614
R1 Industrial		531,867	1,727,180		2,259,047
R1 Commercial		2,828,560	3,219,767		6,048,327
Seasonal	Apr-Oct	62,180	519,381	99,223	680,784
Seasonal	Nov-Mar	48,255	192,153	12,701	253,108
R4	Jan-Mar	32,143	6,507		38,651
R4	Apr-Dec	168,370	1,844,443		2,012,813

Table 3 2023 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.

To forecast 2023-2027 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 2023-2027 are forecast by applying a geometric mean annual growth rate to the 2022 average customer count for the R1 Industrial, R1 Commercial, R2 Seasonal and R4 rate classes. The R1 Residential forecast is based on 207.5 new attachments each year. The customer counts for rate classes R3, R5, and R6 are unchanged through the 2023-2027 period except for known new customers in these rate classes. 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 156 observations from 2010:01 to 2022:12. 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 31.24m^3 in 2010 to 40.1m^3 in 2022 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 1: Prais-Winsten, using observations 2010:01-2022:12 (T = 156)				
Dependent variable: ExLNResAverageTrend				
rho = 0.193393				
	coefficient	std. error	t-ratio	p-value
const	0.19950	0.0550	3.63	3.9E-04
LNHDDJanuary18	0.84146	0.0137	61.42	1.1E-105
LNHDDFebruary18	0.83844	0.0139	60.13	2.1E-104
LNHDDMarch18	0.83519	0.0144	58.09	2.5E-102
LNHDDApril18	0.80379	0.0154	52.03	1.1E-95
LNHDDMay18	0.77716	0.0181	42.84	3.3E-84
LNHDDJune18	0.53825	0.0249	21.61	3.5E-47
LNHDDSeptember18	0.43984	0.0198	22.18	1.9E-48
LNHDDOctober18	0.73694	0.0163	45.24	2.1E-87
LNHDDNovember18	0.80611	0.0148	54.30	3.0E-98
LNHDDDecember18	0.83795	0.0141	59.33	1.4E-103
Statistics based on the rho-differenced data				
Mean dependent var	3.74268	S.D. dependent var	2.029	
Sum squared resid	9.28252	S.E. of regression	0.25302	
R-squared	0.98546	Adjusted R-squared	0.98445	
F(10, 121)	714.39981	P-value(F)	0.00000	
rho	-0.00286	Durbin-Watson	2.00570	

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:

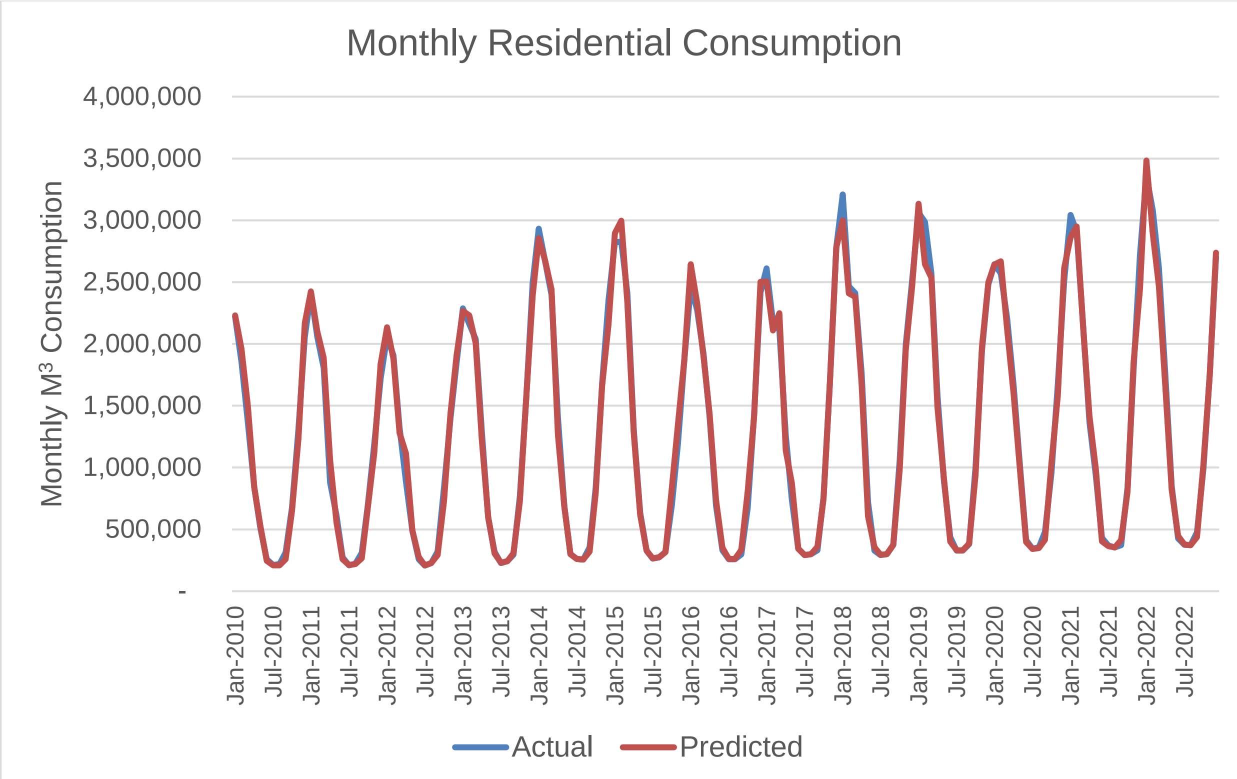

Figure 1 R1 Residential Predicted vs Actual observations

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 2.0%. The MAPE calculated monthly over the period is 4.5%.

	Residential		Absolute
Year	**Actual**	**Predicted**	**Error (%)**
2011	12,393,486	12,619,277	1.8%
2012	11,751,822	11,967,652	1.8%
2013	14,287,143	14,097,633	1.3%
2014	16,127,158	15,664,771	2.9%
2015	14,948,329	15,355,359	2.7%
2016	14,417,053	14,979,673	3.9%
2017	15,400,135	15,394,040	0.0%
2018	17,442,260	16,805,589	3.7%
2019	18,000,452	17,578,664	2.3%
2020	16,837,081	16,755,638	0.5%
2021	17,299,257	17,009,201	1.7%
2022	18,758,836	18,463,668	1.6%
Total	**187,663,014**	**186,691,165**	**0.5%**

Mean Absolute Percentage Error (Annual)	2.0%
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 156 observations from 2010:01 to 2022:12. The natural logarithm of heating degree days at 16°C for the months from August to May 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 369.6m^3 in 2010 to 832.7m^3 in 2022 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 2010:01-2022:12 (T = 156)				
Dependent variable: ExLNR1AverageTrend				
rho = 0.364886				
	coefficient	std. error	t-ratio	p-value
const	1.01692	0.2535	4.01	9.6E-05
LNHDDJanuary16	1.03801	0.0653	15.90	1.4E-33
LNHDDFebruary16	1.03255	0.0664	15.55	1.1E-32
LNHDDMarch16	1.05365	0.0681	15.46	1.8E-32
LNHDDApril16	1.06915	0.0719	14.88	5.5E-31
LNHDDMay16	1.04287	0.0791	13.18	1.4E-26
LNHDDAugust16	1.46671	0.4556	3.22	1.6E-03
LNHDDSeptember16	1.07421	0.1050	10.23	7.9E-19
LNHDDOctober16	1.35208	0.0786	17.20	7.9E-37
LNHDDNovember16	1.24916	0.0710	17.59	8.8E-38
LNHDDDecember16	1.09089	0.0674	16.18	2.8E-34
Statistics based on the rho-differenced data				
Mean dependent var	5.67786	S.D. dependent var	3.078	
Sum squared resid	192.40655	S.E. of regression	1.15193	
R-squared	0.86897	Adjusted R-squared	0.85993	
F(11, 120)	55.10249	P-value(F)	0.00000	
rho	-0.04155	Durbin-Watson	2.08288	

Table 6 R1 Industrial Regression Model

Using the above model coefficients we derive the following:

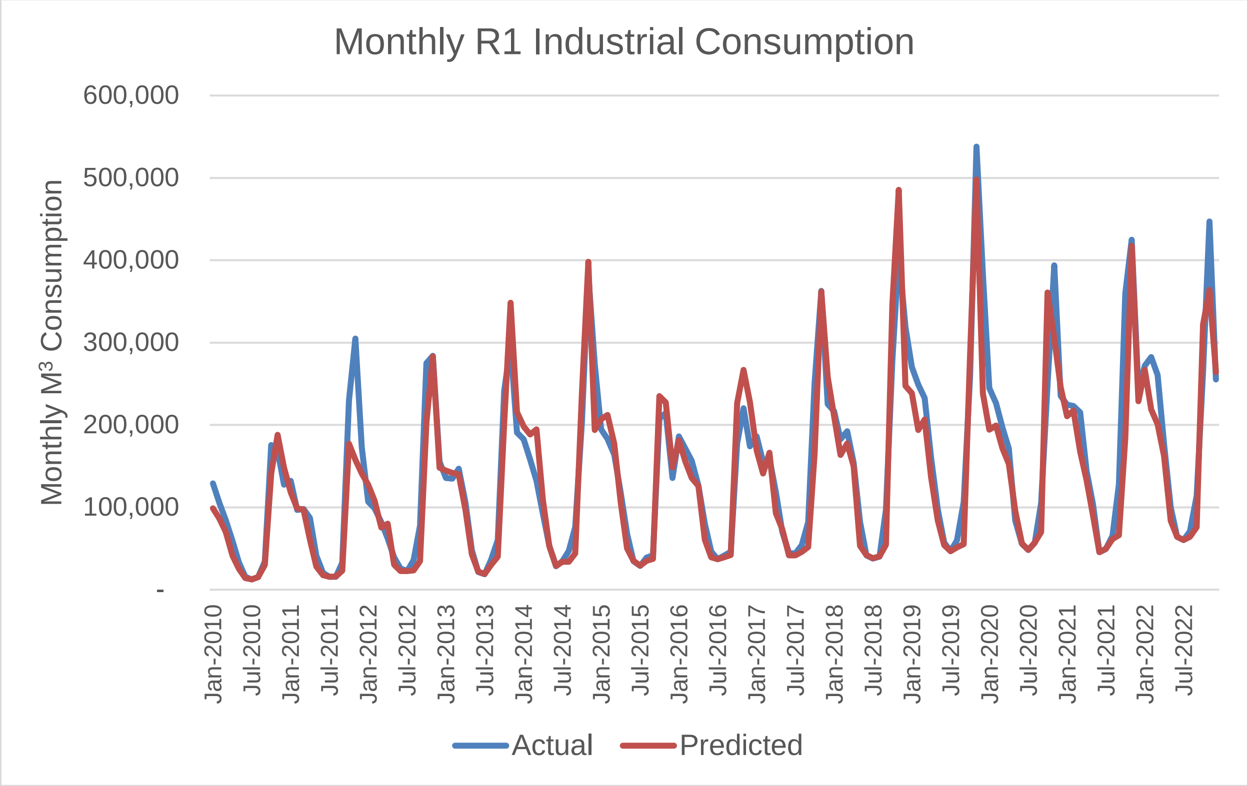

Figure 2 R1 Industrial Predicted vs Actual observations

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	951,011	23.8%
2012	1,265,913	1,158,936	8.5%
2013	1,436,592	1,442,083	0.4%
2014	1,666,209	1,715,358	2.9%
2015	1,430,900	1,500,396	4.9%
2016	1,462,707	1,538,305	5.2%
2017	1,752,123	1,609,192	8.2%
2018	2,050,371	2,008,706	2.0%
2019	2,461,420	2,088,873	15.1%
2020	2,067,358	1,956,951	5.3%
2021	2,226,121	1,871,801	15.9%
2022	2,367,680	2,147,072	9.3%
Total	**21,434,771**	**19,988,685**	**6.7%**

Mean Absolute Percentage Error (Annual)	8.5%
Mean Absolute Percentage Error (Monthly)	18.6%

Table 7 R1 Industrial model error

3.3 R1 COMMERCIAL

For the R1 Commercial Class consumption the equation was estimated using 156 observations from 2010:01 to 2022:12. 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 179.5m^3 in 2010 to 235.0m^3 in 2022 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 2010:01-2022:12 (T = 156)				
Dependent variable: ExLNComAverageTrend				
rho = 0.165835				
	coefficient	std. error	t-ratio	p-value
const	1.24515	0.1689	7.37	1.2E-11
LNHDDJanuary18	0.92851	0.0424	21.89	8.4E-48
LNHDDFebruary18	0.92876	0.0432	21.52	5.6E-47
LNHDDMarch18	0.92198	0.0445	20.71	3.7E-45
LNHDDApril18	0.89339	0.0479	18.66	2.2E-40
LNHDDMay18	0.86619	0.0564	15.36	3.2E-32
LNHDDJune18	0.55866	0.0782	7.14	4.1E-11
LNHDDSeptember18	0.60088	0.0623	9.65	2.5E-17
LNHDDOctober18	0.82348	0.0506	16.26	1.7E-34
LNHDDNovember18	0.89404	0.0460	19.43	3.3E-42
LNHDDDecember18	0.92245	0.0437	21.09	5.1E-46
Statistics based on the rho-differenced data				
Mean dependent var	5.19977	S.D. dependent var	2.339	
Sum squared resid	90.64136	S.E. of regression	0.79064	
R-squared	0.89316	Adjusted R-squared	0.88579	
F(10, 121)	92.37976	P-value(F)	0.00000	
rho	-0.02626	Durbin-Watson	2.05251	

Table 8 R1 Commercial Regression Model

Using the above model coefficients we derive the following:

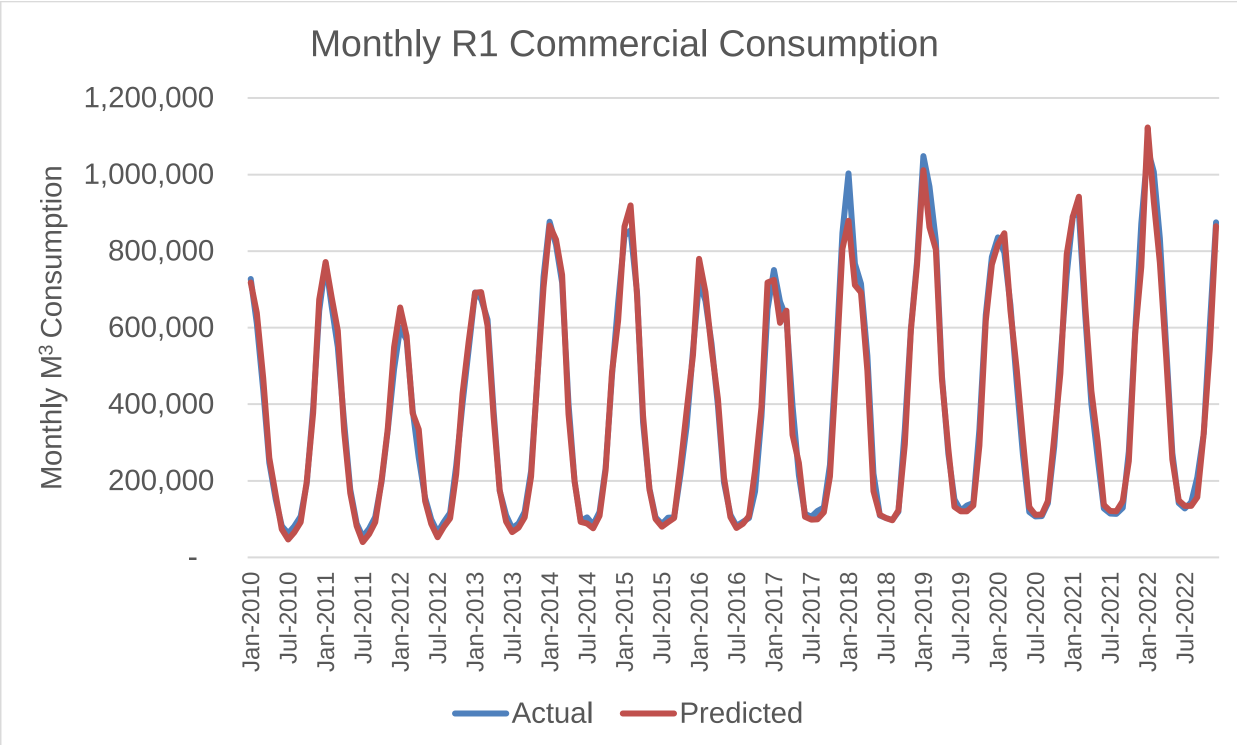

Figure 3 R1 Commercial Predicted vs Actual observations

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 3.4%. The MAPE calculated monthly over the period is 7.7%.

Year	R1 Commercial Actual	Predicted	Absolute Error (%)
2011	3,846,511	3,899,645	1.4%
2012	3,526,397	3,620,390	2.7%
2013	4,352,319	4,248,952	2.4%
2014	4,788,282	4,704,383	1.8%
2015	4,420,443	4,539,208	2.7%
2016	4,117,374	4,354,622	5.8%
2017	4,734,213	4,472,140	5.5%
2018	5,363,288	5,028,672	6.2%
2019	5,890,482	5,608,530	4.8%
2020	5,028,438	5,193,549	3.3%
2021	5,306,940	5,343,929	0.7%
2022	6,146,717	5,904,090	3.9%
Total	**57,521,403**	**56,918,111**	**1.0%**
Mean Absolute Percentage Error (Annual)			3.4%
Mean Absolute Percentage Error (Monthly)			7.7%

Table 9 R1 Commercial model error

3.4 R3

For the R3 Class consumption the equation was estimated using 156 observations from 2010:01 to 2022:12. 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(165) in December 2022) 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 workdays in each month.

The following table outlines the resulting regression model:

Model 5: Prais-Winsten, using observations 2010:01-2022:12 (T = 156)				
Dependent variable: LNContractR3Average				
rho = 0.637238				
	coefficient	std. error	t-ratio	p-value
const	11.60118	0.3480	33.34	5.0E-69
LNHDDJanuary20	0.26885	0.0152	17.64	1.3E-37
LNHDDFebruary20	0.25901	0.0156	16.65	3.3E-35
LNHDDMarch20	0.65358	0.1236	5.29	4.6E-07
LNHDDApril20	0.63512	0.1316	4.83	3.6E-06
LNHDDMay20	0.63286	0.1511	4.19	4.9E-05
LNHDDSeptember20	0.06265	0.0144	4.34	2.7E-05
LNHDDOctober20	0.61239	0.1391	4.40	2.1E-05
LNHDDNovember20	0.63863	0.1277	5.00	1.7E-06
LNHDDDecember20	0.24707	0.0152	16.21	4.1E-34
lnTrend	-0.56125	0.0790	-7.10	5.4E-11
d2009	-1.05753	0.2421	-4.37	2.4E-05
Shoulder	-2.58631	0.7897	-3.28	1.3E-03
June	0.19752	0.0682	2.90	4.4E-03
Statistics based on the rho-differenced data				
Mean dependent var	10.10527	S.D. dependent var	0.789	
Sum squared resid	7.19646	S.E. of regression	0.22512	
R-squared	0.92546	Adjusted R-squared	0.91864	
F(13, 118)	69.07876	P-value(F)	0.00000	
rho	0.00492	Durbin-Watson	1.98311	

Table 10 R3 Regression Model

Using the above model coefficients we derive the following:

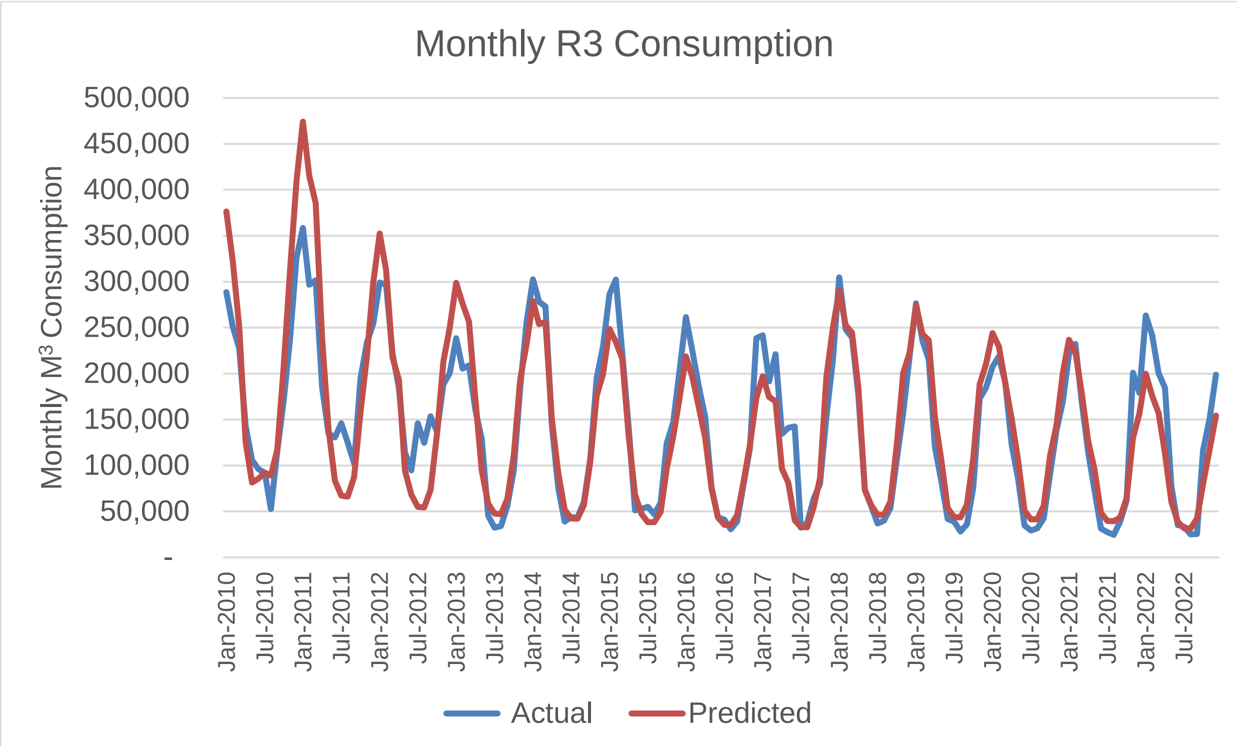

Figure 4 R3 Predicted vs Actual observations

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 10.6%. The MAPE calculated monthly over the period is 22.6%. 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	2,634,280	6.9%
2012	2,161,705	2,018,666	6.6%
2013	1,644,742	1,851,259	12.6%
2014	1,792,006	1,703,940	4.9%
2015	1,692,328	1,473,771	12.9%
2016	1,492,346	1,322,257	11.4%
2017	1,653,466	1,411,364	14.6%
2018	1,711,013	1,802,294	5.3%
2019	1,510,164	1,717,242	13.7%
2020	1,361,184	1,565,026	15.0%
2021	1,372,372	1,383,227	0.8%
2022	1,551,993	1,201,491	22.6%
Total	**20,408,006**	**20,084,818**	**1.6%**
Mean Absolute Percentage Error (Annual)			10.6%
Mean Absolute Percentage Error (Monthly)			22.6%

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 2023 to 2027. 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 1983 to 2022 was used to evaluate each method's predicted heating degree days against the actual heating degree days for each month since January 2003. Data from Environment Canada's London Airport weather station was used for the period from 1983 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
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	5	2	3	7	4
2020	1	3	5	6	7	2	4
2021	1	5	3	2	7	6	4
2022	5	3	6	7	1	2	4
Average Rank							
Monthly	4.01	3.81	4.20	4.23	3.99	3.82	3.94
Annual	3.25	3.60	4.85	4.70	4.70	2.90	4.00
Variance between Predicted and Actual							
Monthly	3,993	3,543	3,984	4,313	3,847	3,478	3,725
Annual	65,310	57,285	66,510	74,967	64,146	51,738	60,966

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 2003 predicted value uses the trend from the average heating degree days from 1983 and 1992 to the average from 1993 and 2002.

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.

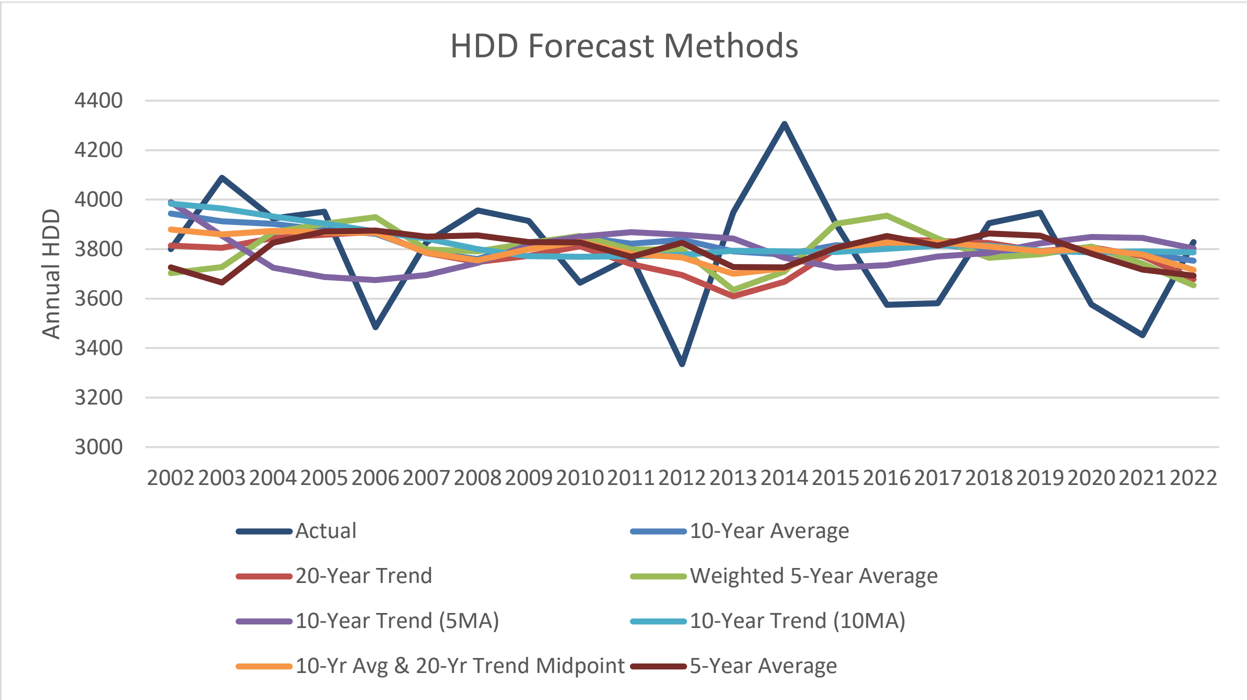

Figure 5 Weather Forecast for Various Methods

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**
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	722	651	551	349	137	29	5	9	66	237	439	589	**3,785**	**3,829**
2023	722	647	553	358	137	29	4	9	63	234	444	579	**3,780**	
2024	722	645	553	363	137	29	4	9	62	232	447	575	**3,778**	
2025	722	643	554	368	137	29	3	9	61	231	450	570	**3,775**	
2026	722	640	554	373	136	29	3	8	60	229	452	566	**3,772**	
2027	722	638	555	378	136	28	2	8	58	228	455	561	**3,770**	

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
2012	6,896	1,705	11,756,626	11,751,822	1,894	13,046,922
2013	7,181	1,990	14,289,175	14,287,143	1,954	14,020,251
2014	7,470	2,162	16,150,603	16,127,158	2,002	14,945,357
2015	7,726	1,938	14,974,492	14,948,329	1,900	14,671,795
2016	7,956	1,813	14,425,323	14,417,053	1,887	14,999,537
2017	8,110	1,892	15,347,218	15,400,135	1,978	16,084,611
2018	8,400	2,075	17,426,321	17,442,260	2,051	17,238,095
2019	8,657	2,083	18,035,211	18,000,452	2,032	17,562,490
2020	8,805	1,911	16,828,031	16,837,081	2,000	17,620,927
2021	8,983	1,927	17,311,669	17,299,257	2,036	18,277,228
2022	9,132	2,055	18,765,676	18,758,836	2,041	18,633,571
2023	9,340				2,014	18,779,614
2024	9,547				2,022	19,275,421
2025	9,755				2,031	19,776,619
2026	9,962				2,039	20,281,194
2027	10,170				2,047	20,789,326

Table 14 Actual vs Normalized R1 Residential

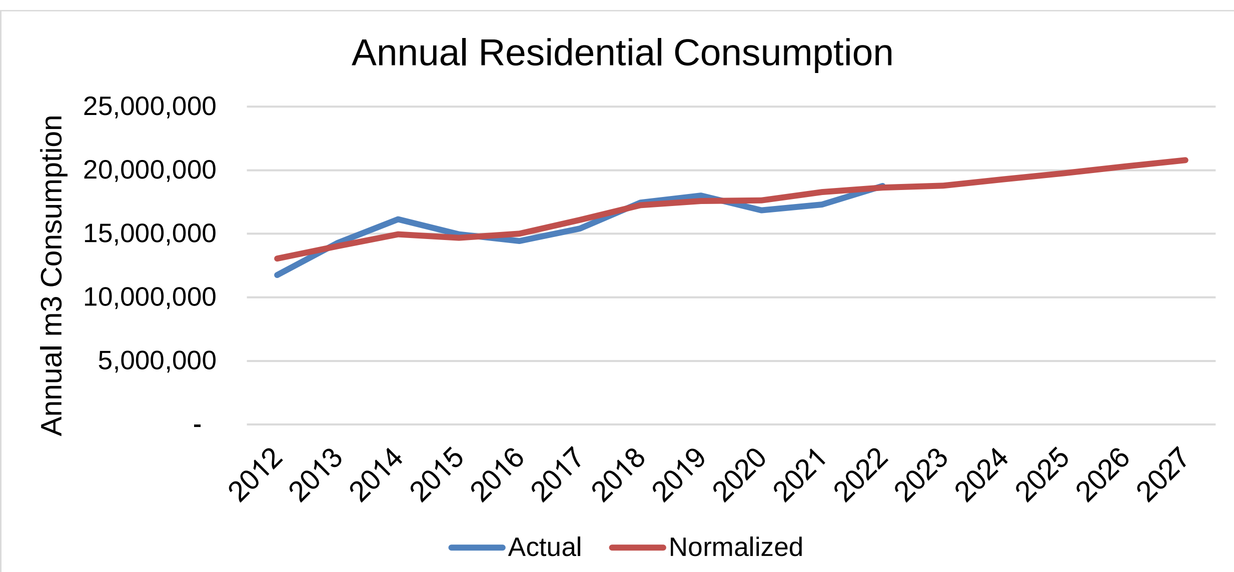

Figure 6 Actual vs Normalized R1 Residential

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

R1 Residential			
	Tier 1	**Tier 2**	**Total**
2021	17,181,790	117,467	17,299,257
2022	18,632,003	126,833	18,758,836
2023	18,654,216	125,397	18,779,614
2024	19,146,993	128,428	19,275,421
2025	19,645,136	131,483	19,776,619
2026	20,146,647	134,548	20,281,194
2027	20,651,702	137,624	20,789,326

Table 15 Forecasted R1 Residential Tiered Consumption

The R1 Residential customer count is forecast to increase by 207.5 customers per year through the 2023-2027 period. This figure is based on an ENGLP estimate of 200-215 new services per year.

Year	Residential Customers	Percent of Prior Year
2013	7,181	
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	8,805	101.7%
2021	8,983	102.0%
2022	9,132	101.7%
2023	9,340	102.3%
2024	9,547	102.2%
2025	9,755	102.2%
2026	9,962	102.1%
2027	10,170	102.1%

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
2012	51	24,350	1,252,019	1,265,913	26,006	1,350,422
2013	58	24,752	1,429,444	1,436,592	24,112	1,399,049
2014	63	26,306	1,659,456	1,666,209	24,195	1,533,172
2015	62	23,186	1,439,435	1,430,900	24,174	1,487,836
2016	65	22,433	1,461,881	1,462,707	24,383	1,590,683
2017	66	26,620	1,752,499	1,752,123	29,281	1,927,090
2018	68	29,425	2,005,771	2,050,371	28,123	1,956,196
2019	73	33,281	2,440,611	2,461,420	32,999	2,435,499
2020	75	27,629	2,067,592	2,067,358	29,696	2,222,763
2021	75	29,576	2,215,758	2,226,121	35,624	2,685,467
2022	77	30,934	2,371,575	2,367,680	31,356	2,399,540
2023	79				28,622	2,259,047
2024	81				29,080	2,358,149
2025	83				29,538	2,461,008
2026	86				29,996	2,567,756
2027	88				30,455	2,678,530

Table 17 Actual vs Normalized R1 Industrial

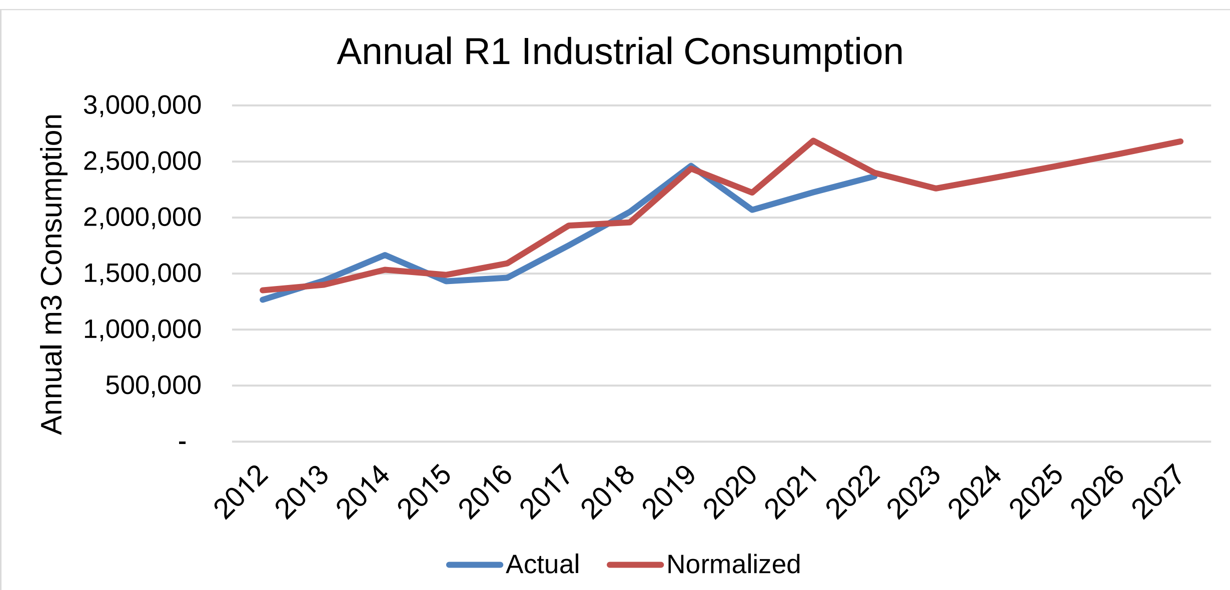

Figure 7 Actual vs Normalized R1 Industrial

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

	R1 Industrial		
	Tier 1	**Tier 2**	**Total**
2021	515,516	1,710,605	2,226,121
2022	558,813	1,808,867	2,367,680
2023	531,867	1,727,180	2,259,047
2024	557,652	1,800,497	2,358,149
2025	584,455	1,876,553	2,461,008
2026	612,313	1,955,444	2,567,756
2027	641,263	2,037,267	2,678,530

Table 18 Forecasted R1 Industrial Tiered Consumption

The Geometric mean of the annual growth from 2016 to 2022 was used to forecast the growth rate from 2023 to 2027. 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
2013	58	
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	75	100.1%
2022	77	102.3%
2023	79	102.7%
2024	81	102.7%
2025	83	102.7%
2026	85	102.7%
2027	88	102.7%

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
2012	415	8,515	3,533,844	3,526,397	10,582	4,381,790
2013	424	10,227	4,336,095	4,352,319	11,061	4,702,608
2014	437	10,964	4,795,706	4,788,282	10,931	4,775,722
2015	445	9,935	4,421,983	4,420,443	10,096	4,494,668
2016	453	9,065	4,102,131	4,117,374	9,680	4,395,803
2017	462	10,219	4,716,893	4,734,213	11,592	5,365,875
2018	487	10,958	5,332,657	5,363,288	11,243	5,495,155
2019	536	10,970	5,880,685	5,890,482	11,221	6,023,512
2020	535	9,378	5,017,149	5,028,438	10,438	5,595,654
2021	552	9,615	5,309,753	5,306,940	10,260	5,663,756
2022	567	10,840	6,140,947	6,146,717	12,317	6,979,306
2023	585				10,364	6,048,327
2024	604				10,417	6,278,022
2025	624				10,469	6,516,256
2026	644				10,522	6,763,341
2027	665				10,575	7,019,600

Table 20 Actual vs Normalized R1 Commercial

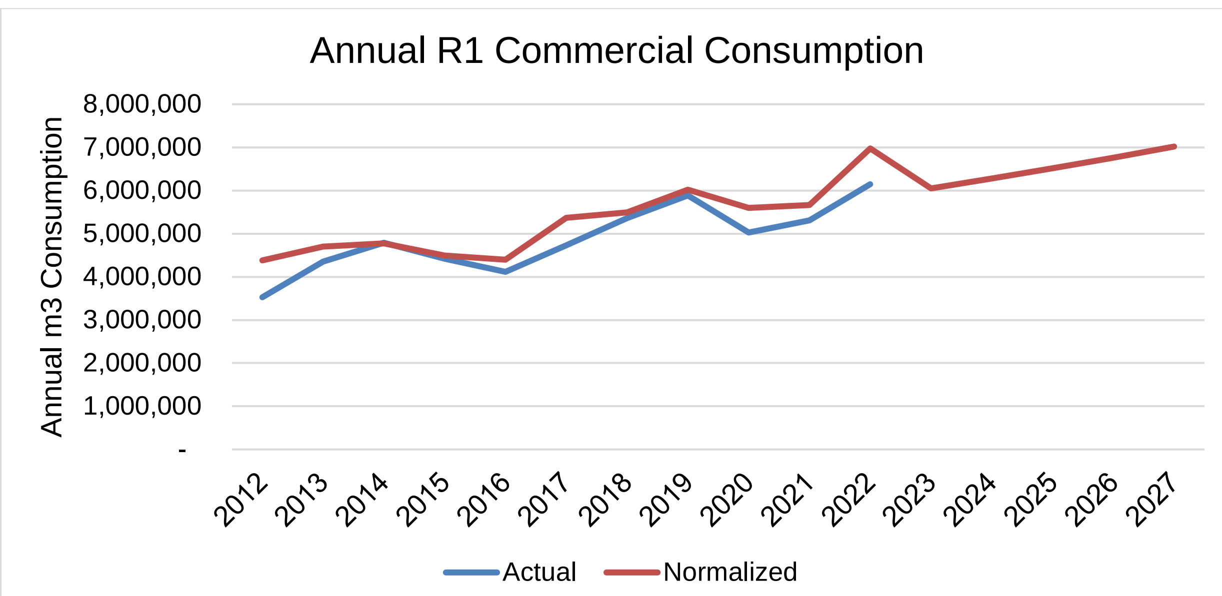

Figure 8 Actual vs Normalized R1 Commercial

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

	R1 Commercial		
	Tier 1	**Tier 2**	**Total**
2021	2,470,535	2,836,404	5,306,940
2022	2,867,817	3,278,901	6,146,717
2023	2,828,560	3,219,767	6,048,327
2024	2,938,593	3,339,430	6,278,022
2025	3,052,789	3,463,467	6,516,256
2026	3,171,303	3,592,038	6,763,341
2027	3,294,295	3,725,305	7,019,600

Table 21 Forecasted R1 Commercial Tiered Consumption

The Geometric mean of the annual growth from 2013 to 2022 was used to forecast the growth rate from 2023 to 2027.The following table includes the customer Actual / Forecast customer count on this basis:

Year	R1 Commercial Customers	Percent of Prior Year
2013	424	
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	552	103.2%
2022	567	102.6%
2023	585	103.3%
2024	604	103.3%
2025	624	103.3%
2026	644	103.3%
2027	665	103.3%

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
2012	4	540,426	2,161,705	2,161,705	571,188	2,284,754
2013	4	411,186	1,644,742	1,644,742	407,389	1,629,555
2014	4	448,002	1,792,006	1,792,006	426,437	1,705,747
2015	4	423,082	1,692,328	1,692,328	420,880	1,683,519
2016	4	373,087	1,492,346	1,492,346	380,560	1,522,241
2017	5	375,566	1,690,049	1,653,466	380,591	1,671,904
2018	6	285,169	1,711,013	1,711,013	279,984	1,679,906
2019	6	251,694	1,510,164	1,510,164	244,272	1,465,629
2020	6	226,864	1,361,184	1,361,184	230,564	1,383,384
2021	6	244,734	1,386,823	1,372,372	252,702	1,416,047
2022	5	310,399	1,551,993	1,551,993	310,991	1,554,954
2023	5				231,490	1,219,400
2024	6				222,920	1,324,601
2025	6				215,189	1,285,943
2026	6				208,169	1,374,744
2027	7				201,759	1,638,793

Table 23 Actual vs Normalized R3

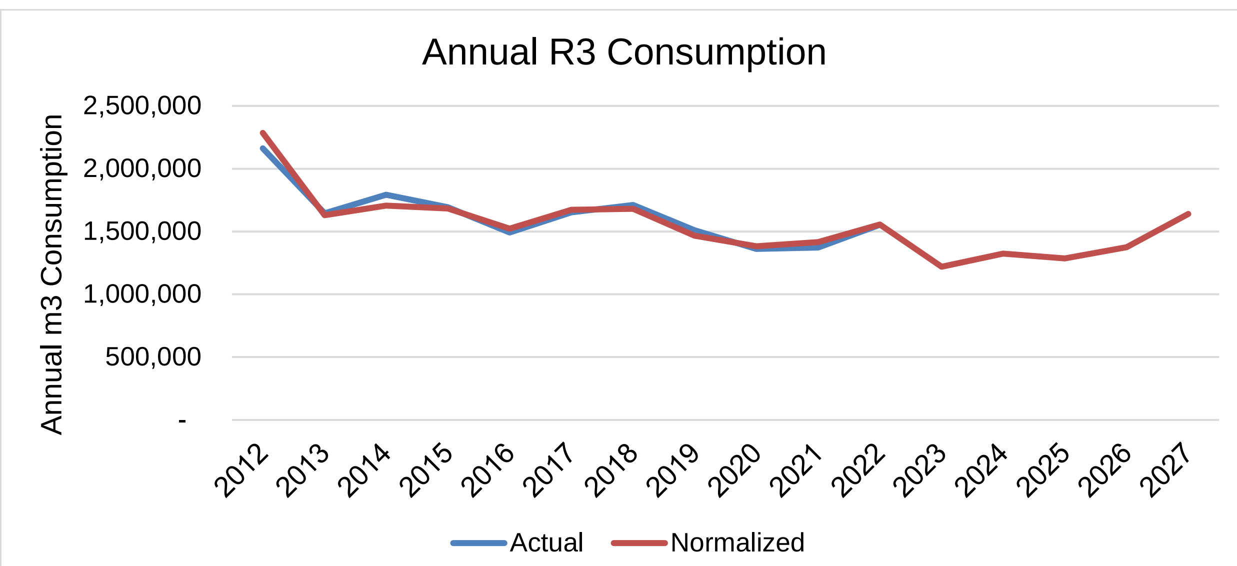

Figure 9 Actual vs Normalized R3

The R3 class has fluctuated between 4 and 6 customers since 2009. The current count of 5 customers is expected to increase to 6 in October 2023 and to 7 in October 2026 based on known customer additions.

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
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	50	16,464	825,967	829,096		
2022	52	16,236	836,134	838,908		
2023	50				18,659	933,892
2024	49				18,659	911,088
2025	48				18,659	888,840
2026	47				18,659	867,136
2027	46				18,659	845,962

Table 24 Actual vs Normalized R2 Seasonal

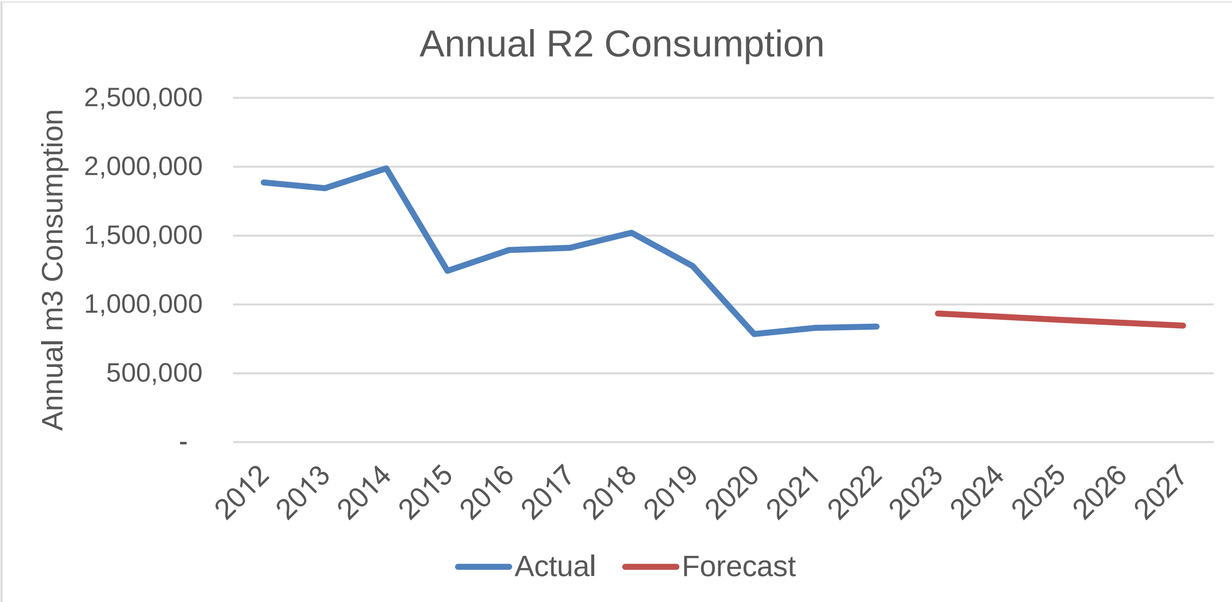

Figure 10 Actual vs Normalized R2 Seasonal

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**
2021	55,203	461,098	88,089	42,840	170,590	11,276	829,096
2022	55,856	466,555	89,131	43,347	172,609	11,409	838,908
2023	62,180	519,381	99,223	48,255	192,153	12,701	933,892
2024	60,662	506,698	96,800	47,077	187,461	12,391	911,088
2025	59,180	494,325	94,436	45,927	182,883	12,088	888,840
2026	57,735	482,254	92,130	44,806	178,417	11,793	867,136
2027	56,326	470,478	89,881	43,711	174,061	11,505	845,962

Table 25 Forecasted R2 Seasonal Tiered Consumption

The Geometric mean of the annual growth from 2013 to 2022 was used to forecast the growth rate from 2023 to 2027. The following table includes the customer Actual / Forecast customer count on this basis:

Year	R2 Seasonal Customers	Percent of Prior Year
2013	64	
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	50	104.0%
2022	52	102.7%
2023	50	97.6%
2024	49	97.6%
2025	48	97.6%
2026	47	97.6%
2027	46	97.6%

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 reasonably consistent from 2020 to 2022 so the 2023 forecast is based on a 3-year average. The load of one known new customer with above average consumption has been added beginning in July 2023.

R4						
Year	Customers	Consumption		Actual	Normalized	
		Per Customer	Total		Per Customer	Total
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	41	43,427	1,766,026	1,793,580		
2022	41	38,392	1,590,079	1,601,181		
2023	43				47,657	2,051,464
2024	44				48,105	2,132,436
2025	45				48,105	2,196,351
2026	47				48,105	2,262,182
2027	48				48,105	2,329,986

Table 27 Actual vs Forecast R4

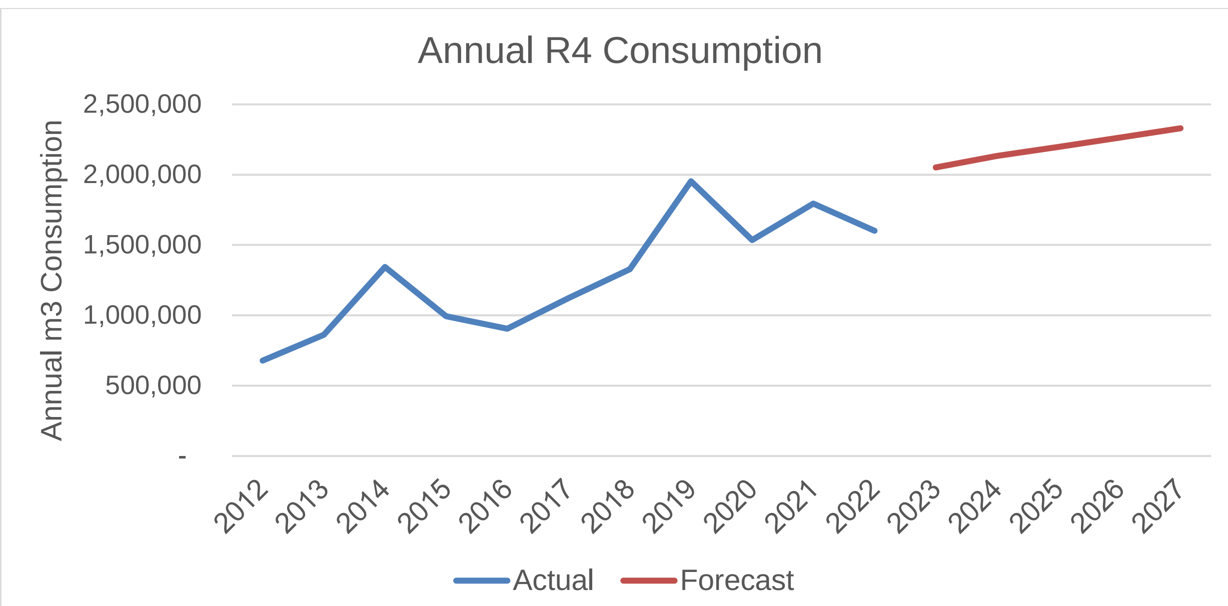

Figure 11 Actual vs Normalized R4

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**
2021	28,103	5,689	147,205	1,612,584	1,793,580
2022	25,088	5,079	131,414	1,439,600	1,601,181
2023	32,143	6,507	168,370	1,844,443	2,051,464
2024	33,412	6,764	175,016	1,917,244	2,132,436
2025	34,414	6,967	180,261	1,974,709	2,196,351
2026	35,445	7,176	185,664	2,033,897	2,262,182
2027	36,507	7,391	191,229	2,094,858	2,329,986

Table 28 Forecasted R4 Tiered Consumption

The Geometric mean of the annual growth from 2013 to 2022 was used to forecast the growth rate from 2023 to 2027.

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

Year	R4 Customers	Percent of Prior Year
2013	32	
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	41	100.6%
2022	41	101.8%
2023	43	103.0%
2024	44	103.0%
2025	45	103.0%
2026	47	103.0%
2027	48	103.0%

Table 29 Forecasted R4 Customer Count

6.3 R5

Consumption per R5 customer has fluctuated considerably since 2011. The 2023-2027 forecast is based on a 3-year average from 2020 to 2022, 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
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	146,488	585,954	585,954		
2023	4				160,993	643,974
2024	4				160,993	643,974
2025	4				160,993	643,974
2026	4				160,993	643,974
2027	4				160,993	643,974

Table 30 Actual vs Forecast R5

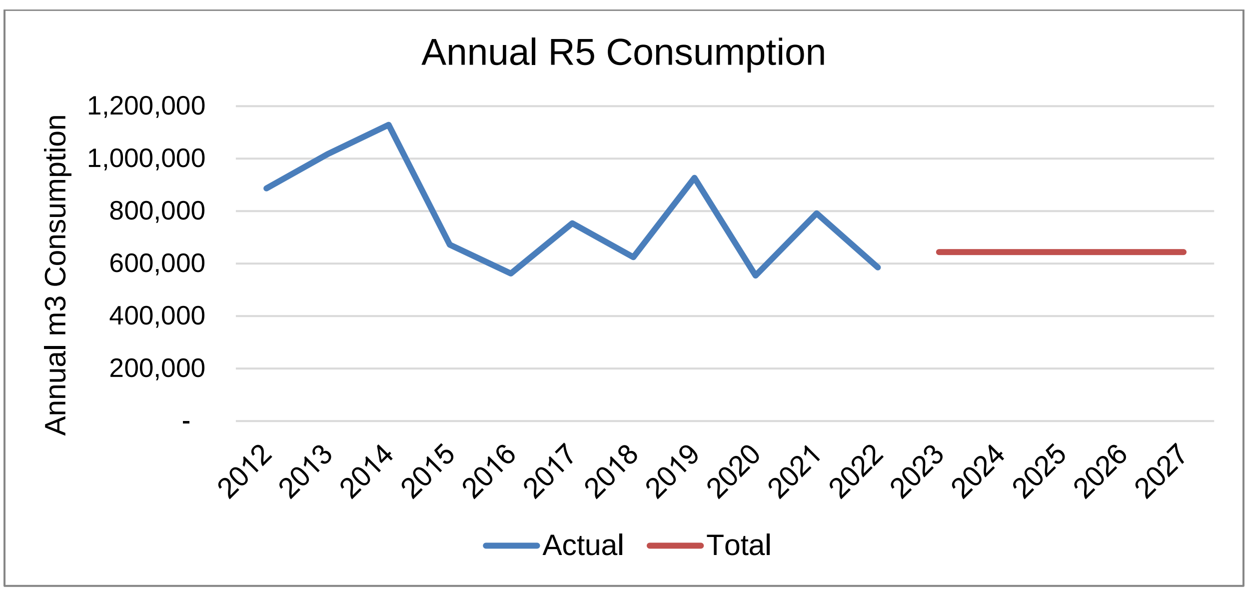

Figure 12 Actual vs Normalized Large Use R5

The R5 class had 5 customers from 2009 to 2017 and had 4 customers from 2018 to 2022. It is expected to maintain 4 customers through 2023 to 2027.

6.4 R6

R6 consumption increased significantly in 2019 over historic volumes. The 2023-2027 forecast uses average 2020-2022 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
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	62,040,423	62,040,423	62,040,423		
2023	1				61,267,873	61,267,873
2024	1				61,267,873	61,267,873
2025	1				61,267,873	61,267,873
2026	1				61,267,873	61,267,873
2027	1				61,267,873	61,267,873

Table 31 Actual vs Forecast R6

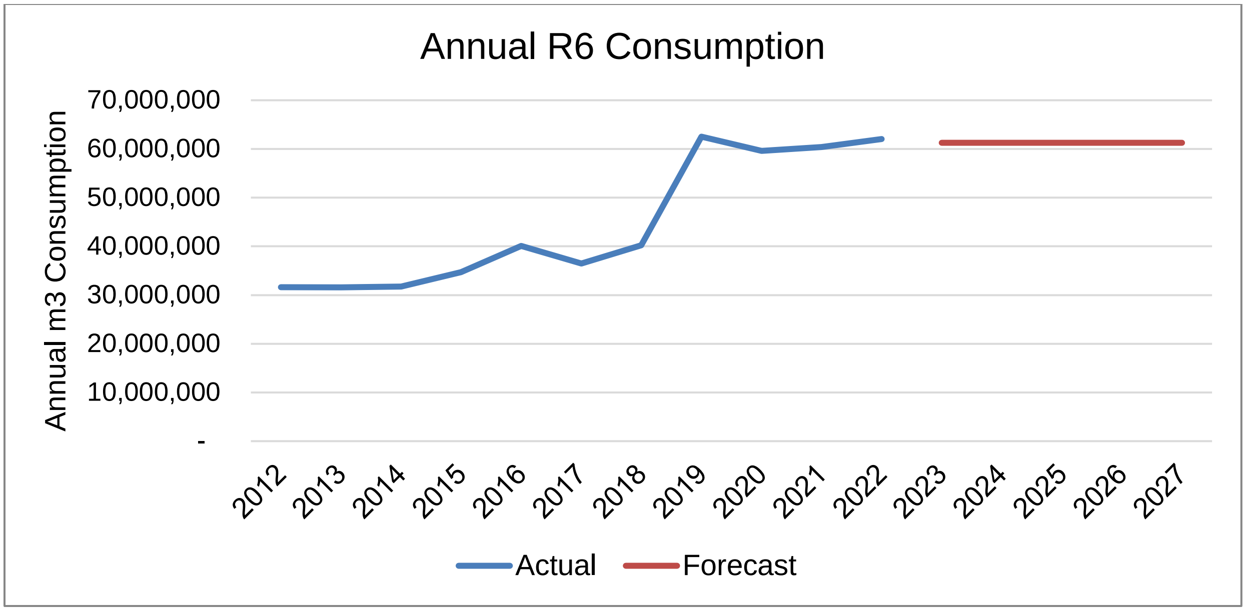

Figure 13 Actual vs Normalized R6

The R6 class has one customer and is expected to persist with one customer through 2027.

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 3,452.2 HDD (at 18°C) in 2021. 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 2023 to 2027 are provided with the normal forecast for reference. Forecast and actual HDDs from 2013 to 2022 are provided in Table 13.

Low Forecast	HDD	3,452.2	3,452.2	3,452.2	3,452.2	3,452.2
	2022 Actual	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**	**2026 Forecast**	**2027 Forecast**
R1 Residential	18,758,836	17,767,976	18,246,086	18,729,766	19,217,116	19,708,310
R1 Industrial	2,367,680	2,098,341	2,193,471	2,292,242	2,394,784	2,501,228
R1 Commercial	6,146,717	5,704,377	5,924,567	6,153,059	6,390,161	6,636,191
R2 Seasonal	838,908	933,892	911,088	888,840	867,136	845,962
R3	1,551,993	1,181,856	1,288,536	1,250,690	1,339,077	1,604,938
R4	1,601,181	2,051,464	2,132,436	2,196,351	2,262,182	2,329,986
R5	585,954	643,974	643,974	643,974	643,974	643,974
R6	62,040,423	61,267,873	61,267,873	61,267,873	61,267,873	61,267,873
Total	**93,891,693**	**91,649,753**	**92,608,032**	**93,422,796**	**94,382,302**	**95,538,462**

Table 32 Low HDD Forecast

Normal Forecast	HDD	3,780.2	3,777.6	3,775.0	3,772.4	3,769.9
	2022 Actual	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**	**2026 Forecast**	**2027 Forecast**
R1 Residential	18,758,836	18,779,614	19,275,421	19,776,619	20,281,194	20,789,326
R1 Industrial	2,367,680	2,259,047	2,358,149	2,461,008	2,567,756	2,678,530
R1 Commercial	6,146,717	6,048,327	6,278,022	6,516,256	6,763,341	7,019,600
R2 Seasonal	838,908	933,892	911,088	888,840	867,136	845,962
R3	1,551,993	1,219,400	1,324,601	1,285,943	1,374,744	1,638,793
R4	1,601,181	2,051,464	2,132,436	2,196,351	2,262,182	2,329,986
R5	585,954	643,974	643,974	643,974	643,974	643,974
R6	62,040,423	61,267,873	61,267,873	61,267,873	61,267,873	61,267,873
Total	**93,891,693**	**93,203,592**	**94,191,565**	**95,036,865**	**96,028,200**	**97,214,044**

Table 33 Normal HDD Forecast

High Forecast	HDD	4,306.0	4,306.0	4,306.0	4,306.0	4,306.0
	2022 Actual	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**	**2026 Forecast**	**2027 Forecast**
R1 Residential	18,758,836	20,390,164	20,926,436	21,468,557	22,014,349	22,564,011
R1 Industrial	2,367,680	2,503,997	2,610,264	2,720,479	2,834,779	2,953,304
R1 Commercial	6,146,717	6,599,647	6,849,129	7,107,870	7,376,211	7,654,503
R2 Seasonal	838,908	933,892	911,088	888,840	867,136	845,962
R3	1,551,993	1,278,066	1,380,384	1,339,316	1,426,360	1,687,966
R4	1,601,181	2,051,464	2,132,436	2,196,351	2,262,182	2,329,986
R5	585,954	643,974	643,974	643,974	643,974	643,974
R6	62,040,423	61,267,873	61,267,873	61,267,873	61,267,873	61,267,873
Total	**93,891,693**	**95,669,077**	**96,721,584**	**97,633,261**	**98,692,864**	**99,947,578**

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.

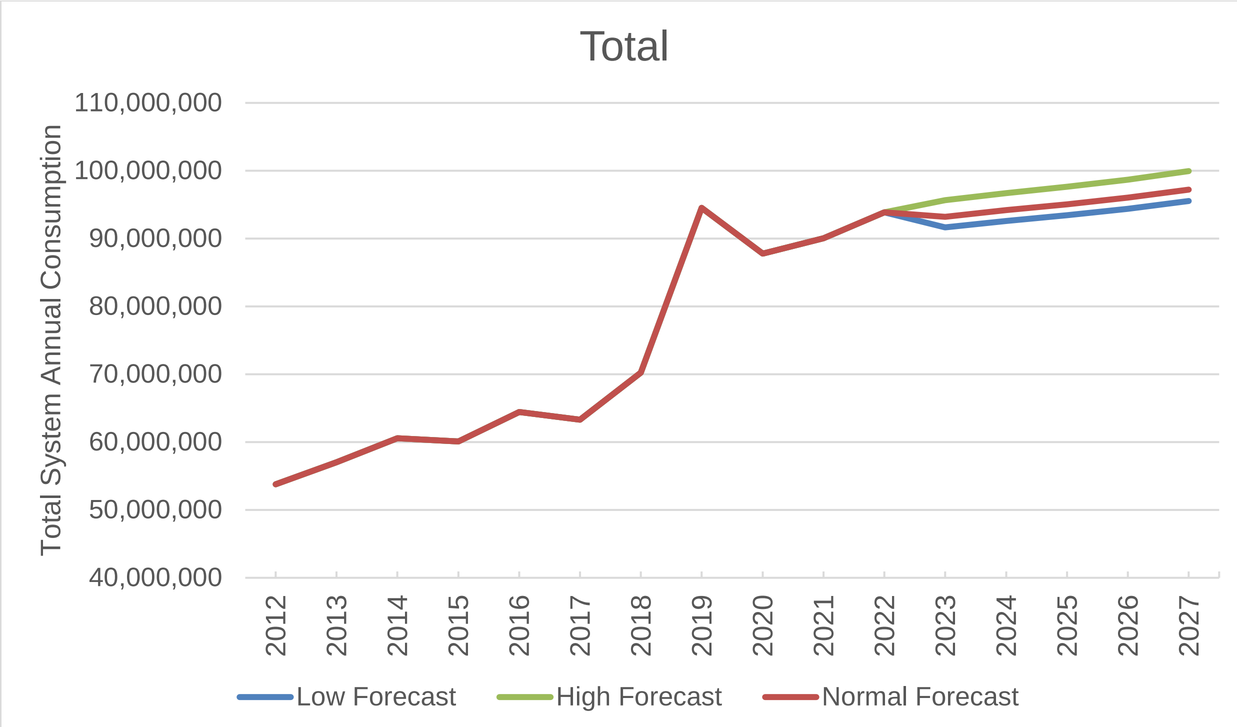

Figure 14 Weather Sensitivity – Total Consumption

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.

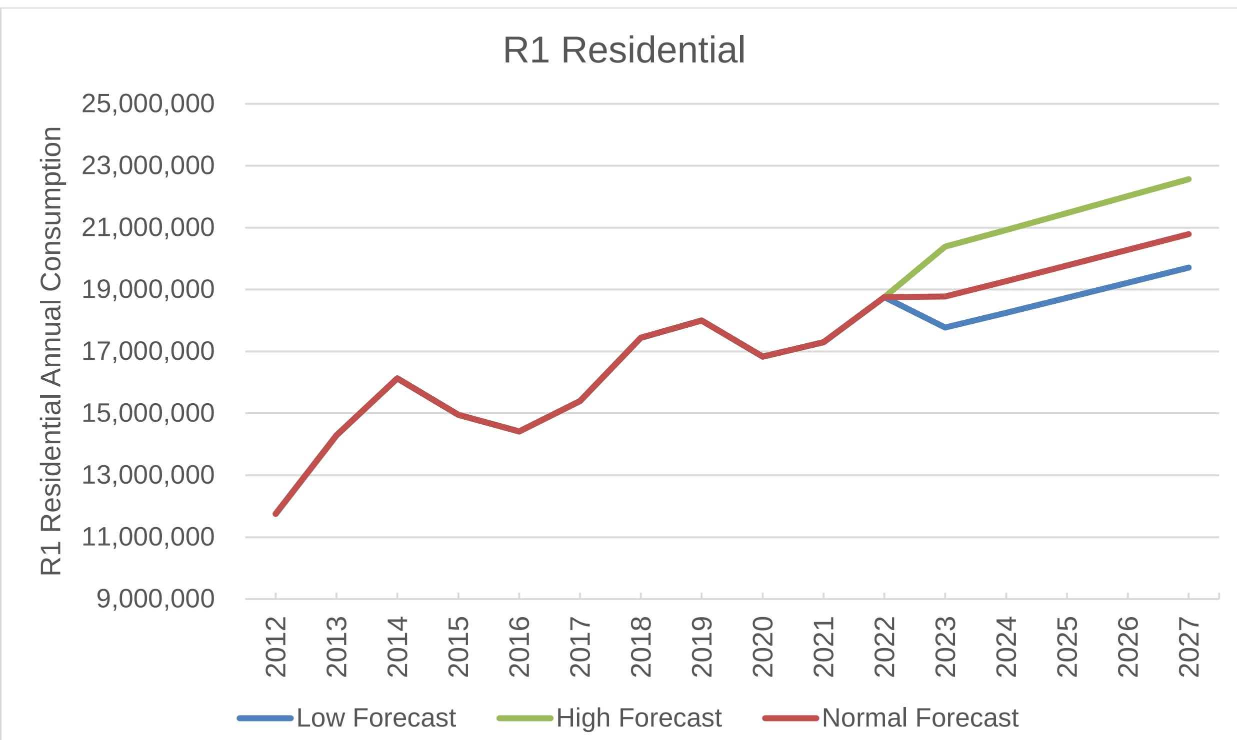

Figure 15 Weather Sensitivity – R1 Residential

Appendix F – ENGLP Aylmer Performance Metrics Scorecard

OEB Guiding Principle	Performance Categories	Intent of Measures	Measures	2020	2021	2022	3-yr Average
1. Cost Effectiveness	Policies & Procedures	Demonstrates consideration of alternate Enbridge rates	Annual rate review	C	C	C	n/a
	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%**	**Well gas: -5% Lake gas: -5%**	**Well gas: -5% Lake gas: -5%**
OEB Guiding Principle	Performance Categories	Intent of Measures	Measures	2020	2021	2022	3-yr Average
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%	100%	100%
			2. Enbridge Overrun Charges	$0	$0	$0	$0
	Coordination	Demonstrates ENGPL ability to invest in capital distribution required to meet design day demand	Monthly meetings between gas supply & engineering operations	4	12	12	N/A
	Communication	Ensure ongoing communications	Communication to ratepayers re material bill impacts	C	C	C	N/A
	Diversity	Demonstrate the diversity of the portfolio	1. % Firm local gas flow	95%	97%	98.82%	97.06%
			2. Local production as % of system gas	37.08%	37.01%	40.95%	38.35%
	Reliability	Demonstrate the reliability of the portfolio	1. Days failed to deliver to customers	0	0	0	0
			2.Days customer interrupted	0	0	0	0
OEB Guiding Principle	Performance Categories	Intent of Measures	Measures	2020	2021	2022	3-yr Average
3. Public Policy	Supporting Policy	Reports public policy in ENGLP supply plan	1.Community expansion	C	C	C	N/A
			2. FCC	C	C	C	N/A
			3. RNG	N/A	N/A	N/A	N/A
			4. DSM	N/A	N/A	N/A	N/A

Definitions:

1. Years refers to calendar years (January 1st to December 31st)
2. Cost Effectiveness: The gas supply plans will be cost-effect. Cost effectiveness is achieved by appropriately balancing the principles and in executing the supply plan in an economically efficient manner

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

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