INTRODUCTION

The Framework for the Assessment of Distributor Gas Supply Plans ("Framework") emerged from years of dialogue among ratepayers, Board Staff, and Ontario's two major gas distributors at the time—Union Gas Ltd. (UGL) and Enbridge Gas Distribution (EGD). The initial proceeding examined each distributor's gas supply planning process with the stated objective of "gaining a deeper understanding of the risk/cost trade-offs being made as they develop their plans." [1]

Board Staff, in their concluding report, underscored the stakes for consumers: "In our view, the importance of natural gas supply to the customer's bill suggests a more robust regulatory approach is needed to protect consumers in Ontario." [2]

Building on this, the Board issued its Report establishing the Framework, with the explicit purpose of ensuring "transparency, accountability and measurability regarding the distributors' gas supply plans to assure they deliver value to consumers."[3]

Despite this intent, the Update process has proven inadequate. Ratepayer representatives, including FRPO, consistently raised concerns that the process has prevented the introduction of meaningful evidence to assess consumer impacts.[4] Review of the initial plan and subsequent annual updates has been limited to written questions, company presentations, party submissions, and Staff reports. The only departures from this constrained process were the forgone 2020 Assessment[5] and the issue-specific hearing on the Vector Contracting Decision. [6]

This current proceeding therefore represents the first genuine opportunity for rigorous testing of the Gas Supply Plan. Only through such examination can the Board and stakeholders fully understand the impacts on ratepayers and ensure that the Framework delivers on its promise of consumer protection, transparency, and measurable value.

FRPO appreciates the provision of an adjudicated hearing and the resulting data and evidence that was elicited through interrogatories and the Technical Conference. However, as the dialogue in the Technical Conference reveals, the complexity of the trade offs in Gas Supply require explanation. As we learned more from each step, we looked forward to a hearing wherein we could test our understanding and receive

[1] OEBltr_revised_Gas Supply Planning_20151020, p.1
[2] EB-2015-0238 STAFF REPORT TO THE ONTARIO ENERGY BOARD, Distributor Gas Supply Planning, August 12, 2016, p.7
[3] EB-2017-0129 Report of the Ontario Energy Board **Framework for the Assessment of Distributor Gas Supply Plans**, October 25, 2018
[4] While there were many submissions on this matter, SEC_Comments_EGI GSP_20240717 and especially the contents of FRPO_SUB_EGI 2024 GS UPDATE_20240717 provide ratepayer concerns.
[5] EB-2020-0135 Board Letter, July 6, 2020
[6] EB-2023-0326 Hearing on the Ontario Energy Board's own Motion on Enbridge Gas Inc.'s 2021 Vector Contracting Decision

confirmation or clarification on market data that was not on the record. Despite our request for an Oral hearing,[7] the proceeding moved to submissions.[8]

As a result, the following submissions are narrowed to the very important issue of load balancing for which we have sufficient evidence, information and knowledge to recommend a constructive improvement to the Gas Supply plan. In addition, we highlight that there are outstanding questions regarding how a methodological change in demand determination has led to an increase in ratepayer costs in spite of utility assurances. Lastly, we encourage more evidence in support of the Gas Supply plans.

A) LOAD BALANCING – A RISK MANAGEMENT EXERCISE

The guiding principles for the assessment of gas supply plans are cost effectiveness, reliability and security of supply and public policy.[9] The Framework Report clarifies that there is a balance amongst the principles in the approach that is chosen by the utility to manage customer impacts and risks and ultimately value to the customer. Said differently, the process is a disciplined approach to prudent risk management while delivering firm services to customers year-round.

Effective gas supply planning depends on a robust demand forecast. Right-sizing supply assets and contracts requires a clear understanding of demand patterns, which can be divided into three main components: Peak Day Forecast, Annual Demand Forecast, and Seasonal Demand Forecast.

1) DEMAND FORECAST COMPONENTS

a) Peak Day Forecast

The Peak Day Forecast determines the maximum single-day demand by location. Utilities must ensure their supply plans can meet all firm customers forecasted or contracted daily requirements under reasonably possible conditions, preventing pressure drops or outages. This exercise involves using physical assets and firm delivery contracts with peak day design criteria established to guarantee supply at all franchise locations.

b) Annual Demand Forecast

The Annual Demand Forecast estimates the total gas needed for the franchise under normal weather conditions. However, "normal" weather is inherently uncertain, so the

[7] FRPO_SUB_EGI 5YR GSP PROC_20251021
[8] PO 2_EGI GSP_20251105
[9] EB-2017-0129 Report of the Ontario Energy Board: Framework for the Assessment of Distributor Gas Supply Plans, October 25, 2018, pg. 7-8

forecast will always carry some error—either overestimating or underestimating actual demand.

This uncertainty leads to two important recommendations:

- Sensitivity Analysis: Utilities should use scenario testing and sensitivity analysis to determine the minimum contract level based on a reasonable lower bound of expected consumption.
- Market Flexibility: The supply plan should include the ability to make discretionary purchases (e.g., at the Dawn hub) to address higher-than-expected consumption, reducing the risk and cost of underutilized transport capacity while diversifying the supply portfolio.

c) Seasonal Demand Forecast

The Seasonal Demand Forecast assesses the variability in heat-sensitive consumption, often on a monthly basis, to inform load balancing[10] strategies. Like the annual forecast, this estimate is subject to error but can largely be managed through discretionary market purchases.

While commodity prices can be volatile during extremes, a disciplined, forward-looking approach—such as managing discretionary purchases to meet month-end storage targets—can help mitigate the impact.

Conclusion

An effective gas supply plan relies on accurate forecasting and strategic flexibility. By using sensitivity analysis, incorporating market-based discretionary purchases, and rationalizing third-party contracts, utilities can create a resilient and cost-effective portfolio that meets customer needs and adapts to changing conditions.

2) TOOLS AVAILABLE TO MEET DEMAND

The main tools that are used for effective load balancing are storage - both reservoir-based and synthetic - and gas delivered at the storage hub.

a) Traditional Reservoir-based Storage

When one thinks of storage, it is often the traditional reservoir-based storage. These storage caverns can be depleted natural gas wells or salt caverns that are porous rock surrounded by non-permeable rock to create the reservoir. Storage providers install

[10] Load Balancing is used as a generic term to describe the service gas utilities provide by using tools at their disposal to ensure that customer demands are met recognizing that these demands vary seasonally while pipeline contract capacity is constant throughout the year

piping and compressors to allow a seasonal injection and withdrawal of natural gas often known as deliverability. Depending on the nature of the well, the quantity of deliverability varies from one pool to another. The ability of the storage operator to adjust deliverability using compression makes this tool the most flexible. However, for each storage pool, the inventory in the well at that time will have a significant impact on deliverability. When the storage pool is close to full, the injection capability is limited due to the elevated pressure associated with the quantity of gas. Conversely, when the pool nears empty, the lack of quantity of gas reduces the pressure thus limiting withdrawal capability. These limitations and the annual cycle increase the importance of using other tools to manage variances in load balancing need when conditions vary from those forecasted.

b) Synthetic Storage

The concept of synthetic storage comes from the idea that appropriate contracting of natural gas can be removed from or added to the system through agreements established with suppliers or marketers. By the utility selling certain amounts daily in the summer and buying back that same amount in the winter, potentially over a different number of days, can provide a notional way to store the gas.

c) Contracted Deliveries

An alternative to storage is to contract for additional deliveries of gas during high demand times. One of the benefits of this approach is that the gas arrives at the location above ground and therefore is not limited by withdrawal rights from storage. Given that the contracting specifies deliveries for high demand periods, the price of gas can be higher than during low demand periods depending on a number of external factors in the market.

3) THE RIGHT COMBINATION OF TOOLS TO MEET ALL DEMANDS

Utilities will bring gas to their franchise using transportation contracts. These contracts are demand based contracts which specify a daily delivery quantity which is held constant throughout the year. One of the challenges for the utility is to match the consumption profile of its customers, which vary seasonally, given a relatively constant amount of gas being brought to their franchise by the transportation contracts.

Historically, traditional natural gas reservoir-based storage has been the foundation of the gas utility load balancing plan. Ontario is fortunate that EGI owns a considerable storage facility in the Sarnia area at Dawn. However, the quantity of storage available at cost base rates is not sufficient for EGI to meet the needs of all of its franchise especially within the traditional Enbridge Gas Distribution (EGD) rate zone. As such, the utility chose to contract for additional reservoir base storage at market prices and/or a combination of synthetic storage and delivered gas at Dawn.

Prior to amalgamation, intervenors, including FRPO, have been encouraging EGD to use delivered gas at Dawn in the winter in lieu of storage. Further, we have proposed fixing the price of some of those deliveries ahead of the winter to capture market value and reduce some of the risk of weather-related inflation of costs at Dawn during the cold snaps. FRPO proposes that EGI fix the price of some winter delivered gas in advance of the winter as part of a disciplined portfolio approach to providing prudent load balancing of their delivery services.

a) Cost-based, Reservoir Storage is the Foundation of Load Balancing

The Ontario gas market benefits from a large amount of natural gas storage at the Dawn Hub. Given that much of this storage was developed decades ago, the cost of load balancing from cost-based storage is very favourable at C$0.330/GJ to C$0.387/GJ.[11]

However, the NGEIR decision resulted in a cap on the amount of the most economical tool for meeting in-franchise load balancing. Given the NGEIR imposed cap, EGD did not have sufficient cost-based storage, resulting in the purchase of storage priced at market rates supplemented by gas delivered to the hub in the winter.

b) Market-priced Storage Includes Value Not Beneficial to Ratepayers

In the Ontario market, EGI can sell the combined non-utility storage developed by predecessor companies Union Gas Ltd. (UGL) and EGD. This storage is sold to ex-franchise utilities, producers, marketers and even some large end-use customers such as power generators and large industrials. When an entity buys the market-priced storage that is provided with daily nominations to adjust the quantity which can be varied with demand, the tool has optionality to allow the entity flexibility to meet varying demands.

However, with market-based storage, the price of this storage is not based on its cost, but what the market will pay for the storage; hence, market-priced. The utility is primarily interested in the intrinsic value of storage that is often determined by the difference between the price of deliveries in the summer versus the price of deliveries at the same location in winter. This traditional cycle involves buying gas, injecting the gas in the summer, and withdrawing that gas in the winter to meet demand.

On the other hand, other storage market participants, such as marketers, view the extrinsic value of storage - which enhances intrinsic value by the optionality to inject and withdraw - that is not driven only by demand needs but also by market volatility. This flexibility allows the contract holder to extract value from commodity price

[11] EB-2024-0111 Exhibit I 4.2-FRPO-47

volatility by cycling the storage multiple times over the annual period. Therefore, the storage operator benefits from marketers' participation in the market to drive up the price of the storage beyond the intrinsic value associated with utility utilization.

c) Synthetic Storage as a Market-priced Alternative

As described earlier, a utility can create load balancing by selling gas to a marketer in the summer and receiving that same amount of gas in winter, which is often called synthetic storage. However, at the simplest level, for the marketer to make a profit on the transaction, they must add margin to the transaction which increases the price beyond the intrinsic value. Further, to guard against the perception of being accused of speculation, the utility will usually ensure that the same amount of gas is bought and sold with the same counter-party at the same time, thus locking in the dates at which the gas will be returned in the winter. This contractual approach makes synthetic storage much less flexible than purchasing storage rights to space and deliverability. While not the most economical, utilities can supplement their contracted storage rights with some synthetic storage.

d) Winter Gas Delivered at Hub - Economic Load Balancing Alternative

We have laid out some of the load balancing tools above, each with their respective costs and characteristics. However, a very simple and, in our view, economic approach is to contract for the deliveries of gas at the hub during the winter. The gas arrives above ground, obviating the need for withdrawal from storage, reducing the costs associated with fuel, UFG and deliverability issues as the contract balance becomes depleted. The single transaction reduces the transaction costs such as margin more effectively than synthetic storage. Also, since the purchases are not locked into equal daily quantities to return the gas sold to the provider in the summer, the purchases can be shaped to fit the anticipated demand of specific months during the winter.

For example, November is an important month at the storage hub. The traditional injection season finishes near the end of October. Before initiating the withdrawal of gas from storage, the operator desires for the pools to stabilize such that injected gas can migrate within the pool and a resulting maximum pool pressure can be established for planning and accounting purposes. Given that weather during this "shoulder season" can be fickle, if there is not sufficient weather-related demand, the utility does not want to contract for additional November deliveries that cannot be stored without disrupting the stabilization of the pools. Contracting for delivered gas during the winter creates the opportunity to start the deliveries in December and perhaps increasing the daily amount in January and February while decreasing the deliveries in March when, again, the weather-related demand can be quite variable.

While contracted winter deliveries can have great efficacy as a supplemental tool to cost-based storage, winter demand and associated price volatility can create additional risk. These risks come in two forms: Volume risk and Price risk.

i) Volume risk – the unpredictable nature of winter can vary demand considerably in the winter. A utility does not want to over-contract and buy gas for demand that does not materialize resulting in carrying costs and likely alterations to the next gas year supply plans.
ii) Price risk – since natural gas demand in North America varies with heat-sensitive customer consumption, all things being equal, the price of gas that is delivered on index will go up with cold winter weather and down with warm winter weather.

4) FIXED PRICE WINTER GAS – AN ECONOMICAL LOAD BALANCING APPROACH

To address the two risks identified in the previous section, Volume and Price Risk, FRPO has requested evidence and data to test the efficacy of our approach and to understand EGI's reluctance to apply a prudent approach to mitigating these risks on load balancing services. To address the volume risk, we asked EGI to determine the minimum amount of winter gas that would need to be delivered to supplement storage even in the warmest of winters, which they have determined to be 29PJ (or 29,000 TJ).[12] [13] This is one form of using scenarios to test the efficacy of the load balancing plan.

We respectfully submit that, as a starting point. the Board direct EGI to fix the price of delivered winter load balancing gas during the months of December to March at Dawn for a total of 20 to 25 PJ per winter using 3 to 5 transactions spaced throughout the year with none being after August 31st ahead of that winter season. Through the remaining submissions on this issue, FRPO will refer to this load balancing strategy as the Proposed Approach. By EGI implementing this Proposed Approach, ratepayers would benefit from EGI being in the market multiple times to transact and fix the price of the delivered gas not unlike Dollar Cost Averaging in investing.[14]

FRPO would also ask that EGI be directed to file pricing information (in aggregate to avoid confidentiality issues) for the cost of gas entered into for both of the transactions

[12] EB-2025-0065_20250916_Volume 1 Transcript pg. 67-69
[13] Exhibit JT1.8
[14] Dollar Cost Averaging is a strategy in which instead of making one lump-sum purchase of a financial instrument, the investment is divided into smaller sums that are invested separately at regular predetermined intervals until the full amount of capital is exhausted. The volatility of a financial instrument is the risk of upward or downward movement, which is inherently present in financial markets. DCA minimizes volatility risk by attempting to lower the overall average cost of investing. https://corporatefinanceinstitute.com/

to fix the price ahead of winter and the transactions for the remaining gas bought during the winter in a traditional manner.

a) Ratepayers Seeking Diversified, Economical Load-Balancing Approach

In Phase 1 of the Rebasing Proceeding, EGI proposed the addition of 10PJ of market-based storage.[15] Through development of the issues list, the provision of load balancing services was captured in the following issues:

> *10) Is the purchase of storage service at market-based rates by Enbridge Gas from Enbridge Gas for in-franchise customers appropriate?*
>
> *11) Is the proposal to add 10 PJ of market-based storage at a cost not currently included in the 2024 Test Year gas cost forecast appropriate?*

With this issue moved to Phase 2, the result of extensive negotiations on these and other issues resulted in a Settlement Proposal which included the following agreements which were subsequently approved by the Board:[16]

> *As part of an overall settlement of the Storage issues, Enbridge Gas has agreed to withdraw its proposal to add 10 PJ of market-based storage. The amount of storage to be included in rates is 217.7 PJ, which is the amount calculated using the aggregate excess methodology for bundled customers and contracted storage space by semi-unbundled customers. This means that Enbridge Gas will have 18 PJ of market-based storage (adjusted annually based upon need determined as noted in this paragraph). Where the annual adjustment results in the need for further storage, then Enbridge Gas will consider market-based load balancing alternatives.*
>
> *Enbridge Gas will manage the reduction from the current 26 PJ of market-based storage to 18 PJ of market-based storage by not renewing contracts as they expire.*
>
> *Enbridge Gas will manage its load balancing requirements above the 217.7 PJ of storage in a manner that it deems appropriate. Among other things, Enbridge Gas will agree to consider the use of forward contracts for winter gas purchases, though it will not commit to the use of that approach.*
>
> *Enbridge Gas agrees that in total it will need to explain and justify the prudence of its load balancing costs. This will be done as part of annual deferral and variance account disposition applications.*

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[15] EB-2022-0200 Exhibit 4, Tab 2, Schedule 1, Page 1
[16] EB-2024-0111 dec_order_Sett_Prop_EGI_2024_Rates_Ph2_20241129_esigned Exhibit N, Tab 1, Sch.1, pg.23

In our view, the Settlement Proposal establishes a more diversified approach. FRPO recognizes that not all of the storage space can be used as some amount must be left in storage in the spring to contribute to deliverability. For the purposes of illustration, we assume that somewhere around 150 PJ of winter load balancing demand comes from a blend of cost-based and market-based storage. This supply would be supplemented by a forecasted 64PJ of Dawn-delivered winter gas in 2025/26.[17] The 64TJ represents about 30% of the supply of load balancing gas from Dawn winter purchases.

FRPO views this reduction of the proposed storage level with increased reliance on winter purchases as a good step toward managing the volume risk and, in many years at an economically favourable price. However, that economy could be lost if all of those winter purchases are made on index or short-term fixed transactions in a very cold winter.

b) Staggered Multiple Transactions Reduces Price Risk

Throughout this current proceeding and previous proceedings, FRPO has been trying to understand EGI's reluctance to transact ahead of the winter to fix the price of winter deliveries. Using the minimum amount of Dawn-delivered winter gas as 29 PJ[18] as the amount to be delivered at fix rates, we asked EGI to provide an estimate of the gas cost if equal portions amounting to the minimum were transacted at intervals 3, 6, 9 and 12 months ahead of the winter season[19] to get an understanding of the impact on load balancing costs. For the winter of 2024/25, EGI calculated that the cost of the gas procured in this fashion was C$4.356/GJ.[20]

EGI elaborated that this price was almost equivalent to actual price of gas transacted at Dawn in this most recent winter (C$4.343).[21] We are unsurprised with this result as this approach to fixing the cost of the commodity is intended to stabilize the price to remove volatility. However, if EGI were to wait until the winter, the price of its transactions, whether short-term fixing or leaving the cost of gas on some form of index, would be impacted by the volatility that may arise from swings in weather patterns.

The potential impact of allowing load balancing gas to stay on some level of index (NYMEX + Dawn Basis or other) and only making short-term transactions to fix some pricing for deliveries[22] can be seen in analyzing the transactions that could have been made following this approach. In JT1.9, EGI provided the pricing that was available to be fixed for winter load balancing gas delivered at Dawn for the winter of 2025/26. The

[17] Exhibit JT1.7
[18] Exhibit JT1.8
[19] EB-2025-0065_20250916_Volume 1 Transcript pg.69-78
[20] Exhibit JT1.10
[21] Ibid.
[22] Ibid.

dollar-averaged price was estimated at C$4.978. While this price is higher than the previous winter, once again, the goal is price stability. An appropriate measure is what would the prices be at Dawn if the prices of the gas were not fixed and the transaction price was based on index and daily prices at Dawn for the months of December to March. Using market closing prices from November 28, 2025, the price of the four months, determined by an average of the forward monthly contracts for those months is C$5.96/GJ [23] which is almost C$1/GJ higher than the cost of transactions fixed by multiple staggered transactions following our Proposed Approach.

FRPO acknowledges the assessments of the last two winters demonstrate the potential economy of this approach (in 2025/26) but also shows that this lower cost is not always the outcome (2024/25). Those results are unsurprising as we are <u>not</u> saying that fixing the delivered price months or even a year in advance will always yield lower prices. What we are recommending is a strategy that, through multiple transactions performed ahead of the winter, the pricing achieved would be more stable for load balancing purposes by mitigating winter volatility. Even EGI acknowledges the importance of mitigating risk by diversifying timing in a portfolio as the company provided to Board staff in response to their interrogatory:[24]

> *Enbridge Gas actively mitigates price risk by procuring gas supply at* ***different times throughout the year,*** *at all accessible supply hubs, from a wide-variety of suppliers, using both indexed and fixed pricing mechanisms, resulting in a diverse and layered gas supply portfolio that is reflective of the overall market-value of natural gas. (****emphasis added)***

This direct acknowledgement of the role of building a portfolio approach ought to encourage EGI to use a similar approach to mitigating price risk for load balancing.

In gas markets, while utilities transact to meet physical needs, some other market participants transact to profit from the volatility of the market. With winter delivered natural gas, the price volatility is greatly increased over what is experienced in the summer due to the heat-sensitive nature of demand and variability in weather and weather forecasting. To demonstrate this volatility, while preparing these submissions, FRPO took a snapshot from a publicly available source of prices in the forward market for the January 2026 delivered gas at Henry Hub.[25]

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[23] This price was taken from a report of Canadian financial institutions. We had expected to file this data ahead of the hearing to allow us to walk through the ratepayer cost consequences with EGI but without an oral hearing, we can only inform from our sources.

[24] Exhibit I.2-STAFF-15

[25] Henry Hub prices are the prices used as the North American standard for transactions on the New York Mercantile Exchange (NYMEX). While regional prices can and will vary from Henry Hub, unless there other market constraints, pricing at other hubs like Dawn move directionally with NYMEX prices

PRICE OF JANUARY CONTRACT AT HENRY HUB (AUG-DEC. 10/26)[26]

While these prices are not for Dawn specifically, they demonstrate the volatility that can be experienced in the natural gas market as all market participants transact given their risk profile and their assessment of market value depending upon weather experienced and forecasted in combination with other variables.

c) A Longer Assessment Yields a More Robust, Economic Test

However, a much better test of our recommendation would be over a longer period of time. In Table 1 below, we have used data in a response provided by EGI in Phase 1 of the rebasing proceeding as we sought the intrinsic value of storage[27] determined with forward market pricing that was available at intervals of 9, 12, 18 and 24 months in advance of the winter.[28]

[26] https://www.cmegroup.com/apps/cmegroup/widgets/productLibs/esignal-charts.html?type=p&code=NG&title=Chart+-+Jan+2026+Henry+Hub+Natural+Gas&venue=1&monthYear=F26&year=2026&exchangeCode=XNYM&interval=1 As of December 10th, 7:05PM.
[27] As described above, the intrinsic value of storage is often determined by the difference between summer delivered gas and winter delivered gas
[28] EB-2022-0200 Exhibit I.4.2-FRPO-84

TABLE 1 – FORWARD CONTRACT PRICES FOR SUMMER & WINTER DELIVERIES

Filed: 2023-03-08
EB-2022-0200
Exhibit I.4.2-FRPO-84

Forward Summer & Winter Prices at Dawn

with FRPO Additions

Date	Apr – Oct (US$/mmbtu)	Nov – Mar (US$/mmbtu)	Sum/Winter Differential (US$/mmbtu)	Average Dawn Winter Price (US$/mmbtu)
2018/2019	(a)	(b)	(c)	(d)
Feb. 1/18	2.637	2.964	0.327	$ 3.34
Nov. 1/17	2.678	3.040	0.362	
May. 1/17	2.677	2.979	0.302	
Nov. 1/16	2.741	3.259	0.518	
	AVG, NOV-MAR	3.061		
2019/2020				
Feb. 1/19	2.533	3.002	0.469	$ 2.00
Nov. 1/18	2.472	2.915	0.443	
May. 1/18	2.275	2.749	0.474	
Nov. 1/17	2.521	2.937	0.416	
	AVG, NOV-MAR	2.901		
2020/21				
Feb. 1/20	1.780	2.427	0.647	$ 2.71
Nov. 1/19	2.211	2.757	0.546	
May. 1/19	2.403	2.868	0.465	
Nov. 1/18	2.346	2.801	0.455	
	AVG, NOV-MAR	2.713		
2021/2022				
Feb. 1/21	2.693	2.999	0.306	$ 4.40
Nov. 1/20	2.824	3.237	0.413	
May. 1/20	2.436	2.840	0.404	
Nov. 1/19	2.197	2.723	0.526	
2022/2023	AVG, NOV-MAR	2.950		
Feb. 1/22	4.385	4.708	0.323	$ 3.74
Nov. 1/21	3.684	4.019	0.335	
May. 1/21	2.417	2.755	0.338	
Nov. 1/20	2.446	2.933	0.487	
	AVG, NOV-MAR	3.236		

Please note: FRPO has enhanced the interrogatory response with two additional contributions:

1)We have added an arithmetic average of the prices provided by Enbridge that were available for winter delivered gas at Dawn in column (b).

2) In column (d), we have provided the average price of gas transacted at Dawn during the respective winters as a proxy for the price available to EGI for gas that was not forward contracted.

There are a number of insights we can make with this data. One of the initial insights is the fluctuation of the intrinsic value of storage. While the prices vary, one can see that the intrinsic value fluctuates between US$ 0.306-0.647/mmBtu. This variability provides supporting evidence for our recommendation that EGI transact multiple times in the year (or two) prior to the winter for which the gas provides load balancing.

To test the economic value of these options versus market-based storage, one would need the price of market-based storage available for that year. EGI does not generally contract for storage for one year. As displayed in their Summary of Enbridge Gas Market-based Storage Contracts,[29] EGI contracts a portfolio of 2 to 5 year contracts resulting in an annual market-based storage cost that is a blend of active contracts and pricing for that year. However, the actual price of the storage contracts is protected by confidentiality and was not in evidence in this proceeding.

The best recent information that allows for some comparison was provided by ICF in its study provided in support of EGI request for additional storage at the outset of the rebasing proceeding.[30] For the purposes of testing the proposal for incremental storage, ICF provided storage values in a range from C$0.87-0.96/GJ.[31] Using a prevalent exchange rate of C$1.37/$US in the month ahead of the publishing date of the ICF study (which was October 12, 2022), yields a range of $US 0.67-0.75/mmBtu for market-priced storage that allows for a comparison with the unit values in our table above. A further insight is that this range of storage prices is above all intrinsic values for the winters reported. Again, this is unsurprising as the market will value the storage with both intrinsic and extrinsic value.

FRPO acknowledges market-based storage prices do fluctuate also and therefore there is a possibility that the market-based storage price could have been less in some earlier periods on the table. What is clear though is that when that storage price range is compared to the intrinsic values for the then upcoming winter of 2022/23, the intrinsic values are considerably lower than the market-based storage value.

Another insight from this data is that the average of the prices that were available to transact for fixed-price, winter delivered gas at Dawn is lower than the average price of gas bought on the day at Dawn throughout the winter (comparing the highlighted data for each winter season) for most years. In our respectful submission, this data demonstrates the economic value of transacting to fix the price of gas ahead (even much ahead) of the winter period for which the gas will be used for load balancing.

[29] Gas Supply Evidence, Table 9, pg. 48
[30] EB-2022-0200 Exhibit 4, Tab 2, Schedule 1, Attachment 6
[31] EB-2022-0200 Exhibit 4, Tab 2, Schedule 1, Attachment 6, pg. 35, footnote 19

d) Fixed-price Winter Gas Represents Fraction of Load Balancing Portfolio

It should not be lost that by fixing the price of a maximum 29 PJ, there remains 35 PJ that would need to be procured in an average winter (more in a colder than normal winter) that will remain on index providing a price reflective of the market and balancing the portfolio of winter delivered gas. Therefore, less than half of the gas delivered in the winter for load balancing would be fixed.

At the same time, we would like to highlight that these winter gas deliveries would be on top of the amount of gas withdrawn from storage. Using withdrawals from the 217.7 PJ of cost-based and market-based storage (estimated at 150PJ) combined with delivered gas whose price is not fixed, 29 PJ would represent 10-15% of the load balancing gas used over the course of a winter. In our view, this approach is more prudent than leaving all winter delivered gas on some form of index at the outset of the winter where it would be subject to winter volatility.

e) The Proposed Approach is Not Precluded by OEB Commodity Decision

In the Technical Conference, FRPO attempted to understand EGI's reluctance to transacting to fix the price for load balancing services.[32] Instead, we got caught in semantics that were not resolved until EGI provided the requested undertaking.[33]

One issue that was clarified in EGI's response was their reference to market variability versus market volatility. We consistently requested their responses to our questions on how their approach impacts volatility which is what we were and are seeking. It is clear from a re-read of the transcript that the EGI was wanting to answer on the impact on variability. In the undertaking provided,[34] EGI noted that, by not fixing the price of the gas, the price paid for that gas would not "vary" much from the market price thus reducing market "variability". In our view, ratepayers draw little comfort from the notion that the price they pay reflected the market price - especially if that price escalates quickly resulting in EGI recovering those higher costs later.

More important than the semantics, it is clear from a re-read of the Technical Conference transcripts that EGI fails to distinguish between commodity that is bought to provide molecules for the System Gas program and purchases made at Dawn during the winter for the purpose of contributing to load balancing. We will address these purchases separately.

[32] EB-2025-0065_20250917_Volume 2 Transcript pg.1-10
[33] Exhibit JT2.1
[34] Ibid.

In exploring our Proposed Approach, we asked a number of times about transacting to fix the gas to be delivered in the winter for the purpose of load balancing.[35] However, EGI inevitably went to how they purchase commodity for their system gas program. These responses included their elimination of fixing the cost of natural gas procured for this purpose stemming back to the Board's decision in EB-2007-0606 and 0615.[36] The decisions of the Board were focused on the then on-going or proposed actions of EGD and UGL to transact forward contracts to reduce volatility of their respective System Gas programs. FRPO was not asking about natural gas procurement for the System Gas programs.

What we were asking about was the transacting to fix the price of winter delivered gas at Dawn for the purpose of mitigating the risk of load balancing costs. Load balancing, including storage and other tools, are a monopoly service of the distributor provided to almost all customers. EGI already provides risk management for load balancing through creating a portfolio of market-based storage contracts entered into annually for terms of 2 to 5 years. EGI does not know of any prohibition of the Board on the entering into a five-year storage contract.[37] In our view, EGI has demonstrated that it is unable or unwilling to differentiate commodity procurement from load balancing commodity purchases.

FRPO respectfully requests that the Board, in its decision on these matters, provide a determination of the appropriateness of transacting forward fixed-price contracts for winter gas deliveries for the purposes of load balancing while distinguishing its previously determined views on risk management for commodity procurement of the System Gas program.

f) The Proposed Approach is NOT Speculative

As shown in EGI's undertakings JT1.9 and JT1.10, FRPO requested that EGI provide the resulting unit cost of procurement of the minimum amount of winter Dawn deliveries to supplement storage for the purpose of load balancing. We did not ask them to target a certain price as if we had some "crystal ball" to know what an economic price for gas would be that winter. We simply asked for the prices that would have been available at 4 points spread 3 months apart in advance of the winter.

In elaborating on their response to our request for any study the company had done that showed the benefit of index price purchases, EGI goes on to create a scenario whereby in one single transaction November 1, 2023 for gas for the deliveries in the following winte of 2024/25. As outlined many times in the submissions above, FRPO requested

[35] Transcript Volume 1 20250916, pg. 57, line 22 to page 64, line 10
[36] Transcript Volume 2 20250917, pg. 8-9
[37] Transcript Volume 2 20250917, pg. 9, line 23 to pg. 10, line 1

multiple purchases in the year prior. EGI goes on to show that the hypothetical November purchase would produce a negative outcome for ratepayers, and we agree as their hypothetical approach is not our Proposed Approach. In fact, their hypothetical emphasizes why FRPO's approach is structured the way it is to avoid the risk of the timing of a single purchase. By fixing all of the winter gas in one transaction, EGI has created a situation where they have not diversified risk through multiple purchases. This type of putting all the eggs in one basket could be itself called speculative.

Ironically, EGI goes on to refer to our Proposed Approach as speculative[38] because we have no information about future prices. What is true is that we don't know the specific prices, but we do know that winter prices can be particularly volatile. Risk management or mitigation puts in place tools and instruments to protect against significant harm caused by uncertain future events. Our approach is the opposite of speculation since we are proposing that the transactions be staggered at multiple times during the year ahead of the winter to provide prudent transactions to mitigate volatility for load balancing purposes not unlike EGI's approach to commodity purchase provided in response to Staff-15, excerpted above. Further, we have shown the results in the EGI undertakings JT1.9 and 1.10 and in Table 1 which used previously available forward market prices compared to winter prices at Dawn. It is not speculative in that the pricing data has been provided for past winters. Moreover, our representative in this proceeding has employed a similar approach in providing gas management services to natural gas utilities with empirical results demonstrating the prudency of this approach.

US LDC's Employ Fixed-Price Delivered Contracts as Load-Balancing Tool

From the opportunity we have had to preview the submissions of the Consumers Council of Canada (CCC), FRPO understands that they are providing examples of US natural gas utilities that use fixed price contracting as part of their procurement strategies and some regulators in the US explicitly support this approach.

We want to take to provide a more specific example of a comparable utility to EGI. Nicor is a natural gas utility serving 2.2 million customers in the State of Illinois[39] and owns approximately 140 PJ of storage[40] making a very good comparator to EGI in both size and assets available (proportionately).

[38] Ibid.
[39] https://www.nicorgas.com/company/where-we-are/our-service-area/underground-storage.html
[40] https://www.nicorgas.com/company/about-us/history.html#:~:text=Today%2C%20Nicor%20Gas%20has%20eight,feet%20of%20annual%20storage%20capacity

From filings made by Nicor to its regulator, the Illinois Commerce Commission, we have extracted the following evidence:[41]

"These tables illustrate trends in seasonal demand, highlighting the importance of aligning storage levels with forecasted consumption. By analysing historical data and employing robust forecasting techniques, utilities can better anticipate fluctuations and allocate resources efficiently. This evidence underscores the necessity of ongoing review and adaptation to optimize supply reliability and cost management.

In Nicor Gas Exhibit 2.0, the tables show:

Source of Supply	Winter Volume (MMcf)	% of Portfolio
Nicor Owned Storage Withdrawals	~ 90,000	~ 45%
Fixed-Price Delivered Citygate Contracts	~60,000	~30%
Spot Market Purchases	~40,000	~20%
Pipeline Balancing/Other	~10,000	~5%

Nicor Gas's supply portfolio during the reconciliation period included fixed-price delivered city gate contracts. These contracts provided firm winter deliverability at the Chicago Citygate and were structured to hedge against price volatility. The Company complemented these delivered contracts with withdrawals from its owned underground storage fields, thereby diversifying supply and mitigating exposure to spot market fluctuations."

This excerpt provides an excellent comparator and Nicor succinct reasoning parallels the reasoning that FRPO is advancing in these submissions.

CONCLUSION

Like many aspects of natural gas utility services, risk management is the foundation for prudent delivery of reliable services to its customers. While EGI has built portfolios for many aspects of the Gas Supply Plan, the development of a portfolio of tools for load balancing service has not been emphasized. Part of their reluctance has been their concern about perception of hedging which in our view is misapplied to the prudent practice of mitigating risk for load balancing. We respectfully request that the Board direct EGI to initiate the practice of purchasing forward contracts as part of its load balancing practices while opining on the distinction between load balancing and

[41] Illinois Commerce Commission, Nicor Gas Ex. 2.0, ICC Docket 22-0701

commodity procurement hedging. Further, we ask that EGI be instructed to provide appropriate reporting to examine the efficacy of the approach.

B) DEMAND METHODOLOGY CHANGES DRIVE COST

As the Framework makes clear, any Gas Supply plan must begin with demand[42]—the forecast of what will be supplied and delivered. For annual demand, EGI and its predecessor companies, like most gas utilities, have relied on weather-normalized historic consumption adjusted for growth and other factors. Daily demand, however, is far more complex, requiring assumptions about climate, non-heat sensitive usage, contract customer obligations on design days, and even the definition of base temperature.

In the first phase of the rebasing proceeding, EGI introduced changes to its method of determining Design Day Demand, presented as a harmonized approach.[43] FRPO tested this evidence through interrogatories to assess its impact. While some responses reduced concern, our confidence rested primarily on EGI's own assurances:[44]

> *The proposed harmonized method increases the design day demand by 0.4% or 34 TJ/day and includes an increase of 113 TJ/day in the EGD CDA offset by decreases in the EGD EDA, Union North and Union South rate zones of 17 TJ/day, 17 TJ/day and 44 TJ/day respectively. As a result of the proposal to use the Union Gas design day demand method, there are no incremental transmission or storage facilities required to serve the design day demand as the process was refined but did not materially change.*

Yet in reviewing the Gas Supply evidence, we were struck by a significant and unexplained increase in Design Day Demand for the EGD CDA—an increase that drives additional transportation and contract assignments. Unlike past Gas Supply plans,[45] the daily demand evidence provided[46] does not include a comparable figure from the prior year, depriving stakeholders of a critical benchmark.

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[42] EB-2017-0129 Report of the Ontario Energy Board **Framework for the Assessment of Distributor Gas Supply Plans**, October 25, 2018, p.8
[43] EB-2022-0200 Exhibit 4, Tab 2, Schedule 3
[44] EB-2022-0200 Exhibit 4, Tab 2, Schedule 3, p.33
[45] EGI_2024 Annual Update Gas Supply Plan_updated 20240327_signed, p. 26, Table 4
[46] EGI_5-Year Gas Supply Plan_20250501, p. 25, Table 4

FRPO sought to understand the drivers of this 6% increase and its implications for the Dawn-Parkway system through interrogatories[47] and at the Technical Conference.[48] Despite these efforts, the responses failed to reconcile the discrepancy. More troubling, the offsets referenced in the rebasing proceeding appear to have vanished, and assurances of "no incremental transmission or storage facilities" ring hollow when increased transportation and third-party contracts still impose costs on ratepayers.

EGI provided parameters and outputs from its analysis in response to our Technical Conference inquiry.[49] However, EGI does not provide how these factors are parameters are applied in a formula nor a clarification on specific drivers that have varied the result over time.[50] These gaps in evidence are particularly important when one simply views the comparison of 2023/24 with the 2024/25 determinations in the extracted table:[51]

Comparison of 2023/4 & 2024/5 Heating Degree Day (HDD) & Design Day Demand

		2023/24 Forecast (EB-2024-0067)		2024/25 Forecast (EB-2025-0065)	
Line		Design HDD_w (°C)[7]	Demand (TJ/d)	Design HDD_w (°C)[8]	Demand (TJ/d)
		(a)	(b)	(c)	(d)
1	CDA-Niagara[9]	38.8 (-20.8)	3,378	37.8 (-22.8)	3,578
2	CDA-Central[10]	41.4 (-23.4)		41.4 (-26.4)	
3	EDA	48.2 (-30.2)	723	47.5 (-32.5)	723

What is clear from a simple read of the data, the design day temperature (HDDw) goes down or stays the same while the resulting calculated demand stays the same or goes up which is counter-intuitive.

At this point, without the benefit of an oral hearing to understand further, the answers provided leave us without the evidence necessary to assist the Board in its duty to safeguard ratepayers. Without transparency and reconciliation of these demand figures, the Board cannot be informed sufficiently to approve a plan that risks unnecessary costs and undermines confidence in the integrity of the Gas Supply process.

[47] Exhibit I.2-FRPO-11 to -FRPO-19
[48] Transcript Volume 1, Sept. 16, p. 45-57 and Undertakings JT-1.5 & 1.6
[49] Exhibit JT1.5
[50] FRPO-10, pg. 3, footnoted provides reference to the Rebasing proceeding, specifically EB-2022-0200, Exhibit 4, Tab 2, Schedule 3, paragraph 51 which describes the factors but does not provide an understanding of the formulaic steps to determine.
[51] JT1.5 Table 1

C) Data to Inform Understanding of Alternatives and Choices

As a generic comment on the Gas Supply Framework, FRPO would submit that the use of interrogatories and a Technical Conference provided a significantly more robust proceeding with insights gained from the process. We would request that the Board direct EGI to provide quantitative evidence in support of its evaluation of alternatives and choice amongst those alternatives similar to 2024/25 Enbridge CDA Shortfall – Holistic Analysis.[52] We would further request that the Board consider allowing for, at least an interrogatory phase, perhaps ahead of a stakeholder presentation for GSP Updates to ensure that a more fulsome understanding can be created prior to submissions.

COSTS

FRPO worked diligently throughout this proceeding, including the above submissions, to assist in testing and understanding the EGI 5YR Gas Supply plan. This effort included answering questions for and collaborating with other parties to enhance a shared understanding of the EGI evidence and our views and recommendations. As a result, we respectfully request the award of 100% of our reasonably incurred costs at such time as the Board calls for those costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED ON BEHALF OF FRPO,

Dwayne R. Quinn
Principal
DR QUINN & ASSOCIATES LTD.

[52] GSP Evidence, Appendix C