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VIA RESS, EMAIL and COURIER

November 18, 2019

Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario
M4P 1E4

Re: EB-2019-0137 – Enbridge Gas Inc. (Enbridge Gas) – 5 Year Gas Supply Plan – Reply Submission

In accordance with the Ontario Energy Board's correspondence dated September 27, 2019, enclosed please find Enbridge Gas' reply submission in the above noted matter.

Should you have any questions on this matter please contact the undersigned.

Sincerely,

(Original Signed)

Brandon Ott
Technical Manager, Regulatory Applications

Cc:
David Stevens, Aird & Berlis LLP
All Interested Parties EB-2019-0137, EB-2017-0129 & EB-2015-0238

<u>**OEB Consultation to Review Natural Gas Supply Plans**</u>

Reply Submission of Enbridge Gas Inc.

EB-2019-0137

November 18, 2019

A. Introduction and Overview

1. On May 1, 2019, Enbridge Gas Inc. ("EGI") filed its 5 year Gas Supply Plan (the "Plan") in accordance with the Ontario Energy Board ("OEB", or the "Board") Framework for the Assessment of Distributor Gas Supply Plans (the "Framework"). The Plan sets out how EGI plans to meet annual, seasonal and design day natural gas delivery requirements for its customers, while adhering to the Guiding Principles identified in the Framework.

2. As contemplated by the Framework, stakeholders were given the opportunity to submit written questions to EGI and a Stakeholder Conference was convened for EGI to answer questions and provide more information about the Plan. The transcribed Stakeholder Conference was held on September 23 and 24, 2019. The participants included EGI, OEB Staff and 17 stakeholders representing consumer groups, producers, a gas transportation company and other market participants. During the Stakeholder Conference EGI's witnesses, Mr. Jamie LeBlanc and Ms. Erin Liberty, made presentations addressing the written questions received and answered follow-up questions from stakeholders.

3. Following the Stakeholder Conference 13 parties submitted written comments.[1] The comments are either supportive of the Plan or raise discrete issues about the Plan. No stakeholder submits the Plan fundamentally fails to address the Guiding Principles in the Framework, or that a comprehensive OEB hearing is required to complete the review process contemplated by the Framework.

4. The current step in the process is the opportunity for EGI to respond to the stakeholder comments received and/or revise its Plan based on comments received. Following that, OEB Staff will prepare a draft Staff Report outlining its initial assessment of the Plan against the Guiding Principles. Parties may comment on the draft Staff Report, which will then be finalized and filed. The Board will review OEB Staff's final Report and decide whether any adjudicative process is required.

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[1] The following parties submitted written comments: Anwaatin Inc. ("Anwaatin"); Building Owners and Managers Association, Greater Toronto ("BOMA"); Canadian Manufacturers & Exporters ("CME"); Energy Probe Research Foundation ("Energy Probe"); Environmental Defence ("ED"); Equinor Natural Gas LLC ("Equinor"); Federation of Rental-Housing Providers of Ontario ("FRPO); London Property Management Association ("LMPA"); Ontario Petroleum Institute ("OPI"); Pollution Probe; School Energy

5. This Reply Submission sets out EGI's response to the stakeholder comments received. EGI has endeavoured to respond to the main points raised by each party but may not have touched on every item. Failure to respond to any particular item should not be interpreted as agreement from EGI.

6. As EGI explained in its filing, "[t]he objective of EGI's Plan is to identify an efficient combination of upstream transportation, supply purchases, and storage assets to serve sales service and bundled direct purchase customer annual, seasonal and design day natural gas delivery requirements while adhering to a set of gas supply planning guiding principles as outlined in the Framework."[2] As demonstrated in the Plan itself, and in EGI's Stakeholder Day Presentation, the Company has been successful in meeting this goal. EGI has created a flexible, responsive Plan that responds to the Framework and the Board's Guiding Principles and meets the needs of its customers.

7. Numerous parties expressed their support for EGI's Plan and EGI's approach to the Board's review process. CME called EGI's Plan "informative and well presented"[3] and LPMA noted it is "generally supportive of the five-year gas supply plan."[4] VECC submitted "the current plan forms an adequate basis for the QRAM price setting for the next 12 months"[5] and SEC found EGI's witnesses to be "very helpful during the Stakeholder Meeting responding to questions."[6] BOMA's submission offered a positive review of the Plan on a number of fronts, including to note that "[t]he Board should also be congratulated for using an approach which will enable Enbridge to respond to market changes, opportunities, and, most importantly, customer needs."[7]

8. Through their submissions, many parties focused on a forward-looking continuous improvement approach to how the Plan can improve in subsequent years, rather than on

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Coalition ("SEC"); Six Nations Natural Gas ("Six Nations"); and Vulnerable Energy Consumers Coalition ("VECC").
[2] Plan, page 5.
[3] CME Comments, page 2.
[4] LPMA Comments, page 1.
[5] VECC Comments, page 2.
[6] SEC Comments, page 1.
[7] BOMA Comments, page 3.

making criticisms of the current Plan. In this regard, BOMA noted “it is a work in progress, subject not only to continuous improvements but to a steady approach to fulsome integration…it would be inappropriate to micromanage at this stage.”[8] CME stated “the gas supply consultation process should undergo further refinement in the coming years.”[9] In suggesting an improvement to the Plan, LPMA suggested “EGI should report back to the OEB and interested parties as part of its annual update filings.”[10] These comments are consistent with comments made by OEB Staff at the Stakeholder Conference, who noted “we certainly expect to learn a lot about the process, and with your feedback we [are] going to track what worked well and what may need some improvement, and starting as early as next year we may implement some of that with the annual updates…”[11]

9. As described in further detail in this Reply Submission, EGI is committed to continuous improvement of its gas supply planning activities. EGI will be providing appropriate and responsive Annual Updates to its Plan and will ensure the Board and stakeholders have appropriate and necessary information about the impacts of evolving circumstances.

10. The criticisms and concerns in stakeholder submissions about EGI’s Plan were relatively limited. Where appropriate, this Reply Submission includes EGI’s specific responses to such items.[12] EGI will review and provide its comments in response to the draft OEB Staff Report as permitted.

11. As explained, EGI believes its Plan appropriately responds to the Framework and the Board’s Guiding Principles. EGI believes the Stakeholder Conference process has been an effective way to provide further information about the Plan to all parties. EGI submits the Board’s review process, inclusive of the Stakeholder Conference and submissions of interested parties, demonstrates that EGI’s Plan is reasonable and appropriate and that there is no requirement for an adjudicative process to determine outstanding issues related to the Plan.

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[8] *Ibid*. page 4.
[9] CME Comments, page 2.
[10] LPMA Comments, page 2.
[11] 1Tr. 2.

B. Regulatory Process & Cost Consequences

12. After extensive consultation over the course of a year and a half, built upon the insight and recommendations of several previous regulatory initiatives[13], the Board released the Framework on October 25, 2018. During the Board's consultation to develop the Framework a number of stakeholders suggested "the process should follow more of an adjudicative approach rather than the stakeholder model…"[14] The Board ultimately found that "the information contained in the review and assessment of gas supply plans is intended to inform other related applications and provide a basis of understanding about the plans for the OEB when it is deciding on related applications."[15] The Board confirmed "the assessment of the gas supply plans will not result in a decision on the costs or cost recovery."[16]

13. The Board clarified its expectations in a letter dated July 25, 2019 initiating a Consultation to Review Natural Gas Supply Plans ("Initiation Letter"). The Board noted it was in receipt of correspondence requesting expansion of the Plan review process set forth in the Framework, and also noted similar requests regarding process were made during the development of the Framework. In the Initiation Letter, the Board declined to add further process steps, indicating such steps "were ultimately not included in the Gas Supply Framework and the OEB is not persuaded that it is necessary to make provisions for them now."[17]

14. The 5 Year Gas Supply Plan consultation and review process represents a significant expansion of the gas supply review processes in place prior to implementation of the Framework. Prior to 2019 and amalgamation, Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union") filed their Gas Supply Memoranda in their Annual Rates[18] applications. EGD also filed some related gas supply evidence in these applications, while Union filed an Incremental Transportation Contracting Analysis in its annual Disposition of

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[12] While some of the responses included in this Reply Submission are fairly lengthy, in order to provide proper context and explanation, the length of these submissions should not be viewed as an indication of widespread stakeholder criticism of EGI's Plan.
[13] Framework, pages 5-6.
[14] Framework, page 2.
[15] *Ibid*.
[16] *Ibid*.
[17] Initiation Letter, page 2.

Deferral Account Balances applications.[19] Both the Gas Supply Memoranda and the Incremental Transportation Contracting Analysis were submitted to the Board for informational purposes; not for explicit approval. All information included in those documents has been transferred in expanded form to the 5 Year Gas Supply Plan. Importantly, the Board's new process under the Framework now requires EGI to go beyond the information provided in those previous documents by including new or expanded sections such as the Supply Option Analysis. The process as envisioned has met the "need for the Board to receive enhanced information and data" on this area of EGI's business as requested by FRPO in their comments.[20]

15. EGI explained at the Stakeholder Conference, "[a]s set out in the Framework, there will not be any specific approvals of the cost consequences of the Plan."[21] This is appropriate. Point in time approval of gas supply costs would be difficult to implement, because (as described below), "the costs associated with gas supply plans are always changing."[22]

16. Despite the Board's previous direction, several parties continue to question the Board's use of a stakeholder consultation approach to reviewing distributors' gas supply plans, instead calling for the use of an adjudicative approach. VECC provided its views at the Stakeholder Conference that issues ultimately "need to get resolved not by a staff report but by something in front of the Board."[23] SEC submitted comments "[t]he Board must ensure the annual gas supply updates are considered and tested through a hearing process."[24] Similar comments suggesting the Board's process should result in a Decision were brought forward by FRPO, who argued the Board "must ultimately approve the decisions of the utility".[25]

17. EGI submits that the foundation of the Board's process for the review of gas supply plans, namely the use of a stakeholder consultation rather than an adjudicative approach, remains appropriate. Though EGI expects this new process will evolve within the high-level

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[18] EB-2017-0086 (EGD) & EB-2017-0087 (Union).
[19] EB-2018-0105.
[20] FRPO Comments, page 1.
[21] 1Tr. 12.
[22] *Ibid*.
[23] 1Tr. 18.
[24] SEC Comments, page 2.
[25] FRPO Comments, page 6.

construct set by the Framework, the stakeholder consultation approach is an effective one that takes account of the dynamic nature of gas supply planning and the challenges inherent to regulating such activities on a granular, prospective basis.

18. Gas supply costs, be they commodity, transportation, or market-based storage costs, are a function of market prices. By way of example, slide 34 of EGI's Day 1 Stakeholder Day Presentation showed updated costs for a number of options considered in one of EGI's Supply Option Analyses. As explained by Ms. Liberty, "you can see that it is very fluid, and we expect that market pricing and forecasts will change over time. The analysis is very theoretical, because it is prepared so far in advance, and when it is time to make a decision we will take a deeper look at all options."[26] This dynamic was also noted by SEC, who observed that "the nature of gas supply decision-making is often very fact specific and their reasonableness can only be evaluated at the time the decisions are made or are expected to be made."[27]

19. It is difficult to approve gas supply costs on a prospective basis through an adjudicative process because the facts at hand change daily if not minute-to-minute and are not conducive to the timelines required for a full adjudicative review. Typically, the final decision on a future transaction will not be made until after submission of the Plan and/or its Annual Updates, because the final decision will make use of the best and most current information. The Board appears to acknowledge this reality on page 1 of the Framework, stating "[t]he 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."

20. It is unrealistic to expect the Board to pre-approve a specific course of action based on information affected by minute-to-minute market fluctuations. Situations may arise where continuing to comply with a Board Order would be more costly for ratepayers. To avoid that situation, gas distributors would have to frequently seek permission to diverge from Board Orders in order to remain prudent in their administration of the gas supply function as new information becomes known. In practice, this approach is unmanageable as it would require

[26] 1Tr. 89-90.
[27] SEC Comments, page 1.

frequent hearing and re-hearing of the same or similar decisions. Such a process would not create optimal decisions in the planning or execution phases of EGI's Plan and would create undue risks and burdens for the Board, gas distributors and ratepayers, who will ultimately bear any resulting incremental costs.

21. While the Framework is clear that the review process will not result in a decision on costs or cost recovery[28], it does state the review process "will provide the main OEB assessment of the cost consequences using the criteria set out in the Framework"[29]. EGI submits this expectation should be read together with the statement in the Framework that review of the Plan will "focus on determining whether or not a distributor has successfully balanced all of the guiding principles,"[30] including the principle of cost-effectiveness. Taking these items together, EGI anticipates the Board's focus on cost consequences "using the criteria set out in the Framework" will be to assess the degree to which the Plan is cost-effective, and the degree to which cost-effectiveness is balanced against other Guiding Principles. The Board offered clarification of its assessment of whether or not a gas distributor had demonstrated cost-effectiveness, stating:

> For clarity, cost-effectiveness does not necessarily mean the "lowest cost," reliability does not mean "reliable at any cost" and support for public policy does not mean "support at any cost" or "any level of reliability." Rather, the intent is to strike a balanced approach to the benefit of the customers.[31]

22. Parties have suggested EGI has highlighted QRAM as an opportunity to undertake discovery and testing of the cost consequences of implementing the Plan. CME submitted "EGI's witness did indicate that there would be other opportunities to investigate costs and the gas supply plan more fulsomely in forums such as QRAM applications."[32] FRPO and SEC's submissions echoed this point.[33] This is not the point EGI was trying to convey. EGI agrees with the statement made by CME[34] and SEC[35] that QRAM is meant to be a summary mechanistic process. In its evidence at the Stakeholder Conference, EGI was simply pointing to the fact that cost consequences of <u>some</u> gas supply decisions will be reviewed in

[28] Framework, page 2.
[29] Framework, page 13.
[30] *Ibid*. page 7.
[31] *Ibid*. page 8.
[32] CME Comments, page 2.
[33] FRPO Comments, pages 7-8 and SEC Comments, page 2.
[34] CME Comments, page 2.

other proceedings. To that point, at the reference noted by VECC and FRPO, Ms. Liberty specifically referred to her understanding that "the deferral application process, as well as the QRAM process…do speak to differences between actuals and plans."[36]

23. In its submission, FRPO claims that a variety of cost related information required by the Framework is missing in the Plan.[37] EGI disagrees. The Framework provides a list of cost related information to be included in the Plan's description(s) of Supply Option Analyses. As explained in the following paragraphs, EGI's Plan includes this information.

24. Under the heading "Supply Option Analysis" [38], the Framework directs that distributors will provide information that supports their planning decisions, including the following:

- A description of the costs associated with the various options considered and how the final option(s) was/were chosen;

- Analysis of the bill impact of options considered and how these compare to the chosen option(s), including a description of the considerations used to determine the final plan;

- A description of how the options considered (and chosen) impact price volatility and predictability and how the distributor determined what level of volatility was deemed acceptable for customers;

- A description of the various options considered to deliver reliable supply to customers and why the final option(s) was/were chosen;

- Analysis of the cost and bill impact of options considered and how these reliability options compare to the chosen option(s), including a description of the considerations used to determine the final plan; and

- A description of the distributor's approach to balancing reliability and flexibility within a plan and what the cost and risk trade-offs are associated with their approach. [39]

25. Below is an example from the Plan that demonstrates how EGI has met the above-noted requirements in the Supply Option Analysis section of the Framework. On pages 45 through 48 of the Plan, EGI presents a Supply Option Analysis for meeting design day in the Enbridge CDA. This section presents:

[35] SEC Comments, page 2.
[36] 1 Tr. 26.
[37] FRPO Comments, page 7.
[38] Framework, page 9.
[39] FRPO Comments, page 7.

- A series of available options to meet design day demands;
- The aggregate annual costs for each option;
- Incremental bill impacts for each option;
- The reliability of each option;
- The impact each option will have on the diversity and flexibility of the gas supply portfolio, which form critical components of EGI's risk mitigation approach and can in turn impact long-term cost-effectiveness and reliability;
- A detailed description of the ways in which these variables were balanced, including description of the trade-offs that were made; and,
- A preferred planning strategy, or a selection of the option which EGI intends to proceed with based on the information available at the time the Plan was developed, subject to changes in supply, demand, market variables or other relevant variables (e.g. system constraints, new options becoming available).

26. With the exception of price volatility, which was addressed implicitly in EGI's discussion of portfolio diversity, every piece of information expected by the Board (and referenced by FRPO) is explicitly provided. The same approach was taken in each of the EGI Supply Option Analyses presented. Contrary to FRPO's suggestion, there are no "missing elements" relating to costs in the Plan.[40]

27. In EGI's view this approach to costs, as requested by the Board and responded to by EGI, is entirely appropriate with a focus on the relevant decisions at hand rather than the aggregate costs of the gas supply portfolio. As noted on page 7 of the Plan, the key elements of the Plan "have been developed over a long period of time, and as a result, changes to the portfolio are limited to changes in demand requirements, contract expiries, and new opportunities as they become available in the market." To present the full costs of all upstream activities as though they were under review would be unproductive, as the majority of assets are already in place and are not available for reconsideration within the duration of the Plan due to the terms associated with EGI's contracts, which are purposefully staggered and diverse.

[40] *Ibid.*

28. In summary, EGI submits the prescribed process to presenting the 5 Year Gas Supply Plan (with indicative cost information) as outlined in the Framework and described above is a manageable and reasonable approach. It provides the Board and stakeholders with appropriate information and comfort that the utility has prepared and will implement a flexible, responsive 5 Year Gas Supply Plan that responds to the Framework and the Board's Guiding Principles.

C. Gas Supply Integration

29. EGI presented a combined Gas Supply Plan for all of its rate zones, where common information for the entire utility is presented at the outset (such as Process, Resources and Governance; and Market Overview), followed by information specific to the EGD and Union rate zones set out separately. Planning separately for different rate zones is nothing new; Union had distinct gas supply plans for each of its rate zones for many years.

30. The combined Plan is one of the steps taken towards integrating gas supply functions within the amalgamated utility. Other notable steps taken to date include[41]:

- Integrating the legacy gas supply teams into a single team;
- Aligning multiple processes for more efficient execution; and
- Completing EGI's first Blind RFP for market-based storage.

31. EGI acknowledges it is only at the beginning of its integration of the gas supply function. Work to fully integrate will continue, but this will take time.[42] While some changes can be made in the immediate term, others must wait until rebasing. Items that will be addressed at rebasing are discussed further in the "Demand Forecasting" section within this Reply Submission.

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[41] See the EGI Presentation from Stakeholder Conference ("EGI Presentation"), slides 10 – 13, and 1Tr. 32-38. Though not within the same immediate department that oversees gas supply planning and execution of the Plan, EGI's broader Energy Services department has also consolidated the gas control and nominations functions. This integration will help to ensure a more efficient and consistent execution of the Plan.
[42] EGI Presentation, slides 14-16, and 1Tr. 39-42.

32. A common theme in stakeholder submissions[43] is that EGI should move quickly and purposefully towards full integration of the gas supply plans for the legacy utilities, because this will save money for ratepayers (through increased purchasing power[44] and rationalization of contracts[45]).

33. As confirmed at the Stakeholder Conference, EGI is committed to working towards integration of processes and methodologies that impact the Plan.[46] Near term goals include a combined gas supply procurement policy and integration of IT systems that support gas supply execution and reporting. EGI has committed to providing a more detailed plan about the stages of integration as part of the first Annual Review process.[47]

34. EGI believes it is appropriate to temper expectations regarding the ratepayer benefits that may result from further integrating the Plan and gas supply activities. Further integration will not result in dramatic cost reductions. EGI's Plan and its related costs and decisions are directly correlated to the physical location and natural gas demand of EGI's customers. As an amalgamated utility, EGI's delivery areas will remain and persist into the future and are not affected by the amalgamation of the legacy utilities. As was the case both before and after amalgamation, EGI's Plan does not incorporate excess assets. With amalgamation having no impact on demand and no excess assets to shed, there is no alternative combination of assets as an amalgamated utility that would drive significant savings for customers relative to present conditions.[48]

35. The most apparent benefits for ratepayers will likely be realized through improved administrative efficiencies and streamlined decision-making which allows for enhanced resource productivity. To the degree these changes result in reduced O&M costs they may be shared with ratepayers through EGI's earnings sharing mechanism within the deferred rebasing period and will ultimately result in savings at the time of rebasing.[49]

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[43] See, for example, VECC Submission, page 2; CME Written Comments, page 3; and SEC Submission, page 2.
[44] SEC Submission, page 2.
[45] FRPO Submissions, page 2.
[46] 1Tr. 38-39.
[47] EGI Presentation, slide 15.
[48] EGI Presentation, slide 16, and 1Tr. 40-42.
[49] 1Tr 38.

36. EGI's execution and optimization of the Plan takes place within a competitive marketplace. Counterparties with which EGI conducts commercial business offer services at the market-clearing prices based on the supply and demand fundamentals that prevail at the time. If there are opportunities to achieve lower prices through larger purchases, EGI will be able to share those benefits with all customers. There is no guarantee larger purchases will result in lower costs. EGI does not have market power with respect to upstream assets, either before or after amalgamation, and will continue to procure assets required at the most competitive prices available at the time decisions are made.

37. The Gas Supply function might achieve nominal savings through optimization of the Plan, as opposed to the composition of the Plan itself. However, EGI must ensure the execution and optimization of its gas supply assets does not benefit one rate zone over another (unless or until rates are harmonized in a manner that renders this unimportant).[50] For example, in a situation where EGI temporarily optimizes a Union North upstream asset for the benefit of the EGD rate zone, the EGD rate zone will need to pay some form of compensation to Union North to ensure ratepayers in Union North are kept whole.

D. Demand Forecast & Methodologies

38. The demand forecasts are a key input into the Plan. They set the basis for determining what gas supply requirements must be met by the utility on a design day and on an annual basis. As explained in EGI's filing, "[t]he common starting point in developing EGI's Plan for either the EGD or Union rate zones is the creation of a demand forecast; an in-depth analysis that focuses on key factors impacting demand including customer growth, normalized weather, design day requirements, customer consumption patterns and economic outlooks".[51] In the Plan, the demand forecast (for both annual demand and design day) has been completed for each of the two legacy utilities using methodologies and criteria approved by the Board.[52]

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[50] *Ibid*.
[51] Plan, page 7.
[52] Described in detail in the Plan at sections 4.1 and 4.2 (EGD rate zone) and sections 11.1 and 11.2 (Union rate zones). See also EGI Presentation, slides 19 and 20. This was discussed in more detail by Mr. LeBlanc on Day One of the Stakeholder Conference, September 23, 2019 – see 1Tr. 56-61.

39. The processes of demand forecasting and supply planning are separate and distinct. EGI's demand forecast is not prepared by the gas supply team. The demand forecast is used for a number of purposes, not only the Plan. For example, the demand forecast is used for EGI's annual capital plan and long-term strategic plan and, where applicable, for rate applications. The same forecast is also provided for studies like 'Achievable Potential Study' which requires the Company's volumetric forecast as an input.

40. Therefore, as explained by Mr. LeBlanc at the Stakeholder Conference, "the annual demand is really an input into the gas supply plan, and not part of the plan itself".[53] The demand forecast is used as a base for the determination of the Plan and is not changed as a result of the Plan. Stated differently, decisions that are made through the Plan will not change or impact the demand forecasting methodologies and the demand forecasting methodologies will not be influenced by the Plan. In response to a question from Energy Probe about whether post-amalgamation there has been any change to the demand forecast or the peak demand methodology for the Union and EGD rate zones, EGI confirms that there has been no change.[54] The demand forecasting methodologies in place prior to amalgamation continue to be applied, and the results are reflected in the Plan.

41. The approach taken in EGI's Plan is consistent with the expectations set out in the Framework, which confirms that "[d]istributors already prepare volume forecasts and the Board expects the distributors to use its Board-approved methodology when preparing a gas supply plan."[55] Only a few parties raise any issue with the demand forecasts set out in the Plan.

42. One comment was the two legacy utilities use different approaches to determine their demand forecasts, and this should be reviewed.[56] EGI agrees there are differences in the way the demand forecasts are prepared for the rate zones of each legacy utility. Examples of differences are the approach to determining design day demand, the determination of

[53] 1Tr. 56.
[54] Energy Probe Comments, page 5.
[55] Framework, page 8.
[56] See, for example, Energy Probe Comments, pages 5 and 10; VECC Comments, page 2; LMPA Comments, pages 1 and 2; and Pollution Probe Comments, page 4.

average use, the calculation of demand reductions from interruptible customers and the degree day methodologies used.[57]

43. EGI cannot unilaterally harmonize and/or update its demand forecasting methodologies. Changes to the key methodologies used to prepare the demand forecasts require Board review and approval. Before that can happen, work will have to be done to evaluate and present a proposal explaining EGI's preferred approach and the reasons why. EGI plans to address such items as part of its rebasing proceeding[58] as directed in the MAADs Decision.[59]

44. A related item noted by several parties is that the two legacy utilities use different "versions" of SENDOUT, and this should be aligned.[60] EGI agrees this is something that will be considered and addressed as part of the process to integrate the Plan.[61]

45. ED asserts that considering DSM as a "mere input" into the demand forecast does not recognize potential demand reductions from additional DSM or IRP activities.[62] EGI's approach is appropriate. The Board is currently proceeding with a consultation process to develop a post-2020 DSM Framework which can be expected to set the expectations for what level of DSM activity (and associated demand reductions) is appropriate in upcoming years.[63] Any changes to the volume forecast resulting from updates to approved DSM activity will be reflected in future versions of the Plan.[64]

46. Finally, several parties assert EGI should undertake more "scenario analysis" to assess costs under the Plan where demand is substantially different from what has been forecast.[65]

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[57] 1Tr. 38-39.
[58] 1Tr. 64.
[59] EB-2017-0306/0307 Decision and Order, page 35
[60] See, for example, Energy Probe Comments, page 10; VECC Comments, page 2 and LMPA Comments, page 3.
[61] 1Tr. 45-46. For clarification, the legacy utilities currently use the same version, but different data frequencies in SENDOUT (Union rate zones use monthly, EGD rate zone uses daily).
[62] ED Comments, Page 1 and footnote 1.
[63] EB-2019-0003, Post-2020 Natural Gas Demand Side Management Framework. The Board's September 16, 2019 letter confirmed that the Board will undertake "a comprehensive review of the current 2015-2020 DSM Framework for the purposes of establishing a new framework for the future", which will include "consideration of the objectives to be achieved by DSM activities" and "program mix".
[64] 1Tr. 58.
[65] See, for example, FRPO Comments, page 2; of Energy Probe Research Foundation, pages 3 and 10; and LMPA Comments, page 2.

EGI did include scenario analysis in the Plan, including a report from ICF International which allowed for natural gas prices to increase and decrease based on the weather experiences in North America over an 84-year period.[66] This work, which is not addressed in any detail in the submissions by other parties, performed extreme risk/stress test analysis and confirmed the Plan is resilient to changes in circumstances and fluctuations in demands and market conditions. EGI's evidence explains the ways EGI can react and adapt to changes in circumstances as it implements the Plan throughout a year.[67] EGI does not believe additional scenario analysis is required.

E. Decision-Making Process & Supply Option Analysis

47. A central focus of the Plan is the Supply Option Analysis, which sets out the way EGI assesses decisions required within its gas supply, storage and transportation portfolios.

48. It is important to recognize EGI's planned portfolio only changes marginally over time, because there are many existing contractual commitments for transportation and storage.[68] Therefore, when EGI is looking at supply options, it is looking at upcoming requirements as a result of expiry of existing commitments or change in conditions or circumstances.

49. EGI looks ahead and evaluates options to meet upcoming needs. This analysis is presented in the Plan. The final decisions are not made until the time when the assets are required or decisions are otherwise required to be made, because market conditions and opportunities are often changing.[69] These decisions happen throughout the year/gas supply planning cycle; not just at one part of the year. At the time those decisions are made, the supply option analysis will be updated, as it needs to be made based off the most recent information available at the time.[70] Sometimes decisions need to be made in short order when opportunities or requirements arise (such as new open seasons or term-up requirements). EGI needs to have the discretion and ability to react and commit on a timely basis in order to execute successfully in the interests of ratepayers.

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[66] Plan, pages 59-60 and 97-98 and Appendix E.
[67] See, for example, Plan, pages 60 and 98. See also 1Tr. 72.
[68] EGI Presentation, slides 25-27; and 1Tr. 78-162.
[69] EGI Presentation, slide 34; and 1Tr. 88-90.
[70] 1Tr. 88-90 and 161-162.

50. When EGI evaluates options, and when EGI makes final decisions, it looks at a variety of attributes of the options being considered. EGI evaluates options based on cost, reliability, diversity and flexibility.[71] When making decisions, EGI prepares quantitative and qualitative analysis which both play a part in the decision making.[72]

51. EGI presented lengthy descriptions and details of its supply option analysis for both the EGD and Union rate zones in the Plan.[73] EGI addressed this topic in detail at the stakeholder consultation, with a 27 slide presentation and a lengthy stakeholder question and answer session.[74]

52. Very few of the stakeholder comments raise concerns about EGI's supply option analysis. Three ratepayer representatives raise discrete questions about the supply option analysis.[75] One supplier (Equinor) suggests a number of changes EGI should consider that would give more attention to Equinor's own Delivered Service option.

53. Energy Probe asserts that EGI's evaluation approach of not always choosing the lowest price options "does not seem objective and it is not clear why the OEB should have confidence in it".[76] This position ignores the fact that there are a number of balancing considerations to take into account when choosing gas supply options – in addition to cost, EGI also looks at the reliability of the options as well as how the options do (or do not) contribute to diversity of assets. Operationally, there are also certain points on EGI's system at which minimum amounts of gas must be received, and security of supply will always be given significant weight where such operational requirements are at play.[77] The Board has recognized the importance of these different evaluation criteria in the Guiding Principles set out in the Framework, recognizing reliability and security of supply must be assured, along with cost-effectiveness.[78]

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[71] The option evaluation process is described in slides 30-34 of the EGI Presentation. Specific option analyses undertaken are included in the Plan.
[72] 2Tr. 74.
[73] Plan, pages 43-57, 83-96 and Appendices C, D, H and I.
[74] EGI Presentation, slides 22-50; and 1Tr. 78-162.
[75] The Comments from Energy Probe and FRPO are addressed below. The Comments from ED are addressed in the Public Policy section of this Reply Submission.
[76] Energy Probe Comments, page 9.
[77] 2Tr. 62.
[78] Framework, page 7. See also EGI Presentation, slide 23 and 1Tr. 79, 84-86 and 2Tr. 62-63.

54. Energy Probe also asserts where the evaluation of options is "close" and one of the options being considered is owned by an EGI affiliate, then the utility should choose the non-affiliate option.[79] EGI does not believe this requirement is necessary and notes it would be hard to define what is meant by "close". The utility acts in the best interest of its ratepayers when making gas supply planning decisions. On occasion, this may involve an arrangement with an affiliate. EGI acknowledges such decisions will be subject to scrutiny when presented in a future Plan.

55. FRPO suggests the Board's Framework should allow testing of options not chosen.[80] EGI's transportation evidence already includes information and comparisons relevant to a variety of options considered but not chosen.[81] It is not clear what additional review or evidence would be necessary or appropriate. Indeed, it sounds like FRPO's suggestion could result in after-the-fact evaluation of decisions being made based on hindsight information. That would not be appropriate. EGI's Plan sets out the relevant options being considered for decisions or future expected decisions. Where a decision is made at a later date, the utility will undertake an updated evaluation, using the same approach as described in the Plan.[82]

56. FRPO also argues that EGI should have considered Niagara to Kirkwall capacity as an alternative for the 2021 New Capacity Open Season ("2021 NCOS") for service to the EGD and Union South rate zones.[83] The evidence, as explained several times at the Stakeholder consultation, is that EGI did include this option in its consideration but does not consider Niagara supply to be a viable option.[84]

57. Equinor's submission asserts "EGI did not properly address Delivered Service supply in the Plan and as a result the New Capacity Open Season 2021 (2021 NCOS) was analyzed

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[79] Energy Probe Comments, page 9.
[80] FRPO Comments, pages 7-8.
[81] See, for example the "Evaluation Matrix" tables found throughout the Supply Option Analysis sections of the Plan, as well as the Landed Cost Analysis found in the Appendices to the Plan.
[82] EGI Presentation, slide 34; and 1Tr. 88-90.
[83] FRPO Comments, page 3.
[84] Plan, Appendix I; EGI Presentation, slides 37 and 49 and 1Tr. 146-147 and 166-172.

incorrectly". This is coupled with the statement that Equinor "continues to stand ready and willing to supply Enbridge with [Equinor's Delivered Service]".[85]

58. Equinor sets out five specific "comments and questions" regarding the treatment of Delivered Service under the Plan. EGI disagrees with the premise of Equinor's submissions. EGI did and does consider Delivered Service as a supply option where available and appropriate. It is categorized as a type of Third-Party Service that is used to meet a portion of design day needs for the EGD rate zone.[86]

59. As Mr. LeBlanc explained at the Stakeholder Presentation[87], EGI (legacy EGD) typically uses Delivered Service in winter months to help manage heat sensitive load – there has not been need for such services on a year-round basis because there is already sufficient supply into the delivery areas in summer.[88] Mr. LeBlanc noted an important limitation of the use of Delivered Service, that it is less certain than supply underpinned by firm transportation held by EGI itself. This is an important consideration where Delivered Service is being chosen to meet design day delivery requirements.

60. Taking these considerations into account, EGI believes it is including proper consideration and use of Delivered Service in the Plan.

F. Gas Storage

61. Inclusion of storage assets in the Plan provides a cost effective, reliable and secure alternative to purchasing commodity when required by customers, which is consistent with the Board's Guiding Principles. Storage provides the Plan further operational flexibility and aligns with the targets to fill storage at November 1 and maintain sufficient inventory through the winter to meet design day withdrawal requirements.[89] Ms. Liberty provided more information about the benefits of storage in the Stakeholder Conference presentation,

[85] Equinor Comments, page 2.
[86] EGI Presentation, slide 36 and 1Tr. 92-95.
[87] 1 Tr. 93-95.
[88] See also 1Tr. 104.
[89] Plan, pages 42-43 and 80-81.

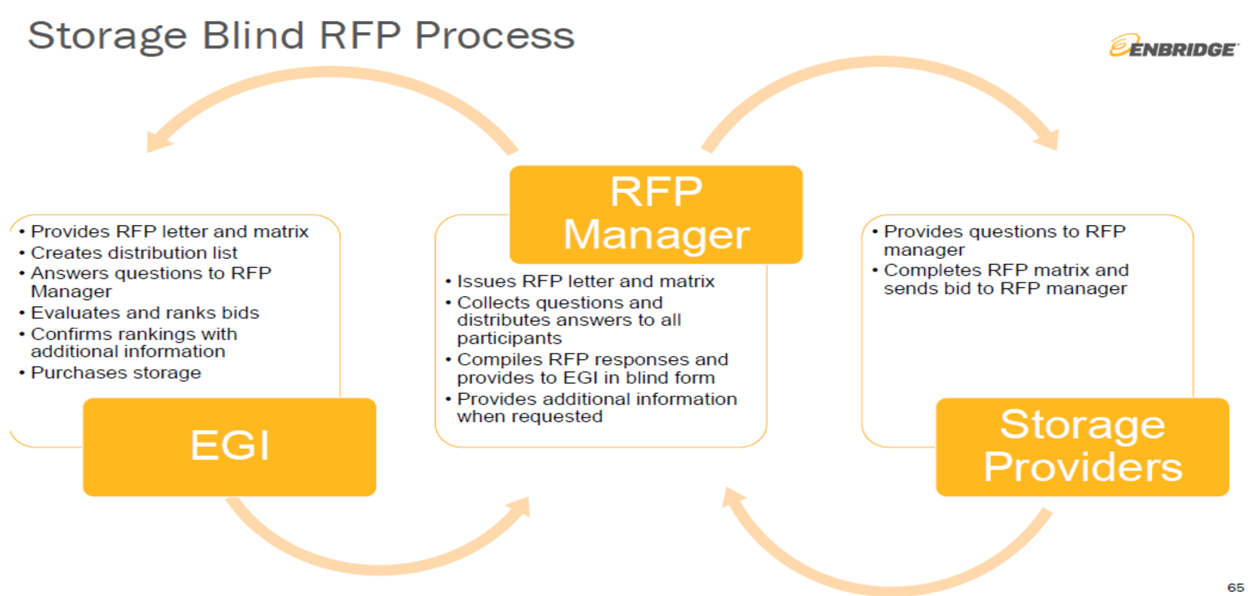
explaining how storage enhances operational reliability, provides supply security and limits exposure to the risk of high winter commodity process.[90]

62. Only one party raised any concern with the inclusion and intended function of storage as part of the Plan. FRPO asserts there should be more scrutiny of the amount of storage acquired for the legacy EGD rate zone to meet load balancing needs. FRPO indicates EGD has contracted for more market-based storage in recent years, and analysis should be provided in Annual Updates about why storage additions could not be better met through Dawn purchases.[91]

63. EGI does not agree with the underlying premise of FRPO's position. First, the amount of market based storage contracted by EGI is lower than asserted by FRPO (26.4PJ is the amount noted in the Plan, not the 30.5PJ asserted by FRPO).[92] Second, the amount of market based storage contracted by EGI (EGD rate zone) is not changing – there have been no storage additions – the amount forecast for 2020 is the same as the Board approved in EB-2017-0086.[93] In these circumstances, where there is no change in the amount of market based storage, EGI does not believe there is a need for additional analysis to be presented.

64. In its presentation at the Stakeholder Consultation, EGI provided details about the blind RFP process it uses when seeking market-based storage to replace expiring contracts. As summarized in the graphic below (reproduced from EGI's presentation[94]), the utility uses a process implemented in 2018 (and since improved) that aims to ensure the key members of the gas supply team who make decisions about which bid(s) to accept do not have information about (and will not be influenced by) the identity of the bidders.

[90] EGI Presentation, slide 62 and 2Tr. 11-12.
[91] FRPO Comments, page 4.
[92] FRPO cites the appendix to the Settlement Proposal from the 2018 DVA proceeding for EGD (EB-2018-0131, Exhibit N1, Tab 1 Schedule) for this assertion. A close look at the table set out at page 15 of that document shows that while the total market-based storage noted is around 30.5PJ, this includes a contract for 5PJ that expired on March 31, 2017 and was replaced by two contracts totaling 6PJ starting the next day.
[93] The total contracted storage as of April 1, 2017 was approximately 26PJ, which is the same amount as forecast for 2020 in the Plan (see page 57).
[94] EGI Presentation, slide 63.



65. The RFP process is coordinated by an arm's length RFP Manager (Deloitte) to ensure there is no preference given to bids providing service from the legacy Union storage.[95] EGI works with the RFP Manager and provides training to ensure the RFP results are captured in a blind matrix to prevent tipping off who the bidders are (e.g. volumes are all converted to GJ and rounded to millions).[96] The bids entered into the blind matrix are all-in prices, including commodity, fuel and any transport for service delivered to Dawn, in order to ensure that the gas supply team sees and evaluates bids for service from Michigan on the same basis as Ontario storage.[97]

66. Several stakeholders have provided comments and suggestions about EGI's blind RFP process. SEC and CME raise concerns that EGI may be able to decipher the identity of a bidder through details in the bid, or through information gathered in follow-up questions through the RFP Manager.[98] FRPO raises a different concern, stating that the blind nature of the RFP process means EGI will not have all the information needed to make the best decisions.[99]

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[95] More details are set out in Ms. Liberty's presentation, found at 2Tr. 13-15.
[96] 2Tr. 15, 20 and 22.
[97] 2Tr. 24-27.
[98] SEC Comments, page 2; and CME Comments, page 2.
[99] FRPO Comments, pages 5-6.

67. EGI believes the process it has implemented is appropriate and effective. The process strikes an appropriate balance between gathering sufficient information to support making cost-effective decisions and protecting the information of bidders, to avoid concerns of bias. EGI strives for continuous improvement in the design and delivery of the blind RFP process and will make changes and updates as appropriate. Where these changes are significant, EGI will report upon them in its Gas Supply Plan Annual Updates.

G. NGEIR

68. On the topic of gas storage, a number of stakeholders advance positions related to the Board's decision in the Natural Gas Electricity Interface Review (NGEIR) proceeding from 2006.[100]

69. Energy Probe asserts that because EGD and Union have amalgamated, it is now appropriate for all cost-based storage held by Union (100 PJ) to be available to the EGD rate zone at cost-based rates.[101] This position was expressly rejected by the Board in the MAADs Decision. The Board found the status quo would continue for the deferred rebasing period such that excess utility storage from the Union rate zones could be sold at market rates, with 90% of the benefit to be assigned to Union rate zone customers.[102] There is no basis to revisit that determination now.

70. Two stakeholders assert the Board should take steps now to reconsider the NGEIR Decision. VECC indicates the amalgamation of the two legacy utilities and harmonization of their gas supply plans provides an opportunity to review the "NGEIR policies".[103] FRPO alleges the storage market in Ontario is not competitive and says that this supports re-opening the NGEIR Decision.[104]

71. There is no need for the findings of the NGEIR Decision to be re-opened or re-examined. As discussed in the MAADs proceeding, the Competition Bureau reviewed the proposed

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[100] EB-2007-0551, Decision with Reasons, November 7, 2006.
[101] Energy Probe Comments, page 6.
[102] MAADS Decision (EB-2017-0306/0307), at pages 50-51.
[103] VECC Comments, page 3.

transaction between Enbridge and Spectra Energy in connection with its mandate to determine whether a proposed merger "prevents or lessens, or is likely to prevent or lessen, competition substantially". The fact the Competition Bureau issued a "no action" letter and did not review its decision within the following year represents a clear conclusion that the merger and resulting common control of the underlying distribution, transmission and storage businesses (including the unregulated storage business) did not have a substantial detrimental competitive impact on market participants.[105]

72. In any event, the Board appears to have already decided it is not appropriate or necessary to revisit the NGEIR Decision during the deferred rebasing term. During the MAADs proceeding, several parties argued for the NGEIR Decision to be revisited (and FRPO also argued for the reopening of STAR).[106] In response, the Board determined issues with respect to review of the NGEIR Decision and STAR "are outside of the scope of [the MAADs] proceeding".[107] Importantly, the Board did not stipulate these items should be addressed in different or later proceedings, as was the case for many other items raised in the MAADs proceeding but not resolved in that forum (examples of items the Board noted for review in later proceedings include, Unaccounted for Gas (UAF), treatment of impact of accounting changes, rate design to allocate rate adjustments between fixed and variable charges, cost allocation and a consolidated Utility System Plan).[108] Had the Board wished for EGI to address items related to the NGEIR Decision (or STAR) during the deferred rebasing term, then the MAADs Decision would have indicated that. It did not.

<u>H. Public Policy and the Scope of the Gas Supply Plan Review</u>

73. The Board's Public Policy Guiding Principle states that "[t]he gas supply plan will be developed to ensure that it <u>supports</u> and <u>is aligned with</u> public policy <u>where appropriate</u>"

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[104] FRPO Comments, pages 8-10. EGI does not agree with the attacks made by FRPO against the evidence from the NGEIR Decision – however, because there is nothing on the record of this proceeding relating to the "examples" given by FRPO, a detailed rebuttal is not provided in this Reply Submission.
[105] See Exhibit JT3.11 in EB-2017-0306/0307.
[106] See MAADs Decision, Appendix A, which summarizes the comments made by parties on these topics.
[107] MAADs Decision, page 48.
[108] MAADs Decision, pages 53, 47, 42, 41 and 34.

(emphasis added).[109] The Framework does not provide guidance about how this Guiding Principle should be interpreted, evaluated or implemented.

74. In EGI's view, the appropriate way to interpret this Guiding Principle is to assess whether the approach and outcomes set out in the Plan are consistent with relevant public policy. EGI does not interpret this Guiding Principle as requiring the utility to design a gas supply plan that goes further than the guidance provided in other proceedings and policy forums that set the path for implementation of public policy.

75. At a high level, EGI has addressed the Public Policy Guiding Principle by designing a Plan that is flexible enough to adjust to any changes that could arise as a result of public policy initiatives.[110] Where the expected outcomes from public policy outcomes are already known (such as the DSM volume assumptions), this is reflected in the demand forecast underpinning the Plan.[111]

76. Only three stakeholders discussed matters of public policy in their submissions.[112]

77. The most expansive of these is ED, which argues the Plan should be updated to address a range of public policy items.[113] ED requests the Plan be amended in four ways, including: compare DSM to supply options as part of the supply option and risk mitigation analysis; report on previous infrastructure projects to determine if the utility's assessment of the benefits was accurate; identify the need for any additional facilities highlighted by the supply plan with a discussion of how non-pipe alternatives will be considered; and set public policy performance metrics based on government emission reduction targets.[114]

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[109] Framework, page 8.
[110] 1Tr.171-172.
[111] EGI Presentation, slide 53 and 1Tr.163.
[112] See ED Comments, pages 1-8; Pollution Probe Comments, page 4; and Anwaatin Comments, pages 5-6.
[113] ED's Comments lay out a long list of benefits that DSM brings to society, customers and the function of operating a gas distribution business. EGI does not agree that this is appropriate venue for discussion of these items.
[114] ED Comments, page 3. ED's proposal to set public policy performance measures based on actual government targets is addressed below, under the heading "Performance Metrics".

78. Similar to ED, Pollution Probe asserts EGI should look at opportunities to “better integrate policy considerations into the Plan, starting with the following examples: Distributed Energy Resources; Community Energy Planning; IRP; and, Provincial Air Quality and Climate Change policies.[115]

79. EGI does not agree there is any need to amend its Plan to address these items.

80. As already described in the Demand Forecasting section above, the impacts of DSM and integrated resource planning (IRP) are an input into the Plan, rather than a focus of examination within the Plan. It is important to emphasize the Plan is highly flexible in its ability to respond to changes in the amount of DSM over time; flexibility which supports and is aligned with the public policy objectives pursued through DSM.[116] If the changes in demand resulting from DSM or other activities are larger than expected, this will be reflected in updated demand forecasts in later versions of the Plan and Annual Updates.[117] Where more becomes known about the impacts of DERs or community energy planning, then those impacts can also be reflected in demand forecasts.

81. The infrastructure items noted by ED (updating assessment of benefits from prior projects, and identifying additional facilities resulting from the Plan) are outside the scope of this process. If these items are to be addressed at all, it would be in the context of facilities approval proceedings. Nowhere in the Plan does EGI propose infrastructure or address costs or benefits associated with infrastructure construction; nor should it. The Plan’s purpose is to describe the demands of customers (after inclusion of the impact from demand-reducing initiatives) and consider the various options available to meet those demands. Where an option presented to and chosen by the gas supply team depends on new facilities being constructed, the approval of such new facilities is dealt with in a leave to construct proceeding. The time and place to hear the viability of available facility alternatives is within those leave to construct applications, where all relevant data and information is available for the Board in rendering its decision.

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[115] Pollution Probe Comments, page 4.
[116] EGI Presentation, slide 53 and 1Tr.164.
[117] 1Tr. 184.

82. Anwaatin argues for greater inclusion of RNG in the Plan, arguing this fits within the Government of Ontario's policy objectives.[118] EGI has explained how its Plan accommodates the inclusion of the planned voluntary offering of RNG to utility customers.[119] Again, even if Board or Government direction to EGI changes in the future such that the anticipated volume impacts of RNG are different than anticipated, the Plan is flexible enough to adapt.

83. One of the primary purposes for the establishment of the Plan and its review process was a concern that previous venues for consideration of gas supply, such as annual rate or deferral disposition applications, did not allow for sufficient focus explicitly on the gas supply function.[120] EGI is concerned that without sufficient boundaries on the scope of the Plan and its review, the same dilution of focus will take place within this process. If the Plan is expected to also meaningfully address DSM, distributed energy resources, IRP, community energy planning, general climate change policy, community expansion, rate design and rate relief, and subsidies for local natural gas production it will cease to be a gas supply plan and will no longer serve the purpose outlined in the Framework.

I. First Nations Community Expansion and Rate Assistance

84. Anwaatin's comments include requests for the Board to require EGI to amend the Plan "in order to outline how Enbridge will assess and ensure access to, and the affordability of, its services for its First Nations customers…expanding reliable natural gas distribution services at affordable rates to Indigenous communities should be a priority in the consideration of the Plan."[121]

85. EGI does not believe the Plan or this review process are appropriate venues to address these matters.[122]

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118 Anwaatin Comments, pages 5-6.
119 EGI Presentation, slide 59 and 1Tr. 168-169.
120 Framework, page 4.
121 Anwaatin Comments, pages 5-6.
122 If these matters are considered in other proceedings, and that results in changes in demand forecasts, then the resulting changes will be reflected in future versions of the Plan (including Annual Updates).

86. Issues about rate design and rate assistance are not matters that are within the scope of the Framework, or a Gas Supply Plan.

87. The question of natural gas access to unserved communities is a matter of facilities construction, something that would be considered by the Board in leave to construct applications relating to system expansion opportunities reaching unserved communities. Community expansion has also been a subject of recent public policy through Bill 32.[123]

J. Local Production

88. OPI provided a submission to the Board on behalf of Ontario natural gas producers. OPI's submission requests Board intervention in commercial commodity purchase agreements which are not subject to Board approval, alterations to distribution rates within the deferred rebasing period, and changes to EGI's operations, including "priority system access" and the ability to allow producers to construct EGI's meter stations.[124]

89. OPI's requests of the Board are beyond the Framework, and the scope of the Board's review of the Plan. As pointed out by Mr. LeBlanc at the Stakeholder Conference[125], the majority of OPI's recommendations amount to requests for EGI to alter its policies and practices in order to subsidize the operations of Ontario natural gas producers using ratepayer funds. EGI is not in a position to endorse the subsidies requested by OPI at the expense of other ratepayers.

90. EGI acknowledges the challenges faced by small natural gas producers operating in a market characterized by increasingly and persistently low commodity prices.[126] However, to the degree that local producers are experiencing challenges in remaining viable, EGI disputes that this is as a result of "phantom, prejudicial gas supply policies"[127] on the part of EGI.

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[123] The *Access to Natural Gas Act, 2018* SO 2018, c15.
[124] OPI Comments, page 13.
[125] 1Tr.197-198
[126] As pointed out in EGI's most recent QRAM application "natural gas prices have been trending downward since spring as Henry Hub spot prices hit multi-year lows. This was primarily caused by downward pressure from increased production in the US – see EB-2019-0193, Exhibit B, Tab 1, Schedule 1, page 2, paragraph 3.
[127] OPI Comments, page 3.

91. EGI is concerned OPI has submitted information to the Board which is incomplete and, in many instances, incorrect. Though OPI's requests are out of scope, EGI feels compelled to reply in order to correct the record in case the Board refers to the filings in this case in a future, more appropriate proceeding. EGI's response to OPI's submission is attached to this Reply Submission as Appendix A.

K. Performance Metrics

92. The Plan includes performance metrics that reflect the criteria the Board has established as a way to monitor the effectiveness of the Plan and how the Guiding Principles have been achieved, and as a means to drive continuous improvements.[128] In EGI's view, the performance metrics should focus on the execution of the Plan and demonstration of its adaptability. The measures proposed by EGI are directed at these types of items.[129]

93. Since gas supply costs are treated as a direct pass-through to customers and there is no opportunity for EGI to earn revenue on its gas supply activities, EGI does not expect performance measurement will be applied in any way that may financially reward or penalize the utility for its gas supply activities.[130] The performance metrics EGI has proposed are informational, rather than a measure of whether EGI has done "better" or "worse" than its forecasts of costs. This is appropriate, because EGI does not set or control the market, and because EGI does not try to "beat" the market.

94. At the Stakeholder Conference, EGI explained that its performance measurement scorecard will evolve over time, as results are filled in and parties evaluate whether the right information is being provided.[131] EGI specifically invited parties to provide suggestions in their submissions about what other or different items should be included in the initial performance measurement scorecard.[132]

95. Only two stakeholders included discussion of performance metrics in their submissions.

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[128] Plan, page 107.
[129] EGI's performance metrics can be found in Appendix J to the Plan, with a brief explanation of each measure's intent. Further explanation of what EGI aims to achieve with these metrics was explained by Ms. Liberty (2Tr. 99-104 and 2Tr.118-119) and is summarized on slide 76 of the EGI Presentation.
[130] Plan, page 107.
[131] 2 Tr. 113-114.
[132] 2 Tr. 114-115.

96. Pollution Probe proposes additions to the scorecard to "promote more effective transparency, accountability and performance measurement."[133] EGI notes that the items related to DSM, community energy plans and IRP proposed by Pollution Probe are out of scope from what the Plan seeks to accomplish). EGI believes the scorecard already includes appropriate reporting about variance between forecast and actual degree days. EGI acknowledges there could be reporting on the number of changes to the Plan that result from the stakeholder consultation process, but it is not clear what would be accomplished or measured by that reporting since the number of changes does not necessarily reflect or measure the appropriateness of the Plan.

97. Pollution Probe also recommends the Board require EGI to update its scorecard, in order to address "missing items".[134] There seems to be a difference in understanding here. The proposed performance measurement scorecard provided by EGI in the Plan is complete; there are no "missing items". What has not been included, because these are not yet available, are the results that will be used to populate the scorecard once there is a year of experience under the Plan.

98. Environmental Defence proposes performance targets that focus on government targets for DSM. The examples given are progress towards meeting CO2 reduction targets and whether all cost-effective DSM has been implemented.[135] Again, these are items that are out of scope for this proceeding. The setting of DSM targets, and the utility's results in meeting those targets, are items to be considered in the post-2020 DSM Framework Consultation, which will presumably set its own DSM-related performance metrics.

99. As a final comment, EGI reiterates its position that it remains open to review what performance metrics are appropriate once there is a year of experience and results.[136]

<u>L. Next Steps and the Annual Update</u>

100. EGI believes the Board's stakeholder consultation process for reviewing the Plan, and the Plan itself, are sufficient and appropriate, and do not require further regulatory

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[133] Pollution Probe Comments, page 6.
[134] *Ibid*.
[135] ED Comments, pages 7 and 8.
[136] 2Tr.114-115.

process beyond the OEB Staff Report. That said, EGI agrees with the sentiment expressed by stakeholders and OEB Staff regarding continuous improvement of the processes to prepare, present and review EGI's Gas Supply Plan.

101. EGI anticipates further comments and recommendations may be presented within the OEB draft Staff Report, to be filed after this Reply Submission. EGI will provide its comments and responses as permitted.

102. At this time, EGI believes it will be helpful to provide the Board and stakeholders with an indication of its current (work in progress) plans for the Annual Update process.

103. The Framework indicates that "the annual gas supply plan update …. will primarily focus on updates to the Outlook section of the gas supply plan, a description of significant changes from previous updates and a historical comparison of actuals to the Outlook."

104. EGI anticipates that its Annual Updates will include the items required by the Framework, but will also include other items identified in the process to review this first 5 year Plan. Examples include a description of EGI's plans to work towards integration of gas supply activities between its rate zones and reporting on results in the performance metrics scorecard. Appendix B to this Reply Submission includes EGI's current plans for what will be included in the Annual Update, and the proposed timing for submission and review.

APPENDIX A: Response to Submission of Ontario Petroleum Institute

1. OPI's central position is two-fold and summarized on page 1 of their submission. OPI believes producers have been subject to "historic myths and abnormal, imposed supply conditions, which Ontario producers faced (and continue to face) for decades due to certain phantom, prejudicial gas supply policies of the former Union…" OPI further submits a desire to re-set arrangements with EGI "in accordance with normal energy market conditions" and provides a series of recommendations to accomplish this.

2. EGI is quite certain producers have not been subject to "myths" or "abnormal" conditions, nor have they been subject to "prejudicial gas supply policies". As described below, EGI's arrangements with producers are in complete alignment with normal energy market conditions, and implementation of OPI's proposals would be an inappropriate divergence from basic market fundamentals and regulatory principles.

3. First, OPI asserts that EGI is putting local producers at an "inappropriate disadvantage" by paying a Dawn Index price for their natural gas.[1] Instead, OPI believes "the market price for Ontario producer gas is the commodity price paid by customers of EGI, namely the Total Gas Supply Commodity Charge."[2]

4. OPI has misunderstood the nature of the Total Gas Supply Commodity Charge. This charge is a QRAM regulatory construct meant to recover the actual pass-through costs of natural gas from customers; not a market price paid for commodity at a specific time and location. It incorporates a wide variety of functions including but not limited to a prospective forecast of natural gas prices over a 12 month period, a true-up of actual prices against forecast prices, a true-up of actual volumes against forecast volumes, an adjustment to the cost of gas in storage, and in the case of the Union South rate zone the cost of upstream transportation to bring gas from other markets into Ontario. The Total Gas Supply Commodity Charge is a blend of past, present and future prices representing diverse purchases from basins across North America, inclusive of some non-commodity costs, and is in no way a reflection of the market price for natural gas commodity at a specific time in a specific geographic location.

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[1] OPI Comments, page 8.

5. On a related note, at the Stakeholder Conference OPI stated "the utility is not to make anything on the gas that they sell, to my understanding. But they are clearly making money on [local producers'] gas that they're selling."[3] This statement is incorrect; EGI's gas supply function is administered on a pass-through basis. As per the explanation above, EGI assumes this misunderstanding stems from an incorrect understanding of what the Total Gas Supply Commodity Charge represents.

6. Unlike the Total Gas Supply Commodity Charge, a Dawn Index price is a market price and it is the appropriate market price to charge producers for their commodity. Not only is Dawn proximate to the physical locations of producers in Southwest Ontario, it is also where EGI may otherwise purchase commodity without the volumes from producers. Without producers, current local production volumes would be made up for through purchases at Dawn or at an alternate economical location to provide supply for ratepayers. To pay any amount higher than the price at Dawn would be to subsidize producers at the expense of EGI's ratepayers beyond the subsidies already in place discussed below.

7. Further, the use of a Dawn Index price marks a change made to the Gas Purchase Agreement ("GPA") in 2016 at the request of OPI by way of a letter to Union dated May 4, 2016. OPI's request was promptly considered and granted by Union as communicated by letter on August 10, 2016, and further discussed at a stakeholder meeting between Union and Ontario natural gas producers on August 22, 2016.

8. To the degree a local producer does not wish to sell gas to EGI at a Dawn Index price under the GPA, they may elect to sell their gas into the open market using EGI's M13 service.

9. Second, OPI points out that locally produced gas is "delivered into the EGI system downstream of EGI's storage assets and most of its infrastructure assets."[4] OPI further submits that locally produced gas purchased under the GPA "should receive an avoided

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[2] *Ibid*.
[3] 1Tr. 187
[4] OPI Comments, page 9.

cost of service premium as it is delivered downstream of the majority of EGI's assets…"[5] OPI has misunderstood the role of locally produced gas in EGI's system operation and, as a result, is incorrect in this assertion.

10. This matter was contested by Energy Objective and adjudicated by the Board some time ago in RP-2003-0063/EB-2003-0087/EB-2003-0097 in relation to the M13 balancing fee. The basic facts have not changed since that decision. As described in the Board's Decision with Reasons, "Union stated that Energy Objective's assertion that Ontario production gas was used to service local markets was irrelevant. On any given day, including peak days, there may be no gas deliveries from Ontario producers. This is the rationale for Union's imposition of a balancing fee for the gas producers."[6]

11. The Board went on to state the following regarding the operation of Union's system as it relates to locally produced natural gas:

> Union operates a fully integrated gas distribution system. Its operation is dependent upon the maintenance of a balanced series of inputs and outputs. Gas supply by Ontario producers necessarily augments and displaces other source of supply within the pipeline. The fact that any given producers' gas contribution to the system may be withdrawn prior to the end point of the distribution system should not result in any particular or preferential treatment. It is impractical and inefficient to attempt to track specific gas molecules within the system in order to tune transportation charges according to presumed and unverifiable distances. Such a practice would be inconsistent with the most cost effective operation of a fully integrated broad service distribution network.[7]

12. None of the above circumstances have changed since the Board's Decision with Reasons. The inconsistent nature of local production is such that EGI must plan to provide gas to these locations either way, including any required gas supply assets and distribution assets. There are no savings associated with the downstream nature of producers' gas, but there are costs. Local producers are not required to nominate their volumes for entry into EGI's system or issue invoices; EGI handles all administration in addition to the cost of balancing intermittent production injected into its distribution system. The cost of balancing intermittent sources should not be unduly subsidized by ratepayers, and is thus recovered from producers through EGI's transportation and balancing fee.

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[5] *Ibid*.
[6] RP-2002-0063/EB-2003-0087/EB-2003-0097 Decision with Reasons, page 150.
[7] *Ibid*, page 153.

13. Third, OPI asserts that "[t]here have been a number of instances where producers have been effectively blocked and told by the utility that it cannot accept volumes or pressures, without justification. In many of these instances, historically, the system has not had constraints."[8] OPI goes on to recommend that Ontario producers "should have some form of priority access when requesting to deliver local gas into the EGI system…"[9]

14. Without examining a specific instance EGI cannot comment on the situation referenced by OPI or the validity of the assertion that connection was denied in instances where "the system has not had constraints." Like all customers, EGI works with individual producers to facilitate connection, but must ultimately prioritize the effective, safe and reliable operation of its system appropriately. In instances where there may not be enough local demand or appropriate operating conditions to facilitate the potential supply a producer plans to inject into EGI's system, EGI simply cannot facilitate the connection without expensive facilities such as compression. Further, in instances where locally produced gas is unable to meet pipeline quality specifications as defined in the contract, EGI cannot facilitate continuing to accept locally produced gas into its system.

15. Fourth, OPI has asserted that "Ontario producers believe (know) that cost estimates received by EGI significantly exceed the reasonable cost to construct a Meter Station."[10] OPI goes on to provide Appendix 3B to their submission, comparing an actual Union Meter Station cost estimate to "OPI Cost Estimates". EGI uses certified and approved contractors to build its meter stations and is not willing to compromise the safety of its system. To charge producers below the cost of a meter station would result in a direct subsidy to producers at the expense of other ratepayers.

16. OPI's assertion regarding producers' treatment with respect to the cost of meter stations is particularly bold given the fee structure for meter station maintenance currently in place under the GPA, which has been fixed at an amount of $90 per station, per month since the 1990's. Though the cost of station maintenance varies depending on the size of the station,

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[8] OPI Comments, page 10.
[9] *Ibid.*
[10] OPI Comments, page 11.

the fees paid by M13 customers of $957.58 per station, per month are generally much more reflective of the cost to maintain producers' meter stations. This represents a significant subsidy realized by local producers contracted under the GPA.

APPENDIX B: EGI's Annual Update Proposal

1. The Framework describes the minimum information which distributors must include in their Annual Updates,[1] including:
   - Significant Changes to the Gas Supply Plan
   - Updated Gas Supply Plan Outlook
   - Three-Year Historical Review

2. The fluid nature of gas supply is such that different sections of the Plan may or may not be subject to an update in any given year depending on whether significant changes take place with respect to demand, supply options, or other relevant factors such as operational requirements. Some sections, such as Demand Forecasts and the Three-Year Historical Review, will be updated each year. Others, such as the Supply Option Analysis, will only be updated if conditions change from the original plan such that there are changes in market conditions, alternatives offered or a new preferred planning strategy has emerged based on updated information.

3. Beginning with the first Annual Update, to be filed by May 1, 2020, EGI plans to file a combined document for both legacy utilities, with each section being subdivided by rate zone.

4. On the next page is a draft outline for the form of the Annual Update document that EGI plans to prepare and file each year. In some years, certain sections may not be necessary, and in those years no updates shall be provided for those sections.

[1] Framework, page 20.

Section Heading	Description	2020 Expectations
Administrative Information	This will include an introduction of the Annual Update, and a summary of significant changes.	EGI will provide this in all Annual Updates.
Integration Update	An update on integration progress and an introduction to any new integration efforts or initiatives.	EGI anticipates bringing forward a more detailed plan for integration of gas supply.
Market Outlook	Where applicable, this will include an updated outlook on the market.	EGI anticipates minimal updates to the market outlook for 2020.
Demand Forecast Analysis	This will include updated annual demand and design day forecasts.	EGI will provide updated forecasts for annual demand and design day in all Annual Updates.
Current Portfolios	This will include updated commodity, RNG, transportation, storage, and unutilized capacity portfolios for the planning period. The transportation section will include the transportation contracting analysis for transportation decisions made since the previous filing.	EGI will provide updated portfolios for each rate zone. EGI will provide the transportation contracting analysis for decisions made since the 5 year Plan was filed for each rate zone.
Supply Option Analysis	This will include a discussion on significant changes to any assumptions and alternatives to meet demand requirements. If significant changes occur, it may result in updates to design day analysis, average day requirement, contract renewals, or storage renewals sections.	EGI anticipates few updates in 2020 to the preferred strategy of the Supply Option Analysis.
Gas Supply Plan Execution	If significant changes occur, this will include an updated procurement process and policy.	EGI will provide an updated procurement process and policy based on integration efforts discussed at the Stakeholder Conference.
Three-Year Historical Review	This will include an updated three-year review of heating degree days, demand, supply and unutilized capacity.	EGI will provide this in all Annual Updates, and anticipates little change in format, content and approach on a year over year basis.
Performance Measurement	This will include a completed performance metrics scorecard for the prior year and supporting documents as applicable.	EGI will complete the performance metrics scorecard for 2019 results.
Continuous Improvement	This will include any updates on continuous improvement strategies.	EGI anticipates in the 2020 Annual Update this section may incorporate demonstration of how EGI heard and responded to comments from the Board and OEB Staff in their reports/decisions relating to this review process.