BEFORE THE ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S. O. 1998, c. 15, Schedule B;

AND IN THE MATTER OF a generic hearing on Integrated Resource Planning.

Green Energy Coalition Final Submissions

March 31, 2021

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Contents

A. Overview

Enbridge and its pipeline company parent have a long history of earning shareholder returns by placing pipe in the ground. In response to the Board's direction it has tabled a proposal for an integrated resource planning framework. Despite widespread agreement about a number of its components, the company's proposal provides little assurance that it will deliver much more than the current inadequate practices for consideration and implementation of alternatives to gas facilities. In large measure this is due to the lack of specific, timely regulatory safeguards. While extending its annual Asset Management Plan (AMP) horizon from 5 to 10 years, there is no corresponding commitment that will ensure adequate forecasting, recognition of risks and uncertainties, meaningful consultation, timely assessment, or timely regulatory scrutiny.

Of particular concern to GEC is the utility's reluctance to recognize the implications of the emerging energy transition toward a low carbon economy, despite the company's acknowledgement of that impending transition. This reluctance is most clearly evidenced in the company's resistance to proposals for scenario analyses that would allow demand forecasts and assessment of alternatives in light of a range of lower carbon futures, and in its correspondingly blinkered outlook for the future role of gas infrastructure. The company's approach obscures a good understanding of the risks to both demand and price forecasts. It undermines a proper assessment of the costs and benefits of both facilities and IRPAs. And it ignores the potential for stranding of assets. Quite apart from the environmental implications of that approach, the economic implications are immense.

Equally concerning is the company's failure to accept the need for timely regulatory determinations that could avoid poor and needlessly expensive facility commitments. The company proposes leaving the review of decisions to pre-screen out or assess out IRPAs until leave to construct applications. As past cases have shown, this is far too late to allow for correction. The possibility of a penalty for such bad decision making, which is always difficult for a regulator to impose, is a poor substitute for least cost planning on a timely basis.

Several particulars of the Enbridge proposal are also fundamentally flawed, most notably its insistence on a DCF+ test that would conflate cost-benefit analysis with rate impact and equity analysis.

As set out below in greater detail, GEC proposes several critical changes to the company's proposal that address these concerns at a framework level, including:

Regulatory Review and Stakeholdering:

- Creation of a consultative working group with a broad mandate to enable early and informed review of pre-screening and IRPA assessments and to ease regulatory burden. Annual reports would accompany AMP filings. Where there is controversy identified in the working group report, and urgency and materiality, early Board intervention would be warranted. Otherwise review and formal approval of AMP results on a 3 year cycle would occur.
- Every third year the Board would review and formally rule on the AMP determinations and working group IRP reports. This would provide a timely regulatory backstop well in advance of need dates, and enable a portfolio assessment of rate impacts and any framework revisions. The utility would also be free to bring forward individual IRPA applications.
- Utilization of the working group to inform framework evolution and pilot designs.

Pre-Screening Criteria:

The following items should not be pre-screened out as the company proposes:

- IRPA evaluation for community expansion projects unless the specific expansion project is mandated by law.
- IRPA evaluation for reinforcement projects between $2 million and $10 million.
- IRPA evaluation for relocations and replacements between $2 and $10 million where capacity is being increased.
- IRPA evaluation for projects driven in whole or part by ex-franchise load where not previously contractually committed.

Economic Analyses:

- Separation of cost-benefit testing from equity analyses – so the Board and other parties can understand both what options are lowest cost and what equity/rate impacts may result from different choices.
- Initial utilization of the TRC+ test for cost-benefit analyses.
- Consideration of rate impacts by way of a broader portfolio analysis.
- A requirement for demand forecasts and IRPA assessments to include scenario analyses that cover a representative range of realistic climate policy futures and other significant economic risks.

- Subsequent refinements to the economic tests based on initial experience and working group input to capture further costs and benefits such as hedge, option, and commodity price suppression benefits.

Shareholder Incentives:

- Rate basing of IRPA-related expenses with subsequent consideration of further incentives.
- Allocation to shareholders of stranded asset risks associated with customer-specific and ex-franchise driven investments.
- The determination of who bears the risk of IRPA underperformance should be case-specific as it can be due to exogenous factors or due to the company's poor performance.

B. Procedural Background

A history of too little too late:

In its April 28th, 2020 Notice of Hearing the Board recited previous OEB initiatives addressing IRP dating from 2014 that recognized the need to improve Enbridge's planning. Most recently in the Bathurst Reinforcement leave to construct case the Board found "that EGD's process for considering DSM as a viable alternative to this Project was not appropriate".

OEB Staff captured the problem succinctly in their presentation slide:

> **"Lack of adequate lead time to meet system need has been persistent stumbling block to IRPA consideration in LTC applications"**

C. Purpose of the IRP Framework

GEC submits that the framework should serve the purposes of encouraging:

- Rational planning with due regard to uncertainties, policy trends, and economic risks and with particular recognition of the emerging energy transition toward a low carbon economy

- Least societal cost solutions while ensuring an appropriate degree of equity among customers
- Timely decision making to ensure reliability and avoid lost opportunities for cost-effective alternatives
- Efficient, informed, and meaningful stakeholder engagement
- Regulatory accountability and efficiency

The company would appear to agree with the latter four of these objectives but disputes the first one, which requires a recognition of the economic risks associated with the emerging energy transition and a realistic appraisal of the likelihood of significant changes in the utilization of the gas grid.

IRP in the context of a decarbonizing energy transition

Enbridge's pipe dream must be exposed for what it is.

Throughout the hearing the experts and the parties, including the company, recognized the inevitable 'energy transition' toward a decarbonized future. In light of that, and despite this being a framework proceeding, there was a considerable amount of discussion about the future price, availability and applicability of technologies such as RNG, hydrogen and electric heat pumps. While the Board is not being asked to make determinations about any given technology, the likelihood of, and degree of uncertainty about, these technologies playing a major role in the coming years will help to inform several framework level issues such as the inclusion of non-gas alternatives, and the need to address uncertainty and risk as those factors may affect economic assessments, as well as the appropriate timing of approvals.

Enbridge argues that policy goals such as net zero by 2050 are not sector specific. However, given that natural gas use accounts for close to a third of Ontario's emissions, it is inconceivable that the policy will not require a significant reduction in fossil gas use.

The discussion in the hearing of carbon reducing technologies shed light on the utility's objectivity, or lack thereof, about the future of gas infrastructure expansion, and the corresponding implications for the framework requirements, especially the extent of regulatory oversight required.

A few examples of the disparate views on these technologies will illustrate the point:

RNG and Hydrogen: Enbridge points to these technologies to assert that there is no significant risk of stranded assets, no need to shorten amortization and depreciation of facilities, and no need to assume significant electrification of loads to accommodate an energy transition toward Canada's carbon reduction goals. Yet the evidence before the Board is to the contrary:

- RNG in the Enbridge program costs 7.8 times more than natural gas[1]
- RNG potential is estimated in the MACC study to be 2.4% of 2018 gas volumes[2]
- Hydrogen currently costs 19 to 29 times more than gas[3]
- Hydrogen has 1/3 the energy by volume of gas and therefore a system switched to hydrogen cannot accommodate existing demand let alone growth in demand. Indeed, there is no evidence that hydrogen could be more than 20% by volume, which is just 6% by energy content, in existing gas pipes. That level could not even offset Enbridge's forecast residential demand growth over the next twenty years, let alone displace existing fossil gas.[4]
- In addition to the added cost of producing hydrogen and replacing piping susceptible to hydrogen embrittlement, most end uses would require a refit to accept significant hydrogen proportions which is both an economic and logistical challenge.

Heat Pumps: Enbridge's interrogatory responses portrayed electric heat pumps as too expensive to run and too disruptive of the electricity system to play a significant role in lessening gas demand. At I.Staff.14 in response to questions about the role of technologies in avoiding gas infrastructure Enbridge's response highlights how gas-fired electricity has a source efficiency of 40% versus the 95% efficiency for newer gas furnaces but fails to mention any of the facts discussed at v.2, p. 120 *et seq*, and provided by Mr. Neme in his oral evidence in chief, all of which lead to the opposite conclusion:

- Gas fuels only 7% of electric generation so much of any fuel switched heating load would not be fulfilled by gas-fired electricity generation[5].
- Gas generation occurs at centralized plants so moving the fuel burn from the furnace to the central electricity generator addresses gas system constraints by unburdening most if not all the distribution system facilities.
- New cold climate heat pumps can function to -35C with average heating specific performance factors as high as 15.2, which equates to an average coefficient of

[1] K2.1, p. 8 and see M2.GEC-ED at p. 51
[2] K2.1, p.10 citing OEB MACC
[3] K2.1, p. 9
[4] K2.1, p. 11, and demand forecasts in J1.7
[5] K1.4, p. 27

performance of 4.45. Even assuming 40% efficient gas-fired electricity generation the effective combined efficiency is 178%[6].

- The average efficiency of gas furnaces and boilers is closer to 80-85% not 100%[7]
- Ground source heat pumps can maintain full efficiency despite low ambient temperatures.
- Even at design day temperatures of -20C the latest air source heat pumps can achieve COPs greater than 2.[8]
- Enbridge estimates residential electricity rates at 2.2 times gas rates per GW assuming $170/tonne for carbon. Thus an ASHP with COP greater than 2 will increasingly be more cost effective for customers as carbon charges ramp up.[9]
- Because the electricity system winter peak is lower than summer peak, available winter system capacity can accommodate 2 GW of heat sensitive load, equivalent to roughly 10% of existing gas heating load and approximately 20 years of residential demand growth according to Enbridge's forecast, and this would likely ***lower*** electricity rates.[10]
- It is not an all or nothing choice. We do not need to see 100% electrification to see major impacts on gas infrastructure economics and choices, and it is highly likely that we will see some significant electrification.[11]
- The carbon intensity of gas heating will be dramatically more than that attributable to electric heat pumps powered by the mix of generation on Ontario's system.
- The high efficiency of heat pumps means that the economic proposition for customers and for the system as a whole has already shifted significantly.

At v.2, p. 126, at the end of GEC's cross examination on this topic there was agreement about most of these facts and about the uncertainty ahead, but Ms. Giridhar expressed the concern that the implications for the electrical system must be considered, not simply those for the gas system. GEC does not disagree, but the answer is not to ignore the matter entirely, it is to address the issue with the best available information and recognize the uncertainties by way of scenarios or probabilistic analyses.

These considerations should inform the framework's enunciation of goals and its elaboration of the mechanisms to achieve those goals.

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[6] K1.4, p. 28
[7] V.4, p. 96
[8] V.4, p. 97
[9] J3.8 Toronto rates
[10] V.4, p. 98
[11] V.4, p. 99

Enbridge, in an effort to constrain such considerations, points to the Board's statutory objectives. GEC submits that a proper reading of those objectives is no constraint on IRPAs:

> The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:
>
> 1. To facilitate competition in the sale of gas to users.
> 2. To inform consumers and protect their interests with respect to prices and the reliability and quality of gas service.
> 3. To facilitate **rational** expansion of transmission and distribution systems.
> 4. To facilitate rational development and safe operation of gas storage.
> 5. **To promote energy conservation and energy efficiency** in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.
>
> 5.1 **To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas**.
>
> (emphasis added)

GEC submits that in the face of an increasingly decarbonized future, *irrational* expansion (as opposed to expansion contained by cost-effective efficiency) can ultimately jeopardize the financial viability of the gas industry. Enbridge risks such irrational expansion, depreciates the value of energy efficiency, and jeopardizes societal economics by its resistance to recognizing the potential implications of decarbonization on price, demand, and technologies. Accordingly, we urge the Board to construct a framework that encourages the recognition of uncertainties in planning, that can respond to the realities of the unfolding 'energy transition', and that can act as a check on the utility's tendency to see the future in a way that places gas industry growth ahead of customer and societal value.

GEC submits that a framework that has as its purpose the encouragement of least cost planning and accounts for the risks inherent in the impending energy transition is entirely consistent with the Board's statutory mandate as highlighted above.

As set out below in greater detail, GEC submits that requiring scenario analyses in both demand forecasts and IRP assessments is a manageable mechanism to address this gap in the company's planning and IRP proposal.

D. Learnings from Other Jurisdictions

Both Gas IRP and Electricity IRP have lessons to offer. Guidehouse, ICF and Mr. Neme (EFG) provided an overview of the gas IRP framework in New York State. EFG also drew on the more widespread experience of DER assessments in the electricity world. While Enbridge initially suggested and continues to argue that there are important differences between the situation in eastern New York and that in Ontario, and between gas and electric utilities, under cross-examination all the experts and company witnesses agreed that these differences were relevant to inputs but not to the question of framework architecture (apart from the shareholder incentive structure due to Enbridge's single fuel role as opposed to ConEd's dual fuel business).[12]

Most notable is the fact that no other jurisdiction employs a DCF+ test in the manner that Enbridge proposes to assess non-pipe or non-wires alternatives to facilities. (See below under the topic: IRP Assessment Process)

New York State is the acknowledged leader in gas IRP and it is in the process of incorporating a Societal Cost test, realistic assumptions about carbon costs, and a triennial long-term regulatory review in its IRP process.

The National Standard Practice Manuals for Energy Efficiency (EE) and for Distributed Energy Resources (DERs) offer detailed advice on assessments including the complex issue of ensuring appropriate equity amongst customer groups (discussed below under IRP Assessment Process).

With respect to stakeholder participation, Mr. Neme provided insights gleaned from Vermont and Illinois. Again, Enbridge sought to highlight differences between Vermont and Ontario, but if anything, the differences suggest that a working group approach may be easier to apply in Ontario with our single dominant entity. It offers a means to cure Enbridge's weak stakeholdering and adjudication proposals while containing regulatory burden.

In short, the best practices and experience elsewhere all support the alterations to Enbridge's IRP model that we propose throughout these submissions.

[12] We note this exchange at V.2 p.71:
"MR. POCH: Okay. So I think we are in agreement that these differences that you've noted between your situation and ConEd's, they might affect -- they are obviously going to affect inputs, but they don't drive you to select a different test. You are not suggesting they should drive the Board to select a different test, and perhaps the one area that might -- where we might see a difference is in ultimately what the Board feels is necessary as a shareholder incentive because of this difference between a single fuel and a dual fuel utility, fair?

MS. VAN DER PAELT: I would agree. I would agree.

E. Approvals Sought

i) Guiding Principles

Goals of IRP

In Exhibit M2.GEC-ED Mr. Neme sets out his recommendation for the goals of IRP which goals are supported by GEC:

1. **Reliability**: The starting point for any IRP is that gas customers' energy needs must be safely met.

2. **Cost minimization**: A core objective of any IRP framework is that it must enable identification of and require deployment of the least cost mix of resources – based on an assessment of all relevant costs and benefits – for meeting reliability requirements.

3. **Risk minimization**: Another core objective of any IRP framework should be to minimize risk – both reliability risk and economic risk – of meeting reliability requirements. Economic risk is related to and should be reflected in cost-effectiveness assessments.

4. **Alignment with other governmental policy objectives**: IRP rules should lead to investments that are aligned with governmental policy objectives. If they do not, ratepayers will either pay additional costs in the future – and ultimately higher total costs – to re-align system investments with policy and/or incur unnecessary risk. Where possible, impacts on other policy objectives should also be reflected in cost-effectiveness assessments.

5. **Equitable consideration of all viable resource options**. To ensure that costs and risk are minimized, all resource options that could address reliability needs – both demand and supply options – must be considered and evaluated. Moreover, all of the costs and benefits each resource offers (not just those associated with T&D reliability) must be considered and evaluated. Though this might be considered more of a "how" to structure the framework than an outcome "goal", is it so central to successful IRP that it merits calling out.

6. **Alignment of utility interests with IRP goals**: If the utility cannot be sufficiently profitable while pursuing the other framework goals (above), achievement of those other goals will be undermined. Thus, utilities should have a financial incentive to implement the non-pipe solution where it is the most cost-effective option. Again, though this could be considered more of a "how" to structure the framework to meet other "goals", it is so central to achievement of those goals that it merits calling out.

While most of these proposed goals may be seen to be consistent with Enbridge's suggested goals, certain critical differences should be noted. Specifically, Mr. Neme's evidence elaborates on two such matters:

- cost minimization as a primary objective, as opposed to an incomplete version of rate minimization
- the need to minimize economic risk, not just reliability risk and in particular the economic risks flowing from climate policy related objectives

We address these differences in approach below under the topic: IRP Assessment Process.

A further area of consideration for framework goals is the topic of procedural fairness and effectiveness. This includes both accountability to the Board and a meaningful role for stakeholders.

Enbridge's proposal offers no opportunity for timely regulatory challenge of the screening out of alternatives at either the binary pre-screening stage or the IRPA assessment stage. While Enbridge will present a summary of its determinations to the Board in its annual AMP filings, scrutiny would be minimal apart from immediate budget considerations:

At TC-1, p. 17 Mr. Shepherd asked:

> So that is a change to your current position? You're now going to -- in future rate cases, you're going to say, yes, it's okay to ask questions about the AMP; is that right?
>
> MR. STEIRS: No, I don't think so…

Mr. Stevens added:

> …we may be able to respond to some of those questions. It's not, however, a sea change in how we view the examination of ICM requests in a particular rate case.

At TC-1, p. 75 the matter was further clarified:

> …Enbridge's decision to screen out a non-pipe solution. Enbridge's proposal is that that decision would not be open for adjudication by the Board in that annual rates case; right?
>
> MR. STEIRS: Correct.

Accordingly, the first assured opportunity for meaningful discovery and regulatory challenge of a decision to proceed with a pipeline rather than an IRPA would typically be at a leave to construct proceeding. Too late to evaluate, plan and implement most IRPAs.

As to stakeholdering:

At TC-1, p. 9 Mr. Quinn asked:

> …please clarify whether EGI subscribes to a guiding principle to the effect that any IRP framework that the OEB adopts for EGI should ensure that the process for dealing with disputes between EGI and other stakeholders over the alternative that should be implemented to solve the system constraint should be one that is fair and reasonable to those on different sides of the dispute.

Mr. Steirs responded:

> …to the extent that parties are seeking for opportunities for input, we set out a stakeholder plan to achieve that. But what you described is not one of the guiding principles that we've outlined.

And at TC-1, p. 75 Mr. Elson followed up asking:

> And so the stakeholdering day, you are proposing questions, but again, if I am understanding this correctly, you are not proposing a formal interrogatory process where Enbridge must answer questions relating to the prudence of its IRP decisions outlined in the AMP; is that correct?
>
> MR. STEIRS: That's correct.

Accordingly, there appears to be a need to augment Mr. Neme's list of guiding principles:

> **7. Timely and accountable assessment of alternatives:** Where possible, the screening, assessment, and regulatory review of projects must occur with due process and far enough in advance of need dates to allow for the potential substitution of alternatives.

ii) IRP Proposal Elements

a) Types of Available IRPAs

Technologies, policy goals and costs continue to evolve. FRPO made the point that contractual supply arrangements can be structured to obtain temporary assistance meeting regional system peaks and can be utilized as bridging solutions to buy time for cost-effective alternatives to ramp up. Creative solutions such as that should be encouraged by the framework. **GEC submits that the framework should not constrain the range of alternatives available for consideration in IRP.**

Enbridge has asked the Board to indicate whether it is appropriate for the company to offer or facilitate non-gas solutions such as electric heat pumps.[13] GEC is supportive of the inclusion of such options. **IRP should include non-gas alternatives. However, should the Board determine that Enbridge is not the appropriate entity to deliver or facilitate delivery of lower cost electricity options, or that it shouldn't be expected to pay for all of the cost of such solutions, Enbridge should nevertheless be obliged to analyze such options to ensure that it does not promote less than optimal solutions. Where the electric option is better, Enbridge should be required to work with electricity sector partners to institute the least cost alternative.**

Enbridge has indicated it will seek market delivery of alternatives where available. GEC agrees that market-based solutions are preferable when available to support the growth of that sector. That said, **where the market (with support of the utility) is not capable of delivering the optimal alternatives, Enbridge should be permitted to deliver and, as needed, to own such assets.**

Enbridge has proposed that widespread efficiency initiatives such as regional DSM programs be addressed through the next DSM framework.[14] GEC submits that the DSM framework as currently structured does not account for the full benefits of facilities avoidance and its budget does not reflect such savings. **To accommodate regional demand reducing programs the DSM framework would need to accommodate the potential for simultaneous implementation of several non-system-wide offerings (in addition to system-wide offerings), would need to reflect the value of facilities cost avoidance, and would need a potentially substantial budget increase to recognize both geotargeted facilities cost savings and the other broader system-wide objectives of DSM such as reducing customers' energy costs and carbon emission reductions. Accordingly, GEC submits that while the existing DSM framework can be harnessed to assist in the planning and oversight of IRPA investments, an IRP framework will best provide a means to assess and to fund DSM that addresses widespread facilities deferral or avoidance.**

b) IRP Assessment Process

Pre-Screening Criteria

In JT1.11 the company provides its current view of the information that will be provided in the AMP about projects pre-screened or assessed out. It amounts to a yes or no answer to whether

[13] See I.Staff.17
[14] Discussed at TC-2, p. 194

IRPAs are appropriate. Moreover, the response also suggests that the pre-screening criteria are not limiting:

> "Where a project or need is screened out, Enbridge Gas notes that it will be done either on the basis of an objective binary screening criteria established by the Board as part of the IRP Framework, or *on the basis of **some insight** regarding the Company's obligation to safely and reliably meet the needs of its customers*." (emphasis added)

Enbridge's proposal that the application of the pre-screening criteria is not to be subject to any timely meaningful oversight and that the basis for eliminating IRPA consideration is not even strictly limited by those criteria is unacceptable.

In JT1.5 and JT1.7 Enbridge indicates that if potential Board adjudication of its pre-screening or assessment determinations prior to LTCs were to be required it should occur in the year following the company's decision, to allow time for reconsideration.

As discussed below under the topic Stakeholdering, GEC submits that a working group review of pre-screening decisions could act as a means to identify controversial determinations eliminating IRPAs that would require Board review.

> **GEC proposes a timely mechanism for a working group to review pre-screening decisions, to report on them to the Board annually, and for timely Board review where warranted.**

Below under the heading *Future IRP Approvals Sought - Plan Applications* we propose a triennial escalation of the AMP review process. That process could be utilized for Board review of contested pre-screening determinations where time allows. Where lead time would not allow that process to provide a timely remedy, the Board could convene a review of a particular pre-screening decision in an annual IRP proceeding, or discretely, if urgency and materiality so dictate.

EGI's Proposed Criteria:

Enbridge proposed six pre-screening criteria and added a seventh during the hearing. In addition, Enbridge would preclude projects supported by ex-franchise 'needs' and make IRP for reinforcements under $10M optional. We deal with each of these in turn:

i. Safety

In J1.4 Enbridge Gas has acknowledged that longer-term safety related system constraints or needs may be appropriate for an IRPA solution and would be considered on a case-by-case basis. Accordingly, **GEC submits that the criteria be confined to emergent safety needs.**[15]

ii. Timing – (3 Year Lead Time)

Enbridge has acknowledged that this criterion should not exclude supply-side solutions or bridging alternatives.

Mr. Neme has indicated that 3 years is a reasonable default cut off at the outset while experience is gained.

GEC submits that the Board should only endorse this criterion as an interim proposal while awaiting further learnings. It should not apply to supply-side or bridging alternatives.

iii. Project-specific Considerations - (Ability to leverage non-utility investments)

Enbridge has withdrawn this element indicating that it is subsumed within the Safety and Pipeline Replacement and Relocation Projects criteria.

iv. Customer-specific Builds

Enbridge has suggested that where there is full CIAC or a long-term firm services commitment IRP be inapplicable.

GEC submits that a long-term firm services commitment should not preclude IRP as other customers will still bear residual financial risk should the customer fail to fulfill its commitment. Alternatively, Enbridge should be required to carry such risk.

Further, GEC submits that this criterion be amended as recommended by EFG[16]:

If supplying gas to a new large customer requires upgrading the capacity of elements of the T&D system that serve many other customers, then the utility should be required to consider non-pipe alternatives. In addition, Enbridge should also proactively work with potential new customers to consider non-pipe alternatives early on where that would reduce overall system costs and risks.

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[15] See also V2, p. 90 where EGI agrees it should be only for emergent safety concerns. EGI's Argument in Chief concurs.
[16] M2.GEC-ED, p. 31

v. **Community Expansion & Economic Development**

Absent a legal requirement to pursue a particular project, there is no reason to exclude such situations from the IRP regime. This is particularly so given government policy goals of reducing carbon emissions.[17] The mere availability of such funding absent a requirement to proceed should not excuse the potential project from the ambit of IRP. As evidenced by the $64,701 per customer subsidy that was given to the North Bay Community Expansion Project, It is a disservice to potential customers and to existing customers or taxpayers who are being asked to cross-subsidize expansions to proceed with less than optimal solutions.[18] The cost to connect the 210 projects listed in the Board's report on *Potential Projects to Expand Access to Natural Gas Distribution* would come to over $58,000 per customer.[19] For less than that all the residences in those communities could enjoy lower heating bills with deep building envelope retrofits and high efficiency cold climate heat pumps.

Absent a *legal requirement* to extend service to the particular community, Enbridge should be required to work with the IESO and electricity distributors to ensure that the least cost alternative is pursued in all cases.

vi. **Pipeline Replacement and Relocation Projects –** (if a project is being advanced for replacement or relocation of pipeline, and the cost is less than $10 million, then that project is not a candidate for IRP analysis.)[20]

Enbridge added this sixth pre-screen and then qualified it in the oral hearing to apply only where the pipeline is not being enlarged. However in the reissuance of its list of pre-screening criteria that qualification does not appear.

This criterion should be amended to read: If a project is being advanced for replacement or relocation of pipelines, and the cost is less than $10 million, <u>and its capacity is not being increased</u>, then that project is not a candidate for IRP analysis.

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[17] At M2.GEC-ED, p. 31, EFG has recommended that "At a minimum, such expansions should not be permitted unless either (1) mandated by government; or (2) Enbridge can demonstrate that (A) they would lower total long-term (e.g., over 30 years) energy costs for customers in the Community, relative to alternatives (including electrification), and including consideration of at least a significant probability of having to replace increasing amounts of fossil gas with much more expensive renewable gas; (B) the Community is prepared to pay for the entire cost of the gas line extension; and (C) existing ratepayers will never have to pay for the capital costs of the line extension, even if demand for gas drops dramatically in response to future climate policy regulations (i.e. with the risk born by either utility shareholders and/or the Community receiving the line extension)."
[18] J2.5 and J2.6 which indicates electric ASHPs would be $150-250 less expensive annually.
[19] Report to the Minister of Energy, Northern Development and Mines and to the Associate Minister of Energy: Potential Projects to Expand Access to Natural Gas Distribution, Table 3 – (total funding/total customers year 10)
[20] JT2.11

vii. Ex-Franchise demand driven need:

Enbridge has indicated that it does not view a facility that is justified in whole or part by contracted ex-franchise transportation needs as subject to IRP because it cannot influence alternatives available ex-franchise. However, it is clear that domestic customers face economic risks from ex-franchise transportation contracts that may not be extended after their typical 15 year life.[21]

If ex-franchise load (beyond the term of existing contractual commitments) is not accommodated by incremental facilities, ex-franchise customers will have IRPA options to consider. Ontario customers should not be forced into a less than optimal alternative to meet domestic needs plus existing contractual commitments to ex-franchise customers and be left carrying economic risks due to future, avoidable ex-franchise commitments.

If an IRPA can potentially accommodate domestic needs and existing ex-franchise contractual commitments there is no reason to exclude IRP analysis due to future, avoidable ex-franchise load commitments. Furthermore, the company's shareholders and its ex-franchise customers should be required to pay for incremental infrastructure or IRPA expenditures beyond that necessary to meet domestic need and bear any risk of future stranding of such assets.

viii. Reinforcements under $10M

In JT1.7 the company states: "Enbridge Gas does not believe that it is necessary to have formal adjudication of decisions not to proceed with IRPAs for smaller projects (those under the LTC threshold)." Accordingly, where Enbridge decides not to pursue an IFPA, this could amount to a pre-screening criterion. However, during the hearing the discussion suggested that the company may have resiled from that position. Given the competing demands of project cost effectiveness and process cost effectiveness this should be clarified.

GEC submits that there is no reason to prefer pipeline reinforcement over alternatives such as energy efficiency with its many added benefits for long-term savings, resiliency, and environmental impact reduction. Just as IFPAs entail planning effort so too does reinforcement of pipeline facilities. If IRPAs are more cost effective they should prevail and a decision by the utility to reject IRPAs should not be shielded from regulatory scrutiny. However, we recognize that the cost of assessing and of regulatory review of very small projects can outweigh benefits. Accordingly, GEC submits that reinforcement projects with a projected cost of between 2 and 10 million dollars should not be pre-screened out, should be reported on individually in the

[21] See TC2 p. 82, JT2.10, V.2, pp. 128-129 and J2.8

AMP, should be subject to working group review, and subject to Board review in controversial cases.

GEC submits that IFPA analysis and regulatory scrutiny for controversial reinforcements over $2 million is appropriate. Privileging all pipeline options under $10M is contrary to the objectives of the Act, and contrary to public policy. A streamlining of the approval process for smaller IRPA projects may be appropriate.

Assessment Tests

The EBO 134 DCF or DCF+ Test is the wrong test for IRP

Utility revenue impacts are due to transfers between the customer and the utility and are thus relevant to an assessment of rate impacts, but not to an assessment of costs and benefits. The focus on revenues in the EBO 134 DCF test is an artifact of the genesis of that test. It was developed to look at the impact of system expansion on existing customers' rates when the benefit of system expansion for new customers was taken as a given. In other words, EBO 134 was designed to answer the question of whether existing customers would subsidize new customers. It does not answer the core IRP question of what solution to meeting customers' energy needs is lowest cost. Put another way, like conventional DSM, IRP requires assessment of costs and benefits, not just rate impacts.

EGI's answer to this criticism is that it will sum the results of the three stages of EBO 134 and that will preserve transparency and allow for an overall cost-benefit conclusion. However, as we set out below, the three-stage test, as envisioned, compromises transparency, and the summation of results does not add up to a proper cost-benefit conclusion.

Summing a test that includes revenues (that are in fact transfers) with the results of other stages attempting to capture benefits and costs, inevitably distorts the result. As Mr. Neme put it, that would be adding apples and oranges.[22]

IRP requires both a proper holistic cost-benefit analysis and a separate rate impact analysis. EGI's proposed amalgamation of a stage one test, which is designed to look at rate impacts, with further stages that look at customer and societal costs and benefits, produces a test that is inaccurate for either purpose.

It is thus not surprising that none of the experts could point to any examples of gas or electric utilities employing a test like the DCF+ test in assessments of either non-pipe or non-wires

[22] EFG Presentation slide 15

alternatives.[23] ***No other utility uses utility DCF for IRP Cost-Benefit testing of alternatives precisely because it is not a Cost-Benefit test!***

As set out below, in addition to conflating rate impact analysis with cost-benefit analysis, and in so doing failing to provide accuracy and transparency with regard to overall costs and benefits, Enbridge's proposal fails to provide meaningful transparency or accuracy with respect to customer costs and benefits or to capture all system costs and benefits:

Exclusion of distribution or transmission volumetric charges from stage two distorts customer benefit analyses: At V.2 p. 109 EGI indicated that it only captures changes in volumetric charges in its stage one revenue line and not in stage two, despite the fact that customers implementing energy efficiency may be reducing their volumetric distribution and transmission charges. The reason offered was to avoid double counting with the stage one inclusion of revenues attributed to a facility option that enables more gas sales or more customers. However, this will inevitably distort the assessment of customer savings in stage two.

Exclusion of customer tax impacts ignores customer benefits: Enbridge's fixation with EBO 134 also leads it to leave out customer tax savings. Residential customers typically pay HST with no offsetting ITCs. When asked why the net impact on residential customers of changes to HST paid is not included in stage two despite tax impacts on the utility being counted in stage one, Enbridge responded: to be consistent with EBO 134 (v.2, p. 111). As Ralph Waldo Emerson once wrote: "A foolish consistency is the hobgoblin of little minds, adored by little statesmen and philosophers and divines."

Mixing discount rates is problematic: Summing results as Enbridge proposes also has the confounding impact of mathematically combining analyses with differing discount rates as it proposes a social discount rate for stages 2 and 3 but a corporate discount rate for stage 1.

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[23] See Neme at v.4, p. 131, Guidehouse at V.4, p. 53 and Enbridge/ICF at I.GEC.1(a). Both Enbridge and ICF pointed to differences between the situation faced by Enbridge and that facing electric utilities, New York utilities and Vermont. However, under cross-examination all agreed that the differences would impact the values of inputs to analyses but do not suggest that different forms of analysis are appropriate. In particular we note this exchange at V.2 p.71:

> "MR. POCH: Okay. So I think we are in agreement that these differences that you've noted between your situation and ConEd's, they might affect -- they are obviously going to affect inputs, but they don't drive you to select a different test. You are not suggesting they should drive the Board to select a different test, and perhaps the one area that might -- where we might see a difference is in ultimately what the Board feels is necessary as a shareholder incentive because of this difference between a single fuel and a dual fuel utility, fair?
> MS. VAN DER PAELT: I would agree. I would agree.

Utilizing distinct tests for cost-benefit analysis and for equity analysis would avoid this complication.[24]

Exclusion of upstream savings is problematic: Enbridge indicates that it would not capture any upstream savings in its DCF+ test due to geo-targeted energy efficiency[25].

The need for a holistic analysis distinct from rate impact and equity analyses:

Mr. Neme has suggested that the TRC+ test which has been used in Ontario for DSM for decades be initially utilized as the primary test in IRP analyses. Mr. Neme also suggests that a working group be tasked with proposing enhancements to the test to capture other benefits such as the value of efficiency to participating customers as a hedge against future commodity costs, the option value of IFPAs to all customers by deferring facilities commitments in the face of forecast uncertainty, and the commodity price suppression value to all customers. Importantly, all of these additional impacts should be included in whatever test is ultimately adopted – be it the TRC+, the Societal Cost Test, the Utility Cost Test or even EBO 134 – because they are all impacts that accrue to the utility system. Price suppression also reduces customer rates.

Both the Guidehouse and EFG reports also recommend utilizing a consultative mechanism to refine assessment methodology. In keeping with the approach recommended in the National Standard Practice manuals, Mr. Neme suggested that such a committee could examine indications of public policy in Ontario to inform that exercise.

As discussed above, it is critical to distinguish between equity considerations and cost-benefit analysis. Equity considerations need to be addressed separately (see discussion below).

In his cross examination of Mr. Neme, Mr. Mondrow for IGUA suggested that since system-wide DSM and gas infrastructure deferment are two different things with two different primary

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[24] At M2.GEC-ED, p. 42 Mr. Neme notes why using a social discount rate may be preferable: "There is no mathematical formula for translating policy objectives to specific discount rate values. However, generally-speaking, the more a jurisdiction's energy policies suggest concern for the long-term implications of investment decisions, for future utility customers as well as current customers and/or for jurisdiction-wide or even broader concerns (e.g., for reducing energy burdens for low income customers or reducing environmental damage), the stronger the case for a societal discount rate." Ontario has indeed embraced these broader and longer-term considerations.

[25] TC-2, p. 62, l. 21 "specifically if we, you know, hypothetically could contract for less capacity on TransCanada, those type of costs we are not proposing would be included." And see discussion at TC-2, p. 197 *et seq*.

purposes, it should be fine to have two different primary tests. A hypothetical example may best illustrate why that approach fails:

- An energy efficiency program costs $1.50.
- It produces $4.00 in benefits in four equal parts:
    - $1.00 in energy cost savings
    - $1.00 in carbon tax savings
    - $1.00 in avoided distribution costs
    - $1.00 in avoided transmission costs

If we were to look at whether the energy efficiency program made sense through the lens of a presumed primary objective in any application, we would say it was not cost-effective – i.e., it only provides $1.00 in savings as a measure to defer distribution infrastructure investments at a cost of $1.50; the same for its application for saving energy or as a CO2 emission compliance option, or as a transmission investment deferral option. However, when you look at it holistically, it is highly cost-effective.

It makes no economic sense to suggest we should analyze and choose energy efficiency – or any other resource – based solely on whether it is lower cost than the alternative when looking at only a subset of the attributes of interest.

That said, Stage 1 of EBO 134/188 can still have relevance for evaluating cross-subsidization in system expansion projects, though is less applicable in evaluating equity when dealing with reliability concerns for existing customers. We address that and other equity evaluation considerations below.

GEC submits that the proposed DCF+ test for cost-benefit comparisons of IRPAs to facilities is fundamentally flawed. Such comparisons should be conducted by use of the TRC+ test. An IRP working group should be charged with developing refinements to the test that are in keeping with public policy for subsequent consideration by the Board. Equity concerns should be addressed by a separate analysis.

Risk - Scenario Analysis - IRP in an Uncertain Future

Uncertainty about need and need dates exists for many reasons. The EFG report speaks to seven forms of risk[26]:

[26] M2.GEC-ED, p. 34 *et seq*

Reliability risks:

- **Peak demand forecast uncertainty**: if peak demand forecasts are understated.
- **Non-pipe alternatives performance uncertainty**: if peak savings from non-pipe solutions are not as large as expected.

Economic risks:

- **Environmental regulation uncertainty**: more stringent environmental regulations, particularly with respect to greenhouse gas emissions from gas combustion, could (A) drive up the cost of gas relative to what was assumed when IRP analysis was completed and resource choices were made; and/or (B) reduce demand for gas relative to IRP forecasts (e.g. because of increased electrification and/or increased cost of gas resulting from higher carbon taxes, renewable gas requirements, etc.).
- **Peak demand forecast uncertainty**: if peak demand forecasts are overstated, consumers will pay for an investment that was not needed.
- **Gas market price uncertainty**: the actual cost of gas can be greater or lower than forecast.
- **Investment cost forecast uncertainty**: the actual cost of either T&D investments or non-pipe alternatives can be greater or lower than forecast.
- **Stranded asset risk**: if the least cost path to achieving substantial levels of decarbonization of buildings required to meet long-term climate goals is (or is even in significant part) electrification, and gas T&D investments made in the 2020s are amortized over a period of 50 years, there could be significant challenges with cost recovery as fixed costs get recovered over increasingly smaller volumes of sales.

Many of these risks can be mitigated by geo-targeted efficiency. The framework should recognize uncertainty, and place value on mitigating both reliability and economic risks associated with uncertainty. Enbridge focusses on reliability risk but largely ignores economic risk or treats it asymmetrically. In its economic assessments it adds the cost of derating to address reliability risk for energy efficiency alternatives but ignores the economic risk costs associated with pipeline facilities. Enbridge's simplistic and non-transparent proposal of a colour coded chart for evaluating risks (as set out in JT2.16) is wholly inadequate.

Demand Forecast Uncertainty

Alternatives such as energy efficiency programs can be scaled up or down over time to react to changing demand or program success, whereas pipelines are sunk costs once constructed. To understand demand risk and how to value differing flexibility of alternatives the accuracy of forecasting must be assessed. Astonishingly, EGI could not produce an analysis of its demand forecast accuracy 5 or 10 years out.[27]

> **The Framework should require regular assessment of the accuracy of demand forecasts.**

Policy and Price Driven Uncertainty

In this framework proceeding we are not asking the Board to determine what the policy future will look like or what the different technologies, fuels or costs will be. We are asking the Board to require Enbridge to recognize that there is great uncertainty in those realms and to plan and propose investments with that recognition.

Enbridge readily acknowledges the likelihood of an energy transition to a low carbon future yet ignores the implications of that likely future on the need for facilities, the capability of facilities, the cost effectiveness of both facilities and alternatives such as energy efficiency, and the implications for rates and thus demand.

Even if we are to accept the company's preferred vision of a hybrid electricity plus hydrogen/RNG future, it would require either a rebuild of the system to accommodate a significant proportion of hydrogen, which has 1/3rd the energy content per cubic meter compared to natural gas, and brings with it technical issues for metal pipes and a need to alter end user equipment, and/or a slashing of the peak demand that the system will serve. In any such scenario the impact on rates would be immense, and the impact of higher rates on demand will follow suit. Adding facilities will exacerbate the risk of underutilized and stranded assets and of rate impacts. In contrast, energy efficiency usually remains functional with other fuels (and would be funded in large part by participant investment). Enbridge's refusal to recognize the implication of these scenarios in its demand forecasting or in scenario analyses is symptomatic of a utility desperate to build rate base and symptomatic of a shareholder corporation focused on pipeline investments both inside the utility and upstream.[28]

The lengthy discussion about the cost and applicability of cold climate electric heat pumps illustrates the distorted lens through which the company views the future and the need for effective and timely regulatory oversight. Ms Giradhar 's portrayal of the implications of electrifying heating loads which ignored relative end use efficiencies, and assumed 100% of furnaces would be converted, exemplifies that phenomenon.

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[27] See JT1.14 and discussion at V. 1, p. 124
[28] Ms. Thompson confirmed that the company's demand forecasts do not take account of impending policy changes such as the announced $170/tonne carbon price. (TC-1, p. 106)

In contrast, Mr. Neme, an expert in energy efficiency, laid out in detail how cold climate electric air source heat pumps (ASHPs) and ground source heat pumps that maintain high coefficients of performance at low temperatures are now on the market and could offset Enbridge's forecast load growth for a decade while *lowering* electricity rates. He stressed that there will be dramatic implications for the gas system of even a partial switchover to efficient forms of electric heating.[29]

Enbridge's vision of hydrogen or RNG being piped throughout the system seems unlikely given the costs and technical difficulties that would entail (see above under: Purpose of the IRP Framework - IRP in the context of a decarbonizing energy transition). More likely, hydrogen will be delivered directly to specified loads such as cement manufacturing where other non-gas alternatives are unsuitable. We see in the New York State staff report a recommendation to conduct a sensitivity analysis that depreciates facilities by 2050 which Mr. Yonge explains is in response to the 2050 greenhouse gas reduction targets in New York State.[30] A similar approach in Ontario would seem warranted given announced government policy goals.[31]

We do not ask the Board to resolve the debate about the costs, likelihood, or potential for electrification of heating loads or of hydrogen or RNG based futures. We do ask the Board to recognize that Enbridge's planning and decision-making must be subject to a regulatory regime that will not tolerate blindness to risks and uncertainties such as those presented by the low carbon 'energy transition', a regulatory structure that will require timely transparency, and that will enable corrective action on a timely basis to minimize societal costs.

Enbridge focuses almost exclusively on reliability risk. Reliability risk would be addressed through its focus on extreme temperatures when forecasting peak demands and its proposal (which EFG supported) to plan for more DSM than needed (as a hedge against underperformance) when assessing IRPAs. However, the Company systematically ignores economic risk which infrastructure investments create and/or which IRPAs could mitigate. For example, when asked about the risk of ex-franchise customers failing to renew transportation contracts which would leave domestic customers holding the bag, Mr. Steirs refused to acknowledge the possibility, citing a history of contract renewals as a certain predictor of the future. In a decarbonizing world to treat this as a certainty and ignore this economic risk

[29] V.4, p. 95 *et seq.*
[30] Staff compendium panels 2-5 at p. 90, and V.4, p. 56
[31] In M2.GEC-ED at p. 41 and in Slide 19, EFG recommends facilities amortization over 20 years and sensitivity analyses utilizing 2035 or 2040 end dates for amortization.

associated with facilities that are in whole or part justified by ex-franchise load is a further illustration of Enbridge's asymmetrical treatment of the options.[32]

Guidehouse agrees that "sensitivity analysis for key assumptions is a good approach".[33]

One key assumption is the demand forecast and in particular the geo-specific demand forecast associated with a constraint or perceived need. Enbridge argues that scenario analysis of demand is too difficult to consider.[34] It is simply inadequate for the company to undermine the accuracy and applicability of IRP by claiming it's a tough job to get the facts right. It may not be possible to obtain geo-targeted demand forecast scenarios that have probabilities calculated with three significant digits. But to simply ignore the reality of significant uncertainties will make IRP an exercise in futility.

Accordingly, GEC submits:

> **Assessments of alternatives must be conducted utilizing the best available information about the likely range of policy futures, in particular, climate change related policies.**
>
> **Planning and assessments, *including demand forecasting*, should utilize scenario analyses or probabilistic risk assessments to enable a balancing of cost and risk.**
>
> **Scenarios should include fully amortizing and depreciating facilities assets by 2035 and 2050 in accord with government carbon policy objectives.**

Carbon Pricing Scenarios as a simple proxy to capture uncertainty

A key variable that was the focus throughout much of the technical conference and hearing was the trajectory of carbon pricing. Carbon pricing scenarios offer a convenient way to capture a range of policy futures in planning and decision-making.

Until mid-way through the oral hearing Enbridge steadfastly refused to acknowledge the need to recognize the federal government's announced plan to move to $170/tonne by 2030. When the company eventually agreed that it would consider that as a scenario in assessments it limited the manner in which it would be considered. Enbridge refuses to recognize the likely

[32] V.2, pp. 128-129 and J2.8
[33] V4, p. 56
[34] EGI Argument in chief footnote 83

increase in carbon pricing in its demand forecast at this time, suggesting that it will consider the matter as part of rebasing (V.2, p. 114 *et seq*). Recognizing the impact of higher carbon charges on IRPA cost-effectiveness is of course helpful, but if the need being addressed is not evaluated in light of the likely range of demand, the analysis of IRPAs and of the facility option will be entirely distorted.

As to the recognition of higher carbon prices on efficiency potential the evidence is somewhat contradictory. Enbridge witnesses said it is captured in DSM analyses, but ICF used the 2017 cost effective achievable potential to produce its estimates of what facilities can be displaced by efficiency. And at TC 3, p. 58 ICF agrees that had they used carbon costs ramping up to $170 it would result in a significant change to the cost effective potential. EFG and Guidehouse agreed.

Thus it appears that Enbridge has captured the likely impact of higher carbon pricing in its DSM cost-effectiveness assessments but if it relies on the ICF work it may not recognize the increased quantity of DSM available to displace facilities. And it is quite clear that at least until rebasing Enbridge will not change its demand forecast and thus its forecast of needs and need dates to reflect a ramp up to an effective quadrupling or quintupling of the commodity cost.[35]

'Best practice' as indicated by the New York example, is to utilize carbon pricing estimates that continue to ramp up over the coming decades whether or not there is legislation requiring that as of today.[36]

In its updated evidence (Ex. B at p. 20) EGI states:

> 41.Enbridge Gas agrees that where risk can be objectively quantified, where it is based on best practices, clear regulatory directives and/or government policy and legislation, it should be considered and/or monetized as part of IRP analyses. To this end, Enbridge Gas supports the approach articulated by Guidehouse, on behalf of OEB Staff.
>
> To the extent that the OEB is providing direction that may influence or be impacted by provincial environmental and policy goals, the OEB should clearly define their underlying assumptions regarding applicable provincial policy goals.

Consistent with that position, and Mr. Neme's suggestions,[37] GEC submits that:

[35] K2.1, pp. 5 & 7
[36] J4.6
[37] V.4, p. 101

> **In addition to a scenario of carbon charges ramping up to $170/tonne by 2030, a second scenario with continued ramp up to $500/tonne in 2050 would be an appropriate proxy for likely potential GHG policies. Such scenarios should capture impacts on the cost-effectiveness of alternatives as well as upon demand.**

IFPA Potential and Risk of IFPA Failure

IRPA assessments will require a consideration of the potential for the alternative to meet the need and to do so on a timely basis.

Enbridge's evidence includes estimates of the extent to which energy efficiency can meet system growth. In I.GEC.13 (discussed at TC-3, p. 52 et seq.) ICF clarifies that its comparison of DSM to infrastructure was based solely on DSM program costs borne by the utility, and did not include the costs and benefits at the customer level. In particular, the analysis did not include avoided commodity costs. ICF's earlier work underlying the achievable potential study did not capture the expected ramp up in carbon costs and therefore significantly underestimates the availability of cost-effective DSM.[38]

> MR. SLOAN: If you're including the value of carbon, particularly at $170, that does change the economics of the projects that are considering the benefits of reducing natural gas, yes –
>
> MR. POCH: And you'd agree it would be a significant change?
>
> MR. SLOAN: When that's part of the calculation it would be a significant change.

It will be important in any pre-screening or assessment looking at the ability of energy efficiency to ramp up fast enough that the availability of cost-effective energy efficiency be based on a fuller assessment of cost-effectiveness. **GEC submits that IRPA assessment of efficiency alternatives be based on updated potential estimates that recognize all costs and benefits and the impact of expected carbon pricing.**

Enbridge's proposal does deal with the risk of energy efficiency alternatives failing to materialize by a proposed derating factor.

Over time, as experience is gained in pilots and IRPA implementations, the energy efficiency derating factor should be adjusted to more accurately reflect the risk. Further, as is the case

[38] TC-3, p. 58

in New York, the company should propose fallback mechanisms where available as a possible mechanism to address this risk.

Enbridge has proposed that the financial risks of IRPA underperformance should be borne by ratepayers. **GEC submits that the determination of who bears the risk of IRPA underperformance should be case-specific as it can be due to exogenous factors or due to the company's poor performance.**

Consideration of Rate Impacts and Equity

As discussed above, equity considerations, for example due to rate impacts on customers who are non-participants in energy efficiency programs, are best addressed with an analysis designed for that purpose. Enbridge's approach treats rate impacts as the first screen and then distorts cost-benefit analyses by combining the two distinct concepts.

Stage 1 of EBO 134/188 can still have relevance for system expansion projects – as a way to make sure existing customers don't subsidize new ones. That is different than dealing with reliability concerns for existing customers for which all choices – infrastructure or IRPA will undoubtedly cause some rate impact and will undoubtedly be pursued to address growing peak demand from only a modest subset of Enbridge customers and is therefore inherently imposing some inequity.

The standard rate impact test utilized in the DSM and CDM world is the Rate Impact Measure Test (RIM). However, as Mr. Neme discussed, the RIM test, like the first stage of EBO-134, suffers from an inability to capture various system-wide benefits, does not lay out the pattern of rate impacts, and fails to consider the overall impact of rate impacts occurring from numerous utility decisions over time.[39]

For example, EBO-134 and RIM do not capture the commodity price suppression value of efficiency programs, which is a rate and bill reducing benefit to all customers.

Nor do these tests capture many of the equity impacts of facilities investments. A facility built to serve the added demand of a subset of customers will typically be paid for by all customers, or all in the affected rate class or community, despite many customers contributing no added demand. The economic costs of facility investment risks such as obsolescence, stranding of

[39] See TC-3, pp. 116-119

assets, asset failure, diminished utilization, changing costs of capital, and loss of ex-franchise contribution are all borne by customers whether they create the need for the facility of not.

A more rigorous approach to equity considerations is desirable.

As referenced by Mr. Neme, the National Standard Practice Manual for DERs provides a useful reference on the topic in its appendix 1.[40] In short, the NSPM recognizes the shortcomings of standard rate impact tests and suggests that a proper analysis requires consideration of rate impacts, bill impacts and participation impacts and that these impacts should be considered on a portfolio basis over a period of time such as 5 or 10 years. The EBO-188 use of portfolio analysis begins to capture this approach but in a much more limited fashion. The NSPM report provides examples of such analyses (for an electric utility in this example) displayed graphically:

Figure A-1. Example Presentation of Long-Term Rate Impacts

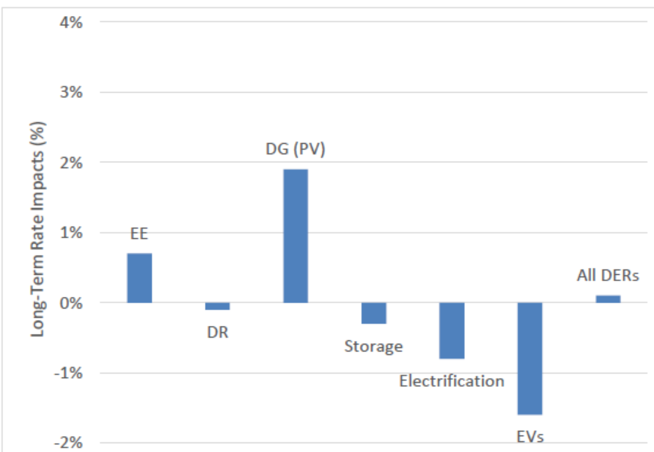
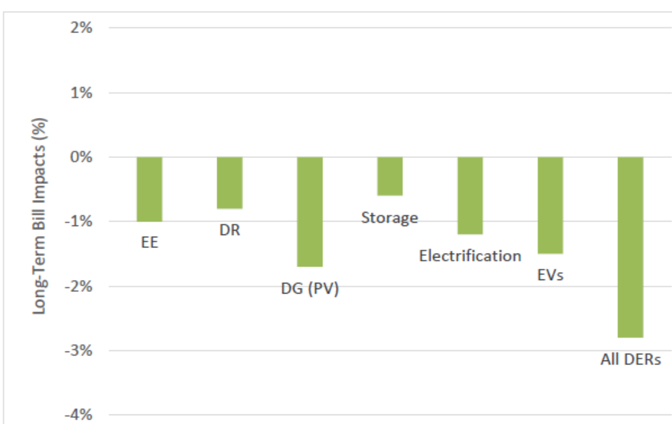
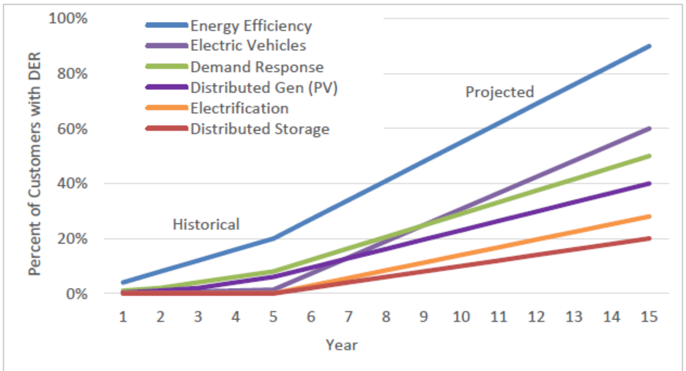


Figure A-2. Example Presentation of Long-Term Average Combined Bill Impacts



40 https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf

Figure A-3. Example Presentation of Long-Term Participation Impacts



The Board will be concerned with equity considerations and need a tool to analyze that from the outset. **GEC submits that the framework should call for estimates of rate impacts, bill impacts and participation rates for a 10 year period capturing such impacts from the portfolio of implemented and anticipated IRPAs and facilities, as well as from system-wide initiatives, particularly system-wide DSM.**

Further, IRPA's that are lower in total cost than an infrastructure option should only be rejected (in favor of the higher cost infrastructure project), if the IRPA is particularly egregious in its inequity.

Subsequent refinements to the tests

As discussed above, the DCF+ test, the Ontario TRC+ test and the RIM test do not capture several benefits that are important for IRPA analyses.

GEC submits that an IRPA working group should be charged with considering refinements to whatever cost-benefit test is chosen to capture benefits including:[41]

Hedge value – Like a long-term fuel contract, efficiency protects customers from future commodity price increases.

Option Value – As the demand forecast changes or the roll out of a targeted DSM program varies from forecast, DSM programs can be ramped up or down and deferred facilities can be moved ahead or back, all of which improves economic outcomes.

[41] See M2.GEC-ED, pp. 36

Commodity Price Suppression Value – Efficiency investments, especially as they affect peak demand, change the marginal price of the commodity and upstream transportation, a benefit enjoyed by all customers.

Project Cost Estimation Error Avoidance – Efficiency can avoid the risk of cost overruns often experienced with facilities projects.

GEC also submits that refinements to any rate impact analysis tool should be considered by an IRPA working group. These might include capturing system-wide benefits such as commodity price suppression, economic risks from facilities projects, and improved mechanisms to consider the cumulative and temporal pattern of rate, bill and participation rate impacts.

c. Stakeholder Outreach and Engagement Process

Enbridge's initial proposal for stakeholder consultation which amounted to little more than a series of one day show and tells was simply unworkable. In ex. JT2.11 we see an estimated 188 projects that would be subject to potential IRPA consideration in the 5 year period of the current Asset Management Plan[42]. Imagine a group of 20 or more stakeholders reviewing a list of perhaps twice the 188 projects for a 10 year period in a one day session. While the expansion of its proposal during the hearing to include more regional consultation is laudable, it would do little to address the inadequacy of the structure to allow meaningful discovery and discussion of the details of projects and plans. We do agree that these consultations, like the IESO process that inspired this model, may serve the purpose of alerting communities and municipalities about forthcoming projects and may encourage further engagement and provision of information. But this form of consultation is no substitute for more in depth engagement with informed stakeholders who have an understanding of the regulatory context and can bring expertise to the discussion.

Accordingly, we are pleased to note Enbridge's apparent agreement to a working group that could potentially allow for such detailed and timely review (See V.2, p. 101). If that mechanism is to enhance outcomes and reduce regulatory burden the details of its structure and role are important.

[42] In J1.1 EGI identified 548 IRPA eligible projects of which 164 were reinforcement projects

In his cross examination of Mr. Neme, Mr. Stevens raised a concern that such a committee would not necessarily reach the high degree of consensus reached in the Vermont or Illinois examples that Mr. Neme referred to. That may be so. However, the Board on receiving a committee report that does not offer a consensus recommendation would have a range of procedural options to utilize. If time is not of the essence, the matter could be dealt with in a triennial escalated review of AMP and IRP reports (as could consensus reports). If urgent, the Board could request written submissions or it could convene an oral hearing were warranted due to the significance of the matter. In short, the Board would remain in control of its process.

We note that Enbridge has objected to the idea that members of the committee would vote. As Mr. Neme explained, this is simply a mechanism to record dissent and the company would remain the 'owner' of the proposal. Enbridge has also proposed that the company convene and manage the working group. GEC believes that having Board Staff in that role will enhance satisfaction with, and effectiveness of, the mechanism.

Consistent with the recommendations of EFG, GEC submits that:

An IRP committee or working group should be mandated by the framework and it should have the following features:

- **The committee should review both the application of the pre-screening criteria and the assessment of alternatives as well as consulting on proposed pilot studies and the implementation of IRPAs.**
- **It should be convened by Board Staff and facilitated by Board Staff or an independent facilitator.**
- **It should meet quarterly with sub-committee meetings as required.**
- **Membership should include knowledgeable persons nominated by experienced intervenors before the Board who represent the major customer segments as well as environmental and low income organizations.**
- **Funding should be available in the same manner as it is for hearing processes before the Board.**
- **The committee should report to the Board annually, or as needed in urgent cases. Committee reports should include minority reports where there is dissent.**
- **The committee should be mandated to make recommendations to the Board for changes to the framework where the committee determines such changes are needed**.

- **The committee should have access to demand forecasts that underlie needs assessments[43].**

d. IRPA Cost Recovery and Accounting Treatment Fundamentals

Rate Basing of IRPA Expenses & Potential added shareholder incentives

GEC agrees with the proposal by the company, supported by Mr. Neme, to rate base approved IRPA expenses that displace facilities investments to give the company a similar incentive. It is recognized that an IRPA proposal that has a lower cost borne by the utility will add less to rate base and for that and other reasons, such as the impact on the shareholder's upstream interests, rate basing may prove to be an inadequate incentive. Enbridge in JT2.5 notes that "Further, consideration of an appropriate incremental incentive mechanism may benefit from the experience gleaned from one or more IRP Pilot Projects that the Company intends to pursue following the establishment of an IRP Framework."

GEC supports rate basing IRPA expenses with consideration of the need for further shareholder incentive a matter within the remit of the working group and for consideration by the Board after initial learnings from pilots and early IRPA experience.

As noted in our submissions on pre-screening criteria, the risk of stranded assets in the context of customer-specific expansions and ex-franchise driven reinforcements should also be borne by the company as a protection for ratepayers and as an incentive to avoid such risks through IRPAs or contractual arrangements.

e. Future IRP Approvals Sought - Plan Applications

As discussed above:

- Enbridge proposes to file a 10 year AMP with the Board annually but with very limited discovery or review.

[43] In JT.1.8 EGI indicates that its long term demand forecasts will only be available when relevant to a particular LTC application before the Board. Without being able to determine if such forecasts are reasonable any stakeholdering will be unable to determine whether the assessment of alternatives is reasonable.

- EGI proposes no review of pre-screened out or assessed out determinations prior to LTC or rate-basing applications.
- Enbridge has made no commitment that leave to construct applications would occur well in advance of need dates to allow for the substitution of alternatives.

Accordingly, there is need for a timely mechanism for transparency and adjudication where warranted.

In his presentation, Mr. Stier repeatedly stated that it would be "exceedingly time consuming" to have a review process for pre-screening decisions. We have proposed a working group review process that would buffer the formal regulatory process from excessive burden. Coupled with a triennial review proceeding, transparency, accountability and timely avoidance of cost-ineffective investments can be achieved without undue regulatory burden.

In contrast, Enbridge's approach would be penny wise and pound foolish – it will lead to needless disputes before the Board to gain discovery and challenge company choices at leave to construct proceedings, a point in time where the only remedy is a penalty rather than a least cost solution. It is easy to imagine that if in any one period just one IRPA project that could have reduced costs by $10 million is precluded, Enbridge's proposal will have cost its customers many multiples of what a more robust process would cost to administer. In short, EGI's proposal will lead to lost opportunities that cost ratepayers and the public at large.

Commissioner Janigan's summation of the companies' proposal was accurate: "So the principal safeguard will be stakeholder consultation?"

But as we discuss above, stakeholdering, either as Enbridge envisioned it in its filings or with the addition of a working group, while important, is simply no substitute for the backstop of timely mandatory discovery and regulatory adjudication.

How and when should such a regulatory mechanism occur?

At TC2 pp. 90-92 we discussed how moving LTCs ahead would compromise the currency of that process but that the current practice precludes timely substitution of IRPAs where Enbridge is found to have made a poor choice. This speaks to the need for an adjudicative step earlier than LTCs. In the New York staff report we learned of New York's proposed long-term process that has a triennial review. **To avoid the shortfalls of Enbridge's too little too late proposal, GEC suggests that a review process as proposed in New York that convenes every three years offers a timely mechanism to avoid undue regulatory burden if accompanied by a longer forecasting horizon to ensure that the review occurs with project need dates no less than ten**

years out. Unless required earlier due to urgency and materiality, this can be accomplished by a triennial escalation of the review of the AMP and working group reports.

GEC assumes that with the assistance of prior working group review the Board will in most cases be reviewing determinations that enjoy a consensus or near consensus approval and the regulatory burden will thereby be contained. **Enbridge would also be free to bring separate applications for significant projects if needed and may choose to do so in the initial period to 'test drive' the process.**

As discussed above under stakeholdering, cases of contested pre-screening or assessments that have sufficient materiality and are too urgent to await the next triennial process could be identified in the annual working group reports and dealt on an exceptional basis in annual IRP processes where the Board so elects.

In short, the Board should strive for a framework with regulatory decision points that prevents a repetition of the past situations where there has been inadequate consideration of alternatives but it is too late for corrective action. At the same time we recognize the need to contain regulatory burden and costs. GEC submits that the stakeholder committee process we have discussed above will be a key component of a framework that balances these concerns. But it will only have the desired effect if there is a timely regulatory backstop that can be invoked as needed.

f. Monitoring and Reporting

Consistent with the proposals discussed above:

The IRP Working Group should receive quarterly updates on proposed pre-screening decisions and assessments.

Annual IRP Working Group reports should accompany the AMP and IRPA Reports.

iii) IRP Costs Deferral Account

No submissions

iv) IRP Pilot Project Proposal

In his report and oral evidence Mr. Neme drew a distinction between research projects that investigate narrow aspects of IRP and pilot projects that comprehensively test IRP planning, implementation and evaluation processes.

GEC submits that as an immediate priority an IRP Working Group should work with the company to develop pilot projects that comprehensively plan and deploy multiple IRPA resources to defer specific infrastructure projects.

v) AMI Acknowledgement

While GEC recognizes that AMI could assist in the determination of localized peak demand and assist with the monitoring and evaluation of IRP, we submit that: **There is insufficient evidence to determine whether widespread AMI is warranted. It is appropriate for the company to research AMI costs and benefits for a range of degrees of implementation, for subsequent consideration by the Board.**

F. Next Steps After Issuance of Framework

As discussed above GEC submits that next steps should include:

- Formation of an IRP working group
- Pilot project development in conjunction with the proposed working group
- Annual IRP working group reports to be received by the Board
- Initial IRP framework update and AMP decisions review by the Board in three years
- Consideration of assessment test and shareholder incentive enhancements by the working group for Board consideration in 3 years

G. Relief Requested

See Summary of GEC Recommendations, below.

H. Summary of GEC positions and correlation with listed issues

GEC submits that to maintain flexibility the Board's framework should take the form of guidelines.

The following is a summary of GEC's recommendations and proposed amendments to Enbridge's proposal:

The framework should serve the purposes of encouraging (Issue 1):

- Rational planning with due regard to uncertainties, policy trends, and economic risks and with particular recognition of the emerging energy transition toward a low carbon economy
- Least societal cost solutions while ensuring an appropriate degree of equity among customers
- Timely decision making to ensure reliability and avoid lost opportunities for cost-effective alternatives
- Efficient, informed, and meaningful stakeholder engagement
- Regulatory accountability and efficiency

Specific Goals of IRP should include (Issue 1):

- Reliability
- Cost minimization
- Risk minimization
- Alignment with other governmental policy objectives
- Equitable consideration of all viable resource options
- Alignment of utility interests with IRP goals
- Timely and accountable assessment of alternatives

Types of Alternatives:

- The framework should not constrain the range of alternatives available for consideration in IRP.
- IRP should include non-gas alternatives. However, should the Board determine that Enbridge is not the appropriate entity to deliver or facilitate delivery of lower cost

electricity options, or that it shouldn't be expected to pay for all of the cost of such solutions, Enbridge should nevertheless be obliged to analyze such options to ensure that it does not promote less than optimal solutions. Where the electric option is better, Enbridge should be required to work with electricity sector partners to institute the least cost alternative.

- Where the market (with support of the utility) is not capable of delivering the optimal alternatives, Enbridge should be permitted to deliver and, as needed, to own such assets.
- To accommodate regional demand reducing programs the DSM framework would need to accommodate the potential for simultaneous implementation of several non-system-wide offerings (in addition to system-wide offerings), would need to reflect the value of facilities cost avoidance, and would need a potentially substantial budget increase to recognize both geotargeted facilities cost savings and the other broader system-wide objectives of DSM such as reducing customers' energy costs and carbon emission reductions. Accordingly, GEC submits that while the existing DSM framework can be harnessed to assist in the planning and oversight of IRPA investments, an IRP framework will best provide a means to assess and to fund DSM that addresses widespread facilities deferral or avoidance.

Pre-Screening Criteria (Issue 6):

- GEC proposes a timely mechanism for a working group to review pre-screening decisions, to report on them to the Board annually, and for timely Board review where warranted.
- **Safety:** GEC submits that the criteria be confined to emergent safety needs.
- **Timing – (3 Year Lead Time):** GEC submits that the Board should only endorse this criterion as an interim proposal while awaiting further learnings. It should not apply to supply-side or bridging alternatives.
- **Customer-specific Builds:** GEC submits that a long-term firm services commitment should not preclude IRP as other customers will still bear residual financial risk should the customer fail to fulfill its commitment. Alternatively, Enbridge should be required to carry such risk. If supplying gas to a new large customer requires upgrading the capacity of elements of the T&D system that serve many other customers, then the utility should be required to consider non-pipe alternatives. In addition, Enbridge should also proactively work with potential new customers to consider non-pipe alternatives early on where that would reduce overall system costs and risks.
- **Community Expansion & Economic Development**: Absent a *legal requirement* to extend service to the particular community, Enbridge should be required to work with the IESO

and electricity distributors to ensure that the least cost alternative is pursued in all cases.

- **Pipeline Replacement and Relocation Projects:** This criterion should be amended to read: If a project is being advanced for replacement or relocation of pipelines, and the cost is less than $10 million, <u>and its capacity is not being increased,</u> then that project is not a candidate for IRP analysis.
- **Ex-Franchise demand driven need:** If an IRPA can potentially accommodate domestic needs and existing ex-franchise contractual commitments there is no reason to exclude IRP analysis due to future, avoidable ex-franchise load commitments. Furthermore, the company's shareholders and its ex-franchise customers should be required to pay for incremental infrastructure or IRPA expenditures beyond that necessary to meet domestic need and bear any risk of future stranding of such assets.
- **Reinforcements under $10M:** GEC submits that IFPA analysis and regulatory scrutiny for controversial reinforcements over $2 million is appropriate. Privileging all pipeline options under $10M is contrary to the objectives of the Act, and contrary to public policy. A streamlining of the approval process for smaller IRPA projects may be appropriate.

Assessment Tests (Issues 2 & 6):

- GEC submits that the proposed DCF+ test for cost-benefit comparisons of IRPAs to facilities is fundamentally flawed. Such comparisons should be conducted by use of the TRC+ test. An IRP working group should be charged with developing refinements to the test that are in keeping with public policy for subsequent consideration by the Board. Equity concerns should be addressed by a separate analysis.
- The Framework should require regular assessment of the accuracy of demand forecasts.
- Assessments of alternatives must be conducted utilizing the best available information about the likely range of policy futures, in particular, climate change related policies.
- Planning and assessments, including demand forecasting, should utilize scenario analyses or probabilistic risk assessments to enable a balancing of cost and risk.
- Scenarios should include fully amortizing and depreciating facilities assets by 2035 and 2050 in accord with government carbon policy objectives.
- In addition to a scenario of carbon charges ramping up to $170/tonne by 2030, a second scenario with continued ramp up to $500/tonne in 2050 would be an appropriate proxy for likely potential GHG policies. Such scenarios should capture impacts on the cost-effectiveness of alternatives as well as upon demand.

- GEC submits that IRPA assessment of efficiency alternatives be based on updated potential estimates that recognize all costs and benefits and the impact of expected carbon pricing.
- Over time, as experience is gained in pilots and IRPA implementations, the energy efficiency derating factor should be adjusted to more accurately reflect the risk. Further, as is the case in New York, the company should propose fallback mechanisms where available as a possible mechanism to address this risk.
- GEC submits that the framework should call for estimates of rate impacts, bill impacts and participation rates for a 10 year period capturing such impacts from the portfolio of implemented and anticipated IRPAs and facilities, as well as from system-wide initiatives, particularly system-wide DSM.
- Further, IRPA's that are lower in total cost than an infrastructure option should only be rejected (in favor of the higher cost infrastructure project), if the IRPA is particularly egregious in its inequity.
- GEC submits that an IRPA working group should be charged with considering refinements to whatever cost-benefit test is chosen to capture benefits including: Hedge value, Option Value, Commodity Price Suppression Value, Project Cost Estimation Error Avoidance.
- GEC also submits that refinements to any rate impact analysis tool should be considered by an IRPA working group.

Stakeholder Process (issue 2):

- An IRP committee or working group should be mandated by the framework and it should have the following features:
    - The committee should review both the application of the pre-screening criteria and the assessment of alternatives as well as consulting on proposed pilot studies and the implementation of IRPAs.
    - It should be convened by Board Staff and facilitated by Board Staff or an independent facilitator.
    - It should meet quarterly with sub-committee meetings as required.
    - Membership should include knowledgeable persons nominated by experienced intervenors before the Board who represent the major customer segments as well as environmental and low income organizations.
    - Funding should be available in the same manner as it is for hearing processes before the Board.

  - The committee should report to the Board annually, or as needed in urgent cases. Committee reports should include minority reports where there is dissent.
  - The committee should be mandated to make recommendations to the Board for changes to the framework where the committee determines such changes are needed.
  - The committee should have access to demand forecasts that underlie needs assessments.

Accounting and Shareholder Risk and Incentives (Issues 8 & 9):

- GEC supports rate basing IRPA expenses with consideration of the need for further shareholder incentive a matter within the remit of the working group and for consideration by the Board after initial learnings from pilots and early IRPA experience.
- GEC submits that the determination of who bears the risk of IRPA underperformance should be case-specific as it can be due to exogenous factors or due to the company's poor performance.

Approvals Process (Issue 3):

- To avoid the shortfalls of Enbridge's too little too late proposal, GEC suggests that a review process as proposed in New York that convenes every three years offers a timely mechanism to avoid undue regulatory burden if accompanied by a longer forecasting horizon to ensure that the review occurs with project need dates no less than ten years out. Unless required earlier due to urgency and materiality, this can be accomplished by a triennial escalation of the review of the AMP and working group reports.
- If time is not of the essence, approvals or challenges to the screening out of IRPAs could be dealt with in a triennial AMP/IRP review (as could consensus reports). If urgent, the Board could request written submissions or it could convene an oral hearing were warranted due to the significance of the matter. Enbridge would also be free to bring separate applications for significant projects if needed and may choose to do so in the initial period to 'test drive' the process.

Monitoring and Reporting (issue 10):

- The IRP Working Group should receive quarterly updates on proposed pre-screening decisions and assessments.
- Annual IRP Working Group reports should accompany the AMP and IRPA Reports.

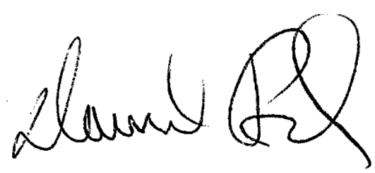
Pilots:

- GEC submits that as an immediate priority an IRP Working Group should work with the company to develop pilot projects that comprehensively plan and deploy multiple IRPA resources to defer specific infrastructure projects.

AMI:

- There is insufficient evidence to determine whether widespread AMI is warranted. It is appropriate for the company to research AMI costs and benefits for a range of degrees of implementation, for subsequent consideration by the Board.

All of which is respectfully submitted, this 31st day of March, 2021



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