Compendium for Enbridge Gas cross-examination of Chris Neme, Energy Futures Group (EFG)

March 4, 2021

1. EFG Report, page 6
2. EFG Report, pages 8-9 and 47
3. EFG response to BOMA Interrogatory 3(b)
4. EFG Report, pages 7, 15 and 29-31
5. EFG Report, page 15
6. Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments, January 9, 2015, Chris Neme & Jim Grevatt, Energy Futures Group, pages 1 and 64
7. Presentation Day Transcript, pages 87-89
8. EFG response to PP Interrogatory #3
9. EFG Presentation, slide 11
10. *OEB Act*, section 2
11. EFG Report, pages 21-24
12. Pages from Vermont System Planning Committee Website - https://www.vermontspc.com/
13. Presentation Day Transcript, pages 62-64
14. Exhibit JT1.3
15. EFG response to PP Interrogatory #10
16. Presentation Day Transcript, pages 64-65
17. Exhibit JT 2.11
18. Presentation Day Transcript, page 76
19. EFG Report, page 48
20. Exhibit JT 3.10

- The rules governing consideration of non-pipe solutions should require consideration of all such local factors.

- Any criteria for screening out consideration of non-pipe solutions must be very carefully designed to ensure that they would not rule out potentially viable projects. That means erring on the side of greater latitude when there is uncertainty (e.g. about the size of load reduction that could be achieved), as what is possible in one location may be very different from the "average", particularly when multiple IRPA options are considered together.

1.3.3 Simultaneous Consideration of All IRPA Resource Options is Required

- There are a range of measures that can be part of non-pipe solutions. That includes energy efficiency; demand response; electrification of gas end-uses with air source heat pumps, ground source heat pumps and other technologies; and localized injection of compressed gas.

- The Gas IRP framework should require that all such measures be considered – individually and in combination with each other – with the least cost mix of such measures selected for investment.

1.3.4 Stakeholder Engagement

- IRP analyses are much more robust if they involve stakeholders in the key steps associated with the making of decisions rather than just as potential sources of information or in perfunctory discussions after decisions have largely been made.

- The Board and stakeholders should be informed and included throughout the IRP process. If that does not occur, planning assumptions and decisions will only be tested in leave to construct hearings, at which point it may be too late to select a non-pipe solution that might require a longer lead time.

- The Gas IRP framework should establish a planning committee, modeled on Vermont's System Planning Committee, to secure input throughout the planning process from key stakeholders.

1.4 Issue #5: Industry Best Practices

1.4.1 More Granular Load Forecasting

- T&D peak demand forecasts that are based primarily on historical data will not reflect the effects of changes in scope or mix of system-wide efficiency programs or major changes in building codes or government efficiency standards for gas consuming equipment.

- Experience in other jurisdictions suggests that more granular forecasting that accounts for such changes can significantly alter estimates of T&D needs.

- The Gas IRP framework should require Enbridge to begin developing more granular forecasting capabilities and, in the interim, to make at least high-level adjustments to forecasts to account for major known changes to efficiency programs and/or codes and standards.

1.5.2 Benefit-Cost Analysis

- Any cost-effectiveness analysis of any gas utility investment options – including pipe and non-pipe solutions – must include all gas utility system impacts, including avoided gas commodity costs, avoided gas storage costs, avoided carbon taxes, and effects on market clearing prices for gas (e.g. market price suppression effects of efficiency programs).
- Cost-effectiveness analyses of any gas utility investment options – including pipe and non-pipe solutions – should also account for all impacts related to government policy goals.
- The Ontario Energy Board should consider establishing a stakeholder workshop process to identify policy goals relevant to cost-effectiveness analysis in Ontario and to ensure that all relevant costs, benefits, and risks are included in the benefit-cost analysis. This could be led by an external expert that would prepare a draft report for the Board's consideration.
- In the interim, the "TRC+" test – which implicitly assumes participant impacts and environmental impacts are relevant to provincial policy goals – should be the foundation of cost-effectiveness assessments of pipe and non-pipe alternatives. However, consistent with the principle that all utility system impacts should be included, application of the test should include the effects on market clearing prices for gas that have historically not been included in Ontario utilities' use of the test.[2]
- Economic risk should always be quantified – and ideally monetized – as part of IRP analyses. That should be the case regardless of what cost-effectiveness test is used (i.e. regardless of what categories of impacts, costs and benefits are included in cost-effectiveness assessments). It is particularly essential that the risks related to climate change are monetized and included in benefit-cost analyses because these risks could be very important from a financial perspective.
- The discount rate used for cost-effectiveness analysis of utility investment decisions should be a function of Ontario's policy objectives. Until an assessment of such objectives has been performed, the Board should require that the same discount rate used to assess cost-effectiveness of system-wide DSM programs (currently 4%) also be used when comparing the costs and benefits of pipe and non-pipe solutions.

1.6 Issues #7 and #9: Cost Recovery and Financial Incentives

- If utilities are to be expected to deploy non-pipe solutions when they are preferable to T&D investments, the utilities and their shareholders should be able to be sufficiently profitable while doing so.
- Conceptually, there are three ways in which utility shareholder incentives for investment in non-pipe solutions could be expressed: (1) incentive payments structured as a percent of the cost of non-pipe solution; (2) capitalizing and earning a return on non-pipe solution costs; and (3) incentive payments based on a percent of net economic benefits (cost savings) resulting from deploying a non-pipe solution instead of a more expensive T&D option.

[2] This requirement should apply to all uses of the test, including assessments of both DSM and non-pipe solutions.

- A case can be made for each of these options. They all have both advantages and disadvantages.
- The best may be capitalizing and earning a rate of return on non-pipe solution costs. Though perhaps not perfect, this option is most consistent with how utilities profit from traditional T&D solutions, is likely to be the option that will result in the strongest utility management support for non-pipe solution investment, and is simple and well-understood. The specific details of this option would need to be designed to ensure that utilities have an incentive to implement the optimal solution (pipe or non-pipe) that it is the best solution for customers.

1.7 Applicability of Lessons from Electric IRP to Gas IRP

- The principles, processes and cost-effectiveness frameworks for considering gas non-pipe solutions are the same as those for considering electric non-wires solutions.
- There are some differences between gas and electric utilities that could theoretically affect the average economic value and/or frequency of cost-effectiveness of non-pipe solutions relative to non-wires solutions. However, it is not clear whether their combined effect would be to make non-pipe solutions more or less economically attractive – on average – than non-pipe solutions.
- As with non-wires solutions, the economic merits of non-pipe alternatives will likely vary considerably from project to project, underscoring the need for project-specific assessments.

magnitude of net benefits, which indirectly encourages minimization of the cost of the non-pipe solution.

A disadvantage of shared savings is that the calculation of net benefits is necessarily based on a number different benefits and a variety of assumptions related to those benefits. Thus, there will need to be careful scrutiny of all net benefit assumptions and calculations. While that is necessary at some level to ensure that IRPAs are cost-effective, the stakes are higher when shareholder incentives are tied to them because it is no longer just a question of whether the non-pipe solution is cost-effective; instead, the amount by which non-pipe solutions are cost-effective is vitally important. In addition, the magnitude of some of the assumptions underpinning net benefits calculations – e.g. avoided energy costs for gas – can fluctuate from year to year, raising and lowering utility shareholder incentives, for reasons entirely or at least largely out of the utility's control. Finally, utility incentives to invest in non-pipe solutions that are only marginally cost-effective may not be large enough for management to support the non-pipe solution investment – even if it is still providing value to ratepayers.

4.5.3.4 The Preferred Solution

A case could be made for adopting any of the three options discussed above. However, the best incentive mechanism might be capitalizing and ratebasing non-pipe solution costs – or at least the costs associated with distributed energy resources, such as energy efficiency, demand response, and electrification.[74] That conclusion is based on three factors: (1) consistency with how utilities profit from traditional T&D investments; (2) experience with utilities that suggests this approach is most likely to result in senior management support for pursuing non-pipe alternatives (when appropriate); and (3) simplicity – there is no need to perform calculations based on assumptions (e.g. changing avoided costs, savings lives, etc.) that can be debated, can fluctuate from year to year, and are often outside of the utility's control. The specific details of this option would need to be designed to ensure that utilities have an incentive to implement the optimal solution (pipe or non-pipe) that it is the best solution for customers.

5. Applicability of Lessons from Electric IRP to Gas IRP

5.1 Summary of Key Points

- The principles, processes and cost-effectiveness frameworks for considering gas non-pipe solutions are the same as those for considering electric non-wires solutions.
- There are some differences between gas and electric utilities that could theoretically affect the average economic value and/or frequency of cost-effectiveness of non-pipe solutions relative to non-wires solutions. However, it is not clear whether their combined effect would be to make non-pipe solutions more or less economically attractive – on average – than non-pipe solutions.
- As with non-wires solutions, the economic merits of non-pipe alternatives will likely vary considerably from project to project, underscoring the need for project-specific assessments.

[74] There may be reasons not to treat deployment of compressed natural gas (CNG) or liquified natural gas (LNG) deployment as part of non-pipe solutions in the same way (see ICF 2020, p. 7).

2-BOMA-3
Ref: Exhibit M2.GEC-ED (Neme, 2020), Page 19, Section 4.2.2.2

Preamble:
In its 2018 analysis of the role efficiency potential could play in deferring gas infrastructure investments, ICF estimated that, based on the most recent provincial Market Potential Study ("MPS"), the maximum achievable potential for peak hour demand savings is "in the range of 1.2% of peak hour demand per year."[17] ICF then noted that only about 17% of Union Gas planned facility investments and 14% of Enbridge planned investments had peak demand growth rates below 1.2% and suggested that meant that "DSM could potentially avoid a little less than 20% of the Gas Utilities' planned investments."

Questions:
a) Please provide your analysis of the differences between electricity IRP and gas IRP.
b) How are they treated differently in a combined utility?

Responses:
a) It is not clear how the question relates to the preamble, so I am not certain about what exactly is being asked. That said, there is no *conceptual* difference between consideration of electric non-wires solutions and consideration of gas non-pipe solutions. As noted in section 5.1 of my report, the principles, processes and cost-effectiveness frameworks should be the same for both gas and electric utilities.

   There will obviously be differences in some of the specifics. For example, the way peak loads are forecast for reliability purposes, the value of deferring T&D infrastructure, the uncertainties associated with future climate policy, the maximum amount of peak load reduction possible, the range of specific measures that can be deployed, and other details may be different for gas utilities than for electric utilities. However, some of those things will be different not only between electric and gas utilities, but also between different gas utilities and even between specific projects for the same gas utility. See Section 5.4 of my report for more information on how the value of gas non-pipe solutions and the value of electric non-pipe solutions may differ (or not).

   Note that for reasons explained on pp. 19-20 of my report, the ICF conclusions reference in the preamble to this question are problematic and misleading.

b) I see no reason why the policy framework for consideration of gas non-pipe alternatives should be any different for a dual-fuel utility than for a gas-only utility. The only possible exception to that statement could be with respect to shareholder incentive mechanisms – to the extent that it is likely that electrification will play a significant role in non-pipe solutions.

1.4.2 Value of Pilot Projects

- There are limits to what can be learned about Gas IRP and non-pipe solutions from just studying what other jurisdictions have done.
- Most jurisdictions that are seriously considering gas and electric IRPAs have started with pilot projects to actually field-test and gain experience with planning processes, deploying geotargeting efficiency and other IRPA resources, evaluating the impact such geotargeting is producing, and valuing such impacts and other key aspects of non-pipe solutions.
- The Board should require Enbridge to begin planning to deploy two such pilot projects in 2021 with actual deployment of IRPA resources beginning no later than January of 2022.
- The Board may wish to consider establishing a collaborative utility-stakeholder process to design the pilots, select the target areas, establish monitoring and evaluation plans, hold regular check-ins on progress and develop modifications to plans in response to market feedback and other lessons learned.

1.5 Issue #6: Screening Criteria & Methodology for Comparing IRPAs and Facility Projects

1.5.1 Pre-Screening Criteria

- T&D projects required to address safety concerns are generally not candidates for non-pipe alternatives. However, there can be exceptions that merit analysis.
- Focusing initially on projects with at least a 3-year lead time for consideration of non-pipe solutions is reasonable. However, this criterion should not be applied rigidly as there may be exceptions. Moreover, the criterion should be revisited once there is more experience with non-pipe solutions.
- The ability to leverage municipal public road, water or other public works investments is not justification for proceeding with T&D investment projects without consideration of alternatives. Non-pipe solutions can still be lower cost and lower risk.
- Individual customer demands for gas connection can be grounds for providing that connection, as long as the customer is prepared to pay for the full cost of their contribution to system costs and risks. However, if demand from a new customer would require T&D investment at a point in the system that serves many other customers, the utility should be required to consider non-pipe solutions. 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 (e.g. heat pumps in new buildings).
- Absent a government mandate that expressly excludes consideration of alternatives (either individually or under conditions that may apply to specific communities or categories of communities), gas line extensions should not be excluded from consideration. There may be cases where policy goals such as access to low-cost energy could be achieved more cost effectively and with less risk than through gas service expansion.

4.2 Issue #2: IRP Process

4.2.1 Planning Horizon

4.2.1.1 Summary of Key Points

- The amount of lead time needed to consider and effectively deploy non-pipe solutions will vary depending on the magnitude of the load reduction required and the size of the geographic area that needs to be addressed.
- The potential to defer T&D investments can be very project-specific, depending on the size of the load reduction required, the timeline over which it needs to be acquired, the economic value of the T&D deferral, and a variety of factors affecting both the magnitude of the load reduction potential and the cost of acquiring it (e.g. customer mix, local demographics, age and condition of building stock).
- In addition, there needs to be a mechanism that stakeholders and the Board can utilize to trigger formal Board review of both forecast needs and proper consideration of alternatives before potentially viable alternatives are precluded due to concerns about inadequate lead times (i.e. to preclude the potential for leave to construct applications to be filed and resolved too late to reasonably consider and cost-effective alternatives).

4.2.1.2 Lead Time Needed

The amount of lead time needed to consider and effectively deploy a non-pipe solution will vary depending on the magnitude of the load reduction required (as a percent of current annual sales) and the size of the geographic area that needs to be addressed. The larger the load reduction needed, the longer the lead time required. For example, less lead time would be needed to reduce forecast gas consumption by 5% than would be needed to reduce it by 10% in the same geographic area. Similarly, all other things being equal, the larger the geographic area served by the T&D facility being addressed, the longer the lead time required.

Some jurisdictions have initial "rough cut" criteria – including lead time – for determining whether a detailed IRPA analysis is warranted. In Vermont, the criteria for consideration of non-wires solutions for deferral of electric transmission system investments are structured around the magnitude of the load reduction required as follows:

- 1 to 3 years for load reductions of 15% or less;
- 4 to 6 years for load reductions of 15% to 20%;
- 6 to 10 years for load reductions of 25%.[10]

[10] Neme, Chris and Jim Grevatt (Energy Futures Group), *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments*, published by Northeast Energy Efficiency Partnerships, January 9, 2015, p. 64.

efficiency programs on top of system-wide ones, and develop cost and timing estimates of gas peak hour demand reductions.[38]

4.4 Issue #6: Screening Criteria and Methodology For Comparing Alternatives

4.4.1 Pre-Screening Criteria

4.4.1.1 Summary of Key Points

- T&D projects required to address safety concerns are generally not candidates for non-pipe alternatives. However, there can be exceptions that merit analysis.
- Focusing initially on projects with at least a 3-year lead time for consideration of non-pipe solutions is reasonable. However, this criterion should not be applied rigidly as there may be exceptions. Moreover, the criterion should be revisited once there is more experience with non-pipe solutions.
- The ability to leverage municipal public road, water or other public works investments is not justification for proceeding with T&D investment projects without consideration of alternatives. Non-pipe solutions can still be lower cost and lower risk.
- Individual customer demands for gas connection can be grounds for providing that connection, as long as the customer is prepared to pay for the full cost of the connection. However, if demand from a new customer would require T&D investment at a point in the system that serves many other customers, the utility should be required to consider non-pipe solutions. 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 (e.g. heat pumps in new buildings).
- Absent a government mandate for them (either individually or under conditions that may apply to specific communities or categories of communities), gas line extensions should not be excluded from consideration. There may be cases where policy goals such as access to low-cost energy could be achieved more cost effectively and with less risk than through gas service expansion.

4.4.1.2 Enbridge's Proposal

In its October filing, Enbridge suggests that non-pipe alternatives should not be considered if any of the following five criteria were applicable:

1. **Safety**. The Company suggests non-pipe alternatives are not applicable and should not be considered if a T&D investment is required in order to address customer safety.
2. **3-Year Lead Time**. The Company suggests that any T&D needs that must be met in less than three years are not viable candidates for non-pipe solutions, presumably because of the lead

[38] Energy Trust of Oregon, "NW Natural and Energy Trust of Oregon GeoTEE Targeted Load Management Project Implementation Plan: Creswell and Cottage Grove", 4/3/2020. Also, personal communication with Fred Gordon, Oregon Energy Trust, 11/17/20.

time assumed to be required to plan, launch and acquire enough savings from non-pipe solutions.

3. **Ability to Leverage Non-Utility Investments**. The Company calls this "project-specific considerations". It suggests that it should be able to proceed with T&D investments when it is possible to leverage municipal infrastructure development. Presumably, the rationale behind this criterion is that the T&D investment will be lower cost if it can leverage other investments such as road works or water mains replacements.
4. **Individual Customer Demands for Gas**. Enbridge suggests that when a customer wants access to gas and is willing to either pay a "Contribution in Aid of Construction" or to contract for long-term firm services, then the Company should be able to make the T&D investment and not consider non-pipe solutions.
5. **Community Expansion and Economic Development**. The Company suggests that projects that are "driven by policy" with the desire to access gas as a way of bringing heating costs down can be pursued without consideration of non-pipe alternatives.

4.4.1.3 Discussion

While some of Enbridge's proposed criteria are generally reasonable, all require some caveats and some are not at all reasonable. Each is addressed below.

1. **Safety**. Enbridge's safety criterion is generally reasonable. Non-pipe solutions typically cannot be viable alternatives to T&D investments made to address safety concerns. However, there can be exceptions. For example, if the Company were to determine that it needs to embark on an expensive plan to replace large amounts of old pipe for safety reasons, there could be cases in which it is possible to eliminate portions of such costs by completely electrifying buildings in a given neighborhood. Downsizing a pipe via DSM could also be cost-effective in some cases, such as for large projects close to the threshold between pipe sizes. The Company should be required to consider such cases.
2. **3-Year Lead Time**. As discussed in Section 4.2.1.2, the lead time required for successful planning and deployment of non-pipe solutions will vary depending on the size of the geography, how many customers are involved and the magnitude of the load reduction required. As the Company is really just getting started with consideration of non-pipe solutions, initially focusing on projects with a lead time of at least 3 years is reasonable. However, this screening criterion should not be applied rigidly as there may be exceptions.[39] However, as the Company gains more experience with non-pipe solutions, that criterion should be revisited and perhaps married to the size of the load reduction required as has been done with non-wires pre-screening criteria in other jurisdictions.[40]
3. **Ability to leverage non-utility investments**. This proposed criterion is problematic. The ability to leverage municipal road work and/or water main replacement can have two effects: (1) it

[39] For example, the Company may propose projects for which the "need" – or at least the portion of the need that is driving a less than three-year lead time – is economic (e.g., enabling access to lower cost sources of gas) rather than reliability-driven. In such cases, there is no reason to pre-screen out consideration of non-pipe alternatives because. The economic trade-offs between pipe and non-pipe solutions – however quickly they can be planned and ramped up – can be considered as part of cost-effectiveness analysis.
[40] Neme and Grevatt, 2015.

can lower the cost of the traditional T&D investment; and (2) it can accelerate the timing of the traditional T&D investment (i.e. before it is needed). Such changes cannot be assumed to preclude the possibility that a non-pipe solution would be economically preferable. In fact, if the timing of the T&D investment is accelerated enough (relative to its actual need), the net present value of the cost of the T&D solution could be even higher as a result of leveraging municipal public works projects. Moreover, as discussed in Section 4.4.2.4.2, climate policy goals create a very real risk that gas T&D investments could become stranded assets. The bottom line is that cost-effectiveness analysis of pipe and non-pipe solutions should still be performed.

4. **Individual Customer Demands for Gas**. This proposed criterion is too vague. If Enbridge means that it should be able to simply extend a gas line to connect a new customer, that is reasonable provided that the customer would effectively be paying for the entire cost of the connection. However, 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 (e.g. heat pumps in new buildings).
5. **Community Expansion and Economic Development**. This criterion is problematic. Given Canadian climate policy goals, the related need to essentially eliminate fossil gas consumption by 2050 (and be on a path to that goal now), and the 50-year period over which gas T&D investments may be depreciated, extending gas lines to new communities is highly problematic and risky. 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).

4.4.2 Benefit-Cost Analysis

4.4.2.1 Summary of Key Points

- Any cost-effectiveness analysis of any gas utility investment options – including pipe and non-pipe solutions – must include all gas utility system impacts, including avoided gas commodity costs, avoided gas storage costs, avoided carbon taxes and effects on market clearing prices for gas (e.g., market price suppression effects of efficiency programs).

- Cost-effectiveness analyses of any gas utility investment options – including pipe and non-pipe solutions – should also account for all impacts related to government policy goals.

- The Ontario Energy Board should consider establishing a stakeholder workshop process to identify policy goals relevant to cost-effectiveness analysis in Ontario and to ensure that all

4.2 Issue #2: IRP Process

4.2.1 Planning Horizon

4.2.1.1 Summary of Key Points

- The amount of lead time needed to consider and effectively deploy non-pipe solutions will vary depending on the magnitude of the load reduction required and the size of the geographic area that needs to be addressed.
- The potential to defer T&D investments can be very project-specific, depending on the size of the load reduction required, the timeline over which it needs to be acquired, the economic value of the T&D deferral, and a variety of factors affecting both the magnitude of the load reduction potential and the cost of acquiring it (e.g. customer mix, local demographics, age and condition of building stock).
- In addition, there needs to be a mechanism that stakeholders and the Board can utilize to trigger formal Board review of both forecast needs and proper consideration of alternatives before potentially viable alternatives are precluded due to concerns about inadequate lead times (i.e. to preclude the potential for leave to construct applications to be filed and resolved too late to reasonably consider and cost-effective alternatives).

4.2.1.2 Lead Time Needed

The amount of lead time needed to consider and effectively deploy a non-pipe solution will vary depending on the magnitude of the load reduction required (as a percent of current annual sales) and the size of the geographic area that needs to be addressed. The larger the load reduction needed, the longer the lead time required. For example, less lead time would be needed to reduce forecast gas consumption by 5% than would be needed to reduce it by 10% in the same geographic area. Similarly, all other things being equal, the larger the geographic area served by the T&D facility being addressed, the longer the lead time required.

Some jurisdictions have initial “rough cut” criteria – including lead time – for determining whether a detailed IRPA analysis is warranted. In Vermont, the criteria for consideration of non-wires solutions for deferral of electric transmission system investments are structured around the magnitude of the load reduction required as follows:

- 1 to 3 years for load reductions of 15% or less;
- 4 to 6 years for load reductions of 15% to 20%;
- 6 to 10 years for load reductions of 25%.[10]

[10] Neme, Chris and Jim Grevatt (Energy Futures Group), *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments*, published by Northeast Energy Efficiency Partnerships, January 9, 2015, p. 64.

Northeast Energy Efficiency Partnerships

Energy Efficiency as a T&D Resource:

Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments

January 9, 2015

Chris Neme & Jim Grevatt, Energy Futures Group

out into the future they go, a 20 year forecast will still do a better job at ensuring that insufficient lead time does not preclude deployment of cost-effective non-wires solutions.

Recommendation 3: Establish Screening Criteria for NWA Analyses

One way to help effectively institutionalize consideration of non-wires solutions is to establish a set of minimum criteria that would trigger a detailed assessment of non-wires solutions. Most of the jurisdictions discussed in this report have such criteria.

All such criteria start with a requirement that the project be load-related. As the Rhode Island guidelines put it, the need cannot be a function of the condition of the asset (e.g. to replace aging or malfunctioning equipment). Some jurisdictions, such as Vermont, have a short "form" that utilities must complete for each proposed project that provides more detail on this question.

Most jurisdictions have additional criteria related to one or more of the following:

- **Sufficient Lead Time Before Need.** The purpose of this criterion is to ensure that there is enough lead time to enable deferring a T&D investment.
- **Limits to the Size of Load Reduction Required.** The purpose of this criterion is to ensure that there is a substantial enough probability that the non-wires solution can be effective before investing in more detailed assessments. The maximum reduction can be linked to the previous criterion around lead time, as the longer the lead time the larger the reduction in load (and/or equivalent distributed generation level) that could be achieved through non-wires solutions.
- **Minimum Threshold for T&D Project Cost.** The purpose of this criterion is to ensure that the potential benefits of a T&D deferral are great enough to justify more detailed analysis.

Table 5 below provides a summary of the criteria currently in place for a number of the jurisdictions assessed in this report.

Table 5: Criteria for Requiring Detailed Assessment of Non-Wires Solutions

	Must Be Load Related	Minimum Years Before Need	Maximum Load Reduction Required	Minimum T&D Project Cost	Source
Transmission					
Vermont	Yes	1 to 3 4 to 5 6 to 10	15% 20% 25%	$2.5 Million	Regulatory policy
Maine	Yes			>69 kV or >$20 Million	Legislative standard
Rhode Island	Yes	3	20%	$ 1 Million	Regulatory policy
Pacific Northwest (BPA)	Yes	5		$3 Million	Internal planning criteria
Distribution					
PG&E (California)	Yes	3	2 MW		Internal planning criteria
Rhode Island	Yes	3	20%	$ 1 Million	Regulatory policy
Vermont	Yes		25%	$0.3 Million	Regulatory policy

Documents that lay out these requirements more formally and in more detail are provided for Vermont and Rhode Island in Appendices D, E and F.

Consistent with the integrated resource planning guideline discussed above, when projects pass such initial screening criteria, the utility should be required to conduct a more detailed assessment of the potential for reduced peak demand in the geographic area of interest through any combination of distributed resources, including additional energy efficiency, demand response, distributed generation and storage. The cost of such additional distributed resources should then be compared to their benefits. The level of depth of analysis would be a function of the magnitude of the deferral project. For projects for which the more detailed assessment suggests that greater EE and DR would have positive net benefits,[108] the utility should be required to pursue the non-wires solution.

Recommendation 4: Promote Equitable Cost Allocation for NTAs

Investments in transmission solutions to reliability needs are commonly socialized across power pools. For example, a large majority of the cost of a transmission investment in Maine can ultimately be borne by ratepayers in the other five states that are part of the New England grid. In contrast, there is no comparable mechanism to socialize the cost of non-transmission investments across the region[109] – even if they would just as effectively address the reliability

[108] As discussed earlier in the report, some NWAs, including energy efficiency, provide a number of benefits beyond deferral of T&D investments. All costs and benefits of both NWAs and traditional T&D investments should be included in any economic comparisons.

[109] Note that though there is currently no mechanism for socializing the costs of implementing NTAs, there is at least an open question as to whether the costs of *analyzing* NTAs could be socialized. Indeed, some costs of analysis of

In this case, you don't have to do a probabilistic kind of a weighted average of these. But if you did, and even if you assigned an 80 percent probability to the business as usual case, the weighted average result would be that it's cost-effective.

I am going to say a couple of words about pilots. I think there has been universal -- not universal agreement -- a number of parties, including the company and Staff and myself have suggested that there be significant value to launching a couple of pilots.

The key point I want to make about pilots, however, is that I think there's particular value in the pilots being more comprehensive than what Enbridge has historically called its pilots in these areas, and what they appear to be thinking about, although it's not entirely clear in this proceeding. That is, it's all fine and good to have a pilot where what you're doing, for example, is testing the effectiveness of a demand response program, how much load reduction can you get from it.

You also get useful information, for example, by assessing what the relationship is between peak demand reduction and annual energy reduction from a set of energy efficiency programs.

Those are all useful things. But they are all small pieces of what ultimately need to be included or addressed in an IRPA, a plan that's actually designed to defer an infrastructure investment.

So when I think of a pilot, I am thinking of a pilot in which the company would test everything it needs to do to try to defer an infrastructure investment. I am working on these kind of pilots on non-wire solutions with both of the large investor-owned utilities in Michigan right now on the electric side.

As part of the pilots, they identified the substations that they wanted to look at deferring, they did an assessment about how much load reduction would be necessary to defer those investments. They looked at the range of options for deferring them. They developed a portfolio of resources, IRPA resources that they would field test.

Then they went out and field tested them. They measured the reduction that they got, assessed cost-effectiveness, et cetera. So it's actually test running the actual effort to defer an infrastructure investment, and I think that more comprehensive level of a pilot is what we need at this stage and would be appropriate.

I have suggested two pilots, and I don't think anyone else has kind of suggested anything different. But I have also suggested that you might want to think about one of them being utility-run like these two Michigan examples I gave. And another one being RFP driven. So we need X amount of peak load reduction in a certain geographic area put on RFP and see what set of solutions come back to you. That's the principal way ConEd has been approaching certainly its non-wire solutions projects.

And you don't necessarily, in the context of a pilot, want to take all of the least-cost resources that come in.

If you're testing certain things, you may want to say, well, we are going to take the cheapest X amount of load reduction from energy efficiency, the cheapest Y amount of load reduction from demand response, the cheapest Z amount of reduction from compressed natural gas that gets trucked in, or whatever kind of mix so that you can actually field test different electrification, different potential resource options and learn something about all of them in the context of a pilot.

Once you actually get to full scale deployment, you want to take the least cost solution. But in the context of a pilot, you may be willing to do things a little bit differently. And as I noted here at the bottom, that's exactly what the State of Maine did with its non-wires pilot for Boothbay Harbor.

Last point, shareholder incentives. I believe that they are necessary and appropriate so that the company has a viable business option -- a business model, I should say, for going through the future if it's investing in the solutions that are best for its customers.

There are a variety of ways that you can structure shareholder incentives; I talk about several of them in my report. There are pros and cons -- there is no perfect answer; there are pros and cons to all of them. I have suggested starting with capitalizing and rate basing IRPA investments. But that approach may want to be revised over time and perhaps even looking at the experience with the pilot programs, if they are comprehensive enough to

Pollution Probe #3

[Exhibit M2.GEC-ED]

Reference: In Section 1.5.2 it is suggested that the "TRC+" test be used for IRP until a better alternative is available.

Questions:

a) Please indicate why the TRC+ test is better than the Societal Cost Test.
b) Does TRC+ include emissions (e.g. carbon) pricing? If not, should that be added?

Response:

a) In the abstract, neither the TRC+ nor the Societal Cost Test (SCT) is "better" than other. As explained in my report and in the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, a jurisdiction's primary cost-effectiveness test should include (1) all utility system impacts; plus (2) all other categories of impacts associated with that jurisdiction's energy policy objectives. That means the correct (or "best") test will be different for different jurisdictions. The best test can essentially range from the Utility Cost Test (UCT) – if there are no energy policy goals beyond minimizing utility costs – to a fully expansive SCT – if policy goals include a very wide range of interest in consumer impacts, other fuel impacts, water impacts, environmental impacts, public health impacts, economic development and job impacts, etc. The TRC+ test is one of many possible tests that include more impacts than the UCT and less than the SCT. The answer to the question of which test is "better" for Ontario should be based on a review of provincial energy policy goals.

   In my report I recommend that the OEB initiative a stakeholder process to identify relevant provincial energy policy goals and determine the categories of impacts that should be included in an Ontario cost-effectiveness test. See my response to EP-GEC/ED-2 for reference to case studies of jurisdictions that have undertaken such reviews. I also suggested that – in the interim (until such a process is completed) – the OEB adopt the TRC+ test. I suggest that the TRC+ test be the interim test because (1) it is already being used for assessing cost-effectiveness of DSM in the province and the same cost-effectiveness test should be used for all utility investment decisions; and (2) the test is being used for DSM at the express direction of the provincial Government.
b) It is my understanding that the TRC+ test includes the cost of the federal carbon tax. That is appropriate – not just for the TRC+ test, but for any cost-effectiveness test – because that tax is a utility system cost of compliance with applicable carbon emission regulations.

Recommendation (2)

- Initiate Board process to assess test refinements per NSPM principles
  - Address utility system impacts not currently captured in Ontario TRC+
  - Identify impacts to add to utility system impacts – based on energy policy goals
  - Assess through stakeholder process
  - Similar to Guidehouse's recommendation
- This should be done *after* initial IRP framework is put in place
  - Do not need to hold everything else up
  - Revise framework if selected test is different than TRC+

Ontario Energy Board Act, 1998

S.O. 1998, CHAPTER 15
SCHEDULE B

Board objectives, gas

2 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.

6. To promote communication within the gas industry. 1998, c. 15, Sched. B, s. 2; 2002, c. 23, s. 4 (2); 2003, c. 3, s. 3; 2004, c. 23, Sched. B, s. 2; 2009, c. 12, Sched. D, s. 2; 2019, c. 6, Sched. 2, s. 2.

4.2.3.2 Discussion

As noted above, one shortcoming of ICF's analysis of the potential viability of non-pipe solutions is that it focused solely on the peak demand reduction potential from energy efficiency. While increased efficiency savings can sometimes be sufficient to defer a T&D investment, that will not always be the case. However, there are IRPA options other than geotargeted efficiency – including demand response programs; electrification of gas end uses with cold climate air source heat pumps,[21] ground source heat pumps, heat pump water heaters, and other technologies; and local injection of compressed gas – that should also be considered.[22] Any rules governing consideration of non-pipe solutions should require that all IRPA options be considered and that the IRPA plan chosen (if one or more combinations of IRPA options could cost-effectively defer a T&D investment) should represent the least cost mix of such options.[23]

4.2.4 Stakeholder Engagement

4.2.4.1 Summary of Key Points

- IRP analyses are much more robust if they involve stakeholders in the key steps associated with the making of decisions rather than just as potential sources of information or in perfunctory discussions after decisions have largely been made.
- The Board and stakeholders should be informed and included throughout the IRP process. If that does not occur, planning assumptions and decisions will only be tested in leave to construct hearings, at which point it may be too late to select a non-pipe solution that might require a longer lead time.
- The Gas IRP framework should establish a planning committee, modeled on Vermont's System Planning Committee, to secure input throughout the planning process from key stakeholders.

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[21] Air source heat pump technology has advanced dramatically in recent years, particularly in the ability to efficiently provide heat at very low temperatures. In fact, there are currently thousands of air source heat pump models that meet cold climate specifications established by the Northeast Energy Efficiency Partnerships (https://ashp.neep.org/#!/product_list/). Those specifications require heat pumps to be able to produce their full nameplate heating capacity at a coefficient of performance (COP) of 1.75 or better when it is 5° F (-15°C) outside. Moreover, the cold climate performance is improving, with one of the major manufacturers about to release a new line that can produce heat at nameplate capacity at -5° F (-21°C) (personal communication with Kevin DeMaster, Manager of Utility and Efficiency Programs for Mitsubishi Electric Trane HVAC, October 2020). For the relatively few hours of winter when such cold climate heat pumps cannot fully meet heating loads, back-up systems – including electric resistance heating coils in the air handler of a centrally ducted heat pump – can be automatically deployed.

[22] One of the lessons learned from a 2015 report on the use of efficiency as an electric T&D resource was that the integration of efficiency with other distributed resources will be "increasingly common and important" (Neme and Grevatt, p. 58). While the peak demand reduction potential of non-efficiency IRPAs may be different for gas and electric utilities, there is no reason to not consider that potential for either fuel.

[23] This assumes impacts relevant to all policy objectives are monetized and included in the IRP economic analysis.

4.2.4.2 Discussion

In its evidence in this proceeding, Enbridge presents a proposal for "stakeholdering". That proposal has three components:

1. **Gathering of Stakeholder Engagement Data and Insight**. Though it is not entirely clear, this component appears to largely be about outreach from the Company to collect market and other data for its service territory that may be relevant to its planning.
2. **"Stakeholder Days"**. Again, though not much detail is provided, this component appears to be a mechanism through which the Company presents what it is doing on IRP and participating stakeholders may ask questions and provide input.
3. **IRPA project geographically-specific engagement**. This appears to be a mechanism through which Enbridge can collect information relevant to specific non-pipe solutions projects that it is analyzing and considering.

While all of these forms of stakeholder engagement may make sense, they collectively fall short of what should be considered industry best practices. Enbridge's proposal appears to be mostly about either (A) collecting data to inform its planning; and (B) periodically presenting what it is doing with IRP and answering questions. In my experience, IRP analyses are much more robust if they involve stakeholders in the key steps associated with the making of decisions rather than just as potential sources of information or in perfunctory discussions after decisions have largely been made. Such involvement should be at all key points in the analytical process – including forecasting of needs, identification of which needs are driven by peak demand-growth, scoping of alternatives to be considered (where appropriate), reviewing draft cost-effectiveness analyses, developing deployment plans, developing monitoring and evaluation plans, tracking progress and discussing strategy adjustments where needed. The utility needs to both develop initial draft assumptions and ultimately "own" final decisions on each of these steps of the process, as it is the entity on the hook for both costs and reliability of service. However, the utility also has a vested financial interest in investing in new capital projects, so a more structured stakeholder process that requires consideration of other perspectives can help to ensure that investment decisions are truly optimized relative to reliability, cost minimization, and other policy objectives. Other parties can have expertise and insights into key planning assumptions and analytical practices from which the Company and ratepayers could benefit. In addition, this greater depth of engagement brings transparency to the process and should reduce litigation costs.

One model that is worth considering is Vermont's System Planning Committee (VSPC). Though set up to address electric system needs, the process is equally applicable to gas. The VSPC includes representatives from all the electric utilities in the state as well as representatives from suppliers of IRPAs (e.g. efficiency organizations and renewable energy companies) and representatives of the public (representing residential and business ratepayers, environmental groups and regional planning organizations).[24] The state's regulator, analogous to the OEB, appoints the IRPA suppliers and public representatives. A Chair is elected at the beginning of each year from among the voting members. The VSPC meets at least quarterly to identify potential for and consider non-wires solutions. The VSPC charter states that the Committee is a "collaborative body" whose purpose is to "ensure full, fair, and

[24] https://www.vermontspc.com/about/membership

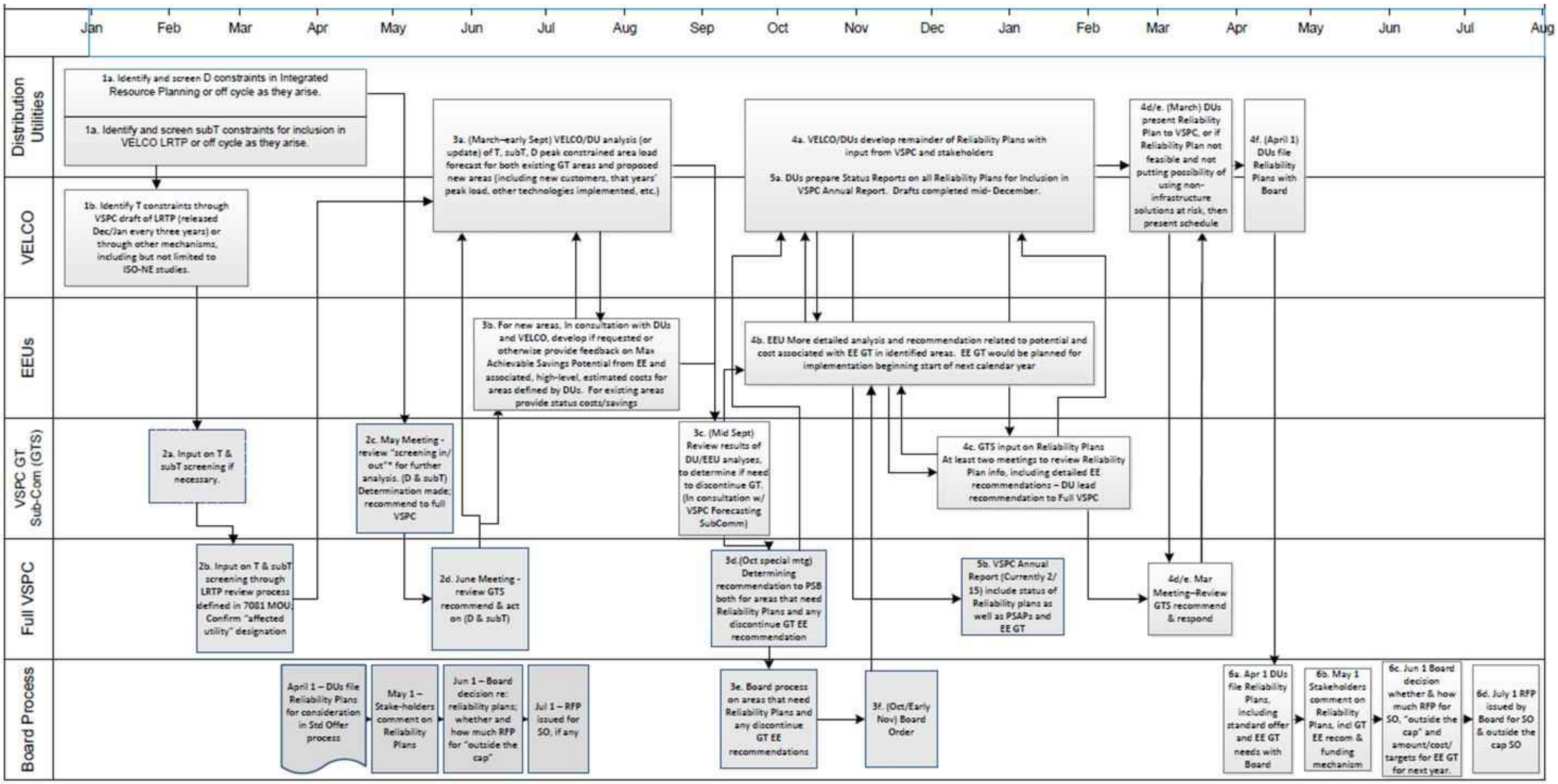
timely consideration of all societally cost-effective solutions to resolve electric grid reliability issues" and which has the following nine objectives:[25]

1. *"Collaborate with and provide formal input to VELCO[26] in the development and review of the Vermont Long-Range Transmission Plan (LRTP) as established in the Docket 7081 Memorandum of Understanding (MOU) and such other processes as may be adopted.*
2. *Jointly review known reliability issues (transmission, sub-transmission and distribution) at least once annually to encourage shared insight and facilitate collaboration among electric grid stakeholders.*
3. *Carry out the functions assigned to the VSPC for screening and analysis of Non-Wires Alternative potential as established in the MOU and the Docket 7874 Screening Framework.*
4. *Enhance transparency and public engagement in electric system planning.*
5. *Provide a forum for the discussion and analysis of the impacts of emerging trends on the behavior of Vermont's electric energy load, including electrification of different end-uses, the installation of storage capacity, demand response measures, distributed generators, merchant projects, and others.*
6. *Seek consensus on the Vermont load forecast to support LRTP development.*
7. *Monitor the installation and impacts of Distributed Energy Resources (DER) to provide broadly shared insight about DER integration and support the development of tools and processes needed to plan for and maintain reliability in an increasingly modernized and intelligent electric grid.*
8. *Provide a forum for utilities and partners to share plans for managing load and infrastructure, and allow for peer-to-peer learning through discussion of shared experiences.*
9. *Maintain regular communication with ISO New England to increase Vermont stakeholder and ISO New England understanding of mutually relevant issues, such as forecasting and grid management."*

A detailed process map of the VPSC consideration of non-wires solutions – including roles of the different parties – is presented in Figure 4.

[25] https://www.vermontspc.com/library/document/download/5641/VSPC_Charter_20160720.pdf
[26] VELCO is Vermont's statewide electric transmission utility. It is jointly owned by all of the state's distribution utilities.

Figure 4: Vermont System Planning Committee Geotargeting Process Map



*"Screening" refers to the use of the Docket 7081 screening tool for bulk and predominantly bulk transmission and the Docket 6290 screening tool for subtransmission and distribution issues to determine their potential to be resolved through energy efficiency and/or alternatives such as generation or demand response (or a hybrid of transmission with efficiency and/or generation). An issue is "screened in" if it has potential for a non-wires solution and therefore requires a Reliability Plan, and "screened out" if no potential is found and, therefore, no Reliability Plan is required.

Key to abbreviations

D	distribution	LRTP	VELCO Long-Range Transmission Plan
DU	distribution utility	PSAP	project-specific action plan
EE	energy efficiency	RFP	request for proposal
EEU	energy efficiency utility	SO	standard offer
GT	geographic targeting	subT	subtransmission (subsystem)
GTS	VSPC Geotargeting Subcommittee	T	transmission (bulk/predominantly bulk)
		VSPC	Vermont System Planning Committee

COVID-19 Update: Protecting the health and safety of our employees, customers, owners and our communities is - and always has been - VELCO's number one priority. Our focus remains on safety and reliability during this unprecedented time. VELCO has implemented our remote work policy in an effort to reduce the spread of COVID-19. During this transition, VELCO's offices will not be open to visitors. If you have questions or need to contact a VELCO representative, please call 802-770-6221 or use our Contact Us form.

VSPC
Vermont System Planning Committee

Home > About

About the VSPC

The Vermont System Planning Committee – VSPC – is a collaborative process, established in 2007, for addressing electric grid reliability planning . Its purpose is to ensure all options to solve grid reliability issues get full, fair and timely consideration, and the most cost effective solution gets chosen, whether it is a poles-and-wires upgrade, energy efficiency, demand response, generation, or a hybrid.

The VSPC process provides transparency, public involvement and collaboration to grid planning

- A transparent reliability planning process through public meetings and this website.
- Public involvement in planning through the appointment of four public members by the Public Utility Commission. Public members represent residential customers, commercial customers, an environmental organization and generation developers.
- A high level of public involvement in the planning process based on recognized principles for effective public engagement.
- A long-term planning horizon of 20 years.
- Advisory votes regarding which utilities are responsible for projects and how costs are allocated for non-transmission alternatives.
- Procedures for facilitating assignment of responsibility for planning and implementation work.
- A prescribed process for identifying grid reliability issues and evaluating the potential to solve them with non-poles-and-wires solutions, such as distributed generation, energy efficiency and demand response.

- Collaboration among energy stakeholders, including all utilities, public representatives, the Public Service Department, the Energy Efficiency Utilities (EEU), and the Sustainably Priced Energy Enterprise Development (SPEED) Facilitator.

VSPC roots

The VSPC is the outgrowth of VELCO's Northwest Reliability Project, which was permitted in 2005. The 63-mile upgrade was the first major project undertaken on Vermont's transmission system for 30 years. In granting its permit, the Public Utility Commission (PUC) concluded that the line was needed, but that, with earlier planning, the reliability problems in question might have been addressed with less costly, non-transmission solutions.

The PUC opened a new proceeding, called Docket 7081, to hammer out a planning process that would ensure "full, fair and timely consideration of cost-effective non-transmission alternatives." The Legislature also enacted changes to Vermont law requiring VELCO to produce a long-range transmission plan and update it every three years.

Following two years of negotiation, most of the parties in Docket 7081 signed a Memorandum of Understanding establishing the VSPC as the forum for addressing the PUC's mandate. Read more about the **VSPC's history**.

Foundations

The basis for the VSPC process and Vermont's approach to transmission planning can be found in Vermont law, PUC orders, and documents that have been created by the VSPC itself. Read more about the governing law, orders and implementing documents, in **Key Documents**.

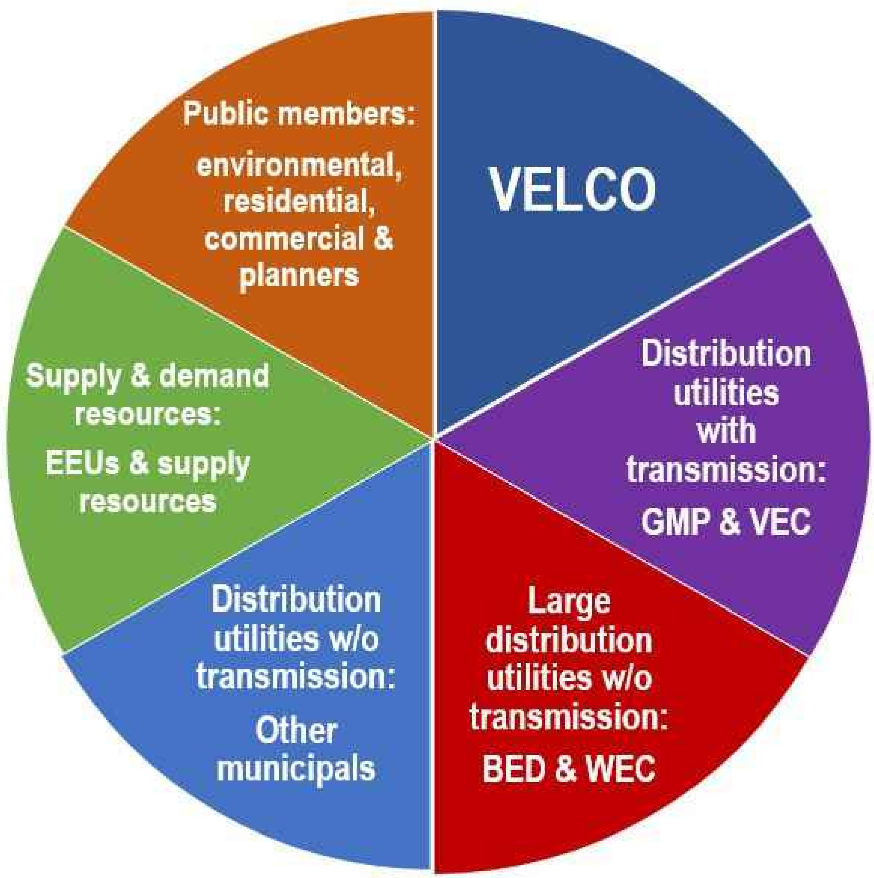
Membership

The members of the VSPC include: representatives of each Vermont electric distribution; VELCO as the owner and operator of Vermont's high-voltage transmission system; the two energy efficiency utilities; a generation developer representative; and three public member representing the interests of residential consumers, commercial and industrial consumers, and environmental protection respectively. In addition three non-voting members participate in the VSPC, including Vermont's Energy Efficiency Utility, the Sustainably Priced Energy Enterprise Development Facilitator, and the Vermont Department of Public Service. Read more »

VSPC Vermont System Planning Committee

Membership

The VSPC is divided into six equally weighted voting sectors, each of which has one vote determined by the majority of members within the sector. The Public Utility Commission appoints the public members and the supply resources representative in the Supply & Demand Resources Sector. The graphic at right shows the composition of the six sectors.



Public Members

Michael Wickenden	Residential Representative	Primary
Tim Duggan	Residential Representative	Alternate
Michael Kirick	Commercial Representative	Primary
Jeff Forward	Commercial Representative	Alternate

Johanna Miller, VT Natural Resources Council	Environmental Representative	Primary
Sandra Levine, Conservation Law Foundation	Environmental Representative	Alternate
Taylor Newton, NW Regional Planning Commission	Planning Representative	Primary
Edward Bove, Rutland Regional Planning Commission	Planning Representative	Alternate

Distribution Utilities with Transmission

Steve Litkovitz	Green Mountain Power	Primary
Douglas Smith	Green Mountain Power	Alternate
Cyril Brunner	Vermont Electric Cooperative	Primary
Michael Beaulieu	Vermont Electric Cooperative	Alternate

Large Transmission-Dependent Utilities

Munir Kasti	Burlington Electric Department	Primary
Bill Powell	Washington Electric Department	Primary

Transmission-Dependent Utilities

Evan Riordan	Barton Village Electric	Primary
Jonathan Elwell	Enosburg Falls Water & Light	Primary
Mike Sullivan	Hardwick Electric Department	Primary
Carol Robertson	Hyde Park Electric Department	Primary
Meredith Birkett	Johnson Water & Light	Primary
Thomas Petraska	Ludlow Electric Department	Primary
Howard Barton	Ludlow Electric Department	Alternate
Bill Humphrey	Lyndonville Electric Department	Primary
Craig Myotte	Morrisville Water & Light	Primary
Stephen L. Fitzhugh	Northfield Electric Department	Primary
John Morley	Orleans Electric Department	Primary
Ellen Burt	Stowe Electric Department	Primary
Reginald Beliveau, Jr.	Swanton Electric Department	Primary
Lynn Paradis	Swanton Electric Department	Alternate

Supply & Demand Resources

David Westman	Efficiency Vermont	Primary
Chris Burns	Burlington Electric Department	Primary
Nathaniel Vandal	Green Peak Solar, LLC	Primary
Olivia Campbell Andersen	Renewable Energy VT	Alternate

Transmission Utility

Hantz Présumé	VELCO	Primary
Frank Ettori	VELCO	Alternate

Non-Voting Participants

Bill Jordan, Engineering Director	Public Service Department
Ed McNamara, Planning Director	Public Service Department
Carolyn Alderman, VEPP Inc.	SPEED Facilitator
Shana Louiselle, VSPC Facilitator/Secretary	Staff

approval of those decisions in the Asset Management Plan, which would be a departure -- as I understand it, I am not an expert in how the Asset Management Plan process works today -- but as I understand it, that would be a departure from the way things work today.

To the extent that there is the ability to reach consensus through the more robust stakeholder process, the Board's focus could be potentially much narrower than it might otherwise have been.

MS. ANDERSON: Mr. Neme, before you leave this slide, just back on the formal stakeholder process. I did take just a glance of what I could see online on the Vermont system planning committee, and it looked to me like part of what that was about was coordinating amongst a number of different utilities, because I saw a utilities commission distributors, transmitters and that seemed to be, I guess, an important element of it that it doesn't seem as, you know, as likely to be needed in Ontario with Enbridge.

So I guess the question is kind of compare and contrast --

MR. NEME: Sure.

MS. ANDERSON: -- that whole kind of system planning element amongst utilities in Vermont versus Ontario.

MR. NEME: Yeah, it's a great question. I would say one of the functions of the committee is to enable that collaboration. There are something like 20 different distribution utilities, electric utilities in Vermont and then a single state-wide transmission utility, and there obviously -- and by the way, the state-wide transmission utility is co-owned by all of those 20 distribution utilities. So they already have some form of integrated planning just by nature of the fact that between distribution and transmission -- by nature of the fact of that ownership structure. But I am sure that the process itself also aids that collaboration. But that's not the only reason that the system planning committee is -- has been established.

There are a number of non-utility appointees to that committee as well. And I will also say that my understanding is that there is an effort across all of the participants in that committee process to endeavour to achieve consensus in the consideration of non-wires alternatives at each of the different stages that I outlined on the previous slide; a pre-screening criteria, the more detailed analysis of the viability and economics of solutions, and then development of the plans.

To my knowledge, as a result of those robust discussions across a range of stakeholders, there has not been a contested case put before the Board. What gets submitted to the Board, our public service Board, which I think has been renamed our public utility commission, you know, that's the end process. But thus far, the committee has enabled resolution of concerns from a range of perspectives on that.

So I think that in a way, the fact that Enbridge is the entire distribution utility pretty much and the entire transmission utility would make this even a little bit easier to implement in Ontario than it is in Vermont, because you don't have as many kind of different utility voices that you need to manage. Does that address your question?

MS. ANDERSON: It does, thank you.

MR. NEME: Great. So I also want to say a few words about my understanding of the Enbridge proposal, which I think is problematic in a couple of ways.

The first is the company appears to be putting an awful lot of emphasis on its kind of annual one-day stakeholder meeting. And I think it's not realistic to suggest that that one-day meeting can be the place where most questions about all decisions from steps 2, 3 and 4, or even steps 2 and 3, could -- you know, from all different types of stakeholders across the entire system could be reasonably addressed.

I believe it was in Staff 8, the response to Staff 8, Enbridge provided a table that showed for its 2021-2025 Asset Management Plan -- so this is only five years of forecast, not the ten years that they are now talking about doing -- there were about 20 different projects which they identified in that interrogatory response as either, you know, potential candidates for IRPAs or not.

If you had a ten-year forecast, you know, maybe it's 40 different projects. It's just hard to imagine that you can get anywhere close to the level of detail and discussion about 40 different projects and the viability of

ENBRIDGE GAS INC.

Undertaking Response to FRPO

To provide the evidentiary or transcript reference to a process for stakeholders to raise alternate IRPAs and have them considered and addressed.

Response:

The process for stakeholders to raise alternative IRPAs is addressed as an objective of the proposed stakeholder approach in Enbridge Gas's Additional Evidence (Exhibit B) at paragraph 88 on page 39:

> Accordingly, the objectives of the IRP Stakeholder Engagement process will be to: (i) ensure planned resources will meet Enbridge Gas's obligation to safely and reliably deliver firm contracted demands; (ii) gather ample geographically-specific information such that IRPAs can be adequately reviewed and monitored; (iii) help inform the development of new or enhanced energy efficiency programming; and (iv) broadly inform Enbridge Gas's long-term strategic planning.
> (emphasis added)

It is further articulated in the Company's Reply Evidence (Exhibit C) at pages 13 and 14 within Section 3.0 Stakeholder Consultation/Engagement.

> Enbridge Gas acknowledges the importance of obtaining stakeholder input ahead of developing IRPAs to address identified system needs/constraints and of establishing a feedback loop to keep stakeholders (including municipal and government representatives, First Nations, end use customers from all sectors, customer and business associations) informed of its investments in and the impact of their respective input into the development of IRPAs.
>
> Enbridge Gas's proposed three component approach to stakeholder engagement, as set out in its Additional Evidence,[1] is meant to go beyond data collection in that it: (i) recognizes that each geographic area being consulted regarding an identified customer need or system constraint and relevant IRPA(s) will have unique attributes and stakeholders;[2] and (ii) seeks to solicit concrete input for Enbridge Gas planners to consider when assessing alternatives to resolve identified system capacity needs/constraints, through engagement with members of the public that are expected to be directly impacted.
> (emphasis added)

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[1] Enbridge Gas Additional Evidence, Exhibit B, para. 89.
[2] Examples of which may include local chambers of commerce and boards of trades and their members, local businesses owners and associations, and local LDC's.

Additionally, Mr. Stiers provided an example of how an alternate IRPA could be brought forward on the proposed Stakeholder Day, as part of Component 2 of Enbridge Gas's proposed Stakeholder process, during his testimony in the Technical Conference on February 10, 2021:[3]

> And so in an effort to put forward a process that is reasonable and efficient, the company has suggested that what is appropriate is for it to focus on identifying the system constraints, as you stated, as it normally does in the normal course of business, and then subsequently to reflect on any input from external parties that it has through existing communication channels, so component one of our stakeholdering process. And then to consider using the IRP assessment process that we have set out in Exhibit B.
>
> Thus, various IRPAs might be reasonable or viable for serving that need. So the company expects that all along this process, it will take into account the input of stakeholders at that first early stage. It will be based on what we received already, but then we do expect that stakeholders will have an early and frequent opportunity to pose questions and provide comments on the decisions that the company has made.
>
> And so, following the identification of system constraints in our asset management plan, we would make the asset management plan public as part of our annual rates proceedings, and stakeholders would have an opportunity at its annual stakeholder day shortly after to pose questions and understand the decisions that the utility has made and to provide input on those, and all of that we intend to record.
>
> So beyond that, we also expect that we will file annual IRP reports and that we will, at the time we make an IRP application to the board, we would in each of those instances also be in a position to explain the decisions that we've made. And so we don't think it would be efficient for us to have additional, let's say, process aside from that.

Mr. Stiers went on to state:[4]

> I am letting you know our intentions going forward are to also hear at the -- for example, at the stakeholder day --from stakeholders, from people in affected geographic locations where a system constraint has been identified, and from parties, <u>whether or not they think there are other viable IRPAs that the utility should consider. Now, some of those we may have already assessed and considered and we may be prepared to speak to on the day or to provide follow-up on in fairly short order. I do foresee that there might be an instance where new IRPAs that were not necessarily considered could also surface, and we would give those consideration as well.</u> That's the purpose of the stakeholdering.
> <u>(emphasis added)</u>

[3] EB-2020-0091 OEB Technical Conference Transcript, February 10, 2021, pp. 12-14.
[4] EB-2020-0091 OEB Technical Conference Transcript, February 10, 2021, pp. 64-65.

After further discussion during his testimony in the Technical Conference on February 12, 2021, Mr. Stiers concluded:

> I think what we set out is up to ten years in advance identifying a system constraint and as quickly as possible, wrapping our heads around what that constraint is and what the appropriate means might be to resolve that constraint from both a facility and a non-facility standpoint, and as immediately as possible looking to consult on what we think makes sense with the public, with First Nations, with parties. We see that as quite timely consultation.

UPDATE

Enbridge Gas is committed to public participation and receiving formal written suggestions and questions that will be answered by the Company and posted online (e.g. as part of its website). As part of its response to OEB Staff interrogatories, the Company stated:[5]

> Enbridge Gas recognizes that as part of these activities, participating stakeholders and Indigenous communities could provide additional insight into IRPAs that the Company did not consider or was unaware of. For example, the stakeholder plan will seek to gain understanding from stakeholders and Indigenous communities on customer growth expectations and willingness to participate in potential demand response programming; economic activity and growth; low carbon alternative opportunities; energy efficiency and conservation potential opportunities; new and emerging technological advances.

Enbridge Gas has put forward an Ontario focused stakeholder engagement model that reflects the vast differences in geography, climate, customer type and demands in communities served by the Company across the province. As discussed in the Company's interrogatory response at Exhibit I.STAFF.9 b), Enbridge Gas's proposed stakeholder engagement strategy has been influenced by and is similar in many respects to the engagement initiatives conducted by Ontario's IESO as part of its Integrated Regional Resource Plan ("IRRP") processes. The IESO stakeholder model has evolved in recent years in response to a cycle of continuous improvement, informed by government policy and the OEB, and is used to engage with stakeholders across a similarly complex energy system.[6] Currently the IESO uses a regional electricity network model that allows for more targeted discussions to be conducted in five specific regions.

Initially, as part of Component 2 of its proposed Stakeholder Outreach strategy, Enbridge Gas proposed to discuss the AMP and any associated IRPA's during an annual Stakeholder Day following the filing of the annual update to the AMP. Following the Technical Conference and the Presentation Day in this proceeding the Company reflected upon whether it would be appropriate, efficient and helpful to expand upon the

[5] Exhibit I.STAFF.9 a).
[6] Exhibit I.GEC.5 b).

proposed annual Stakeholder Day. Enbridge Gas has determined that Component 2 of its stakeholder engagement process could also benefit from this regional focus. Therefore, the Company now proposes to separate the projects identified in its annual update to the AMP (including IRPAs) into similar regional areas in support of conducting multiple targeted annual Stakeholder Days (one in each region annually where projects have been identified). In establishing regions for these purposes, Enbridge Gas will attempt to mimic the regional breakdown of the IESO Regional Electricity Networks wherever appropriate.[7]

[7] https://www.ieso.ca/en/Get-Involved/Regional-Planning/Electricity-Networks/Overview

Pollution Probe #10
[Exhibit M2.GEC-ED] [PollutionProbe_IR_Appendix F-IESO Engagement_20210112]

Question:
Do you agree that the IESO Engagement Principles used to coordinate their planning represent best practices? If not, what changes would you recommend?

Response:
I would propose several modifications to the IESO principles:

1. I modify the 5th principle on "effective facilitation". Specifically, I would recommend that the decision-making body – the IESO in this case – not be the facilitator of discussions. In my experience, dialogue with stakeholders is much more effective if a neutral facilitator is hired. To the extent that an engagement process is expected to be of some length or even on-going, even more structure would ideally be put in place to ensure neutrality. For example, a neutral facilitator should ideally be selected, through a consensus process to the extent possible, by all the stakeholders. The neutral facilitator should also develop meeting agendas based on input from all stakeholders. It should also ultimately answer to all stakeholders (this can be accomplished through a steering committee representing all stakeholders). This process has been used for years in state of Illinois for addressing a wide range of policy and technical issues associated with the state's utilities' efficiency programs through what is called the Illinois Stakeholder Advisory Group (SAG). I have been an active participant in the Illinois SAG for a decade.
2. I would amend the 6th principle on "communicating outcomes" to be clear not only about the how input was considered and the rationale for decisions made, but also about why alternative approaches proposed by one or more stakeholders were not taken. That could be the implicit intent in the description of the IESO principle, but it could be made more explicit.
3. Adding a principle on financial support. For engagements that will involve significant time commitments and/or technical expertise, it is important that stakeholders who can demonstrate they have an important perspective to offer are able to financially afford to bring that perspective to discussions.

I would also note that while stakeholder engagement processes governed by the principles put forward by the IESO (and including modifications I have proposed) are important, there also needs to be a regulatory backstop. That is, there needs to be a regulatory process for resolving disagreements that cannot be resolved through stakeholder engagement. That regulatory process needs to be transparent, enable participation by all stakeholders with a legitimate standing – including through funding of experts and legal fees – and be based on a clear set of rules.

transmission utility would make this even a little bit easier to implement in Ontario than it is in Vermont, because you don't have as many kind of different utility voices that you need to manage. Does that address your question?

MS. ANDERSON: It does, thank you.

MR. NEME: Great. So I also want to say a few words about my understanding of the Enbridge proposal, which I think is problematic in a couple of ways.

The first is the company appears to be putting an awful lot of emphasis on its kind of annual one-day stakeholder meeting. And I think it's not realistic to suggest that that one-day meeting can be the place where most questions about all decisions from steps 2, 3 and 4, or even steps 2 and 3, could -- you know, from all different types of stakeholders across the entire system could be reasonably addressed.

I believe it was in Staff 8, the response to Staff 8, Enbridge provided a table that showed for its 2021-2025 Asset Management Plan -- so this is only five years of forecast, not the ten years that they are now talking about doing -- there were about 20 different projects which they identified in that interrogatory response as either, you know, potential candidates for IRPAs or not.

If you had a ten-year forecast, you know, maybe it's 40 different projects. It's just hard to imagine that you can get anywhere close to the level of detail and discussion about 40 different projects and the viability of

IRPAs for them with multiple stakeholders in the room. I have spent half days, sometimes even longer, just talking about the viability of an IRPA with one utility on one aspect of their system. If you want more than just a superficial, you know, we will take a couple questions from you and then a couple questions from somebody else, that's just -- a one-day stakeholder meeting is just not going to do it.

They do -- the company has suggested that its conclusions on whether IRPAs are ruled out through their binary screening process and/or deemed viable in the kind of subsequent stage would be documented in an Asset Management Plan, which is a good thing, but it doesn't appear as if they are supporting the idea or the potential for an interrogatory process to get more details on those things, and they aren't proposing that there be any kind of formal Board approval of any of those decisions.

As a result, you won't be asked as a Board to adjudicate a proposal and implicitly, then, potentially the ruling out of an IRPA solution, until a leave-to-construct application has been submitted. And, you know, in my humble opinion, and I think past experience suggests that that's just too late to give the Board real choices.

Now I am going to shift over to the issue of economic analysis. I recommend that the Board begin by adopting the TRC, the total resource cost plus test, as its initial primary cost-effectiveness test. This is a test that provide a comprehensive view of cost-effectiveness. It is

ENBRIDGE GAS INC.

Undertaking Response to GEC

To clarify the proportion of identified projects which will now fall under the increased LTC threshold, by percentage of projects and percentage of capital spending.

Response:

There are over two thousand (2,000) projects in the Company's Asset Management Plan ("AMP"). Establishing a scope that requires all of those projects to be considered for IRP analysis in the early stages of Enbridge Gas's implementation of an IRP Framework would not be reasonable or efficient as it would require exponential incremental administrative burden to be borne by ratepayers for limited value. Further, the Company doubts that such a task would be technically feasible.

Following its review of review of the Board's recent Decision and Order for the London Lines Replacement Project (EB-2020-0192), Enbridge Gas has reconsidered whether its singular focus upon growth projects for IRP purposes remains appropriate. Enbridge Gas continues to believe that that IRP will most effectively be applied to projects where growth is the main driver. However, the Company acknowledges that for large pipeline replacement and relocation projects, there may be opportunities to reduce the size of the replacement and these too should be considered for IRP in the future. The Company does not believe that IRP will be appropriate for smaller scale pipeline replacement projects (less than $10 million cost), as the cost savings that would result from downsizing pipeline size will not be significant enough to support consideration of IRP alternatives.

To provide clarity with regard to the nature of projects that are most relevant for IRP consideration, Enbridge Gas proposes to add one additional binary screening criteria, as follows:

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.

Based on these criteria, Tables 1 and 2 below have been developed to reflect the percentage of Enbridge Gas's total capital spending that could feasibly advance beyond the binary screening process to the proposed IRPA evaluation process. However, in order to provide a representative view that might apply in future years, Tables 1 and 2 below do not take into account the Company's proposed Timing criterion (required 3-year lead time). As seen in Table 1 below, 27% of forecasted capital investments could advance beyond the Company's proposed binary screening process.

Table 1

	2021	2022	2023	2024	2025	Total
Main Replacements & Relocations > $10M	$ 206,228,091	$ 174,849,057	$ 106,671,087	$ 161,012,110	$ 127,225,506	$ 775,985,851
System Reinforcement (all)	$ 92,412,034	$ 289,881,388	$ 159,168,683	$ 177,997,863	$ 208,094,403	$ 927,554,370
Total	$ 298,640,125	$ 464,730,445	$ 265,839,770	$ 339,009,973	$ 335,319,908	$ 1,703,540,220
EGI Capital Spend	$ 1,270,478,059	$ 1,405,978,079	$ 1,163,427,104	$ 1,352,601,964	$ 1,111,519,734	$ 6,304,004,942
IRP Eligible Spend as a % of Total	24%	33%	23%	25%	30%	27%

It is also relevant to understand the number of unique projects that are represented in the overall capital forecast for each category, as it informs the amount of effort required to perform the binary screening exercise and then to undertake the two-stage IRPA evaluation process.

Table 2 below sets out the number of projects from the 2021-2025 AMP that are included in Table 1 above. Note that the AMP does not provide granular project-level information about discrete projects for all later years (in some cases the Programs in the AMP are not yet broken down into projects for later years - for example projects anticipated to be driven by changes to Class Location or Municipal Requirements). As a result, the number of projects indicated in Table 2 will change over time.

Table 2

Main Replacements & Relocations > $10M	20
System Reinforcement (all)	168
Total	188
Number of Projects in the AMP	2114
% of Projects	9%

has no meaning from an economics perspective. And the reason for that is that it mixes apples and oranges, it mixes cost-effectiveness factors with rate impact factors.

I will also observe that the company's claim that this test provides essentially the same information as ConEd's test in New York is incorrect. If you were to sum up all of the numbers throughout the three stages that they provide, you don't get the societal cost test, or the TRC, or really anything close.

Secondly, the test is inconsistent with the TRC test that Ontario currently uses for assessing the cost-effectiveness of energy efficiency programs, and it is economically irrational to use different tests for different purposes. In essence, you are -- you can take the exact same efficiency measure, insulating an attic, and say, well, when we look at that in the context of an efficiency program, it's worth $3,000. But when we look at it in the context of trying to defer a distribution system upgrade, it's worth only $500 or some other number. That just doesn't make sense.

Thirdly, the DCF plus test framework, as I understand it, was built on EBO 134 and, as I understand it, EBO 134 was principally designed to ensure that when you're looking at gas system expansions, for example into the new communities, that existing customers don't subsidize new customers. But that has very little to do with comparing the relative economics of pipe and non-pipe solutions.

And finally, as I noted before, nobody else does this.

5.2 Applicable Lessons from IRP Analyses of Alternatives to T&D Investments

At a high level, IRP analyses of alternatives to traditional T&D investments should include each of the following steps:

1. Forecast near and longer-term peak demand for all elements of the T&D utility system.
2. Timely identification of capital investments in T&D that will be required given forecast peak demand growth (absent geotargeted deployment of additional IRPAs).
3. Identify the subset of capital investments in T&D that could potentially be candidates for consideration of IRPAs.
4. Characterize the magnitude and timing of the need for T&D investments:
    a. In what year would the T&D capacity increase be needed?
    b. During which hours of the day do peak demands occur?
    c. How much peak load reduction would be necessary during those hours to defer the T&D investment?
5. Characterize the cost of the T&D investments.
6. Assess whether geographically targeted energy efficiency, demand response and/or other IRPAs could be acquired in sufficient volume and over a short enough period of time to either (1) defer or eliminate the need for each T&D capital investment; or (2) allow for a lower cost T&D investment. This will require:
    a. Characterizing the peak demand reduction that individual efficiency, demand response and/or other IRPA measures can provide;
    b. Characterizing the total potential for each measure – i.e., the number of each measure that could be applied or installed – in the geographic area of interest; and
    c. Characterizing how much of the potential could be realized each year (i.e. participation rates).
7. Where there is sufficient efficiency, demand response and/or other IRPA potential to (individually or in combination) defer or allow for lowering of the cost of a T&D investment, estimating the costs of acquiring the IRPAs.
8. Perform cost-effectiveness analysis of the IRPAs – comparing their costs to the cost savings they would provide. The cost savings of IRPAs includes not only the value of deferring or lowering the cost of the alternative T&D investment, but also the value of other relevant benefits that they may provide, including avoided energy costs.

Each of these steps is necessary for assessment of *both* electric *and* gas IRPAs. Thus, many of the lessons learned from decades of experience with analyses of non-wires alternatives are transferable to analysis of non-pipe alternatives. That includes insights into planning horizons, forecasting future T&D needs, analysis of multiple IRPA resource options for a given geography, and the principles and mechanics of cost-effectiveness analysis.

To be sure, there are some differences between gas and electric systems that will need to be addressed in analyses of gas non-pipe solutions. For example, peak periods of interest may be different, the level of reliability may be different and there are some differences in the range of distributed resource options to consider (e.g., electrification and local injection of compressed gas are only options for non-pipe solutions and distributed photovoltaics and/or diesel generators are only options for non-wires solutions). However, that just means that each of the planning steps outlined above needs to account

GEC Response to Energy Probe Undertaking

Question JT3.10(A)

To Provide a list of the inputs for the "TRC-plus" test.

Response:

Our sense from the discussion with Dr. Higgin during the technical conference is that he was interested in a hypothetical example to illustrate how the different inputs to the TRC+ test would be made. To that end, we have developed a hypothetical and will show how it applies to both a hypothetical demand response (DR) program as an IRPA and a hypothetical energy efficiency (EE) program as an IRPA.

For both of these examples, we assume peak demand of 90 units of gas, an existing maximum capacity of 100 units, and annual growth of 2 units. Thus, in this hypothetical, peak demand would be equal to the maximum existing capacity in five years. In other words, absent any demand-side investment, the capacity upgrade would be needed in five years. We also assume that the capacity addition will cost $25,000 and that a 4% real discount rate is used in the analysis. As Table 1 illustrates, that produces a net present value (NPV) cost for the infrastructure scenario of $20,548. That is the base case against which the two IRPA scenarios are compared.

Table 1: Cost of Infrastructure Scenario

	Year														
Peak Demand	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**15**	**20**	**25**	
Peak Demand w/o IRPA	90	92	94	96	98	100	102	104	106	108	110	120	130	140	
Incremental Annual IRPA Peak Savings		0	0	0	0	0	0	0	0	0	0	0	0	0	
Cumulative Annual IRPA Peak Savings		0	0	0	0	0	0	0	0	0	0	0	0	0	
Peak Demand after DR	90	92	94	96	98	100	102	104	106	108	110	120	130	140	
Costs															**NPV**
Infrastructure		$0	$0	$0	$0	$25,000	$0	$0	$0	$0	$0	$0	$0	$0	$20,548
IRPA		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$0	$0	$0	$0	$25,000	$0	$0	$0	$0	$0	$0	$0	$0	**$20,548**
Other Benefits															
Avoided Energy Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Avoided Carbon Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electricity savings		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other non-energy benefits		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Net Cost		**$0**	**$0**	**$0**	**$0**	**$25,000**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$20,548**
Net Cost Difference vs. Infrastructure		n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.

With respect to DR, and as shown in Table 2, it is assumed that the maximum DR potential is 10 units, but that it would take ten years of marketing and offering of financial incentives to customers to ramp up to that level of DR capacity. It is further assumed that the utility has to pay a financial incentive to customers of $50 to achieve 1 unit of DR capacity, and that such payments are required each year (i.e., it is an annual payment required to keep customers enrolled in the DR program). It is also assumed that the utility must spend a fixed $25 per year, regardless of participation levels, to manage the DR program and market it to customers. For simplicity, it is assumed that there are no gas or electric energy savings that result from the DR program. As Table 2 illustrates, these assumptions lead to a total DR scenario cost of $19,151, or a cost savings relative to the infrastructure scenario of $1397.

Table 2: Cost of DR Scenario

	Year														
Peak Demand	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**15**	**20**	**25**	
Peak Demand w/o IRPA	90	92	94	96	98	100	102	104	106	108	110	120	130	140	
Incremental Annual IRPA Peak Savings		1	1	1	1	1	1	1	1	1	1	0	0	0	
Cumulative Annual IRPA Peak Savings		1	2	3	4	5	6	7	8	9	10	0	0	0	
Peak Demand after DR	90	91	92	93	94	95	96	97	98	99	100	120	130	140	
Costs															NPV
Infrastructure		$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,000	$0	$0	$0	$16,889
DR Incentives		$50	$100	$150	$200	$250	$300	$350	$400	$450	$500	$0	$0	$0	$2,100
DR Non-Rebate Costs		$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$0	$0	$0	$162
DR Customer Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$70	$120	$170	$220	$270	$320	$370	$420	$470	$25,520	$0	$0	$0	$19,151
Other Benefits															
Avoided Energy Costs		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Avoided Carbon Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Electricity savings		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Other non-energy benefits		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Total		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Net Cost		$70	$120	$170	$220	$270	$320	$370	$420	$470	$25,520	$0	$0	$0	$19,151
Net Cost Difference vs. Infrastructure		$70	$120	$170	$220	($24,730)	$320	$370	$420	$470	$25,520	$0	$0	$0	($1,397)

With respect to EE, and as shown in Table 3, it is assumed that a geotargeted set of programs could generate 1 incremental unit of peak savings each year. Savings are assumed to last 15 years, so the theoretic maximum cumulative savings would be 15 units. However, the program is assumed to be stopped after 10 years because the infrastructure project cannot be deferred past year 10. It is further assumed that the utility pays a financial incentive of $250 to customers per unit of peak savings and that represents 50% of the cost of the efficiency measures – meaning customers would incur another $250 themselves. It is also assumed that the utility spends $75 per year to manage and market the programs. Unlike DR, EE provides substantial additional benefits in the form of avoided gas energy costs, avoided carbon taxes, avoided electricity costs (many gas efficiency measures also save electricity) and other customer non energy benefits. The hypothetical assumptions used to value these benefits, along with the other DR and EE assumptions, are presented in Table 4. As Table 3 shows, this hypothetical EE scenario has an NPV cost of $17,021, or $3527 less than the infrastructure option.

Table 3: Cost of EE Scenario

	Year														
Peak Demand	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**15**	**20**	**25**	
Peak Demand w/o IRPA	90	92	94	96	98	100	102	104	106	108	110	120	130	140	
Incremental Annual IRPA Peak Savings		1	1	1	1	1	1	1	1	1	1	0	0	0	
Cumulative Annual IRPA Peak Savings		1	2	3	4	5	6	7	8	9	10	10	5	0	
Peak Demand after DR	90	91	92	93	94	95	96	97	98	99	100	110	125	140	
Costs															**NPV**
Infrastructure		$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,000	$0	$0	$0	$16,889
EE Incentives		$250	$250	$250	$250	$250	$250	$250	$250	$250	$250	$0	$0	$0	$2,028
EE Non-Rebate Cost		$75	$75	$75	$75	$75	$75	$75	$75	$75	$75	$0	$0	$0	$608
EE customer Costs		$250	$250	$250	$250	$250	$250	$250	$250	$250	$250	$0	$0	$0	$2,028
Total		$575	$575	$575	$575	$575	$575	$575	$575	$575	$25,575	$0	$0	$0	$21,553
Other Benefits															
Avoided Energy Costs		$20	$40	$60	$80	$100	$120	$140	$160	$180	$200	$200	$100	$0	$1,876
Avoided Carbon Taxes		$20	$39	$59	$78	$98	$117	$137	$157	$176	$196	$196	$98	$0	$1,835
Electricity savings		$5	$10	$15	$20	$25	$30	$35	$40	$45	$50	$50	$25	$0	$469
Other non-energy benefits		$4	$8	$11	$15	$19	$23	$26	$30	$34	$38	$38	$19	$0	$352
Total		$48	$97	$145	$193	$242	$290	$338	$387	$435	$483	$483	$242	$0	$4,531
Net Cost		$527	$478	$430	$382	$333	$285	$237	$188	$140	$25,092	($483)	($242)	$0	$17,021
Net Cost Difference vs. Infrastructure		$527	$478	$430	$382	($24,667)	$285	$237	$188	$140	$25,092	($483)	($242)	$0	($3,527)

Table 4: DR, EE and other General Assumptions

DR and DSM Assumptions	DR	DSM
Measure Life	1	15
Annual m3 saved	0	100
Annual kWh saved	0	50
Utility rebate	$50	$250
Customer measure cost	$25	$250
Utility non-rebate program cost	$20	$75

General Assumptions		
Real discount rate	4%	
Infrastructure Cost	$25,000	
Avoided Energy Cost ($/m3)	$0.20	
Carbon Tax $/tonne	$100	
Carbon Tax $/m3	$0.20	
Avoided electricity cost ($/kWh)	$0.10	
Customer non-energy benefits	15%	of non-CO2 benefits

The tables above collectively provide all the information needed to assess cost-effectiveness through the TRC+ test, as it is applied today in Ontario for DSM. The categories of impacts included in the TRC+ (again, as applied today in Ontario), along with the values from the hypothetical examples summarized above, are shown in Table 5 below. In this example, both the DR IRPA and EE IRPA would be cost-effective. However, the EE option produces greater net benefits (i.e., cost savings) and has a slightly higher benefit-cost ratio.

Table 5: TRC+ Test Calculations of Cost-Effectiveness

	DR	EE
Benefits		
Avoided Infrastructure Costs	$3,659	$3,659
Avoided Annual Gas Energy Costs	$0	$1,876
Avoided Gas Carbon Taxes	$0	$1,835
Avoided electricity costs	$0	$469
DSM Non-Energy Benefits Adder	$0	$352
Total	**$3,659**	**$8,191**
Costs		
IRPA Incentive Costs	$2,100	$2,028
Other IRPA Program/Admin Costs	$162	$608
Increased Utility O&M	$0	$0
Increased Carbon Taxes	$0	$0
Increase in other Fuel Costs	$0	$0
Increased Customer Costs	$0	$2,028
Total	**$2,262**	**$4,664**
Cost-Effectiveness Determination		
Net Benefits	**$1,397**	**$3,527**
Benefit-Cost Ratio	**1.62**	**1.76**
Non-Pipe Solution Cost-Effective?	**YES**	**YES**

Note that the TRC+ test, like all cost-effectiveness tests, should include all utility system impacts. However, the TRC+ test as currently applied in Ontario is missing a several potential benefits of energy efficiency and potentially other IRPA options. Specifically, it has not included the benefits of:

- market price suppression effects – reductions in demand for gas will lower the market clearing price for gas (even if the reduction is very small, the total value can be non-trivial when multiplied by total gas consumption by all of Enbridge's customers);
- option value – the modular nature of efficiency "buying time" to recalibrate peak load forecasts, which could lead to longer deferrals of even elimination of the need for an infrastructure upgrade; or
- risk mitigation – e.g., efficiency investments reducing customers' exposure to future gas price uncertainty.

All of those impacts should be added to future applications of the TRC+ test in Ontario.

Also, as explained in the EFG report in this proceeding, the analysis of cost-effectiveness of IRPA options such as DR and EE should include sensitivity scenarios, particularly with respect to potential impacts of more stringent climate policy impacts on gas demand and/or gas costs.