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EB-2015-0049

Green Energy Coalition

Cross-examination Materials

For Enbridge Panel 4

Ministry of Energy

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Ontario

OCT 2 3 2014

Mr. Colin Andersen
Chief Executive Officer
Ontario Power Authority
1600–120 Adelaide Street West
Toronto ON M5H 1T1

Dear Mr. Andersen:

RE: Amending March 31, 2014 Direction Regarding 2015-2020 Conservation First Framework

I write in my capacity as the Minister of Energy in order to exercise the statutory power of ministerial direction I have in respect of the Ontario Power Authority (OPA) under the *Electricity Act, 1998,* as amended (Act).

Background

In *Achieving Balance: Ontario's Long-Term Energy Plan* (LTEP 2013), released on December 2, 2013, the Government established a provincial conservation and demand management (CDM) target of 30 terawatt hours (TWh) in 2032. To assist the Government in achieving this target, LTEP 2013 also committed to establishing a new six-year Conservation First Framework beginning in January 2015, replacing the one that is currently winding down.

On March 31, 2014, I directed the OPA to coordinate, support and fund the delivery of CDM programs through licensed electricity distributors ("Distributors") to achieve a total of 7 TWh of reductions in electricity consumption between January 1, 2015 and December 31, 2020, in accordance with specified guiding principles and requirements ("March 2014 Direction").

In the March 2014 Direction, I directed the OPA, in consultation with Distributors, to develop a cost recovery and performance incentive mechanism for Distributors for making Province-Wide Distributor CDM Programs and/or Local Distributor CDM programs available to customers in their service areas. I also directed the OPA to ensure that there is a positive benefit-cost analysis of each CDM Plan and each Province-Wide CDM Program and Local Distributor CDM Program utilizing the OPA's Total Resource Cost Test and the Program Administrator Cost Test found in the OPA's Cost-Effectiveness Guide, dated October 15, 2010, which may be updated by the OPA from time to time ("OPA Cost-Effectiveness Tests").

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On April 24, 2014, the government released its Five-Point Small Business Energy Savings Plan to help mitigate electricity rate increases for small businesses by offering enhanced conservation programs. In partnership with Distributors and key agencies, the plan will help small businesses conserve energy, manage costs and save money. A key element of the plan is promoting the use of energy managers. Energy managers play an important role in encouraging customers to make use of conservation programs and implement conservation measures.

I now wish to give further direction to the OPA with respect to performance incentives under the full cost recovery mechanism, OPA Cost-Effectiveness Tests and the procurement of energy managers.

Direction

Therefore, pursuant to my authority under section 25.32 of the Act, I hereby direct the OPA as follows:

1. Notwithstanding section 1.6(i) of the March 2014 Direction, which provides that incentives shall begin to accrue once a Distributor achieves 100 per cent of the portion of its Distributor CDM Target allocated to the full cost recovery mechanism, the OPA shall make an additional incentive mechanism available to Distributors at the formal mid-term review contemplated in section 6.1 of the March 2014 Direction (by June 1, 2018), subject to the following terms:

   (i) A Distributor shall be eligible for a mid-term incentive if, by December 31, 2017, that Distributor has achieved a minimum of 50 per cent of the lesser of either:

      a. its Distributor CDM Target allocated to the full cost recovery mechanism; or

      b. any amended Distributor CDM Target that is proposed by the OPA pursuant to sections 6.1 and 6.2 of the March 2014 Direction that is not allocated to the pay for performance mechanism set out in section 1.6(ii) of the March 2014 Direction;

   (ii) Notwithstanding section 1(i) of this Direction, where a Distributor participates in a joint CDM Plan, the Distributor shall only be eligible for a mid-term incentive if, by December 31, 2017, the Distributors participating in such joint CDM Plan have collectively achieved a minimum of 50 per cent of the lesser of either:

      a. their aggregated Distributor CDM Targets allocated to the full cost recovery mechanism; or
      b. the aggregate of any amended Distributor CDM Targets that are proposed by the OPA pursuant to sections 6.1 and 6.2 of the March 2014 Direction, that are not allocated to the pay for performance mechanism set out in section 1.6(ii) of the March 2014 Direction;

.../cont'd

(iii) For the purpose of calculating whether a Distributor has achieved a minimum of 50 percent of its Distributor CDM Target or proposed amended CDM target, the OPA shall consider only those electricity savings achieved by December 31, 2017 that are expected to persist to at least December 31, 2020;

(iv) Any performance incentives which accrue once the Distributor achieves 100 per cent of its Distributor CDM Target allocated to the full cost recovery mechanism will be reduced by the amount of any performance incentive a Distributor receives at the mid-term review; and

(v) For greater certainty, nothing in this section amends the requirement set out on the March 2014 Direction that Distributor CDM programs will result in the full achievement of 7 TWh of electricity savings.

2. In ensuring that there is a positive benefit-cost analysis of each Distributor CDM Plan and each Province–Wide CDM Program and Local Distributor CDM Program utilizing the OPA's Total Resource Cost Test and the Program Administrator Cost Test found in the OPA's Cost-Effectiveness Guide, as contemplated in section 3.5(v) of the March 2014 Direction, the OPA shall require that the benefits calculated for the Total Resource Cost Test include a 15 per cent adder to account for the non-energy benefits associated with Province-Wide CDM Programs and Local Distributor CDM Programs, such as environmental, economic and social benefits. The value attributed to non-energy benefits shall be subject to review at the formal mid-term review provided in section 6.1 of the March 2014 Direction.

3. The OPA shall procure and coordinate the cost-effective services of energy managers to ensure their sufficient availability to target small business, commercial and institutional customers across the province. For certainty, this shall not restrict Distributors from developing complementary Province-Wide Distributor CDM Programs and Local Distributor CDM Programs to procure and coordinate the cost-effective services of energy managers within their licensed service areas.

General

4. This direction supplements and amends previous directions to the extent that such previous directions are inconsistent with the provisions of this direction. All other terms of any previous direction remain in full force and effect.

This direction takes effect on the date it is issued.

Sincerely,

Bob Chiarelli
Minister

c. James D. Hinds, Chair, Ontario Power Authority
Serge Imbrogno, Deputy Minister, Ministry of Energy
Halyna Perun, Director, Legal Services Branch, Ministries of Energy, Economic Development, Employment and Infrastructure, and Research and Innovation

Clean Power Plan. That difference may increase the marginal cost of reaching those goals compared to that of the Clean Power Plan. While the Clean Power Plan relies heavily on renewables, efficiency, and gas backing out coal-fired generation, Ontario has already eliminated coal on its electric system. Additional reductions in Ontario carbon emissions will require such further measures as the following:

- backing down gas generation (which requires twice the load reduction per tonne avoided, compared to backing down coal),
- reducing usage of natural gas in buildings,
- reducing usage of oil in buildings,
- reducing industrial fuel use.

2. Extrapolating the 15% Electric Adder to Natural Gas DSM

Q: What is your understanding of the origin of the 15% adder for non-energy benefits of gas DSM?

A: The Minister of Energy ordered the use of the 15% adder for electric DSM, as I discuss in Section III.B.2. The Board then adopted that percent adder in the gas DSM framework.

Q: What was the Board's stated objective in adapting the 15% electric adder to gas?

A: In the Board's own words,

> To effectively align natural gas DSM programs with electricity CDM programs and take into consideration government objectives outlined in the Conservation Directive to the OPA, the Board has concluded that the same approach should be used for screening DSM programs. (Demand Side Management Framework for Natural Gas Distributors 2015-2020, Report of the Board, EB-2014-0134, December 22, 2014, at 33)

Unfortunately, applying a 15% adder to the avoided natural gas costs does not align the electric and gas programs, in terms of reflecting carbon prices, wholesale price mitigation, or most non-energy benefits of DSM.

Q: What implications for gas DSM might be drawn from the 15% placeholder adder for non-energy benefits prescribed by the Minister of Energy for electric DSM?

A: The Minister did not specify the breakdown of the 15% among carbon reductions, other environmental benefits, economic benefits and social benefits, nor the basis for selecting those values. As a result, the electric placeholder can be extrapolated to gas in several ways. One approach would be to assume that the 15% mostly represents carbon emissions (which the Government clearly considers to be very important), compute the dollars-per-tonne price equivalent to the 15% electric avoided-costs and convert that value to dollars per cubic metre.

Union's estimates of electric avoided costs average about \$0.1186/kWh for 2016–2020; 15% of that value would be \$0.0178/kWh or \$17.79/MWh. The carbon emissions from the existing electric system would be almost entirely from gas-fired generation, which appears to be on the margin about 70% of the time in 2016–2020, with zero-carbon sources at the margin the remaining 30%.[17] Assuming carbon emissions of 53.1 kg per MMBtu of gas (1.5 kg/m^3) and a 9-MMBtu/MWh average gas-plant heat rate (averaging combined-cycle, combustion turbine and the Lennox steam plant), the

[17]Boland, Bruce. 2013. "Electricity Generation Optimization in a Period of Surplus Baseload Generation." Presentation, Carnegie Mellon School of Business, April 24, 2013, at 26–30.

\$17.79/MWh would be equivalent to \$53.19/tonne of CO_2. That carbon price is equivalent to about 10.3¢/m^3 of gas, or roughly 50% of the avoided supply cost.

Q: How would the extrapolation from the 15% placeholder adder for electricity to gas values vary were only half the 15% attributable to carbon?

A: In that case, the carbon value would be about \$26.6/tonne of CO_2 and about 5.1¢/m^3 of gas. In addition, the remaining \$8.9/MWh adder, on an equivalent energy value (about 94 m^3/MWh), would be about 9.5¢/m^3 and the total of environmental and non-energy benefits would be about 14.6¢/m^3. That would be about 65% of Union's avoided-cost estimates for 2016–2020.

Ontario is still finalizing its carbon-mitigation rules, but will require additional reductions before 2020. Given the demanding goals facing Ontario policy makers, it is reasonable to assume Ontario will implement carbon pricing by 2017 (about three years earlier than the schedule Synapse assumes for the U.S.). The utilities should immediately incorporate a carbon price in designing, screening, and budgeting their DSM programs.

Q: Why did you use energy content, rather than price, to convert the non-carbon portion of the electric placeholder to a gas equivalent?

A: Many of the non-energy benefits of DSM will vary with the amount of energy saved, rather than the cost of that energy, such as the following benefits:

- the improvement of comfort with reduced drafts and warmer interior walls;
- improvement of health by reducing condensation and mold;
- the benefits of employing workers to blow in insulation, seal gaps, wrap ducts, and replace windows.

- Estimating the extent to which reductions in Ontario gas load reduces the price of gas delivered to Ontario (e.g., at Dawn), compared to production-area reference points.
- Incorporating Ontario's carbon mitigation plan, as that develops.
- Ensuring that the SENDOUT model properly accounts for potential savings between the base case and the DSM cases from the following causes:
    - reduction in existing commitments to pipeline capacity;
    - avoidance of new commitments to pipeline capacity;
    - release of pipeline capacity, when contract quantities cannot be reduced;
    - reduction in existing storage capacity commitments, including injection, withdrawal and storage capacity;
    - avoidance of new storage commitments;
    - reduction of the costs of utility-owned upstream resources (e.g., Union's Dawn storage and Dawn-Parkway pipeline capacity, Enbridge's GTA Segment A) through release, resale, or reallocation.

Third, before relying on any rate impact analysis in constraining DSM budgets, the Board and utilities should recognize that a number of components of avoided costs reduce costs for non-participants, such as avoided distribution, avoided carbon charges, suppression of market prices, and the difference between avoided and average commodity prices.

Table 6: Union Avoided versus Average Commodity Charge
(Dollars per Cubic Metre)

	Avoided Commodity Cost		Avoided Minus Average Commodity[a]	
	Res/Com Baseload	Res/Com Weather-Sensitive	Res/Com Baseload	Res/Com Weather-Sensitive
2015	0.173	0.176	0.022	0.025
2016	0.159	0.161	0.007	0.009

[a]Assumes $0.151/m^3 commodity rate

Q: What is the significance of the differentials you discuss above?

A: Unlike the other components I discuss in this section, these differentials between avoided commodity costs and average commodity costs are included in the utilities' avoided costs (although they appear to be understated). The significance of the avoided-to-average differentials is that they should be reflected as benefits to non-participants in the assessment of rate effects.

D. *Avoided Distribution Costs*

Q: How do the utilities estimate avoided distribution costs?

A: Enbridge provided some cost and load data to its consultant, Navigant, which converted those values to an estimate of avoided distribution costs. Union manipulated the Enbridge estimate of avoided distribution costs to derive an estimate of its avoided distribution costs.

Q: Do the utilities' avoided costs include their local transmission costs, or only distribution?

A: That is not clear.[22] The distinction between transmission and distribution mains varies from one document or application to another. In general,

[22]Obviously, no Union transmission costs are directly reflected in its avoided costs, since it used only Enbridge results.

Enbridge and Union appear to define "transmission" to mean "for wholesale transactions" and "distribution" to mean "for our retail customers." Hence, a single line can be considered to be partially transmission and partially distribution.

Enbridge claims that "transmission, or upstream, avoided costs, such as commodity, transportation and storage costs, were fully captured in the existing avoided gas cost methodology" (Exhibit I.T9.EGDI.GEC.33a), and considers the costs included in Exhibit C, Tab 1, Schedule 4 to be distribution costs.

Enbridge's consultant Navigant entitled its report "Enbridge Avoided Transmission & Distribution Costs," but says,

> During the initial discovery stage of this assignment it was determined that Enbridge's upstream or transmission avoided costs are already fully and accurately captured in their existing avoided cost analysis. The objective was subsequently modified from a study of both transmission and distribution avoided costs to only include the determination of the distribution or downstream avoided costs." (Enbridge Exhibit C, Tab 1, Schedule 4, at 4).[23]

In its presentation for the first workshop with Enbridge, Navigant reviews the avoided costs of a few gas utilities and finds that only one includes capacity as avoidable (Exhibit JT1.23, Attachment 1). In its presentation for the second workshop, Navigant asserts that "Enbridge's existing avoided cost calculation methodology (using Sendout) captures all upstream costs" (Exhibit JT1.23, Attachment 2, at 4). As I discuss in Section III.E.1, Enbridge has not provided on discovery any documentation that

[23]Enbridge has not provided the basis for that "determination," nor any breakout of the avoidable upstream transmission costs.

would have allowed Navigant to reach this conclusion, even though such documentation was requested in GEC 49 and Undertaking 1.23.

Union refers to its reworking of Enbridge's estimate of avoided distribution costs as avoided T&D or infrastructure costs, but makes no effort to include avoided transmission infrastructure.

1. Enbridge

Q: How did Navigant estimate Enbridge's avoided distribution costs?

A: Navigant indicates that Enbridge "provided Navigant with both actual and forecast reinforcement expenditures" (Enbridge Exhibit C, Tab 1, Schedule 4, at 19) for 2010–2019, totalling $189 million (ibid., Figure 3). While Figure 3 does not specify whether the costs are in nominal, real, or a mix of costs, Navigant reports an average of $19 million annually over the ten years in 2015 dollars (ibid. at 20).[24]

Navigant also reports average annual growth in design-day peak for 2010–2019 of 1,047 10^3m^3 (ibid., Figure 4). That would imply a distribution investment of $18,050/$10^3m^3$ of load growth. Oddly, Navigant never reports this critical value.

Navigant annualizes the $18,050/$10^3m^3$ using an idiosyncratic approach, which is described generally at 22–26 of the report, in a section entitled "Detailed Methodology." Unfortunately, Navigant does not provide the details of its computations or even the results in dollars/year per 10^3m^3 of peak load reduction. Backing out the annual cost from the $/$10^3m^3$ values in Table 7 of the report and the peak-to-annual ratios in Table 9 results in an

[24]Enbridge has not provided the underlying data, so we cannot check whether all the costs were actually in 2015 dollars.

annual peak cost of about $1,070/10^3m^3$ of peak-day load. In turn, that value indicates that Navigant effectively applied a 5.9% nominal carrying charge to the investment.

Finally, Navigant converts its estimate of avoided distribution costs to dollars per 10^3m^3 of avoided deliveries (over the year, not on the peak day), using the ratios of peak-day 10^3m^3 to annual 10^3m^3 in Table 9 of the report. These values are reported in Table 7, labeled as nominal dollars per 10^3m^3/peak demand day, even though the values are clearly intended to be costs per annual 10^3m^3.[25]

Thus, Enbridge's estimate of avoided distribution comprises the following six steps:[26]

1. Compile load-related investments over a decade.
2. Determine expected design-day peak over that same period.
3. Divide (1) by (2) to estimate the required investment per 10^3m^3 of peak growth.
4. Multiply (3) by a carrying charge to estimate annual avoided cost per 10^3m^3 of peak growth.
5. Estimate the ratio of design-day peak load contribution to annual consumption by rate class.

[25]Errors of this sort, along with inconsistencies in Enbridge's responses and Enbridge's failure to provide data, make reviewing Enbridge's work very difficult. Enbridge refused to provide its analyses, computations and workpapers supporting the derivation of the avoided distribution costs (e.g., Exhibit I.T9.EGDI.GEC.49, 59).

[26]Some of the steps were conducted by Enbridge and some by Navigant. For simplicity, I will refer to the derivation of avoided distribution costs as Enbridge's method.

6. Multiply (4) by (5) to estimate avoided cost per 10^3m^3 of reduced throughput.

These are all standard steps in estimating avoided distribution (and often transmission) costs.

Q: Did Enbridge properly carry out this analysis?

A: No. Enbridge appears to have made mistakes in steps 1, 2, 4, and 5 (load-related distribution investment, associated load growth, the carrying charge, and the load shape). In addition, Enbridge omitted all load-related distribution O&M costs. I will comment on each of these problems in turn.

a) Load-related Distribution Investment

Q: Did Enbridge include all its load-related investments in the 2010–2019 period?

A: No. Enbridge acknowledged omitting some cost categories, its two tabulations of projects in the attachments to Exhibit I.T9.EGDI.GEC.56 are inconsistent, and it has clearly understated the costs of the GTA project.

Q: Which cost categories did Enbridge acknowledge omitting?

A: Enbridge acknowledged omissions in its identification of distribution reinforcement projects (Exhibit I.T9.EGDI.GEC.56 and 57).

> The reinforcement expenditures for Area 10 and Appendix B were inadvertently omitted from the information provided to Navigant. In addition, an equation error was made in the spreadsheet that was used by Enbridge to provide the reinforcement expenditures to Navigant that double counted the years from 2010 to 2012.
>
> The reinforcement projects in Area 10 are those that were listed in … Exhibit I.T9.EGDI.GEC.57. The reinforcement projects in Appendix B are those that can be found in…Exhibit I.T9.EGDI.GEC.56. (Undertaking JT1.28)

The reinforcement projects in Area 10 (the GTA) in Exhibit I.T9.EGDI.GEC.57 for 2017–2019 were listed in the GTA proceeding (EB-2012-0451) as having cost estimates totaling $50.4 million.[27] The Appendix B projects in Exhibit I.T9.EGDI.GEC.56 are listed at $5.9 million. Enbridge reports that these two categories would total "approximately $55M," which may or may not be consistent with the values reported in the GTA proceeding and Exhibit I.T9.EGDI.GEC.56, depending on the dollars in which each estimate is stated. The cost estimates of the GTA proceeding may have been updated since they were filed in 2012.

Q: What are the inconsistencies between the tabulations of reinforcement projects in Attachment 1 and Attachment 2 of Exhibit I.T9.EGDI.GEC.56?

A: Attachment 1 does not have most pre-2014 projects, since it is a response to a request for forecast additions. From 2014 through 2019, Attachment 1 (the list of projects included in the forecast reinforcement expenditures from 2014 to 2019 in the Navigant analysis) lists some 44 projects, while Attachment 2 (the list of the projects included in the Navigant analysis) lists some 32 projects.[28] 21 projects appear in both lists, while Attachment 1 has 23 projects that do not appear in Attachment 2, and Attachment 2 has 11 projects

[27]It is not clear in what year's dollars these estimates, or any of Enbridge's cost estimates for future projects, are listed.

[28]The Attachment 1 is listed as Table 13 to 21 and Appendix B of some unidentified document, which appears to be the "EGDI planning document from which the forecast reinforcement expenditures from 2014 to 2019 were taken," as requested in GEC interrogatory 56. If Enbridge had provided the entire requested document, some of the discrepancies in its analyses might be easier to reconcile.

that are not listed in Attachment 1. Some of these discrepancies may result from the renaming of projects, and Enbridge says that three of the Attachment 1 projects not listed in Attachment 2 have minimal costs, but it still appears that neither list was complete. Unfortunately, Enbridge has not revealed what projects it included in the data provided to Navigant.

Strangely, while Attachment 2 lists the GTA project in 2015, Attachment 1 does not list the GTA at all.

Q: Are there other inconsistencies in the Enbridge data on capital additions?

A: Yes. In the Asset Plan filed in its last rate case (EB-2012-0459, Exhibit B2, Tab 10, p 53), Enbridge reports reinforcements much higher than those in Figure 3 of the Navigant report. See Table 7.

Table 7: Comparison of Reported Historical Reinforcements

	Navigant Figure 3	2012 Asset Plan
2010	$1.67	$7.05
2011	$1.58	$4.74
2012	$8.71	$15.47

Since the Navigant data appear to be in real 2015 dollars and the Asset Plan is in nominal dollars, the Asset Plan's costs would be a little higher restated in the terms of the Navigant report. It is not clear how the mains reinforcements in 2010–2012 could have declined in the past couple of years.[29]

[29]The Asset Plan also projected 2018–2019 additions about $55 million higher than reported for those years in Navigant's Figure 3.

Q: What GTA costs should have been included in the list of reinforcements?

A: The GTA project consisted of Segment A, which Enbridge classified as 40% related to serving distribution load and 60% related to serving wholesale transmission load, and Segment B, which Enbridge classified as entirely related to distribution load (Exhibit I.T9.EGDI.GEC.52). The investments classified as distribution are all load-related reinforcements.[30] Enbridge excluded some of the costs of the GTA distribution investments from the analysis:

> Reinforcement costs for larger projects such as the GTA Project were adjusted to reflect the proportion of the project costs that were directly attributable to load growth. The reinforcement costs of the GTA Project were captured in the costs shown in year 2015 in EB-2015-0049 Exhibit C, Tab 1, Schedule 4, Figure 3. (Exhibit I.T9.EGDI.GEC.33b)

> The reinforcement costs as shown in Figure 3 include the Ottawa Reinforcement and the GTA Reinforcement costs. Since these projects had multiple drivers, only the costs associated with load growth were included. (Exhibit I.T9.EGDI.GEC.56d)

In Exhibit JT1.17, Enbridge justifies those exclusions as follows:

> [The] minimum pipe [for the GTA] required a NPS 36 build from Sheppard Avenue to McNicoll Avenue, paralleling the existing Don Valley line, to support 10 years of anticipated load growth. This pipeline segment was estimated to cost $40M to $50M.

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[30]One justification for Segment B was reducing pressure on part of the system; load growth had already exceeded the level at which Enbridge could serve all load at the lower pressure that Enbridge considered prudent. Lower load growth in the GTA would have avoided the need for Segment B.

> For the Ottawa Reinforcement Project, it was estimated that 19 km of NPS 16 would be required from Richmond Gate Station, including a rebuild of the gate station, to support load growth only. This project scope was estimated to cost $46M. It should be noted that this is the same alignment as the approved reinforcement project.[31]

The distribution portions of the GTA project (adjusting proportionately the costs provided in the GTA proceeding for each segment by the increase in the total project cost reported in EB-2015-0122, Exhibit D.1.2) are roughly as follows:

- $400 million for Segment A (justified primarily to import additional US gas, and hence more properly a supply cost),
- $200 million for Segment B1,
- $125 million for Segment B2.

These are large investments compared to the $189 million that Enbridge included as the load-related costs for the entire ten-year period.

Q: Are there other categories of load-related investment costs that Enbridge excluded from its analysis?

A: Potentially. Enbridge excluded all "sales" projects, related to the connection of new loads, and all replacement and relocation projects. Both of these categories may contain load-related costs. In particular, the sales projects would provide some of the capacity required for new customers, and the size of new mains may be a function of the efficiency of the new customers, and possibly existing customers served by the same lines. Similarly, the size of replacement mains can be affected by load levels, and replacement of a small

[31]Enbridge does not specify what purpose the Ottawa Reinforcement met, other than meeting demand.

old main with a larger-diameter smooth main can increase the capacity of the line.

Alternatively, the increases in capacity associated with sales, replacement and relocation projects can be reflected by adjusted downward the load growth served by the reinforcement projects, as I discuss in the next subsection.

b) Design-peak Load Growth, 2010–2019

Q: Have you been able to review the data on design-day peak growth that Navigant presents in its Figure 4?

A: No. However, even if the data reflect weather-adjusted peaks for 2010 and Enbridge's forecast for 2019 (the intervening loads do not affect the computation), the peak growth should be adjusted down to reflect the part of the growth that is accommodated by sales projects and upgrades of replacement mains. The cost of reinforcements should be divided by the growth requiring the reinforcements, excluding any growth accommodated by other projects. The lower the growth divisor, the higher the ratio of investment per unit of peak load.

For example, the Municipality of York Pipeline Project (EB-2011-0270) replaced an NPS 4 and an NPS 8 line with an NPS 12 main along the same route, more than doubling the capacity of that section of the system. While the replacement was triggered by a relocation request from the municipality, the update would serve any increase of load in that demand area (Whitchurch-Stouffville and Uxbridge). The load increases that drive the need for reinforcements would be net of the load increases in the Whitchurch-Stouffville and Uxbridge areas, and all other areas in which growth was served by sales, replacement and relocation projects.

c) Annualizing the Avoided Distribution Cost

Q: How does Navigant annualize the avoided distribution costs?

A: Navigant uses a nominal 5.9% carrying charge for the distribution investments, which it does not document. In contrast, I estimate a *real-levelized* carrying charge of about 6%. I used a standard computation of the real-levelized or economic carrying charge, which measures the present-value benefits of a one-year delay in the investment, with the benefit rising at inflation in subsequent years.[32] I suspect that Navigant became confused between real and nominal carrying-charge computations.[33] I cannot test that, since Enbridge has not provided Navigant's workpapers.

A 6% real-levelized carrying charge is equivalent to a nominally levelized carrying charge of about 7.7%. The real-levelized discount rate provides meaningful avoided costs for any period, while the nominally levelized carrying charge is only meaningful for the period over which it is levelized. While the benefit of deferring investments rises as the investments are pushed further back (due to inflation), Navigant somehow concludes that avoided distribution costs would fall over time.

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[32]I used the inputs specified by Navigant in its Table 8, a 2% inflation rate, and a 7% discount rate, based on assumptions elsewhere in Enbridge's filing.

[33]It is possible that Navigant intended that its carrying charge be applied in real terms, but accidentally treated the charge as nominal.

d) Converting from Peak Day to Normal Average Usage

Q: Did Navigant properly apply the load data to convert the avoided T&D in annual dollars per cubic metre on the design day to dollars per cubic metre of annual consumption for each load shape?

A: Navigant did not provide the design-day peak, normal-year peak, annual consumption, or any other data on the load shapes they used. However, Navigant describes the data it used as follows:

> calculated avoided cost in terms of annual DSM volumes saved instead of peak day demand gas savings. This is done by using Enbridge's existing DSM load shape profiles using the peak day demand to annual volume ratio. (Enbridge Exhibit C, Tab 1, Schedule 4, at 6)

> Daily gas consumption for each load shape is gathered. The total annual consumption for the year is calculated and the gas consumption for the peak day demand (January 15) is determined. The consumption for the peak day demand is divided by the total annual consumption. The ratio for each of the four DSM load shapes is used to convert the peak day demand distribution avoided cost ($\$/10^3m^3$ annual peak day demand) to a volumetric avoided cost. (Ibid. at 26–27)

Appendix B to the Navigant study shows graphs of the load shapes that Navigant used. While it is not entirely clear, these seem to be normal load shapes, without any allowance for design conditions.

Q: What is the significance of using normal peak loads instead of design peak?

A: Since design peak is higher than normal peak, each thousand m^3 of annual savings results in greater savings on the design peak than on the normal peak. The distribution system is designed for the design-peak day (or the design-peak hour), while DSM savings are computed for the average year, so the avoided distribution costs should reflect the ratio of design peak to normal average usage.

e) Operating and Maintenance Costs

Q: Are any avoided O&M costs reflected in Enbridge's estimate of avoided distribution costs?

A: No. Navigant's report (Exhibit C, Tab 1, Schedule 4) assumes that no distribution O&M costs are avoidable.[34]

Q: Is this a reasonable assumption?

A: No. Enbridge's GTA application, for example, reports an incremental O&M of over $13 million for such costs as "leak survey, damage prevention, cathodic protection, [and] direct maintenance." (EB-2012-0451 Exhibit E Tab 1 Schedule 1, at 2, updated: 2013-06-03) That is 1.5% to 2% of the project cost (depending on the costs included in the analysis); those costs would increase over time with inflation.

In its third workshop presentation, Navigant corrected its earlier methodology by (among other things), adding avoided annual O&M of 1% of the avoided investment (EB-2015-0049, Exhibit JT1.23, Attachment 3, at 6).

Since the real-levelized carrying charge for distribution is only about 6%, O&M of 1%–2% would add something like 20% to 30% to the carrying charges for the distribution projects.

[34]In Exhibit I.T9.EGDI.GEC.59(b), Enbridge claimed that reductions in O&M for avoided reinforcements should be ignored because its O&M budgeting process does not consider the effect of reinforcements installed or deferred. This claim does not justify omitting O&M from avoided cost for two reasons. First, since O&M costs do vary with the amount of distribution, the effect of deferrals will eventually appear in the O&M budget. Second, avoided cost should reflect actual costs, not budgets. Budgets should be viewed only as a source of estimates of actual costs.

f) Summary of Enbridge Corrections

Q: What is the cumulative effect of correcting Enbridge's apparent understatements in its estimate of avoided distribution costs?

A: In Table 8, I combine rough estimates for the effects of the errors I discuss above. Specifically, I account for the following:

- the projects that Enbridge acknowledges having failed to share with Navigant,
- the unexplained downward revisions in 2010–2012 additions,
- the full estimated costs of Segment B2 of the GTA,
- the cost of Segment B1 of the GTA (as a sensitivity),
- a 20% reduction in load growth associated with the reinforcements, to reflect the capacity upgrades from sales-related, replacement, and GTA projects. For the sensitivity in which Segment B1 is treated as directly load-related, I use a 10% adjustment for load growth met by the other categories.
- correction of the nominal carrying charge to 7.7% (equivalent to a 6% real carrying charge),
- An allowance for O&M of 1% of investment.

I do not have enough data to correct the load-shape ratios, from normal weather to design weather.

Table 8: Corrections to the Enbridge Estimate of Avoided Distribution Cost

	10-yr Additions 2015$ M	10-yr Growth 103m3	Additions per Unit Growth $/103m3	Carrying Charge Nominal	Annualized	O&M	Total
					$/yr/103m3 peak day		
Enbridge	$189	10,470	$18,052	5.9%	$1,065		$1,065
Corrections							
Area 10	$50.4						
Appendix B	$5.9						
2010-12 revisions	$17.4						
GTA Segment B2	$85	−20%					

GTA Segment B1	$200	−10%					
Corrected							
without B1	$348	8,376	$41,508	7.7%	$3,196	$415	$3,611
with B1	$548	9,423	$58,121	7.7%	$4,475	$581	$5,057

The corrected nominally-levelized values are about 3.4 to 4.7 times the Enbridge estimate. In real-levelized terms, the total costs would be about \$2,900–\$4,100/yr/10^3m^3 of peak-day throughput, or 2.7–3.8 times Enbridge's nominally-levelized estimate in 2015, and would rise with inflation.

Q: Did Navigant develop higher estimates of avoided distribution costs than those presented in Enbridge's filing?

A: Yes. In its second workshop for Enbridge, Navigant reported an avoided distribution cost of \$1,165/10^3m^3 savings on the peak day (Exhibit JT1.23, Attachment 2, at 11).[35] In its third workshop presentation, Navigant reported an avoided distribution cost of \$1,523/10^3m^3 savings on the peak day (Exhibit JT1.23, Attachment 3, at 6). These valucs arc about 10% and 40% higher than the \$1,065/10^3m^3 reported by Navigant in Exhibit C, Tab 1, Schedule 4 and apparently used by Enbridge in screening DSM programs.

2. *Union*

Q: How did Union estimate its avoided distribution costs?

A: Union did not develop T&D avoided costs based on its own system, but borrowed the work from Navigant based on Enbridge's system and adapted them for its use. Specifically, Union took the Enbridge estimates of avoided distribution costs by load shape, weighted those values by the share of Union's estimated DSM savings in 2015 for each of the load shapes, and

[35]Navigant does not appear to have used design-day loads in its analyses.

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UNDERTAKING

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To connect with Navigant and respond accordingly re: Avoided Costs reviewed in EBRO 492 and 495, and to break down by load type the transmission costs, and to identify what portion of those avoided energy costs are in fact commodity versus what portion are avoided transmission, capital investments.

RESPONSE

During the course of the Avoided Distribution Cost study and during the initial workshop discussions with Enbridge, it was determined early on in that discussion, that the transmission portion of the Avoided T&D costs were already captured within Enbridge's upstream cost component of the Avoided Gas Costs used for screening purposes within the TRC test. For further information on the above noted discussions, please see the workshop presentations attached in response to JT1.23.

It was out of the scope of the study for Navigant to review all aspects of the Avoided Gas Cost methodology. Based on the workshop discussions with Enbridge staff and given the fact that Enbridge's Avoided Gas Costs have been subject to scrutiny over the past number of years, Navigant determined that Enbridge had accurately captured all upstream costs including transmission.

Please see response to Undertaking JT1.15 for selected component inputs used in Enbridge's Sendout model, including forecasted commodity prices and transportation costs.

Witnesses: S. Mills
F. Oliver-Glasford
H. Thompson
A. Welburn
T. Winstone

Attachment 3 – Transportation Cost Inputs

Avoided Cost SENDOUT Input: Transportation Costs

Date Range: 2012-2021

	Transportation Costs		
	Demand Charge (C$/GJ/Mth)	Commodity Charge (C$/GJ)	Fuel Ratio (%)
TCPL Empress to CDA/EDA	63.848	0.144	2.54
TCPL STS to CDA	1.697	0.000	0.07
TCPL STS to EDA	4.845	0.008	0.40
TCPL Dawn to CDA	7.493	0.014	0.12
TCPL Dawn to EDA	15.525	0.032	0.56
TCPL Empress to Iroquois	62.154	0.140	2.54
TCPL Parkway to CDA	3.145	0.004	0.07
Union M12 - Dawn to Parkway	2.342	*N/A*	0.83
Union M12 - Dawn to Kirkwall	1.977	*N/A*	0.83
Union C1 - Parkway to Dawn (Westerly)	0.548	*N/A*	0.34
Vector	7.495	*N/A*	1.12
Alliance	41.874	*N/A*	4.76

to optimize how additional spending would be allocated – either to maximize additional savings or to address other strategic goals. Again, this is somewhat understandable given the very limited time the Company had to develop a complex filing of which the sensitivity analysis was only one part. However, the fact that it is understandable does not change the fact that it is problematic.

- Related to the point above, Enbridge assumed that its market transformation budget would increase in the same proportion as its resource acquisition and low income budgets – all to support the existing base budget programs. For example, of the roughly $32 million increase in spending in 2016 under the 150% budget scenario, Enbridge assumed that nearly $7 million would go to market transformation programs (none of which produce immediately quantifiable savings). That does not make sense. For the programs that are truly designed to transform markets (e.g. the residential and commercial new construction programs),[45] the base budget should already have been designed to be sufficient to put the targeted markets on a path to market transformation.
- Any formulaic reliance on its potential study estimates of declining yield per dollar spent is problematic. First, even well done efficiency potential studies are inherently conservative.[46] Second, the potential study estimated gross savings potential, not net potential after adjusting for free riders. However, free ridership typically declines as financial incentives for efficiency measures – one of the key drivers to increased budgets – increase. Thus, the relationship of increased savings to increased spending that Enbridge tried to derive from the potential study results inherently understates the magnitude of increased *net* savings (the only metric that matters). Third, and probably most importantly, Enbridge's recent potential study is fraught with so many methodological problems that it has almost no value for informing conclusions regarding achievable savings potential. A few illustrative examples are as follows:
    - In analyzing efficiency potential at the time that new products are being purchased, one needs to estimate how many products are sold each year. Typically, potential studies develop such estimates by assessing the number of a particular type of product in use and dividing by the average measure life for that product. For example, if there are 100,000 commercial boilers in use and the average boiler has a measure life of 25 years, then approximately 4000 boilers are being replaced each year and efficiency programs have the opportunity to influence whether the most efficient boilers are being

[45] Enbridge has some programs in its "market transformation" portfolio that are not really about transforming markets. They are arguably more like resource acquisition programs, or customer education programs (e.g. OPower and Run it Right).

[46] Goldstein, David, "Extreme Efficiency: How Far Can We Go If We Really Need To?", Proceedings of the 2008 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 10, pp. 44-56.

purchased at the time of those replacements. However, Navigant's potential study makes what I consider to be a mathematical error that implicitly leads it to assume that the number of replacement products being sold each year is declining.[47] The result is that it understates the size of equipment replacement markets in the 10th year of its analysis by about 33% for measures with 25 year lives, by about 50% for measures with a 15 year life and by more than 60% for measures with a 10 year life. Needless to say, those underestimates lead to significant under-estimates of savings potential.

- Navigant estimates that economic potential in the commercial and industrial sectors is 96% of technical potential. In other words, virtually all efficiency that is technically feasible is also cost-effective under current (relatively low) avoided costs. That conclusion strongly suggests that the analysis did not truly look at a full range of potential efficiency measures; rather, it just looked at the measures that the utilities were already pursuing and/or anticipating that they might pursue and which are already known to be cost-effective. Put simply, it is not plausible that the supply curve of efficiency is a gradual upward slope to the current cost-effectiveness threshold and then becomes almost vertical.
- Navigant does not appear to have analyzed potential from industry-specific and/or facility-specific custom industrial measures. Indeed, in reviewing the stratified random sample of industrial projects analyzed under Enbridge's 2014 Custom Project Savings Verification process I found that approximately half of the projects employed measures that do not appear to have been addressed in the Navigant study. I should note that is not uncommon for potential studies. They tend to assess only relatively common measures. However, that is an important limitation that makes such studies' conclusions regarding efficiency potential very conservative.
- Navigant appears to have estimated the maximum technical potential for

[47] Rather than taking the entire existing stock of equipment and dividing it by the measure life to get an annual turnover rate for each year of its analysis, Navigant apparently does that only for the first year. For the second year it adjusts the size of the existing stock downward by the number of units replaced in year 1 and divides that smaller number by the measure life, producing a smaller eligible market in year 2. The farther out in time one goes, the smaller the eligible market becomes under this flawed approach. Navigant suggests this approach is reasonable because not all equipment lasts exactly the same amount of time (JT1.22). I concur with that statement. For equipment that has an average measure life of 25 years, a very small number will last only a few years (the "lemons"), some will last 15 years, some 20, some 30 and some 40 or 50 or more. However, what Navigant fails to realize in its analysis is that distribution applies to all products installed 10, 20, 30, 40, and 50 years ago. Thus, all other things being equal (the climate, the economy, etc.) the turnover this year, and next and the year after are all likely to be very similar. There is absolutely no basis for thinking the number of units sold for use in existing buildings will decline over time (except to the extent the existing building stock is demolished, which is only a very small fraction of buildings per year). More importantly, there is no evidence from sales data of major appliances, HVAC equipment, etc. that sales of replacement products decline over time.

operational efficiency improvements in commercial buildings to be no more than about 3%.[48] That is implausibly low.[49]

- o Navigant's estimate of savings from do-it-yourself residential air sealing measures (e.g. caulking, weatherstripping, outlet gaskets, etc.) is implausibly high. The level of savings estimated is achievable, but only through more sophisticated blower-door guided air sealing by professionals. In other words, Navigant got the savings about right, but grossly under-estimated what it would cost to acquire.

- Even if one were to ignore all of the concerns about the use of the potential study, Enbridge made a basic mathematical error in developing the formula it used to apply the decline in savings yield per additional dollar spent derived from its potential study (what the Company calls its "decay factor"). The Company starts by noting that at the level of its base plan budget, the potential study suggests that for every 9% increase in budget there is approximately a 4% increase in savings.[50] It then makes the mistake of using those assumptions in a formula that not only adjusts savings from new spending but adjusts the base level of savings as well. The result is a formula that mistakenly suggests that it is impossible to achieve more than 17% more savings than Enbridge has forecast and that savings would actually start to decline once budgets were increased by about 70%. Those conclusions are inconsistent with the results of the flawed potential study that Enbridge's formula was designed to represent. More importantly, they are inconsistent with the experience of the leading jurisdictions discussed above.

3. Opportunities for Utilities to Acquire Substantial Additional Savings

There are a number of ways in which the utilities could acquire significant additional cost-effective savings. These include:

- **Beginning to use "upstream incentive" program designs.** Upstream incentives – that is, incentives paid to manufacturers, distributors, contractors and/or other key players in the supply chain rather than to the end use customers – can have several advantages. Most importantly, they typically lead to much higher market penetration rates for efficient equipment. That can be seen in Figure 3, which shows that a commercial cooling equipment upstream incentive program (blue bars) run by Pacific Gas and Electric in California for over a decade achieved nine times the level of participation that its former "downstream" customer rebate program design

[48] Exh C/T1/S2 p. 18.
[49] See EB-2012-0451, Exhibit L.EGD.ED.1
[50] Enbridge response to GEC.42.

IX. Consideration of DSM in Infrastructure Planning

1. Overview

In its December 2014 gas DSM framework and filing guidelines the OEB required three things of both Enbridge and Union with respect to consideration of the role DSM could play in potentially serving as a cost-effective alternative to future infrastructure projects:

1. Conduct a study of "the effects that DSM can have on deferring, postponing or reducing future capital investments."[86]
2. "Propose a preliminary transition plan that outlines how the gas utility plans to begin to include DSM as part of its future infrastructure planning efforts."[87]
3. "Provide evidence of how DSM was considered as an alternative at the preliminary stage of project development" for all leave to construct projects.[88]

Both a scope of work for the study (to be completed in time for the mid-term review) and the preliminary transition plan were to be included in the utilities' 2015-2020 DSM plan filings.

In general, Enbridge has been much more responsive to this guidance than Union. A discussion of each utility's approach is provided below.

2. Scope of Work for Study of the Role of DSM in Infrastructure Planning

Union did not provide what could reasonably called even a preliminary scope of work for its study of the use of DSM resources to defer or avoid infrastructure construction. A scope of work is effectively the "meat" of what one would put in an RFP to hire a contractor. It typically:

- Articulates the study objectives;
- fleshes out in detail the information expected to be collected and analyzed;
- provides a summary of information and/or resources that are available to the contractor, including utility staff that will be involved in the study;
- identifies specific tasks it expects the contractor to perform in collecting and analyzing the information; and
- specifies the form in which the results of the study will be presented.

In contrast, all Union has provided is a list of high level questions the study would attempt to answer. At best, that might be analogous to the articulation of study objectives. However, most of the other information one would expect in a scope of work has not been provided.

[86] Ontario Energy Board, "EB-2014-0134 Filing Guidelines to the Demand-Side Management Framework for Natural Gas Distributors (2015-2020)", December 22, 2014.
[87] Ontario Energy Board, "EB-2014-0134 Report of the Board: Demand Side Framework for Natural Gas Distributors (2015-2020)", December 22, 2014.
[88] Ontario Energy Board, "EB-2014-0134 Report of the Board: Demand Side Framework for Natural Gas Distributors (2015-2020)", December 22, 2014.

Moreover, even some of the questions that Union indicates the study will be designed to address are problematic as currently framed. For example, it makes no sense to generically ask the question "What is the required load reduction that would lead to deferral of infrastructure?" The answer to that question will necessarily be specific to each infrastructure project. The same is true of the question "Could DSM programs be designed and implemented to achieve the necessary impact?" Put simply, Union has either invested little effort in attempting to address this issue or it is being intentionally vague about its intentions. Either way, the Company may be sending a disconcerting signal that it is not likely to be serious about even-handedly considering DSM as a potential alternative to more expensive infrastructure investments.

In contrast, and to its credit, Enbridge has fully developed and presented a preliminary scope of work for its study. That said, I do have some concerns about that proposed work scope. Specifically, in the third part of the work scope – what Enbridge calls "Intersection #3: Targeted DSM and Reinforcement Projects" – the Company asks some of the same kinds of generic questions that critiqued Union for asking. Examples include:

- "Is it technical feasible?"
- "Is it possible?"
- "Is it cost-effective"

Unlike Union, and again to its credit, Enbridge has indicated in its scope of work that it intends to address these questions through analysis of specific case studies. That addresses the concern I expressed about Union's approach because the questions are not being asked generically. However, it raises an entirely different set of issues regarding how the case study examples will be selected. As I have noted in two different reports I have written on the electric utility experience with using geographically-targeted DSM to defer T&D investments,[89] DSM cannot address every type of infrastructure need. It only has potential value as an alternative to infrastructure projects that are being driven, at least in part, by load growth. Even then it will not always be applicable – either because the load reduction required is too great, or because it is needed too soon, because the economics of a particular application are not favorable, etc.

My experience with assessing the role that geographically-targeted DSM could play in cost-effectively deferring infrastructure investments – and I have studied every major example of such electric utility efforts over the past two decades, conducted trainings for system planners on how to integrate consideration of DSM into system planning, and am currently working on a pilot project with a Michigan utility – suggests that the key piece of new information most gas utilities would need to assess the potential role of efficiency in deferring infrastructure investments are hourly peak day load shapes (and/or an estimate of

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[89] Neme, Chris and Rich Sedano, "U.S. Experience with Efficiency As a Transmission and Distribution System Resource", published by the Regulatory Assistance Project, February 2012 (see: www.raponline.org); and 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, 2013 (see: http://www.neep.org/initiatives/emv-forum/forum-products#Geotargeting).

the relationship between peak hour savings and annual savings) for each potential efficiency measure. That is a question that could and should be addressed generically and immediately.

Once that generic question is answered, it would be very appropriate to pursue case study assessments as Enbridge has suggested. However, great care must be taken in selecting the case studies. As noted in my reports on efficiency as a T&D resource make clear, the first step in that process is to develop a long-term forecast of potential infrastructure needs. That forecast should be for at least 10 years. Again, to its credit, Enbridge has stated that it will select its case studies from a list of potential infrastructure projects that it will develop (or already has developed). However, it is not clear that that it is planning to comprehensively assemble a 10 year forecast of such projects. (As noted above, Union has not even suggested it is thinking about such a forecast.)

The list of projects in a 10-year forecast should then be put through an initial high level screen to winnow the list down to candidates that would be worth a closer look. Several jurisdictions now require such a high level screening process for all electric infrastructure projects, typically using variants of the following criteria:

- **Is the project driven – at least in part – by load growth?** Only those that are should be considered.
- **How many years before the infrastructure is needed?** Typically, the infrastructure need must be at least three years into the future to be considered. More sophisticated approaches relate the minimum years before the need to the magnitude of the load reduction needed (the larger the reduction, the further out in time the need must be). That relationship is potentially one that an assessment of several gas case studies could inform.
- **What is the maximum load reduction required?** For electric system planning, the maximum typically assumed possible is on the order of 20-25% (relative to forecast future demand). That might be an appropriate starting point for gas as well, though this question is also one that the Enbridge and Union studies, particularly if they include several case studies, could better inform for gas.
- **What is the cost of the infrastructure project?** It does not make sense to invest in detailed assessments of alternatives to very inexpensive infrastructure projects. Thus, most jurisdictions now required consideration of DSM as a potential alternative if the infrastructure project costs at least $1 million.

A summary with more specifics of how different jurisdictions now routinely use such criteria is presented in a table in my most recent report on this topic which I have copied below.

Table 4: 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

The Michigan utility with which I am currently working considered each of these criteria in selecting the pilot project that will be pursued.

Again, to its credit, Enbridge has clearly considered at least the second of these criteria as it has indicated that it will only consider those for which the lead time is at least 4 to 6 years. That is an eminently reasonable place to start. However, it hasn't indicated what other criteria it will use or consider.

Once candidate projects have been selected, more detailed assessments need to be conducted. For example, over the past several months the Michigan utility with which I am working has been assessing the mix of customers in the targeted region (residential, small business, larger customers), how the customers may differ from the average customers in the Company's broader service territory (e.g. in income levels, education, levels, etc.), the types of loads being served (e.g. through review of location specific responses to saturation surveys), historic participation in the utility's different efficiency programs, and other relevant factors. All that information is being used to develop a DSM program strategy for the area. That very same approach should be used for tailoring the assessment of the potential for targeted DSM for case studies for both Enbridge and Union.

3. Transition Plan for Integrating DSM into Infrastructure Planning

If anything, Union's approach to transition planning is worse than its approach to the development of the scope of work for its study. In fact, the Company has said that it did not develop a transition plan because such a plan is premature.

In contrast, Enbridge has put forward a transition plan. In a nutshell, its transition plan is to use real world case examples in the scope of work for the study described above. At a high level, that would be a reasonable approach if (1) the approach to identifying case studies is refined as I suggest above; and (2) the case studies are more than just paper studies. Only so

Discussion around IRP – Call – March 19 @ 2pm

Attendees:

Ken Ross – Manager, IRP and EEC Reporting, Fortis BC (Ken looks after IRP and long term DSM Planning)

Dana Wong – Manager, IRP – Fortis BC

Fiona Oliver-Glasford and Hilary Thompson – EGD

Notes:

- IRP is very time intensive process, strategic and analytic
- Gas not the same thing
- Submit every 2 -3 years
- Working on the last 3 iteration
- Planning process never stops
- Take our snapshot at a given time
- Have IRP planning guidelines....Dana will send them over
- Everyone thinks electric
- Difference is resource options – upstream generation.....build or buy electricity.
- Don't allow much gas generation in BC
- Participate in the IRP technical committees for some of the jurisdictions around (mostly in US)
- Gas IRPs in other jurisdictions primarily about gas purchases.....pipeline and storage resources.
- Start with Demand forecast – 20 year planning horizon at Fortis BC
    - End-use model used from Marbek
- Show what demand side measures could impact
    - Marbek also done DSM planning work
- Account for 95% of the gas supply in BC
- Not impacting build as the DSM found not to impact peak at this point
- 4 years in on DSM
- Not being asked by commission to look at interruptible customers as a solution in IRP
- Only considering firm customers
- A few large Industrial customers coming on line as firm customers
- Been conservative as they "have to serve load on coldest day"
- Annual demand is dropping
- Little analysis of demand side measures on peak to-date – embarking on this now
- Considerations – everyone is going to use a different model for forecasting peak. Everyone has different customer characteristics. Peak demand is mostly residential.

- Launching a Conservation Potential Report (CPR) – both electric and gas – splitting costs with BCHydro (between two orgs cover 99% of energy needs) – starting shortly.
- 3 people in department – Ken, Dana, Tom – used to be 1.5 people but wasn't enough. Needed analytical power.
- Need to pull together a lot of departments and information….
- Project management is primarily the work – system (design) planning, dsm
- Long term planning for DSM also with Ken (EEC) – 5 year planning…
- They see others doing IRP having a mixed bag of approach to org planning, but seem to always have an IRP person or group
- Avista – have an IRP person for gas side and electric side….
- Puget Sound Energy – electric gas combined IRP – small team (5 -6 people doing IRP). Much more prescriptive process….
- In some places it's just about energy purchases versus dsm, in other places it is about build of infrastructure

GREEN ENERGY COALITION INTERROGATORY #3

INTERROGATORY

F2006-2008 DSM Plan Exhibit A7

In percentage and dollar terms, what is the expected rate impact of each of the F2006, 2007, 2008 DSM Plans? Does this include the impact of lower demand reducing the market price for gas?

RESPONSE

The rate impact of each of the Fiscal Years 2006, 2007 and 2008 Demand Side Management ("DSM") Plans are as follows:

Year	First Year $\$/10^3m^3$	%	Over Life of Measure $\$/10^3m^3$	%
F2006	0.88	0.46	(0.17)	(0.07)
F2007	0.89	0.47	(0.18)	(0.07)
F2008	0.87	0.46	(0.19)	(0.08)

The market price of gas is based on indices that are North American wide. The size of the Company's DSM volumes in relation to the market forecast would be immaterial and therefore do not have any impact on the market price for gas.