GEC Response to Energy Probe Interrogatory #1

Question:

Ref: L.GEC1, Neme Report, Page 4

Preamble: Even if $2 per month per non-participating residential customers were an appropriate limit for the impact of gas DSM, the limit should be expressed as $2 per month *net of both DSM spending and DSM benefits to non-participants*.

a) Please Provide the EGDI and Union 2014 DSM cost per Month/residential customer for non-participants.
b) Please provide the 2015 estimates from EGDI and Union (excluding the additional EGDI Budget of $5 million).
c) Confirm whether Mr. Neme is proposing that the TRC plus analysis include a monetary amount for GHG. If so, indicate the amount and point to the policy decisions for this.
d) Please explain in detail the Cost/Benefit "Equation" referred to in the reference, including assumptions.
e) Please provide the complete analysis that shows whether the $2/month/residential customer is/is not appropriate.
f) Please explain "Mr. Chernick has found that Enbridge's avoided distribution costs are actually three to five times higher than Navigant estimated for the Company".
g) Please explain why Mr. Neme claims Navigant's AC analysis is flawed and describe/discuss the differences from Navigant's Avoided Cost analysis (Exhibit C/T1/S4 Summary Table 10). Please provide a clear indication how this has been changed in your analysis e.g. Table 3 and provide supporting reasons.

Response:

a) I have not performed a detailed analysis of the 2014 or 2015 DSM impacts. However, in ballpark terms, the utilities' average 2016 to 2020 annual budgets are on the order of twice their actual spending in 2014 and their proposed spending in 2015. Thus, if their average budgets for 2016 to 2020 are approximately equal to a $2 per month per residential customer, then their spending or budgets for 2014 and 2015 are roughly equal to about $1 per month per residential customer. As the Table below shows, the offsetting downward pressure on rates is on the order of twice Enbridge's DSM spending and six times Union's spending. Thus, if DSM spending would produce the equivalent of about a $1 per month per residential customer increase in rates, then the net effect of DSM spending and the benefits that put downward pressure on rates would be on the order of a reduction of $1 per month for Enbridge and a reduction of $5 per month for Union over the life of the efficiency savings.

Witness: Chris Neme

	2014 DSM Actuals		2015 DSM Plans	
	Enbridge	Union	Enbridge	Union
Value of Benefits that Put Downward Pressure on Rates (2015 $ per Annual m3 Saved)	$1.54	$1.49	$1.54	$1.49
Annual m3 Savings	43,540,000	149,764,000	51,624,000	138,083,738
Value of Benefits that Put Downward Pressure on Rates (total 2015 $)	$67,118,701	$222,626,978	$79,580,520	$205,264,051
DSM Spending/Budgets ($2015)	$33,057,455	$34,280,188	$32,801,309	$33,988,000
Benefits as % of Spending/Budgets	**203%**	**649%**	**243%**	**604%**

b) See response to a).

c) The reference in the preamble is not to a "cost-benefit 'equation'", TRC plus or otherwise, that is or should be used to assess whether a program is cost-effective. Rather, it refers to a separate but related analysis[1] that should be done to assess the impact of efficiency programs on non-participants in the event that such impacts are determined by the Board to be relevant to the establishment of DSM budget caps. Specifically, I am suggesting that the impacts on residential customers be computed as the *net* of (1) the upward pressure on rates caused by DSM spending; and (2) the net present value of the downward pressure on rates resulting from (a) avoided carbon emission compliance costs, (b) price suppression effects, (c) reductions in the utilities' purchases of the most expensive gas, and (d) reductions in capital investments in T&D infrastructure over the life of the efficiency measures installed.

With respect to efficiency program cost-effectiveness screening, when there is an expectation of a utility cost that will be imposed on a system that can reasonably be assumed to be avoided by deployment of efficiency programs, the value of avoiding the cost should be included in assessments of the cost-effectiveness of the efficiency programs. To not do so is to intentionally under-value demand-side investments. The cost should be considered an avoided utility cost under the TRC, not as part of a "TRC plus" adder.

In its December 2014 DSM framework, the Board suggested that the utilities include in the TRC a 15% non-energy benefits adder to account for environmental, economic and social costs that are beyond those that the utilities would themselves directly incur. At the time, the Board may have been assuming that adder would sufficiently address the value of avoided carbon emissions. However, as Mr. Chernick's evidence makes clear, the 15% adder is not close to being sufficient to cover the value of avoided carbon

[1] It is related in that the DSM budget costs are *a portion* of total costs used in both TRC and "TRC plus" analyses, and that the other factors referenced are *subsets* of total benefits that should be included in both TRC and "TRC plus" analyses.

emissions, let alone other non-energy benefits. Moreover, given the additional carbon policy announcements from the Ontario government, I am suggesting that it is reasonable to move the primary consideration of reduction in carbon emissions out of the category of "non-energy benefits" and directly into avoidable utility costs – i.e. it has become an "energy benefit" because it will directly affect ratepayers future energy bills, rather than a "non-energy benefit".

Mr. Chernick provides estimates of the carbon prices for Ontario in Table 3 of his evidence (p. 20). He also discusses the policy rationale for the use of those values in his evidence (pp. 18-25). I provide additional discussion of Ontario greenhouse gas policy in my direct testimony (pp. 15-17).

d) The reference is not to a "cost-benefit 'equation'". See response to c) above.
e) The determination of whether a cap on impacts on non-participants[2] is appropriate and, if so, how large the cap should be, cannot be made formulaically. It requires consideration and weighing of a variety of policy objectives including the magnitude of net economic benefits, job benefits, environmental benefits, support for low income customers, any adverse impacts on non-participants, and the portion of customers who are able to participate in programs over time. Given what I know of both the magnitude of the benefits of additional DSM and the direction of Ontario policy, including the province's "conservation first" policy and its significant greenhouse gas emission reduction commitments, I would conclude that the adverse impacts on non-participants from a $2/month per residential customer net impact on rates would be more than offset by the other benefits. That said, as the preamble to this question highlights, if $2/month per residential customer is determined to be an appropriate limit, it should be expressed as $2/month net of both the upward pressure on rates from DSM spending and the downward pressure on rates from the effects discussed in response to c) above. As noted in my testimony, the current utility proposed DSM plans are likely to produce a net reduction in rates over the life of the efficiency measure savings (see Table 3, p. 18).
f) See Section III.D of Mr. Chernick's testimony, especially pages 41 and 42.
g) The question is unclear. My evidence does not comment on Navigant's avoided costs analysis. My testimony describes the derivation of Table 3, and it is not clear what additional information is being requested. The "supporting reasons" for my adjustments are laid out in Mr. Chernick's testimony.

[2] I focus on non-participants here, as I did in my direct testimony, because participants almost always see net reductions in their energy bills from DSM programs.

GEC Response to Energy Probe Interrogatory #2

Question:

Ref: L.GEC.1, Neme Report Page 9, Figure 1 and Page 15

Preamble: The incremental annual savings forecast by Ontario's utilities equates to approximately 0.6% (Union) to 0.7% (Enbridge) of annual sales to customers other than electric generators over the 2016-2020 period. As Figure 1 shows, leading jurisdictions have already achieved savings levels (actuals for 2014) that are on the order of twice the average of what Enbridge and Union are forecasting to achieve annually over the 2016-2020 period.13 Like the Ontario utilities, utilities in these jurisdictions all have both cold winter climates and very long histories of running gas efficiency programs.

a) Please provide and explain all the criteria for selecting "Leading Jurisdictions".
b) Why are Canadian jurisdictions e.g. Fortis, excluded from the leading jurisdictions or simply just excluded from the sample?
c) Please provide for the selected leading jurisdictions the costs ($/month) of DSM/CDM for a typical non-participating residential customer.
d) Please provide the average spend for all gas utilities in the US. Compare to the avg. for leading jurisdictions in Figure 1 (if 2014 data not available please use another year).
e) Please provide the Annual DSM Spend % as a percentage of sales for Canadian Gas Utilities (latest year available data).
f) Please provide the costs ($/month) of DSM/CDM for a typical non-participating residential customer for Canadian Gas Utilities.
g) Please provide the average spend ($/month/residential customer) for Ontario Electric Utilities, Normalize customer delivered energy cost to an equivalent monthly bill impact comparable to EGDI and Union.

Response:

a) The principal criteria was the level of savings being achieved. However, I also intentionally focused only on jurisdictions with northern, cold climates. The four jurisdictions selected were the top four in ACEEE state rankings for 2013 natural gas efficiency program savings.[1]

b) I am not aware of a Canadian jurisdiction that is achieving savings that are comparable to the leading U.S. jurisdictions identified. Fortis appears to be only getting between 0.3% and 0.4% annual savings as a percent of sales.

[1] Gilleo, Annie et al., "The 2014 State Energy Efficiency Scorecard", ACEEE Report Number U1408, October 2014.

Witness: Chris Neme

c) I have not performed the requested calculation which would require research and calculations that were not required for my report and would be onerous given the time available.

d) The four leading jurisdictions analyzed spent an average of about $96 (2015 CDN) per residential customer in 2013.[2] That is roughly 2½ times what Enbridge and Union are proposing to spend per year over the 2016 to 2020 time period. Comparing the leading jurisdictions to the average U.S. gas utility is problematic because many states in the U.S. do not have gas DSM programs. There are also many parts of the U.S. where gas consumption per customer is much lower because of warmer climates (and many of those are among the states that do not have gas DSM). Among the states that ACEEE gave more than a 0 in its scoring of gas DSM spending, the median spending level was California's at about $34 (2015 CDN), which is very similar to Enbridge's and Union's proposed levels.

e) I have not conducted an exhaustive assessment of Canadian gas utility savings as a percent of sales. As noted above, Fortis in BC is forecasting annual savings equal to between 0.3% and 0.4% of sales.[3] Manitoba Hydro is forecasting roughly similar levels of gas savings over the next decade and a half.[4]

f) I have not performed the calculation requested which would require research and calculations that were not required for my report and would be onerous given the time available.

g) I have not performed the calculation requested which would require research and calculations that were not required for my report and would be onerous given the time available.

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[2] Note that this the total DSM spending on all customers (residential, commercial and industrial) divided by just the number of residential customers. That is the same benchmark used by ACEEE in its 2014 State Scorecard.
[3] For estimates of savings see ICF Marbek, "FortisBC EEC Plan 2014-2018: Program Description and Cost-Effectiveness Results, Final Report", May 2, 2013.
[4] Manitoba Hydro, "Power Smart Plan 2014 to 2017, Supplemental Report 15yr (2014 to 2029)", Appendix 8.1, January 23, 2015, 2015/16 & 2016/17 General Rate Application.

GEC Response to Energy Probe Interrogatory #3

Question:

Ref: L.GEC.1, Neme Report Pages 15 and 16

Preamble: Natural gas accounts for approximately 30% of all greenhouse gas emissions in the province, so some portion of the *additional future emission reductions will almost certainly have to come from the natural gas sector*.

a) Please indicate the sources/data for this statement. Indicate if the figure includes downstream (end use) and/or upstream NG production, transmission.
b) Clarify the statement that "*additional future emission reductions will almost certainly have to come from the natural gas sector*.
c) Specifically explain why NG will be targeted, relative to other higher Carbon Fuels.
d) Please provide your understanding of when and how Trade and Cap will be applied in Ontario to the downstream natural gas sector. Link your response to the assumptions used in the GHG estimates and calculations used by Mr. Chernick.

Response:

a) Ontario's GHG emissions were 171 megatonnes in 2013 (from FEELING THE HEAT: Greenhouse Gas Progress Report 2015, Environmental Commissioner of Ontario, July 2015). We asked Union (JT2.13) and Enbridge (JT1.18) for their total distribution throughput volumes excluding volumes for export from Ontario. The resulting total volume of 26,749,646,000 m^3 times 1.89 kg CO_2/m^3 of gas is 50.5 megatonnes or 29.6% of the province's emissions.

b) The provincial target for 2050 is an 80% reduction in GHG emissions from the 1990 level of 182 megatonnes or approximately 36 megatonnes/y. Even if all other sources of emissions were completely eliminated, reaching the 36 megatonne target would require a reduction of 28% from today's natural gas consumption which results in roughly 50 megatonnes of emissions.

c) It is likely that all sources of greenhouse gas emissions will have to make a contribution to meeting the targets. As Mr. Neme's evidence states governments will allocate reduction targets among the various opportunities for GHG reductions throughout the economy. Their decisions will likely be informed by the relative cost effectiveness of reduction opportunities, and I expect options that produce GHG reductions at no cost to the economy (such as gas DSM) will often be chosen over more expensive options. In any case, regardless of the allocation of reduction targets, allowance trading will encourage over-compliance from low-cost sources (e.g., gas DSM) to generate allowances for sale to high-cost sources.

Witness: Chris Neme, Paul Chernick

d) It is not yet clear exactly how or when the Ontario cap and trade system will be applied to the natural gas sector. In a way it does not matter, at least with respect to the value of carbon emission reductions from gas DSM, as long as the gas sector is "under" the provincial emissions cap. Consider, for example, a scenario in which the gas sector is under the cap but given a number of emission allowances equal to its forecast emissions under a "business as usual forecast with no new DSM programs" – or, put another way, all short-term emission reduction requirements were effectively allocated to other sectors. Under that scenario, even though the gas sector would not *need* to make reductions to stay within its emission allowance allocation, it *could* make reductions through more aggressive gas DSM efforts and sell the allowances that were freed up as a result to the other sectors that were effectively required to reduce their emissions. Put simply, the emission reductions from gas DSM would still have significant economic value to ratepayers.

The only way that carbon emission reductions from gas DSM would not have significant value is if emissions from the consumption of natural gas were not under the provincial cap. We think that is very unlikely. For example, the government has made clear that Ontario plans to "link" with the California and Quebec systems.[1] Cap and trade design consultations make clear that Ontario is proposing that natural gas distributors would be covered as they are in California and Quebec.

See also M.GEC.APPRO.4 and M.GEC.IGUA.1.

[1] "Ontario intends to link its cap and trade program with Quebec and California, two other member jurisdictions of Western Climate Initiative." See http://news.ontario.ca/ene/en/2015/08/ontario-names-board-members-to-western-climate-initiative.html August 5, 2015.

GEC Response to Energy Probe Interrogatory #4

Question:

Ref: L.GEC.1, Neme Report Pages16/17; Table 3 and Footnotes 36-42

Preamble: Mr. Chernick's preliminary estimates are that the value of carbon allowances can be expected to be on the order of $20 USD per ton per year at the start of a carbon cap and trade system, and increase to more than double that amount by the end of a an average gas efficiency measure's 15 to 20 year life. Based on those estimates, the net present value of an m3 of annual gas savings that lasts 16 years (a typical average measure life) is close to $1. Both Enbridge and Union are projecting that their filed plans will achieve average incremental annual savings of about 75 million m3 over the 2016-2020 period. Thus, the value of avoided carbon emissions would be enough to roughly offset the entire Enbridge DSM budget and to more than offset the entire Union DSM budget. As discussed further below, those are benefits that accrue to all gas ratepayers, including non-participants, once a carbon cap-and-trade regulation is put in place in Ontario.

a) Please provide the worksheets for all Table 3 calculations (Excel Format please).
b) Please provide a list of all assumptions and sources for input data. Specifically provide:
   - The long term gas price forecast
   - The load profiles equivalent to those used by Navigant

Response:

a) See response to M.GEC.EP.12(d)
b) As noted in my testimony, I started with the values for the different benefits provided to me by Mr. Chernick. All other inputs are provided in the worksheet provided in response to M.GEC.EP.12(d). Note that I did not need or use a long-term gas price forecast in developing Table 3. For two of the benefits in Table 3 (purchasing less expensive gas and avoided distribution costs) I did have to make assumptions regarding the mix of end uses from which savings would come (principally between space heating and more baseload measures like water heating and industrial process). Those assumptions are provided in the attached worksheet. They came from an analysis of each utilities' 2014 actual savings (excluding the very large industrials in Union's case).

Witness: Chris Neme

GEC Response to Energy Probe Interrogatory #5

Question:

Ref: L.GEC.1, Neme Report Page 27

Preamble: Increasing home retrofit program participation. As noted above, even after normalizing for numbers of residential customers, Enbridge is proposing to ramp up to participation levels that are roughly double what Union is proposing. Moreover, Enbridge's proposed participation levels (between 0.6% and 0.7% of residential customers in 2020), though substantial, are still a factor of at least two or three below the annual participation levels achieved in Ontario at the end of the eco-Energy program or in other leading jurisdiction such as the United Kingdom.

a) What changes to the Home Retrofit Programs does Mr. Neme propose to achieve higher participation rates? Include whether the requirement for two deep measures should be dropped or modified (phased) as Synapse proposes.
b) Indicate if the measures menu should include more options etc. Please describe/discuss your proposals/recommendations in detail.
c) Please provide a ball park estimate of the cost per home for the proposed enhanced home retrofit programs.
d) Please provide an estimate/example corresponding to changes to the RA targets and scorecards for the Residential Home Retrofit Programs.

Response:

a) Given the wide range of issues to be addressed in this proceeding, I have not delved deeply enough into the details of program design and delivery strategy to provide a definitive set of recommendations for program changes. With that caveat, I offer the following comments on some aspects of the utilities' program designs:

   - I disagree with Synapse's suggestion to drop the requirement that customers install at least two major measures to participate. I think the requirement promotes greater comprehensiveness and good retrofit practice. Frankly, Synapse's concern about leaving on the table savings from customers who may only want to replace a furnace is misplaced. Synapse may not have been aware that equipment standards in Ontario already mandate that all new furnaces be condensing, so there are limited additional savings possible in that market. Further, one should always perform air sealing (one of the eligible major measures) before installing insulation. To not do so not only "leaves savings on the table" that will rarely be captured later, it could also degrade the effectiveness of the insulation itself by allowing moisture to get trapped and absorbed by the insulation material.

- I partially agree with Synapse's concern regarding Enbridge's incentive tiers. Enbridge has proposed three tiers: 1) 15% to 24% savings; 2) 25 to 49% savings and 3) 50% savings or more. The range of the second tier is far too large. Very few homes will be able to achieve 50% savings. In fact, only 2% of Enbridge's 2014 participants met that standard.[1] Thus, I would suggest either lowering the third tier to 35% savings or more or making the second tier 25-34% savings and creating a new third tier at between 35% and 49% savings (with the 50% + homes being a new fourth tier). That said, I would be hesitant about adopting Synapse's suggestion of a sliding scale incentive. It might be too complicated to communicate to customers.

- I would recommend Enbridge redefine the baseline from which savings are estimated in homes that replace furnaces (this is more of change in savings estimation than in program design). Right now, the utilities estimate savings assuming that the old inefficient furnace would have remained in place. For homes that include furnace replacements they use a 15 year measure life for all the savings (to account for a much lower life for savings from early retirement of furnaces) rather than the 25 years used for homes that install only thermal envelop measures. Union has proposed to change the baseline to a 90% condensing furnace and use the 25 year measure life for all projects. They also have proposed a lower free rider rate of 5% (rather than the current 15%). I encourage both companies to make those changes prior to their filings. Union did but Enbridge did not.

b) While I would be open to considering specific suggestions for new major measures to add to the list, I think that the list of major measures is pretty robust as is. I do agree with Synapse that the utilities should support the direct installation of low cost measures, where appropriate, at the time home audits take place. However, it is my understanding that they are already doing that.

c) It is not yet clear to me that the cost per home would need to be significantly increased. The demand for Enbridge's program has been growing rapidly. Indeed, Enbridge's program participation in the first three months of 2015 (February through mid-May) was roughly 2½ times what it experienced in 2014 when it finished with over 5200 jobs.

[1] Enbridge response at I.T5.EGDI.GEC.23(c).

Thus, while an increase in incentive levels and/or marketing efforts may be appropriate in the future, it may make sense to gauge first how quickly participation will grow under the current incentive levels before committing to higher incentives. The only potential confounding factor is that Enbridge is likely to run out of money in 2015 because of its rollover budget and targets and it is unclear how a possible resulting decision by the Company to scale back or suspend the program would affect the market.

d) I have not done the analysis necessary to propose specific changes to performance metrics. Obviously, any such change would need to reflect a change in budget available for the program.

GEC Response to Energy Probe Interrogatory #6

Question:

Ref: L.GEC.1, Neme Report Page 7 and page 35

Preamble: Enbridge's Market Transformation and Energy Management metrics should be changed in several ways. If the principle purpose of those programs is to either directly or indirectly drive savings, then they belong in the Resource Acquisition portfolio supporting the Resource Acquisition performance metrics. (p35)

a) Please provide more detail regarding the changes to the MT Scorecards for each of Union and EGD.
b) Specifically provide a "Strawman" Scorecard and Incentive Structure corresponding to the proposed changes

Response:

a) My main proposal is that the MTEM scorecard be revised so that it is only a Market Transformation scorecard with only the Residential Savings by Design, Commercial Savings by Design and Home Rating metrics included. Enbridge has proposed that the four metrics assigned to those three MT programs have 45% of the MTEM scorecard. I would give them 100% of the weight. A reasonable reallocation might be as follows:

Metric	EGD Proposed Weight	My Proposed Weight
Residential Savings by Design Builders Enrolled	10%	15%
Residential Savings by Design Homes Built	15%	25%
Commercial Savings by Design New Developments	15%	40%
(Time of Sale) Home Ratings Completed	5%	20%
Others	55%	0%

The CCM from the HHR program could be added to the small customer CCM target in the Resource Acquisition portfolio. Alternatively, as suggested in my testimony, that program and the School Energy Competition program could be put into a "general energy education" budget category for which there are no shareholder metrics or incentives assigned (but for which there is a budget – perhaps "ring-fenced"). Similarly, the RiR, CEM and New Construction Commissioning programs could be put into a new "pilot program" budget category for which there would also be no shareholder incentive metrics or incentives assigned (but for which there is a budget – also perhaps "ring-fenced").

b) In addition to the changes in structure and weighting suggested in "a" above, I would suggest two other changes to the scorecards (elaborating on points made in my testimony):

Witness: Chris Neme

- Keep the proposed commercial new construction projects target of 15 for 2017, but increase it much more quickly in subsequent years than Enbridge proposed. Enbridge suggests ramping up to 21 projects in 2020 (the fourth year of the new code). I’d suggest getting to at least a 25% market share by 2020 – i.e. more like 42 projects – with a roughly linear ramp up to that point.
- Increase the home ratings metric to 1000 for 2016 and by about 500 per year thereafter (to 3000 ratings in 2020).

GEC Response to Energy Probe Interrogatory #7

Question:

Ref: L.GEC.1, Neme Report Page 36

Preamble: The number of home ratings in 2016 (596) is lower than what was actually achieved in 2014 (662). That clearly makes no sense. Moreover, it is only projected to roughly double by 2020. Again, that is not a path to market transformation.

a) Confirm Mr. Neme participated with stakeholders and EGDI in developing a Settlement Proposal for 2015 RA and MT Budgets and Targets.
b) With reference to EGDI TC Response JT1.36 part (a) and Attachment, please provide your assessment of EGDI's 2015 "Rollover Targets" and the explanation EGDI provided in part (b) referencing Exhibit I.T2.EGDI.CCC.11.
c) Please provide any similar comments on Union's 2015 Targets and Budgets including the apparent decrease in cost effectiveness ($/m3) for certain RA and MT programs.

Response:

a) Confirmed.
b) I concentrated my testimony on the 2016 to 2020 program years because those seemed the years that the hearing could shape. Because the 2015 program year will be mostly over by the time the Board issues an order, I did not invest significant time in analyzing the utilities proposals for that year. Given the range of other questions I have received on my testimony and the limited time available to answer them, I do not have the time to do this analysis now either.
c) See response to "b".

Witness: Chris Neme

GEC Response to Energy Probe Interrogatory #8

Question:

Ref: L.GEC.1, Neme Report Page 44

Preamble: Union's has requested approval of infrastructure expansion projects (EB-2015-0179 - Community Expansion Application).

Please provide comments as to how Targeted DSM should/should not be considered in such Community Expansion projects.

Response:

I am not familiar with this particular proceeding. In general, if the cost of a load-related expansion project is large enough (several million dollars or more), the date at which the expansion is needed is far enough into the future, and the magnitude of the load reduction required for deferring the project is not so large as to be impractical (this may vary, depending on the size of the project and how far into the future the need begins), a detailed assessment of efficiency and other demand resources (e.g., interruptible supply contracts) should be undertaken. Effective use of targeted DSM requires that the utility forecasts regional demand and supply far enough into the future to identify potential constraints in time to implement targeted DSM.

As I understand it, one key piece of information that the gas utilities may be missing for such an analysis is an assessment of the relationship between design-day peak-hour savings and annual savings for different efficiency measures. However, I believe that decent preliminary assessments of those relationships can be made relatively quickly as follows:

- For reductions in industrial loads through custom projects, the estimates could be made on a custom basis (understanding operating schedules of the business), just as custom estimates are made of annual savings.
- For more "mass market" measures that are "baseload" – such as commercial cooking equipment and hot water measures, estimates can be developed based on information regarding times of day when such equipment is typically used. For residential water heating, for example, the gas utilities could leverage electric water heater load shape data to inform estimates.
- For space heating measures, estimates of the ratio of peak hour savings to annual savings could be developed through the use of hourly building simulation modeling.

Witness: Chris Neme

If it appears from both such estimates of peak hour measure savings and assessments of the market penetrations that aggressive geo-targeting of efficiency programs could achieve that an infrastructure project could be cost-effectively deferred, then the demand-side solution (potentially even just a partial demand side solution) should be pursued. The loads on the system of concern should obviously continue to be monitored as the deployment of the demand-side alternatives proceeds to determine whether the forecast load reductions (or reductions in the growth rate of loads) appear to be on track. If loads on system components of concern are growing faster than expected or hoped – whether because the demand-side solutions are not working as forecast or for other reasons – then there could be a mid-course change in plan and the supply-side investment could be pursued to ensure reliability of gas service delivery. As long as the need for the supply-side investment is identified early enough that there is time to change plans if needed, this approach should not only save ratepayers money but do so in a way that does not compromise reliability.

To be sure, investment in additional primary data collection on hourly usage patterns and/or hourly savings could and should be used to inform adjustments to initial peak hour savings estimates over time. If the utilities have historic data from past load research efforts on consumption profiles for individual end uses this could also be useful.

GEC Response to Energy Probe Interrogatory #9

Question:

Ref: L.GEC.2, Chernick Evidence, Page 12 Figure 2

Preamble: The regression line in Figure 2 implies a $0.15/MMBtu decrease in Henry Hub gas price for every quad decrease in annual gas consumption, or $0.00027/m3 per 10^3 m^3 saved (in 2015 Canadian dollars), roughly a quarter of the slope in the 2012 sensitivities.

a) Please provide the current (mid 2015) Basis Differential between Henry Hub and Dawn.
b) Please provide a forecast of Basis Differential for Henry Hub and Dawn in 2020. [For example, refer to current applications by Union and EGDI for Approval of the NEXUS Long Term contracts or other sources such as submissions at the OEB 2015 NGMR Forum]
c) Please explain why DRIPE should/should not be based on Peak Day demand or annual consumption.
d) Please explain why the DRIPE would/would not be identical at Henry Hub and Dawn.
e) Using a Dawn reference price outlook (to 2020) please provide revised DRIPE estimate(s).

Response:

a) Please note that none of the questions in this request appear to be related to the preamble. Assuming that mid-2015 means June-July 2015, the following table provides the DAWN and Henry prices and the basis in US$/MMBtu for deliveries on June 1 to July 14. Summer basis tends to be low for most trading points.

Trade Date	Dawn	Delivery Start Date	Delivery End Date	Henry Hub	Basis
05/29/2015	2.72	06/01/2015	06/01/2015	2.64	0.08
06/01/2015	2.7	06/02/2015	06/02/2015	2.6	0.1
06/02/2015	2.7	06/03/2015	06/03/2015	2.62	0.08
06/03/2015	2.7	06/04/2015	06/04/2015	2.64	0.06
06/04/2015	2.68	06/05/2015	06/05/2015	2.59	0.09
06/05/2015	2.64	06/06/2015	06/08/2015	2.56	0.08
06/08/2015	2.76	06/09/2015	06/09/2015	2.67	0.09
06/09/2015	2.91	06/10/2015	06/10/2015	2.81	0.1
06/10/2015	2.98	06/11/2015	06/11/2015	2.92	0.06
06/11/2015	2.96	06/12/2015	06/12/2015	2.87	0.09
06/12/2015	2.86	06/13/2015	06/15/2015	2.76	0.1
06/15/2015	2.92	06/16/2015	06/16/2015	2.86	0.06
06/16/2015	2.93	06/17/2015	06/17/2015	2.93	0
06/17/2015	2.97	06/18/2015	06/18/2015	2.93	0.04
06/18/2015	2.91	06/19/2015	06/19/2015	2.86	0.05
06/19/2015	2.83	06/20/2015	06/22/2015	2.81	0.02

Witness: Paul Chernick

06/22/2015	2.84	06/23/2015	06/23/2015	2.77	0.07
06/23/2015	2.88	06/24/2015	06/24/2015	2.83	0.05
06/24/2015	2.83	06/25/2015	06/25/2015	2.77	0.06
06/25/2015	2.87	06/26/2015	06/26/2015	2.79	0.08
06/26/2015	2.84	06/27/2015	06/29/2015	2.77	0.07
06/29/2015	2.86	06/30/2015	06/30/2015	2.8	0.06
06/30/2015	2.83	07/01/2015	07/01/2015	2.77	0.06
07/01/2015	2.84	07/02/2015	07/02/2015	2.81	0.03
07/02/2015	2.86	07/03/2015	07/06/2015	2.79	0.07
07/06/2015	2.8	07/07/2015	07/07/2015	2.74	0.06
07/07/2015	2.77	07/08/2015	07/08/2015	2.73	0.04
07/08/2015	2.79	07/09/2015	07/09/2015	2.71	0.08
07/09/2015	2.75	07/10/2015	07/10/2015	2.69	0.06
07/10/2015	2.83	07/11/2015	07/13/2015	2.75	0.08
07/13/2015	2.95	07/14/2015	07/14/2015	2.88	0.07
07/14/2015	2.99	07/15/2015	07/15/2015	2.95	0.04

b) From the question, it appears that Energy Probe has access to the forecasts it is referencing. The Nexus filings do not appear to have any actual or forecast data relevant to the determination of basis DRIPE to Dawn.

c) That depends on the type of market price under analysis. The prices that Mr. Chernick discusses are volumetric energy prices (in $\$/m^3$ or equivalent), not capacity prices. For some applications (such as electric capacity DRIPE in the RTOs with separate capacity markets), peak demands may be relevant.

d) If there is never any congestion between Henry Hub and Dawn, the DRIPE at those hubs would be the same, and would be limited to the continental market price effect. If there is any congestion from Henry Hub to Dawn, there would likely be some basis DRIPE from one location to the other. Depending on the development of the continental market over time, the relevant Dawn basis DRIPE may be from a reference point other than Henry Hub.

e) Mr. Chernick does not understand the request, which does not specify the “Dawn reference price outlook (to 2020)” or any data on the variation in Dawn price as a function of load. Note that Mr. Chernick did not estimate a basis DRIPE value for Dawn, so it is not clear what might be “revised” if the necessary data were available.

Witness: Paul Chernick

GEC Response to Energy Probe Interrogatory #10

Question:

Ref: L.GEC.2, Chernick Evidence Page 14

Preamble: The Navigant Report Figure 4 shows EGD Peak Day Demand rising to over 110,000 10^3m^3 in 2019/20 or an average increase 2015-2020 of 39,653 GJ or 1,047 10^3m^3.

The product of a \$0.00027/m^3 price reduction per 10^9m^3 saved times 28.2 10^9m^3 is a benefit to Ontario of 0.76¢ in reduced gas bills per m^3 conserved, in addition to the benefit of buying less gas (which is the direct avoided supply cost). [Evidence Page 14].

a) Please provide an estimate of the Ontario benefit based on the reduction of peak demand growth, rather than annual consumption and using a Dawn Reference price.
b) Confirm that in a normal weather year, both EGDI and Union meet sales customer's incremental load from storage on peak days.
c) Confirm Spot Gas purchases are primarily for load balancing to offset banked gas customer requirements.

Response:

a) There are many benefits of reducing peak demand (and specifically design-day and design-hour demand), including reducing requirements for transmission, distribution and storage capacity. None of those benefits are closely related to the commodity DRIPE benefits. Of course, a small portion of the annual DRIPE is experienced on the normal peak day, and a smaller amount of the design peak day. Mr. Chernick has not attempted to estimate that portion of commodity DRIPE.
b) It is likely that EGDI and Union withdraw gas from storage on peak days. Neither utility appears to have modeled peak days for its avoided costs, Enbridge has provided no documentation of its dispatch, and Union's documentation indicates that Union assumes that it does not change its use of storage on a monthly basis as a function of load increases and decreases.
c) To the contrary, Union indicates that market purchases at Dawn constitute its primary swing supply in response to DSM. The question does not define "Spot Gas." If Energy Probe intends that Spot Gas be read as daily or hourly purchases, the utilities have provided no information on the operation of their systems on daily or hourly bases. The utilities may buy market gas at Dawn (for example) with monthly, weekly, daily and hourly transactions.

Witness: Paul Chernick

GEC Response to Energy Probe Interrogatory #11

Question:

Ref: L.GEC.2, Chernick Evidence Pages 19 and 21

Preamble: Building on the principle of the non-energy benefit adder…the Board consider…how such potential DSM benefits as carbon reduction… may be used to screen prospective DSM programs and inform future budgets. (Minister's Letter of 4 February 2015).

a) Please explain if Mr. Chernick agrees that in calculating the benefits of DSM Programs, the TRC plus test in the Board's Guidelines is appropriate.
b) Is Mr. Chernick proposing to change the OEB TRC plus Screening to increase the component allocated to Carbon/GHG? Please discuss and indicate by how much.
c) Does Mr. Chernick agree with EGDI's Response to JT 1.36 Question 6 and Exhibit I.T3, EGDI, ED.13?
"The benefits to non-participants are largely societal in nature and include impacts such as environmental benefits through reduced greenhouse gas emission, societal benefits, particularly for low income consumers, and economic stimulus." Please comment.

d) Is Mr. Chernick disagreeing with the Board when he states:
"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."

Please discuss.

Response:

a) Mr. Chernick believes that conceptual framework of the TRC plus is appropriate. The benefits of DSM programs include DRIPE and avoided carbon compliance costs, in addition to non-energy benefits, all of which should be estimated and included in the avoided costs or otherwise counted as benefits. In addition, as demonstrated in Mr. Chernick's testimony, the utilities' estimates of avoided distribution and avoided supply appear to be understated; the Board should take steps to correct those problems.

b) Mr. Chernick assumes that the OEB considered carbon costs to be among the 'non-energy benefits' included in its 15% adder, even though the OEB did not specifically allocate any component of the 15% to carbon (which renders meaningless the portion of the question asking about increasing that component). Since the Board's Framework was released, the Province has raised its carbon reduction targets and announced a plan to use a cap-and-trade system to help reach them. This has the effect of making carbon compliance costs a ratepayer cost that can be avoided (at least in part), rather than solely an externality. He therefore recommends that the value of carbon compliance be added to avoided costs, outside of the 'non-energy benefits' adder. See pages 17 to 25 of L.GEC.2 for the valuation of carbon.

c) The benefits to non-participants include

- reduced greenhouse gas emissions and hence reduced prices of allowances for all emitters and reduced quantities of allowances for gas consumption,
- economic stimulus from increased local employment and reduced utility bills,
- reduced gas prices (due to both DRIPE and reduced use of the most expensive resources),
- avoided infrastructure investment,
- reduced allocation of utility-owned wholesale resources to distribution load,
- reduced public costs (for emergency response and health care) due to improved safety and health (particularly for low-income customers, but for other customers as well),
- reduced gas bills for governmental and other public facilities, and
- reduced need for public financial support for low-income households.

Some of these benefits are avoided costs (allowance, infrastructure and gas costs, DRIPE, allocation of utility-owned resources) while others (economic stimulus, reduced public expenditures) are best described as non-energy benefits.

d) Mr. Chernick agrees with the Board that aligning the gas and electric avoided costs has some appeal. As Mr. Chernick explains in his testimony, the Board did not properly align those costs, and did not reflect the relative value of carbon prices or most non-energy benefits of DSM for gas versus electric efficiency. Nor did the Board reflect wholesale price mitigation, which does not appear to have been considered in setting the 15% adder for electric CDM.

GEC Response to Energy Probe Interrogatory #12

Question:

Ref: L.GEC.2 Chernick Evidence Page 28; Mr. Neme's Evidence Table 3

Preamble: The significance of the avoided-to-average (commodity cost) differentials is that they should be reflected as benefits to non-participants in the assessment of rate effects.

a) Please indicate who prepared the analysis for benefits to non-participants as reflected in Table 3 of Mr. Neme's Written Evidence.
b) Discuss in detail the Components of a Benefit/Cost analysis/equation for non-participants in DSM programs.
c) Specifically indicate an appropriate range of cost/NPV for each of the listed components for each of EGDI and Union. Please provide sources for each.
d) Please provide the worksheets for components in Table 3 of Mr. Neme's evidence. (Excel Format please).
e) Please provide sensitivity ranges to the major components of the Cost/Benefit calculation and provide the overall Sensitivity range.
f) What is Mr. Chernick's DSM Budget range for EGDI and Union based on his analysis of benefits to non-participants?

Response:

a) Mr. Neme prepared Table 3 from inputs provided by Mr. Chernick.

b) Table 3 is not a benefit-cost analysis for non-participants. It is simply a summary of the gas system benefits that accrue to all customers, including non-participants, and a comparison of that subset of the benefits of energy efficiency programs to the program budgets that produce them. A detailed discussion of each of those four components is provided in Mr. Chernick's filed testimony. It should be noted that non-participants also receive benefits from efficiency programs through improvements to economic productivity in the Ontario economy, environmental emission reductions, reductions in electricity prices related to gas price suppression effects, and reduced utility credit and collection costs. The latter is also a benefit that puts downward pressure on gas rates, but which neither Mr. Neme nor Mr. Chernick have quantified. It should also be noted that a widely recognized way to address any concerns about impacts on non-participants is to make efficiency program offerings as comprehensive and wide-ranging as possible and to keep them in place over long periods of time so that all (or the vast majority of) customers have the opportunity to participate over time.

Witness: Paul Chernick, Chris Neme

c) Assuming that the request for “an appropriate range of cost/NPV” is the same as a request for a sensitivity analysis, see answer to ‘e’, below.

d) See Excel file Attachment.

e) It is not clear what the question means by “sensitivity range.” The GEC witnesses have not attempted to produce a probabilistic analysis of avoided costs (supply, distribution, design-day storage capacity, DRIPE, carbon costs) or the effects on non-participant bills. Given the utilities’ refusal to provide even the most basic information about their avoided costs, GEC’s ability to perform sensitivity analysis is very limited. Thus, the only case for which we have provided more than a “best estimate” of the value of the benefits listed in Mr. Neme’s Table 3 is for avoided distribution costs. As noted in his testimony (p. 42), Mr. Chernick estimated that “the corrected nominally-levelized values are about 3.4 to 4.7 times the Enbridge estimate.” Mr. Neme used the mid-point of that range (i.e. 4) to produce his Table 3. Thus, Mr. Chernick suggests that the value of avoided distribution costs in Mr. Neme’s Table 3 is reasonable plus or minus about 15%.

f) Mr. Chernick did not prepare a “DSM Budget range.” In computing the percentages in the last column of Table 3 of his testimony, Mr. Neme used as the denominator each utility’s average annual DSM budget over the five years from 2016 through 2020 (as presented in each utility’s plan filing).[1] Specifically, as explained in footnote 38 to his testimony, the average used for Union was $60.4 million and the average used for Enbridge was $76.2 million. Note that those are averages of the utilities’ proposed budgets in nominal dollars. Because the benefits that I present in Table 3 are expressed in real 2015 dollars (i.e. inflation adjusted), I should have used real average budgets. The averages in real 2015 dollars are as follows: $57.4 million for Union and $72.4 million for Enbridge. An update to Mr. Neme’s evidence will be filed shortly that both makes this correction and updates the table to reflect a change to the Union value for reduced purchases of the most expensive gas. The latter change addresses a refinement to Mr. Chernick’s testimony that was made after Mr. Neme’s testimony was filed.

[1] For Union see Exh A/T3 p. 6; for Enbridge see Exh B/T1/S4 pp. 3-5.