ONTARIO ENERGY BOARD

EB-2012-0451
EB-2012-0433
EB-2013-0074

IN THE MATTER OF an application by Enbridge Gas Distribution Inc. for: an order or orders granting leave to construct a natural gas pipeline and ancillary facilities in the Town of Milton, City of Markham, Town of Richmond Hill, City of Brampton, City of Toronto, City of Vaughan and the Region of Halton, the Region of Peel and the Region of York; and an order or orders approving the methodology to establish a rate for transportation services for TransCanada Pipelines Limited;

AND IN THE MATTER OF an application by Union Gas Limited for: an Order or Orders for pre-approval of recovery of the cost consequences of all facilities associated with the development of the proposed Parkway West site; an Order or Orders granting leave to construct natural gas pipelines and ancillary facilities in the Town of Milton; an Order or Orders for pre-approval of recovery of the cost consequences of all facilities associated with the development of the proposed Brantford-Kirkwall/Parkway D Compressor Station project; an Order or Orders for pre-approval of the cost consequences of two long term short haul transportation contracts; and an Order or Orders granting leave to construct natural gas pipelines and ancillary facilities in the City of Cambridge and City of Hamilton.

SUBMISSIONS AND COMPENDIUM OF ENVIRONMENTAL DEFENCE

Filed November 14, 2013

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Submissions

Compendium of Materials Referred to in Submissions

[1] http://www.ene.gov.on.ca/stdprodconsume/groups/lr/@ene/@resources/documents/resource/std01_079169.pdf

[2] Main report: http://www.ene.gov.on.ca/stdprodconsume/groups/lr/@ene/@resources/documents/resource/stdprod_101103.pdf; Technical appendix: http://www.ene.gov.on.ca/stdprodconsume/groups/lr/@ene/@resources/documents/resource/stdprod_100824.pdf

Tab Contents and sub-tabs [Page No.]

Note: The above documents have been marked-up by counsel.

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OVERVIEW AND SUMMARY

1. Environmental Defence submits that the project proposed by Enbridge Gas Distribution Inc. ("Enbridge") is not in the public interest and should not be approved by the Board.[3] On closer examination, the purported benefits of the project – meeting load growth, lowering gas supply costs, entry point diversity, and improving reliability – are illusory or can be achieved through more cost effective means such as Demand Side Management ("DSM").

2. The first purported need for the project is demand growth. This need is greatly overestimated by Enbridge's flawed and inadequate growth forecast. However, even if Enbridge's forecast is taken as given, all demand growth can be addressed at a far lower cost through DSM. DSM would result in significant *net benefits* to consumers through lower energy bills. Whereas DSM is *profitable* and would lead to lower overall bills, the supply-side option is highly costly and would lead to *increased* rates and bills. The DSM option would also lead to significant *additional* benefits such as decreased greenhouse gas ("GHG") emissions; improved corporate productivity and competitiveness; higher GDP and government revenues; and more jobs for Ontarians.

3. The second purported benefit of the project is gas supply savings that Enbridge asserts its customers will obtain by switching from long-haul service (from Empress on the TCPL mainline, with its more expensive tolls) to short-haul service (from Dawn). However, a large portion of every dollar "saved" will directly translate into revenue lost by TCPL, which will be made up through increased tolls and through other payments under the settlement agreement. These increased tolls and payments will be borne by consumers, thus erasing the intended savings.

4. While the toll savings will largely disappear, Enbridge's customers will be left paying the higher Dawn gas prices. Also, Enbridge's forecast of the Dawn-Empress gas price

[3] These submissions do not specifically address the application by Union Gas Ltd. ("Union") under the assumption that other intervenors will adequately address how the issues raised by these submissions (including a denial of Enbridge's application) will impact Union's application.

differential is unreasonably optimistic, and far out of line with Union’s and TCPL’s forecasts. When the TCPL revenue requirement issue *and* a realistic Dawn-Empress price differential forecast are considered, the gas supply savings become significant losses that customers will bear in addition to the already high cost of the project.

5. In comparison, based on Enbridge’s own evidence, the *net* benefits from just the *incremental* DSM needed to offset growth in the GTA area from 2014 to 2025 is approximately $1.7 billion cumulatively ($140 million per year). These DSM benefits are not subject to anything close to the economic risks posed by Enbridge’s proposed project.

6. The third purported benefit – entry point diversity – can be achieved simply by connecting Union’s proposed Parkway West Gate Station to the Enbridge system with only a short pipeline. This would relieve the over-reliance on the Parkway Gate Station. The vast majority of the project is not needed for this purpose.

7. With respect to the fourth purported benefit – reliability – it cannot be disputed that Enbridge’s proposed $686.5 million project will improve reliability and flexibility (it would be inconceivable to expend those sums and not improve reliability). However, Enbridge has not established that the reliability benefits, including the reduced pressure on certain lines, are (i) truly necessary, (ii) worth the cost, or (iii) are the highest priority on Enbridge’s network.

8. Furthermore, Enbridge has not established that the project is the preferred alternative to achieve the reliability benefits as compared to a combination of DSM and increased interruptible service (and operational measures, and/or minor capital improvements, if necessary). The reliability benefits have only been considered as part of a larger project to address other issues such as meeting demand growth and lowering gas supply costs. Enbridge has *not* provided the evidence (or the analysis of alternatives) to justify the project on reliability grounds once those other purposes are taken out of the equation.

9. The lack of more detailed analysis and evidence regarding reliability needs is particularly problematic seeing as (i) Enbridge has acknowledged that its system will meet all minimum standards with or without the proposed project, (ii) the two lines in question

have operated at current pressure levels (i.e. over 30% SMYS) since they were built, (iii) there presumably have not been service losses as a result of this pressure issue for the approximately 40 years these lines have been operating at these levels, and (iv) Enbridge and Union each have *hundreds* of kilometres of pipelines that also operate at above 30% SMYS.

10. From 2015 to 2025, Enbridge estimates that it would earn more than $185 million in incremental net income from this project alone, whether or not the purported benefits materialize. Consumers, on the other hand, would be faced with very high risks and would most likely end up with significantly higher rates and energy bills and a lost opportunity to implement highly profitable DSM.

11. For these and the other reasons discussed below, Environmental Defence requests that this application not be approved. The specific relief requested by Environmental Defence is outlined in paragraphs 214 and 215 below.

ENBRIDGE'S PROPOSED PROJECT

12. Enbridge is proposing to build a series of new pipelines in the Greater Toronto Area at a total cost of $686.5 million. This would be the largest capital project in Enbridge's history.

13. The project consists of two main parts, Segment A and Segment B, as illustrated on the following page. At a high level, the costs of the project can be broken down as follows:

GTA Project Component	**Cost**
Parkway West Gate Station and tie in	$28M
Segment A - approximately $356M	$356M
Segment B (E-W)	$189M
Segment B (N-S)	$113M
TOTAL	**$686.5M**

Correspondence from Enbridge Counsel, August 1, 2013

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14. The following figure illustrates certain key components of the project and describes a number of concepts addressed in these submissions. The proposed new Enbridge pipelines are illustrated in dotted orange lines.

Figure 1: Illustration of the GTA Project

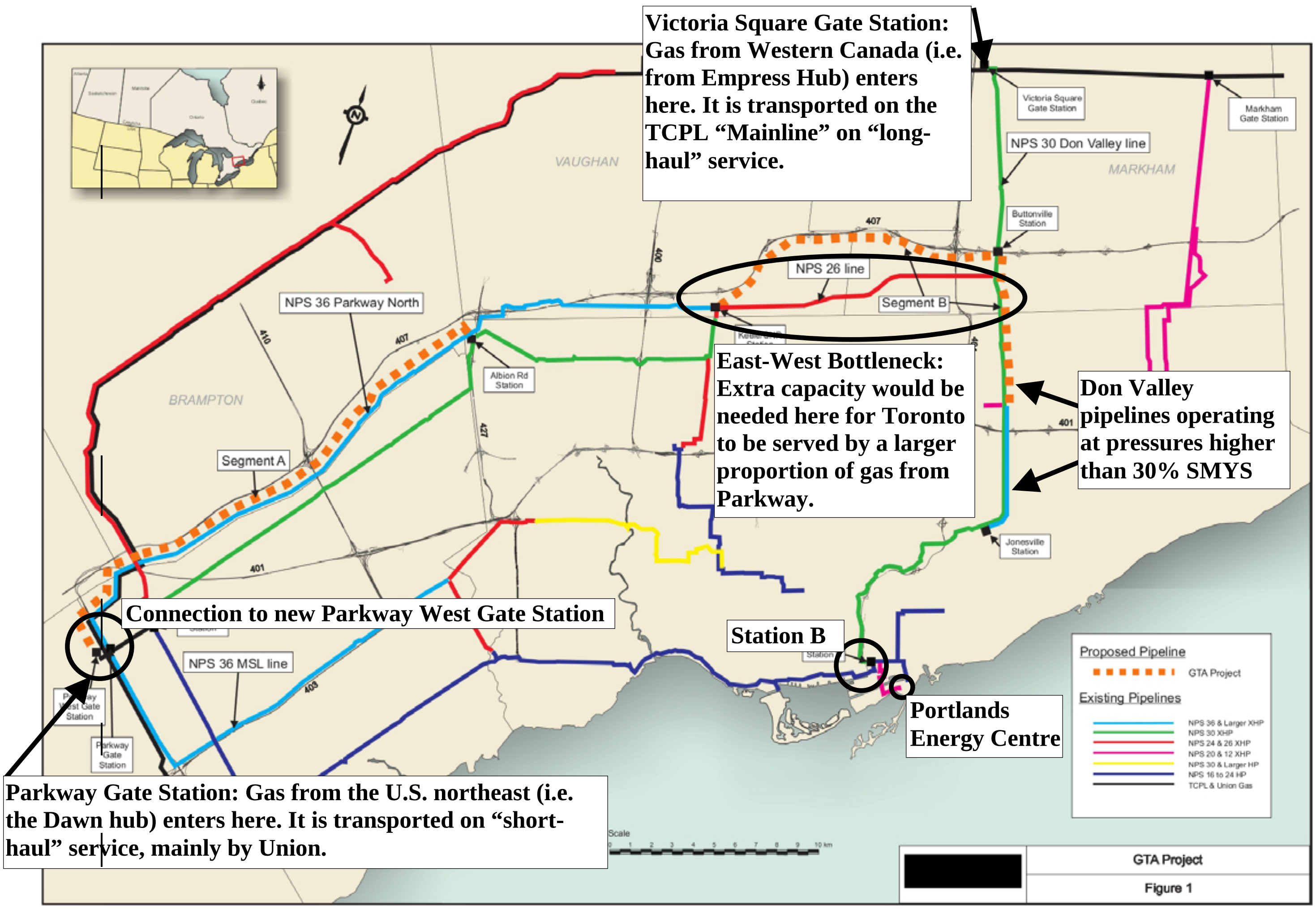

Exhibit A, Tab 9, Schedule 3, Attachment 2

ASSESSMENT OF PURPORTED NEEDS AND BENEFITS (ISSUE A1)

15. Enbridge summarizes the need for its project as follows:

> The GTA Project will:
>
> a. Meet customer growth requirements over the period from 2015 to 2025 by reinforcing the XHP distribution network;
>
> b. Reduce operational risks and enhance safety and reliability by:

i. Improving diversity and flexibility of the distribution system through additional looping of single feed XHP lines and providing additional supply sources for the major XHP lines in the GTA Project Influence Area; and

ii. Providing the ability to lower pressures on key supply lines;

c. Provide entry point diversity by reducing the dependence upon Parkway Gate Station which currently provides more than 50% of the supply to the GTA Project Influence Area and does not have alternate means of supply; and

d. Improve supply chain diversity, reduce upstream supply risks and reduce gas supply costs over the period 2015 to 2025.

Application Excerpt re Purpose Summary, p. 1-2 (Ex A-3-1) [Compendium, tab 2]

16. These submissions address those purported needs in the following order: (1) demand growth, (2) entry point diversity, (3) gas supply costs, and (4) reliability and safety.

Demand Growth

17. Enbridge's demand forecast overestimates growth and is highly flawed. However, even if the forecast is taken as given, DSM can eliminate all peak demand growth – both in the long and short term, including the needs in the winter of 2015/2016.

Enbridge's Demand Forecast Overestimates Growth and is Unreliable

18. Enbridge's demand forecast overestimates growth and is unreliable because:

a. The forecasting methodology is flawed;

b. The results are inconsistent with trends; and

c. The forecast disregards and is completely inconsistent with the Government of Ontario's GHG reduction targets and programs, as detailed below.

Unreliable Forecasting Methodology

19. By way of background, the steps in Enbridge's forecasting methodology can be summarized as follows:

a. First, Enbridge estimated the number of new customers for each customer type (i.e. commercial, apartment, residential, industrial).

b. Second, it multiplied the number of new customers by an estimated average demand per customer by type.

c. Third, it summed the forecast demand growth for each customer type to generate a preliminary forecast of the demand growth from *new* customers.

d. Fourth, Enbridge reduced that preliminary growth forecast from *new* customers -- i.e., customer additions -- by a 35% reduction factor (the "Reduction Factor").

e. Fifth, after it had applied the Reduction Factor to the growth from *new* customers, it added the load from new customers to the load from existing customers (i.e. the base).

Transcript Vol. 5, p. 12 ln 24 to p. 13 ln 22 [Compendium, tab 3]
Summary of Enbridge's Peak Load Forecast Calculations [Compendium, tab 5]

20. Mathematically, the demand from existing customers is constant in the model and the demand growth from new customers is simply added on top. The 35% Reduction Factor is applied only to the growth from new customers but is intended to capture *all* of the variables affecting *both* new customers *and* existing customers.

Transcript Vol. 5, p. 13 ln. 23-25 & p. 14 ln. 10-15 [Compendium, tab 3]

21. There are at least three fatal flaws with this methodology.

22. First, Enbridge asserts that the Reduction Factor captures "everything, all of the forces that are impacting our load growth," including the impact of Enbridge's DSM programs, customer losses through building demolition, improved efficiencies occurring *outside* Enbridge's DSM programs, and more stringent building codes on new buildings and renovations. This is simply untrue. It only captures the impact of Enbridge's status quo existing DSM programs.

Transcript Vol. 5, p. 16 ln. 21 to p. 18 ln. 15 [Compendium, tab 3]
Undertaking Response JT2.29 (Re: Reduction Factor) [Compendium, tab 17]

23. The Reduction Factor only accounts for a demand reduction approximately equal to the expected impact of Enbridge's existing DSM programs. It does *not* account for other factors that would reduce demand growth, such as those listed above. The Reduction Factor amounts to a demand reduction of approximately 12,000 m^3/hr per year (the precise figure rises steadily from 11,792 m^3/hr in 2013 to 12,454 m^3/hr in 2025). This is approximately equal to the peak hour demand reduction that Enbridge estimated would result from continuing with its existing DSM budget each year (12,000 m^3/hr).

Transcript Vol. 5, p. 20 ln. 21-25 [Compendium, tab 3]

Summary of Enbridge's Peak Load Forecast Calculations [Compendium, tab 5]

Summary of Enbridge's DSM Evidence [Compendium, tab 6]

Interrogatory Response I.A4.EGD.ED.14 (Re: DSM Needed to Offset Growth) [Compendium, tab 15]

24. On cross-examination Mr. Fernandes responded to this issue by asserting that the Reduction Factor also accounts for factors that would *increase* demand. However, Enbridge has provided no analysis or data to support this. Indeed, Enbridge's original application indicated that the Reduction Factor only accounted for factors that would *decrease* demand, namely "[DSM] and customer losses through building demolition."

Transcript Vol. 5, p. 21-22 [Compendium, tab 3]

Application Excerpt re Reduction Factor (Ex. A-3-4, p. 8) [Compendium, tab 16]

25. The only example provided by Mr. Fernandes of a factor resulting in increased demand is a trend toward larger buildings. However, the customer additions forecast already factors in the average use trends per sector over the past five years for new customers, which would incorporate for the trend to larger buildings. Furthermore, the average use trends per sector (which, again, would incorporate the trend to larger buildings and other factors impacting average use) have in fact been *declining*, as discussed below.

Transcript Vol. 5, p. 21-22 [Compendium, tab 3]

Interrogatory Response I.A4.EGD.ED.12 (Re: Forecast Methodology) [Compendium, tab 8]

26. Because the Reduction Factor only reduces the forecast demand by an amount equal to the expected savings from DSM, it cannot be said that it or Enbridge's forecast properly accounts for other factors which would reduce demand such as (i) customer losses through building demolition, (ii) improved efficiencies occurring outside Enbridge's

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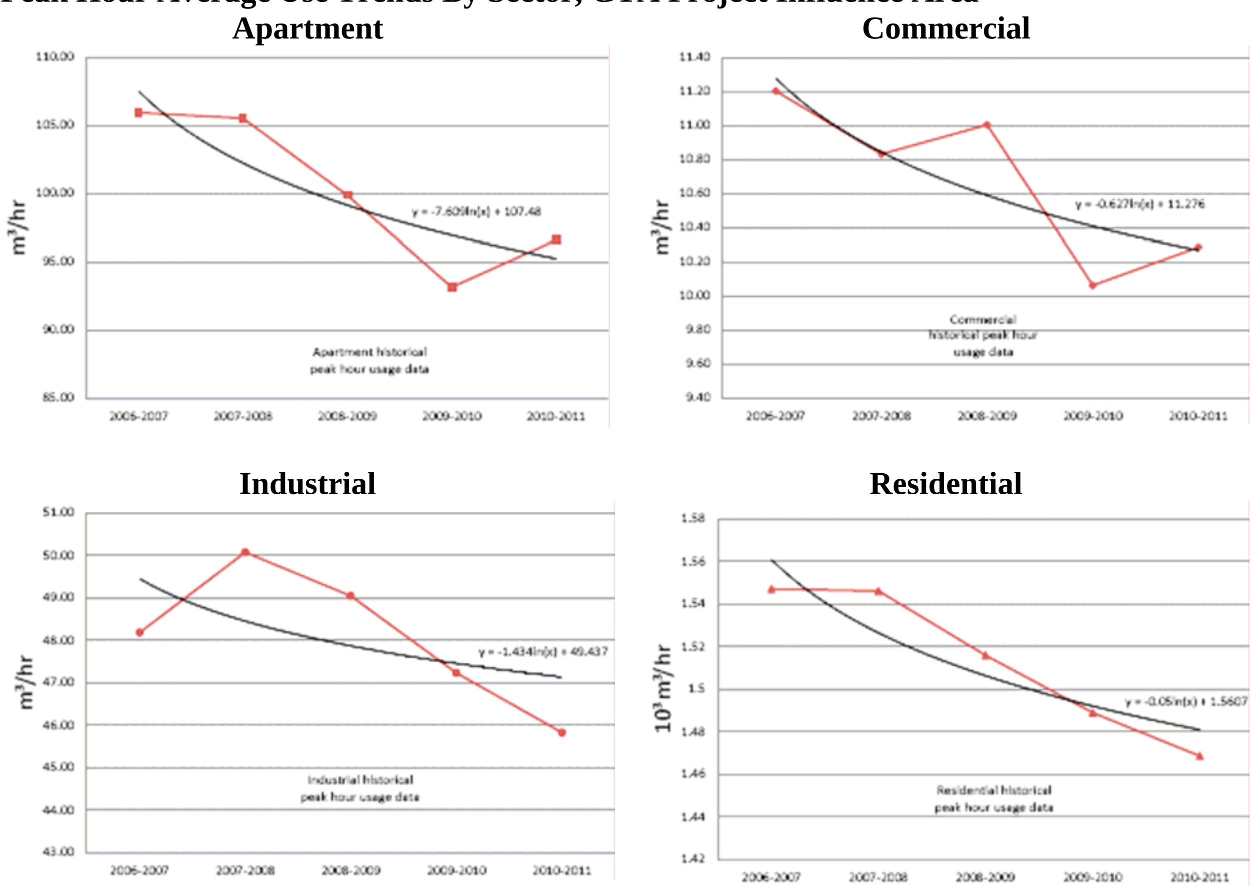
DSM programs, (iii) more stringent building codes, and so on. The forecast therefore seriously overestimates demand.

27. The second related problem with the methodology is that it does not account for the fact that the average per customer peak hour use is steadily declining in every sector in the *existing* building stock in the GTA project influence area. Enbridge provided the following charts detailing these declining use trends:

Peak Hour Average Use Trends By Sector, GTA Project Influence Area



Undertaking Response JT2.27 (Re: Declining Average Use Trends) [Compendium, tab 7]

28. Those declining average use trends were only applied to the growth from *new* customer additions – not to the existing customers. Again, the demand from existing customers remains constant in Enbridge's model. Although the Reduction Factor is intended to incorporate all variables impacting the new *and* existing customers, as detailed above, it

in fact only incorporates the impact of Enbridge's status quo DSM programs. Therefore, the declining average use trends are not accounted for in the forecast.

Interrogatory Response I.A4.EGD.ED.12, p. 2 [Compendium, tab 8]
Transcript Vol. 5, p. 13 ln. 23-28 [Compendium, tab 3]

29. The third problem with Enbridge's methodology is that the Reduction Factor is a complete "black box"; Enbridge cannot explain in any detail how it was arrived at and what elements it contains. Enbridge acknowledged that the Reduction Factor is a "broad-brush estimate" that was developed "without an underlying model or detailed calculations." Enbridge also acknowledged that it cannot "break apart this reduction factor and explain what percent is attributable to DSM or what percent is attributable to building demolitions and the like."

Transcript Vol. 5, p. 24 [Compendium, tab 3]

30. This lack of an underlying model or detailed calculations invalidates Enbridge's entire forecast. Again, the Reduction Factor is intended to "capture *all* of the variables affecting both new customers and existing customers" (emphasis added). Therefore, *all* variables (except the growth from new customers) are accounted for in Enbridge's forecast *through an unexplained broad-brush estimate arrived at without an underlying model or calculations*. The resulting forecast is not sufficiently reliable to satisfy Enbridge's burden in justifying this $686.5 million project.

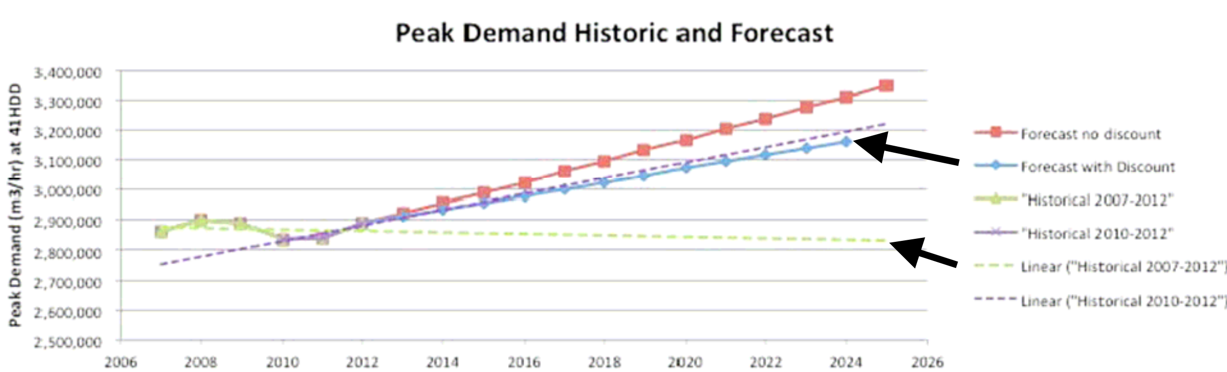
Transcript Vol. 5, p. 14 ln. 12-15 [Compendium, tab 3]

31. In addition, Enbridge's inability to break apart and quantify the component elements of the Reduction Factor effectively deprives the parties from the ability to assess and challenge the reasonableness of Enbridge's assumptions on those component elements. For example, the parties cannot challenge Enbridge's assumptions on the expected declines in demand resulting from building demolition, improved efficiencies occurring outside Enbridge's DSM programs, more stringent building codes, and so on. This is yet another reason why Enbridge's forecast is inadequate.

Inconsistency with Historic Demand Trends

32. Enbridge's demand forecast is also inconsistent with historic demand trends.

33. First, peak hour demand in the GTA has been relatively constant in the GTA Influence Area. The below chart (excerpted from the evidence of Enerlife Consulting Inc.) compares the growth trend forecast by Enbridge and the historic trend obtained from the derived normalized peak demand data provided by Enbridge in I.A4.EGD.ED.3. As the chart indicates, the normalized peak hour demand in the past six years shows a slightly *declining* trend (the dotted green line). However, Enbridge's forecast predicts a very significant *upward* trend (the blue line with diamond shaped markers).



Enerlife Consulting Report p. 17 (Ex. L.EGD.ED.1) [Compendium, tab 14]

34. When questioned on the Enerlife chart during the hearing, Enbridge acknowledged that the data was represented accurately, but rebutted the relevance of the chart by (i) asserting that the six-year time frame was too short and (ii) making reference to the trend data provided by Enbridge in Exhibit A, tab 3, schedule 5.

Transcript Vol. 5, p. 14 ln. 12-15 [Compendium, tab 3]

35. Regarding the first issue, Enerlife used six years of data because Enbridge only provided six years of data (despite a more expansive request). Enbridge indicated that changes in data collection methods in earlier years made year-to-year comparisons irrelevant for the earlier data. In response to Environmental Defence interrogatory nos. 3 and 5, Enbridge specifically stated as follows:

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> **Data has only been provided for 2006** onward as EGD implemented a new load gathering system. Prior to 2004, load gathering was completed on a legacy main frame system and the archived data is not readily accessible. From 2004 to 2006 there were **numerous changes in customer classifications which make year to year comparisons irrelevant** due to changing base data. (emphasis added)

Interrogatory Response I.A4.EGD.ED.5 [Compendium, tab 10]

Interrogatory Response I.A4.EGD.ED.3 [Compendium, tab 11]

36. The Enerlife chart focuses on the most relevant time period because the earlier data, according to Enbridge, is unreliable.

37. However, even if reliable data for the earlier period is available, it cannot be argued that the trend from the past six years of data (which is normalized to account for temperature variation) would be unrepresentative by an order of magnitude sufficient to bring it in line with Enbridge's forecast. As the above chart shows, the difference between the historic trend and Enbridge's forecast is very large.

38. Furthermore, the declining trend over the past six years is not the simply result of customer losses or declining average industrial consumption due to the 2008 recession. Over the past six years, there have been *no* year-over-year declines in the number of Enbridge's GTA customers for any sector (residential, commercial, apartment, or industrial). The number of customers for each sector steadily increased over those years. Furthermore, the declining average use trends by sector (see paragraph 27 above) show that industrial use is declining the *slowest* as compared to other sectors, which is inconsistent with a hypothesis that the 2008 recession caused the declining trend over the past six years.

Interrogatory Response I.A4.EGD.ED.4 [Compendium, tab 12]

Undertaking Response JT2.27 [Compendium, tab 7]

39. Enbridge also responded to the Enerlife historic trend chart by pointing to the data in Enbridge Exhibit A, Tab 3, Schedule 5. However, of the five relevant figures, Figures 1, 2, and 4 relate to the Central Weather Zone portion of the Enbridge service area, not to the GTA Project Influence Area. It is worth noting that Figure 1, which shows an increasing trend in the un-normalized annual gas demand in the Central Weather Zone

appears to conflict with the data for the GTA Project Influence Area, which shows a *declining* trend in the un-normalized annual gas demand.

Application Excerpt re Natural Gas Demand (Exhibit A, Tab 3, Schedule 5), Figures 1-5 [Compendium, tab 16]

Enerlife Consulting Report (Ex. L.EGD.ED.1), p. 18 [Compendium, tab 14]

40. Only Figures 3 and 5 relate to the GTA area. These are addressed below.

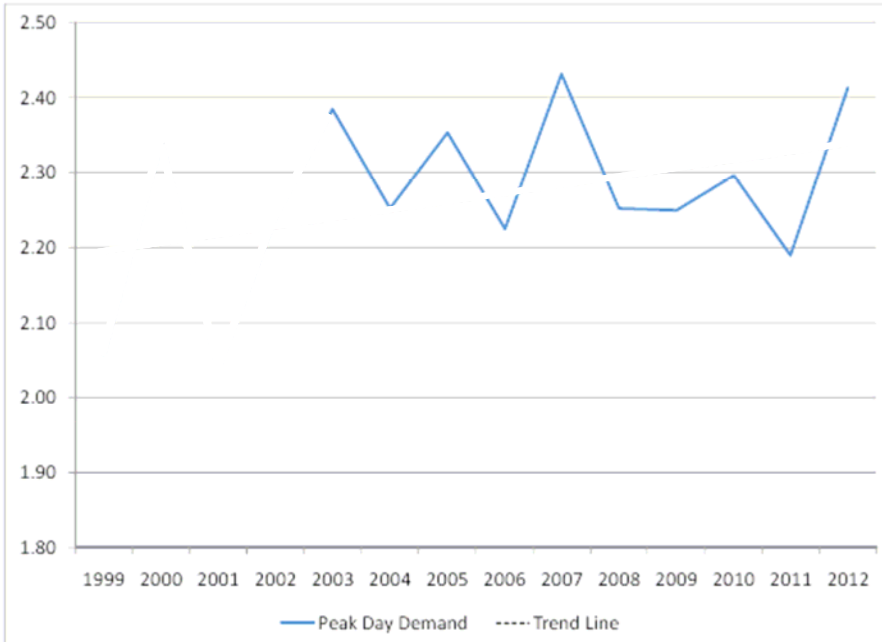
41. Figure 3 is not inconsistent with and does not invalidate the Enerlife historic trend chart:

a. First, it presumably uses data that is subject to the data limitations discussed in paragraph 35 above, which make "year to year comparisons irrelevant" for peak hour data prior to 2006.

b. Second, it shows the peak *day* demand, not the peak hour demand used for system planning purposes.

c. Third, the 14-year time period appears to be have been arbitrarily chosen and is unrepresentative. The six years of *reliable* data provided by Enbridge above show a declining trend. Also, the past 10 years of data show a relatively stable and (perhaps even declining) peak day trend. The below chart is a reproduction of Figure 3 showing only the past 10 years (i.e. with the first four years and the 14 year trend line removed). It shows a relatively stable or declining demand.

Figure 3: Normalized Peak Day Demand – GTA Project Influence Area (PJs)



42. Figure 5 shows that demand in the GTA has become more "peaky" over the past 14 years. However, no analysis is provided to (1) assess whether this trend is expected to continue (it appears to have dropped off in recent years), (2) qualitatively or quantitatively assess the magnitude of impact of the increasing "peakiness" on overall peak demand growth, or (3) compare this impact with other factors, such as the overall declining annual demand. Without this further analysis, the mere statement that demand is becoming more peaky does not validate Enbridge's demand forecast.

43. Enbridge's demand forecast is inconsistent with historic demand trends based on the past six years of *reliable* data or based on the past ten years of data.

Disregard (and Inconsistency with) Ontario's GHG Emission Reduction Targets

44. Enbridge's demand forecast disregards and is completely inconsistent with the Government of Ontario's GHG reduction targets and initiatives.

45. First, Enbridge did not consider the Government of Ontario's GHG emission reduction targets or initiatives in developing its demand forecast. Mr. Naczynski, who was responsible for developing the forecast, admitted on cross-examination that he was not

even aware of the actual targets. Nor was he aware of the Government of Ontario's projected GHG emission reductions from industrial and commercial natural gas DSM programs. Nor did Enbridge consider whether the Government of Ontario would look to the natural gas sector for further greenhouse gas reductions in addition to what it is currently forecasting to address the gap it faces in meeting its targets.

Transcript Vol. 5, p. 25 ln. 8-28 to p. 26 ln. 1 (re overall targets), p. 28 ln. 1-17 (re natural gas initiatives) & p. 31 ln. 23 to p. 32 ln. 2 (re the additional gap) [Compendium, tab 3]

46. It is therefore no surprise that the resulting demand forecast is completely inconsistent with the Government of Ontario's GHG policies. The project is justified on an assumption of continued overall growth in demand and *no* growth in DSM. In contrast, Ontario's GHG policies call for significant *net* reductions in natural gas use and increased natural gas DSM.

47. The growth in *peak* demand forecast by Enbridge implies that *annual* demand will also grow. There is a positive correlation between annual and peak demand. As stated by Enerlife Consulting, "Enbridge uses linear interpolation between annual consumption to derive peak hourly data, which supports the correlation between annual volume and peak hourly demand." Enbridge also assumed that current DSM would simply continue at existing levels.

Enerlife Consulting Report, p. 18 (Ex. L.EGD.ED.1) [Compendium, tab 14]

Interrogatory Response I.A4.EGD.ED.14 [Compendium, tab 15]

48. In contrast, Ontario's GHG policies call for significant *net reductions* in natural gas use in the future and *increased* natural gas DSM. Overall, Ontario's GHG policy calls for the following reductions in GHG emissions relative to 1990 levels (1) 6% by 2014, (2) 15% by 2020; and (3) 80% by 2050. Ontario's 2012 Climate Change Progress Report includes a list of initiatives to achieve those targets, including very substantial projected net reductions specifically from natural gas DSM programs.[4]

Government of Ontario, *Ontario's Action Plan On Climate Change*, August 2007, p. 6 [Compendium, tab 19]

---

[4] Ontario is projecting reductions of .6 MT and 1.0 MT from industrial natural gas DSM by 2014 and 2020 respectively. It is also projecting reductions of 1.6 MT and 2.9 MT from non-industrial buildings, including from natural gas DSM, by 2014 and 2020 respectively.

Government of Ontario, *Climate Change Progress Report*, 2012 (Technical Appendix A), p. 12 [Compendium, tab 21]

Transcript Vol. 5, p. 25 to 28 [Compendium, tab 3]

49. The reductions projected by Ontario are *net* reductions relative to 1990 levels. They therefore require that *overall natural gas consumption* decrease in Ontario. To achieve net reductions relative to 1990 levels, DSM must offset customer growth *and* lead to further reduction so that the overall emissions decrease. For example, Ontario projects 1 MT in net reductions from industrial natural gas DSM by 2020. That requires that enough industrial DSM be implemented to (1) offset demand growth, *and* (2) provide *additional* demand reductions to achieve the *net* 1 MT reductions.

50. Furthermore, the above-referenced GHG reduction initiatives still leave Ontario far short of its targets. Even if all of the projected reductions from the natural gas DSM programs and other initiatives are achieved, Ontario will still be 9% (3 MT) short of its 2014 target and 40% (28 MT) short of its 2020 target. Very large GHG emission reductions are needed in addition to the initiatives in the *Climate Change Progress Report*. As Paul Chernick noted during the hearing, Ontario will need to look to natural gas DSM to help close the gap:

> So even in the unlikely event that all the other emissions were eliminated, including all the natural gas used in electric generation, all the coal, all the oil, all the transportation, Ontario can't meet its greenhouse gas target unless the non-generation natural-gas use is reduced by least 23 percent, because it's now about 45 megatonnes, and the total allowed is 35. And of course, you're not going to meet a zero target for everything else, so the reduction would have to be even more than the 23 percent.

Transcript Vol. 7, p. 50 [Compendium, tab 22]

Government of Ontario, *Climate Change Progress Report*, 2012 (Technical Appendix A), p. 10 [Compendium, tab 21]

Enbridge Response to Environmental Defence Interrogatory No. 5 in EB-2012-0394 (Re: Natural-Gas Related GHG Emissions) [Compendium, tab 20]

Transcript Vol. 5, p. 26 & 30-32 [Compendium, tab 3]

51. Again, Enbridge’s project is justified on an assumption of continued growth in overall demand and no growth in DSM whereas Ontario’s GHG policies call for the opposite. If the Board approves this project and Ontario even comes close to implementing its GHG

emission policies, the GTA consumers will be saddled with unnecessary and expensive excess capacity.

Conclusion re Demand Forecast

52. For those reasons – including the flaws in Enbridge's demand forecast methodology, the inconsistency with historical trends, and the inconsistency with Ontario's GHG policies – Enbridge's demand forecast overestimates growth and is completely unreliable.

Demand Growth can be Completely Offset by DSM

53. Even if Enbridge's demand forecast is taken as given, all demand growth can be easily offset with increased DSM. This can be achieved through increases in Enbridge's existing programs. However, the adoption of the programs proposed by Ian Jarvis and Chris Neme would yield even greater results. These submissions address first the DSM potential based on Enbridge's existing DSM model followed by an assessment of the models by Mr. Jarvis and Mr. Neme.

DSM Potential Based on Enbridge's own Estimates and Existing Programs

54. According to Enbridge's own data, forecast demand growth in the GTA area can be more than offset simply by increasing Enbridge's existing DSM programs. This would require an incremental DSM budget of approximately twice the existing DSM budget for the GTA area. According to Enbridge's estimates, the incremental DSM budget required each year would be approximately $34 million (subject to inflation).

Summary of Enbridge's DSM Evidence [Compendium, tab 6]

Transcript Vol. 5, p. 32 - 37 [Compendium, tab 3]

Transcript, Tech. Conf. (June 13), p. 170 ln. 14 to p. 172 ln. 12 [Compendium, tab 23]

Interrogatory Response I.A4.EGD.ED.14 (Re: DSM Needed to Offset Growth) [Compendium, tab 15]

55. The *net* benefits (i.e. with the costs netted out) from this incremental DSM would amount to approximately $140 million per year, or $1.7 billion cumulatively from 2014 to 2025.

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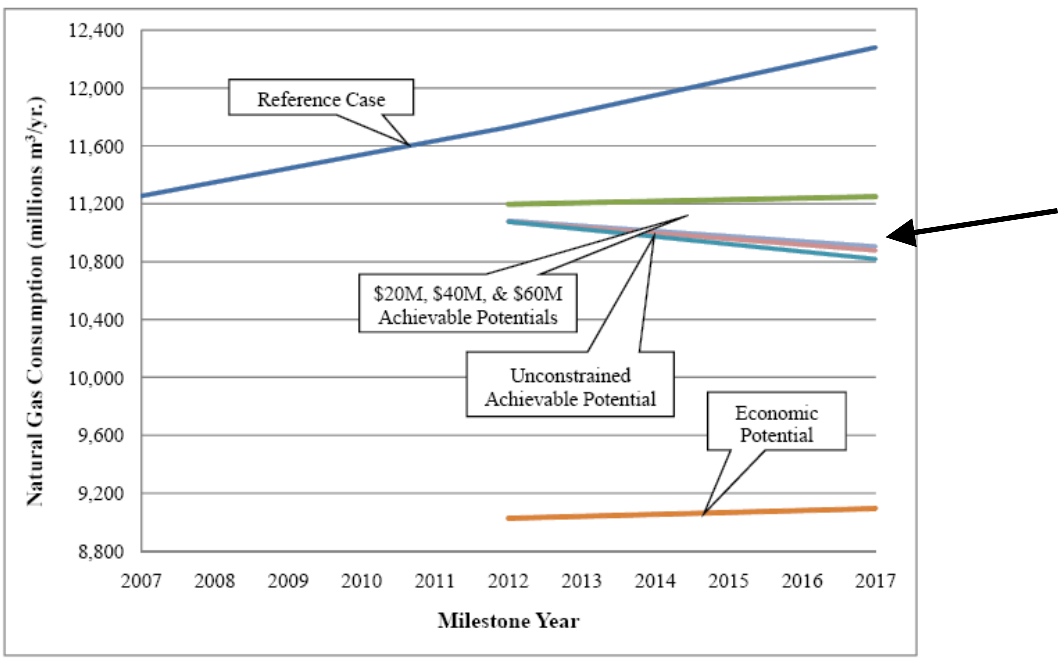
Therefore, growth could be offset through a solution that comes with no net costs, and instead, provides very significant net benefits.

Summary of Enbridge's DSM Evidence [Compendium, tab 6]

Transcript Vol. 5, p. 32 - 37 [Compendium, tab 3]

56. In 2008, Marbek Consulting estimated that Enbridge's overall consumption growth could be offset with DSM. This Marbek report is Enbridge's own evidence and Enbridge expressly supports the conclusions in the report. The below chart from the Marbek report compares a reference case of quickly increasing consumption to various DSM scenarios. The scenarios with an DSM budget of $40 million or higher show a steadily *declining* consumption for the total Enbridge Service Area (the $40 million scenario is indicated by the light blue line directly above the $60 million scenario indicated in pink).

Exhibit 2.1: Graphic of Forecast Results for the Total Enbridge Service Area – Annual Natural Gas Consumption



Marbek Consultants, *Natural Gas Energy Efficiency Potential: Update 2008: Residential, Commercial and Industrial Sectors, Synthesis Report* (I.A4.EGD.ED.14, attachment 1), p. 10 [Compendium, tab 24]

Transcript Vol. 5, p. 37 ln. 21 to p. 39 ln. 18 [Compendium, tab 3]

57. Enbridge confirmed on cross-examination that Environmental Defence's reading of the chart in the Marbek report is correct. It also confirmed that it still supports the conclusions in the Marbek report. However, Enbridge pointed out that the Marbek report focuses on annual (not peak) demand over the total Enbridge service area (not just the GTA) and only for a test period. However, there is nothing to suggest that the conclusions in the report would not apply to the GTA area or that there will not be a positive correlation between annual and peak demand in the future. At the very least, the Marbek report would be directionally accurate.

Transcript Vol. 5, p. 37 ln. 21 to p. 38 ln. 4 & p. 39 ln. 11-18 [Compendium, tab 3]

58. As discussed in the following section (see paragraph 64 onward), Environmental Defence submits that there is considerably more DSM potential in the GTA area than what Marbek estimated. However, even the Marbek report (i.e. Enbridge's own evidence) confirms that consumption can be offset with DSM. Furthermore, the budget estimates provided by Marbek ($40 to $60 million per year for the entire franchise area) are considerably lower than the growth-offsetting budget estimated by Enbridge for this proceeding.

Marbek Consultants, *Natural Gas Energy Efficiency Potential: Update 2008: Residential, Commercial and Industrial Sectors, Synthesis Report* (I.A4.EGD.ED.14, attachment 1), p. 10 [Compendium, tab 24]

59. It should be noted that DSM was screened out as an alternative mainly because it could not address the other drivers of Enbridge's project, such allowing an additional 600 TJs of gas to flow from the Parkway Gate Station to the east of the city to facilitate the switch from long- to short-haul. The other drivers of the project are addressed below. However, with respect to demand growth, Enbridge's *own data and evidence* shows that existing demand can be met with DSM.

Transcript, Tech. Conf. (June 13), p. 170 ln. 14 to p. 172 ln. 12 [Compendium, tab 23]

Interrogatory Response I.A4.EGD.ED.14 (Re: DSM Needed to Offset Growth) [Compendium, tab 15]

Interrogatory Response I.A4.EGD.ED.18 (Re: Screening Out DSM) [Compendium, tab 25]

60. Finally, DSM can be relied on to address peak demand needs even though it may be the case that Enbridge has not established a "verified relationship between DSM efforts and

peak load reductions." On cross-examination, Enbridge acknowledged that its estimate of the peak load reductions resulting from its DSM programs is "the best estimate [it] could come up with" and that it made "best efforts." Although it did not establish an exact relationship, this does not invalidate its estimates (in the very least, directionally) and does not mean that DSM should be ruled out as an alternative. This is particularly the case seeing as Enbridge has an incentive to *underestimate* the impact of its DSM programs on peak demand (see paragraphs 206 to 209 below regarding Enbridge's incentives).

Transcript Vol. 5, p. 4 ln. 12-4 & p. 33 ln. 21 to p. 34 ln. 34 [Compendium, tab 3]

61. Furthermore, a review of Enbridge's DSM programs by the Energy Futures Group found that "the vast majority of the Company's DSM savings are being produced by measures that save energy at peak hours."

Chris Neme & Jim Grevatt (Energy Futures Group), *DSM Potential in the GTA*, Exhibit L.EGD.GEC.2, p. 5

62. In addition, Enbridge's failure to establish a precise and verified relationship between its DSM programs and peak demand should not be used as an argument *against* DSM as an alternative or *against* Environmental Defence's case. Enbridge has the onus to establish that its project is the preferred alternative. Environmental Defence and the Green Energy Coalition repeatedly requested precise estimates of the impact of Enbridge's DSM programs on peak demand. Enbridge's failure to establish a precise relationship is a factor that goes *against* Enbridge's case and its assessment of alternatives, rather than an argument against DSM as an alternative to this project.

Transcript, Tech. Conf. (June 13), p. 169 ln. 27 to p. 170 ln. 13 [Compendium, tab 23]

63. In sum, according to Enbridge's own estimates, based on an expansion of its existing programs, load growth can be offset in the GTA area with an incremental DSM budget that will provide *net benefits* of approximately $140 million per year, or $1.7 billion cumulatively.

DSM Potential Based on Ian Jarvis' and Chris Neme's Estimates and Programs

64. The evidence of Ian Jarvis (President and founder of Enerlife Consulting) and Chris Neme (Principal and co-founder of Energy Futures Group) show that there is considerably more cost-effective and achievable DSM potential in the GTA area than Enbridge has estimated. This potential can not only offset growth, but can produce very significant *declines* in peak demand in the GTA area.

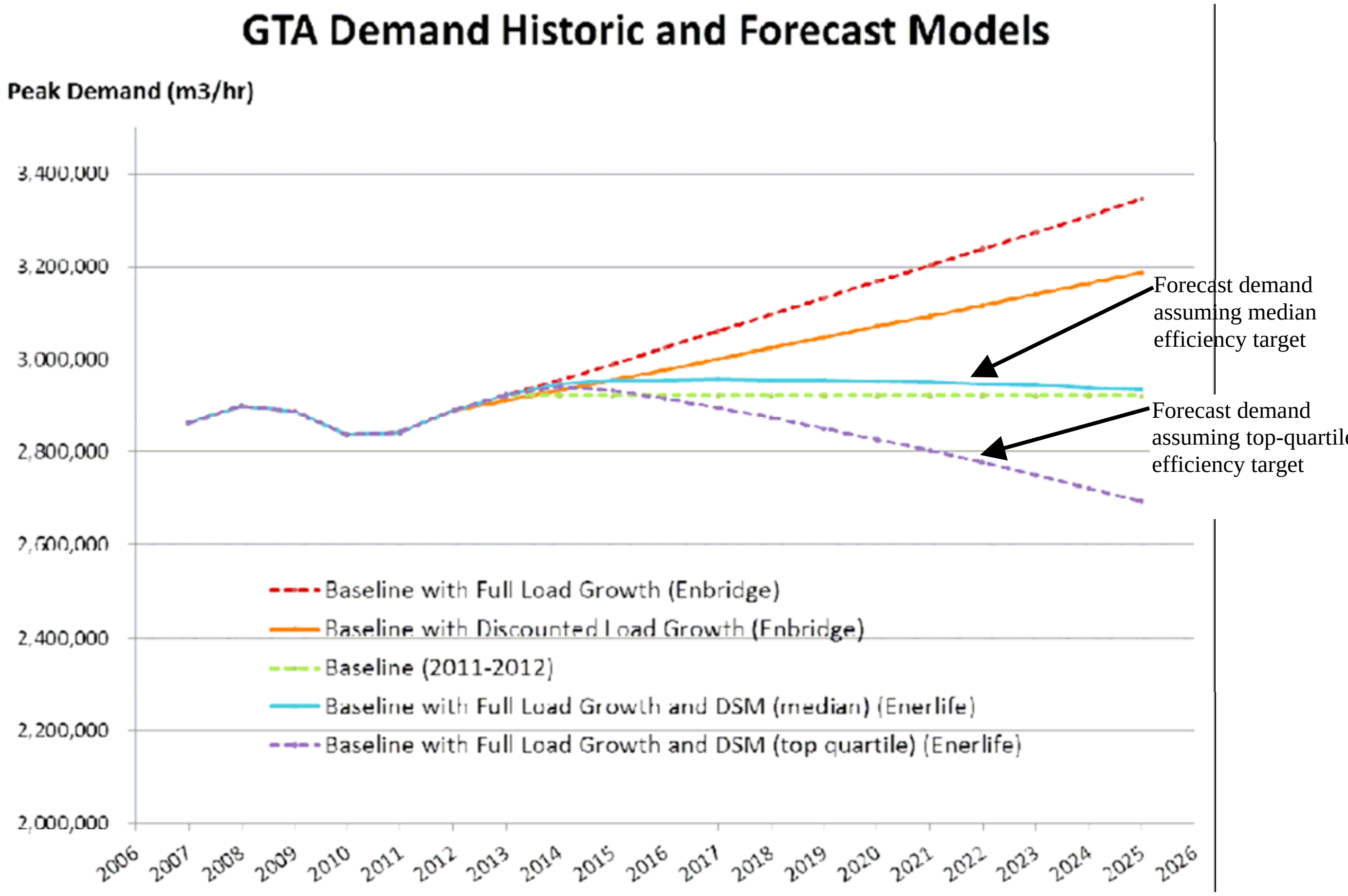
65. The DSM expert retained by the Green Energy Coalition, Chris Neme, has more than 20 years of experience with the design, implementation and evaluation of energy efficiency programs. Mr. Neme's evidence provided an estimate of the achievable cost-effective residential DSM potential in the GTA area, including a realistic ramp up. His estimates were based on a review of the DSM savings achieved in other jurisdictions. He found that other jurisdictions are achieving significantly more savings than Enbridge is forecasting and have demonstrated a "rapid ramp up" of their DSM programs. Mr. Neme's evidence will be discussed in more detail in the submissions of the Green Energy Coalition.

66. The DSM expert retained by Environmental Defence, Ian Jarvis, has been at the forefront of the building energy efficiency sector for over three decades. For example, Mr. Jarvis was a Partner and Director at Engineering Interface Ltd until 1984. During that time he was involved in "pioneering work" around energy analysis of existing buildings. Until 1999 Mr. Jarvis was the President, Chair, and Chief Executive Officer of the energy performance contracting company Rose Technology Group. In that position he oversaw a staff of approximately 200 and tripled revenues to $52 million over four years. Mr. Jarvis is currently the President of Enerlife Consulting, which he founded in 2001.

Transcript Vol. 7, p. 57-60 [Compendium, tab 22]

67. Mr. Jarvis and his firm estimated the achievable cost-effective commercial and apartment DSM potential in the GTA area, including a realistic ramp up. The Enerlife report also estimates and charts the overall DSM potential in the GTA area using (i) the data provided by Mr. Neme for residential and industrial DSM and (ii) Enbridge's demand growth forecast (prior to the application of the "reduction factor"). Enerlife found that the

DSM potential for all four sectors is sufficient to steadily reduce demand over time. The results are summarized in the below chart.



Enerlife Consulting, *Evidence Concerning Demand Side Management Potential in GTA* (L.EGD.ED.1), p. 8 [Compendium, tab 14]

68. As discussed below, Enerlife's data and analysis show that it is possible to bring commercial and apartment buildings up to at least the top-quartile of each sector in terms of natural gas use per square foot. The above chart shows the overall GTA area DSM potential based on top-quartile attainment (the declining dotted purple line) and median attainment (the slightly declining light blue line).[5] In both scenarios, demand steadily declines at a constant rate after a 3-4 year ramp up period.

[5] In both scenarios the residential and industrial DSM potential is the same. These are simply inputs for the numbers provided by Chris Neme. The only change is in the

69. Enerlife's approach differs from the approach taken by Marbek in its DSM potential report (discussed in paragraph 56 to 58 above) and by Enbridge in its overall DSM program. That difference is summarized by Enerlife as follows:

> The Performance-Based Model presented in this evidence for calculating commercial and apartment DSM potential is derived from Enerlife's substantial and growing database of actual energy performance data for buildings. The approach is consistent with a growing number of provincial and national programs. It takes a different approach from the DSM Potential Study conducted for Enbridge in 2009 by Marbek Resources Consulting Inc. **Rather than relying on technologies, assumed penetration levels and engineering calculations, the Performance-Based Model analyzes actual, benchmarked energy use of different building types and establishes the potential savings due to all buildings reaching intensity levels already achieved by one half (median) or one quarter (top-quartile) of the peer group. …**
>
> **Measures to improve efficiency in high gas intensity buildings go beyond those included in Marbek's DSM Potential Study and are typically site-specific equipment repairs, upgraded control of buildings systems, and testing, tuning and rebalancing of heating plant and systems.** Such projects show generally good Total Resource Cost ("TRC") test values, can be implemented quite quickly, and serve to improve building performance as well as energy efficiency. They require a systematic approach to identify target buildings, engage owners, isolate the inefficiencies, implement the necessary improvements and verify the results. (emphasis added)

Enerlife Consulting, *Evidence concerning Demand Side Management Potential in GTA* (L.EGD.ED.1), p. 2-3 [Compendium, tab 14]

70. In other words, rather than focus on the adoption of energy efficient equipment (e.g. new, more efficient boilers), a benchmarking approach identifies the least efficient buildings and implements site-specific solutions that often involve relatively low cost operational measures. In this way, a utility can use its wealth of billing and customer data to focus on areas where the greatest and least costly gains are available. According to Enerlife, Enbridge is "already starting down the path on this new, data-driven performance-based conservation programming," but additional focus on a benchmarking approach is needed to achieve the full potential.

Enerlife Consulting, *Evidence concerning Demand Side Management Potential in GTA* (L.EGD.ED.1), p. 2-3 [Compendium, tab 14]

71. Ian Jarvis and Enerlife are very confident that top-quartile results are attainable. These results are possible in part because there are many inefficient buildings, including some in which 3 to 5 times the amount of gas is being used compared to what is needed and is

already achieved by comparable buildings. In other words, the inefficient nature of the building stock presents significant opportunities.

> **Enerlife Consulting, *Evidence concerning Demand Side Management Potential in GTA* (L.EGD.ED.1), p. 13 [Compendium, tab 14]**

72. In addition, the top-quartile results have been confirmed by a number of peer-reviewed pilot projects, by Enerlife's multi-year database of energy use by buildings (which is the largest of its kind in Canada), and by Enerlife's own work with many of its clients. Mr. Jarvis describes this work as follows:

> [F]or our own work, when we're working on individual projects … **we've yet to find a building that will not meet and exceed those targets. We work more generally to the top decile level.**
>
> So I think the gas targets presented in these numbers have been pretty well road-tested, and to date we've not found a condition within buildings, notwithstanding the comments about the marathon runners and so on, we've yet to find buildings that cannot reach those kind of target levels. (emphasis added)

> **Transcript Vol. 7, p. 62-63 [Compendium, tab 22]**
>
> **Enerlife Consulting, *Evidence concerning Demand Side Management Potential in GTA* (L.EGD.ED.1), p. 4 [Compendium, tab 14]**

73. However, even if Enbridge were to only aim for median efficiency levels, that would be sufficient to offset growth in the GTA area.

74. Enerlife estimates that the DSM potential identified in its report could be achieved for a very modest budget of approximately $23.5 million per year for the top-quartile results or only approximately $14 million per year for the median target (including customer incentives). Furthermore, the measures needed to improve inefficient buildings, as discussed in the Enerlife report, are generally inexpensive and have good TRC test values. Enerlife estimates that a performance-based program would result in hundreds of millions of dollars in net savings in avoided gas use alone.[6]

> **Enerlife Consulting, *Evidence concerning Demand Side Management Potential in GTA* (L.EGD.ED.1), p. 3 [Compendium, tab 14]**
>
> **Interrogatory Response M.ED.EGD.15 [Compendium, tab 27]**
>
> **Interrogatory Response M.ED.BdStaff.1 [Compendium, tab 28]**

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[6] Enerlife's net savings estimates cannot be considered to be a complete TRC analysis as they only include avoided gas costs. They do not incorporate other avoided costs such as avoided capital expenditures.

75. Chris Neme also concluded that the residential programs discussed in his report would have positive TRC values (i.e. they would be profitable). Overall, he expects that the proposed significant DSM expansion would have net economic benefits of *at least* $1 billion over the next 12 years.

Chris Neme & Jim Grevatt (Energy Futures Group), *DSM Potential in the GTA*, Exhibit L.EGD.GEC.2, p. 13-14

76. Enerlife Consulting and the Energy Futures Group did not intend to produce a comprehensive DSM program complete with detailed incentive structures and TRC estimates. That is clearly Enbridge's role and evidentiary burden. Instead, this evidence is intended to show that there is significant, additional, untapped, cost-effective, and achievable DSM potential in the GTA area that can result in considerable year-over-year reductions in demand *and* net savings for consumers. Supply-side investments to address load growth cannot be justified while these highly profitable DSM alternatives exist.

<u>The Project is not Urgent and is not Needed to Meet Demand in the Winter of 2015</u>

77. Enbridge has stated that this project must urgently be built in order to meet short-term demand growth. In particular, Enbridge asserts that its "forecast is that, in the absence of the proposed facilities, it will not be able to meet its *design day* conditions at Station B during the 2015/16 winter" (emphasis added). As detailed below, there is no urgency to build the project because Enbridge can meet its 2015/2016 demand by (i) using currently contracted interruptible load (which is not accounted for in its design day) *or* (ii) implementing additional DSM and/or contracting for additional interruptible load. In other words, there are many low or no cost options at Enbridge's disposal to meet needs in the 2015/2016 heating season and for the short term thereafter.

Enbridge Argument in Chief, October 21, 2013, p. 23

Short-Term Demand can be Met with Currently Contracted Interruptible Load

78. Enbridge can meet its short-term demand with currently contracted interruptible load.

79. Enbridge assesses its capacity needs in relation to a "design day" with certain characteristics, such as cold temperatures. The purpose is to ensure that capacity will be

sufficient to meet peak demand even on unusually cold winter days. However, surprisingly, Enbridge's design day assumes that customers with interruptible service (i.e. whose gas can be interrupted on unusually cold days when peak demand spikes) will continue to consume gas at peak times. In other words, the design day assumes that interruptible loads are "on" rather than "off," even at peak times. Therefore, these interruptible loads can still be used to address spikes in demand if needed.

Transcript Vol. 7, p. 17 ln. 6-15 [Compendium, tab 22]

80. According to Enbridge, there is approximately 100 10^3 m^3/hr of interruptible load in the GTA project influence area. If this interruptible load is utilized on the rare high peaks faced by Enbridge, the soonest that a deficit could arise is in the winter of 2017/2018 (again, this conservatively assumes that Enbridge's forecast is accepted, *no* increases in DSM, and *no* additional interruptible service contracts). The below table lists the forecast demand (Ex. A-3-4 p. 9), the capacity of Enbridge's system (I.A4.EGD.ED.17), the interruptible load (Ex. A-3-7 p. 4, and confirmed by Enbridge counsel), and the resulting supply capacity/deficit. Again, currently contracted-for interruptible loads can address the deficits forecast by Enbridge for the winters of 2015/2016 and 2016/2017.

Enbridge's System Supply Surplus / Deficit with Interruptible Loads Off (10^3 m^3/hr)				
Year	Forecast Peak Demand	System Capacity	Interruptible Volumes	System Capacity Surplus/Deficit
2015	3,093	3,037	100	44
2016	3,117	3,037	100	20
2017	3,141	3,037	100	-4

Application Excerpt re Forecast Peak Hour Demand (Ex. A-3-4, p. 9) [Compendium, tab 29]
Interrogatory Response I.A4.EGD.ED.17 [Compendium, tab 30]
Application Excerpt re Interruptible Volumes (Ex. A-3-4, p. 4) [Compendium, tab 31]
Email from Enbridge Counsel re Interruptible Volumes [Compendium, tab 32]

81. The above table accounts for the interruptible load for the entire GTA project influence area, not only in the area around Station B (in eastern downtown Toronto, where Enbridge is forecasting the supply deficit to arise). This is a logical and valid assumption because Enbridge has justified the need for the project based on a growth forecast for the entire GTA project influence area and has *not* provided a forecast focusing only on

growth in the area around Station B. Therefore, customer additions far away from Station B in the north or west of the city count toward the deficit Enbridge is forecasting at Station B. Because of this, Enbridge has acknowledged that the DSM needed to address demand growth could be spread out across the GTA and need not to be localized around Station B. The same logic applies to interruptible loads.

Transcript, Technical Conference (June 13, 2013), p. 174 ln. 23 to p. 175 ln. 25 & p. 177 ln. 26 to p. 178 ln. 24 [Compendium, tab 23]

Interrogatory Response I.A4.EGD.ED.24 [Compendium, tab 33]

82. However, regardless, there is far more than enough interruptible load in the area served by Station B to address the deficit expected by Enbridge at that expected location. As a result of Enbridge's overall forecast, a deficit of 15 10^3 m^3/hr (on a design day) is expected at Station B in the winter of 2015/2016. However, there are 47.5 10^3 m^3/hr in interruptible loads available in the area served by Station B. This is more than is needed to address the demand on those few peak days (if they even arise). Enbridge has not provided the expected deficit at Station B beyond 2015/2016, but it appears that interruptible load would be sufficient to meet the demand for an additional few years seeing as the surplus (with interruptible loads "off") is a healthy 32.5 10^3 m^3/hr in 2015/2016.

Interrogatory Response at I.A1.EGD.BOMA.25, p. 2 [Compendium, tab 34]

Email from Enbridge Counsel re Interruptible Volumes [Compendium, tab 32]

Transcript Vol. 7, p. 17 ln. 6-15 [Compendium, tab 22]

83. It is worth noting that Enbridge would only rarely (if ever) need to rely on interruptible loads to meet demand. Enbridge acknowledges that its demand is "extremely peaky," that "the vast majority of time the demand is far below the overall capacity," and that "the peaks are short-lived and few in number." The below chart of the hourly gas demand in the GTA area over 2011/2012 shows how extreme, infrequent, and short-lived the hourly peaks in demand are.

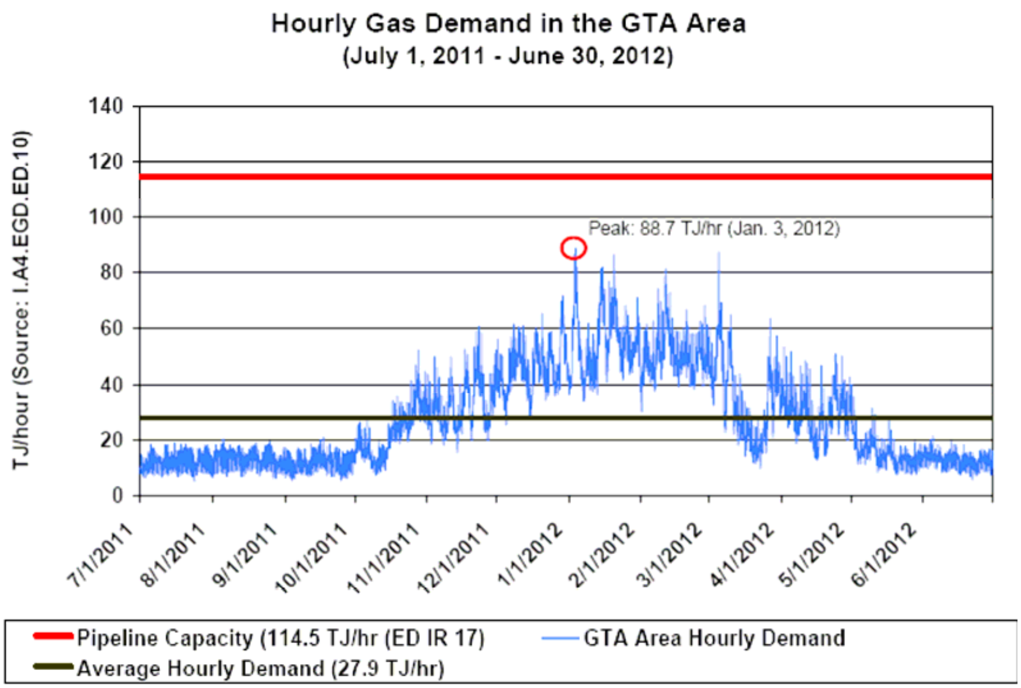

Chart of Hourly Gas Demand in the GTA Area (Ex. K4.5, Tab 1, confirmed accurate by Enbridge at Transcript Vol. 4, p. 120) [Compendium, tab 4]

Transcript Vol. 4, Sept. 19, p. 120 ln. 25 to p. 121 ln. 7 [Compendium, tab 35]

84. Not only are the peaks extreme, infrequent, and short lived – there is no guarantee that the *design day* peak will be reached at all. Again, the design day represents an unusually cold day. Therefore, there is a good chance that the 2015/2016 demand can be met *without* relying on interruptible loads at all. However, if a design day peak does occur, interruptible loads could be relied on, and would only be needed for very short periods.

Short-Term Demand can be Met with Incremental DSM and/or Interruptible Load

85. In the alternative, if the Board does not accept the above with respect to the currently contracted-for interruptible load, short-term demand can be met with additional incremental DSM and/or additional interruptible service contracts.

86. Both Mr. Jarvis and Mr. Neme have proposed cautious and conservative 3-4 year ramp up periods for the DSM potential discussed in their reports, which they are confident is readily attainable. The result is illustrated in the chart accompanying paragraph 67 above. If Enbridge commits the resources required to attain top-quartile efficiency levels,

demand peaks in 2014 with the year-over-year declines in demand increasing during the ramp up period. If Enbridge targets only median efficiency levels, demand growth slows significantly during the ramp up period, peaking in 2017, followed by slowly declining demand.[7] In other words, the conservative ramp up periods proposed by Mr. Jarvis and Mr. Neme will provide enough DSM to address Enbridge's capacity concerns in the winter of 2015 and onward, whether median or top-quartile results are targeted.

> **Chris Neme & Jim Grevatt (Energy Futures Group), *DSM Potential in the GTA*, p. 12 (Exhibit L.EGD.GEC.2)**
>
> **Enerlife Consulting, *Evidence concerning Demand Side Management Potential in GTA* (L.EGD.ED.1), p. 8 [Compendium, tab 14]**

87. The ramp-up proposed by Mr. Neme for residential DSM is supported by proven examples in other jurisdictions. The ramp up proposed by Mr. Jarvis for commercial and industrial DSM is supported by Enerlife's and Mr. Jarvis' extensive experience in attaining top-quartile savings with its customers and in pilot projects. It is also based on a strategy to start with the lowest hanging fruit; the ramp up proposed by Mr. Jarvis obtains significant savings in the early years by starting with the largest building owners with the largest potential efficiency gains, easing the transition to a benchmarking and performance-based model.

> **Chris Neme & Jim Grevatt (Energy Futures Group), *DSM Potential in the GTA*, p. 8 (Exhibit L.EGD.GEC.2)**
>
> **Interrogatory Response M.ED.BdStaff.2 & 3 (Re: Ramp Up) [Compendium, tab 36]**

88. Although DSM alone can address the short-term supply deficit forecast by Enbridge at Station B, Enbridge could also contract for additional interruptible load (e.g. by approaching the Portlands Energy Centre, "PEC"). The additional interruptible load could be implemented in lieu of DSM to address short term needs or simply as a supplementary backup for the DSM. We understand that the possibility of further interruptible load will be addressed in more detail in the submissions of the Green Energy Coalition.

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[7] The 2017 peak for the median efficiency level (2,957 10^3 m^3/hr) is considerably lower than the capacity of 3,037 10^3 m^3/hr (see I.A4.EGD.ED.17). Although the Enerlife's forecast does not include Enbridge's two unbundled customers (Enbridge refused to provide that data, see Tech. Conf. Tr. June 13, p. 179 ln. 19-27), the addition of those two customers likely would not be problematic. In addition, the two unbundled customers likely have (or could be approached for) interruptible service.

89. In sum, there is no need to build additional capacity by November, 2015, because the supply capacity deficit forecast by Enbridge at Station B can be met by (i) using currently contracted interruptible load (which is not accounted for in its design day) or (ii) by implementing additional DSM and/or contracting for additional interruptible load.

Conclusion re Demand Growth

90. In sum, for the reasons outlined above, this project cannot be justified in whole or in part based on forecast demand growth. Again, Enbridge's demand forecast overestimates growth and is highly flawed. However, even if the forecast is taken as given, DSM can eliminate all peak demand growth – both in the long and short term, including any supply deficit in the winter of 2015/2016 (if one truly exists).

Entry Point Diversity

91. Enbridge also justifies its proposed project as providing entry point diversity, and thus more security of supply. In particular, Enbridge asserts that its project will:

> Provide entry point diversity by reducing the dependence upon Parkway Gate Station which currently provides more than 50% of the supply to the GTA Project Influence Area and does not have alternate means of supply.
>
> **Application Excerpt re Purpose Summary, p. 1-2 (Ex A-3-1) [Compendium, tab 2]**

92. However, this purpose can be achieved simply by connecting Union's proposed Parkway West Gate Station to the Enbridge system with only a very short pipeline. This would relieve the over reliance on the Parkway Gate Station. Enbridge has expressly acknowledged that this would prevent any distribution customer losses that might result from an outage at the Parkway Gate Station. In response to Environmental Defence Interrogatory No. 35, Enbridge states that:

> the construction of the proposed Parkway West Gate station and associated facilities would allow for a complete shutdown of the existing Parkway Gate Station while still maintaining supply to the distribution system.
>
> **Interrogatory Response I.A1.EGD.ED.35 [Compendium, tab 37]**

93. Therefore, the vast majority of the project is not needed for this purpose.

Gas Supply Savings and Access to Dawn (Addressing both Issue A1 & A3)

94. A major purpose of the proposed project is the alleged gas supply savings. Another related purpose is providing additional “market access” to Dawn gas. However, these purposes are one and the same. Gas is gas. The only benefit of obtaining access to Dawn gas is lower costs (unless this provides more secure upstream supply, which is not the case, as discussed in paragraphs 177 to 179 below).

Application Excerpt re Purpose Summary, p. 1-2 (Ex A-3-1) [Compendium, tab 2]

95. As detailed below, this project will not save customers money. Instead, it will result in significant losses on top of the high cost of the project.

96. This section will address the gas supply savings purpose of the project (issue A1) and the project economics more generally (issue A4), as these are intertwined topics. The following economic impacts of this project are discussed below:

a. TCPL charges would increase, eliminating the savings from switching from long- to short-haul;

b. Consumers would pay the higher Dawn gas prices (and the Dawn-Empress price differential will likely be more than Enbridge is forecasting);

c. The project would not result in additional distribution revenues;

d. Revenues from shippers would likely decline or disappear in the medium term;

e. As a result of the above, the project would be highly uneconomic;

f. The settlement terms would not make the project profitable; and

g. $1.7 billion in net savings would be lost by failing to implement the foregone DSM alternative.

Increased TCPL Charges

97. Enbridge asserts that its customers will obtain savings by switching from long-haul service (from Empress on the TCPL mainline, with its more expensive tolls) to short-haul service (from Dawn). However, a large portion of every dollar "saved" will directly translate into revenue lost by TCPL. This revenue will be made up through increased tolls and through other charges under the settlement terms. These charges will be borne by consumers, thus eliminating the intended savings.

98. TCPL filed evidence detailing the above. It stated as follows:

> [T]he savings that Enbridge and Union claim for their respective projects… will not be realized ….
>
> [T]he projects are likely to represent net costs rather than savings
>
> **Supplementary Evidence of TCPL, August 16, 2013, p. 1 [Compendium, tab 38]**
>
> … Ontario consumers have historically paid increased TransCanada tolls, off-setting the short-term savings that the Ontario LDCs have realized by switching from long-haul to short-haul service on the Mainline. …
>
> [T]he savings that Enbridge and Union (and Gaz Métro) hope to realize with lower transportation costs will evaporate and Ontario consumers will have paid for more expensive Dawn-sourced gas to no benefit resulting in a net loss.
>
> If the projects proceed … **the net revenue reduction experienced by TransCanada would be approximately $400 million per year.** (emphasis added)
>
> **Supplementary Evidence of TCPL, August 16, 2013, p. 4 [Compendium, tab 38]**

99. TCPL's evidence was filed before the settlement terms were reached. However, TCPL confirmed on cross-examination that the above evidence was accurate at the time it was filed. TCPL also confirmed that, after the settlement agreement, the marginal impact of the $400 million per year revenue reduction will still be factored into TCPL's new rates:

> Mr. Elson: … **the settlement agreement, in a sense, eliminates the $400 million per year revenue … shortfall** discussed in the TCPL evidence. Is that roughly accurate, Mr. Schultz?
>
> Mr. Schultz: Well, in that, yes, there won't be a deferral account building with that shortfall in it. **It will be factored into the new set of rates that will be produced and then charged to all customers.**
>
> …
>
> Mr. Elson: … the overall effect of people transitioning from long-haul to short-haul, and in particular **the potential lost revenue, that gets factored into the new rates**; is that right?

Mr. Schultz: **Right**, in that it's used to create what the rates are. (emphasis added)

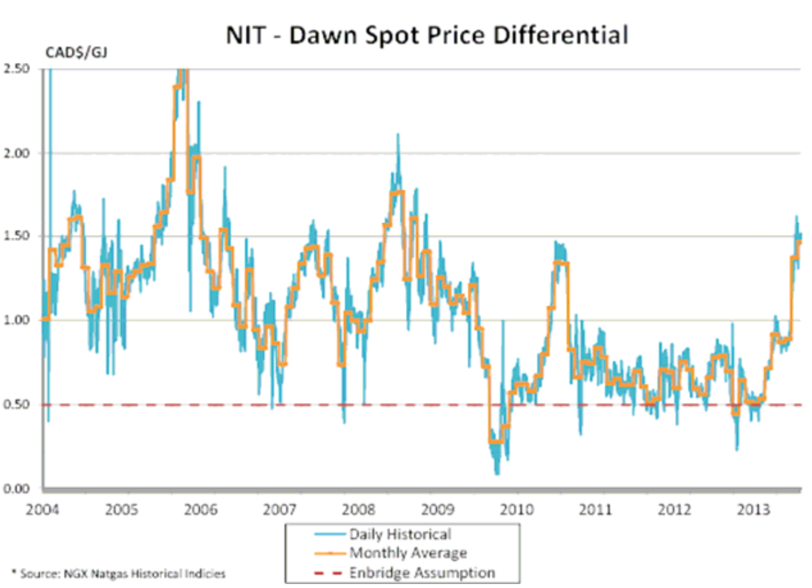
Transcript Vol. 8, Oct. 8, p. 67 ln. 21-28 & p. 72 ln. 1-21 (see also p. 59-65 re accuracy of evidence prior to settlement agreement) [Compendium, tab 39]

100. Although the mechanics are different with and without the settlement agreement, the alleged gas supply savings evaporate when the losses suffered by TCPL from the mainline are passed on to consumers through increased tolls or through payment made under the settlement terms. If anything, the settlement agreement exacerbates the problem by ensuring that consumers will bear a majority of TCPL's losses resulting from the shift from long- to short-haul

Higher Dawn Gas Prices and Price Differential Assumptions

101. While the toll savings will largely disappear, Enbridge's customers will be left paying the higher Dawn gas prices. Enbridge, Union, and TCPL all agree that the Dawn gas price will be significantly higher than the Empress gas price. This is not disputed.

102. However, Enbridge's forecasts an overly optimistic price differential. Enbridge predicts an average price differential of only $0.51 whereas Gaz Metro and Union forecast an average of $0.73 and $0.92 respectively. Based on the below chart, TCPL notes that the current differential of $1.50 is within the historical average.



Supplementary Evidence of TCPL, August 16, 2013, p. 7 [Compendium, tab 38]

103. Enbridge’s assumed price differential is indicated in the above chart as the dotted line far below the historical trend. TCPL provided this chart and the related data to show that (i) “the price differential assumed by Enbridge is overly optimistic” and (ii) “the price differential fluctuates a lot and is unpredictable, which means that the savings predictions are inherently unreliable.”

Transcript Vol. 8, Oct. 8, p. 62 ln. 23 to p. 63 ln. 2 [Compendium, tab 39]

104. Needless to say, the settlement terms have no impact on the price differential issue. If TCPL was correct about the differential prior to the settlement agreement, it continues to be correct today.

Transcript Vol. 8, Oct. 8, p. 73-74 [Compendium, tab 39]

105. This is the largest capital project in Enbridge’s history. The volumes at issue are huge. Therefore, the $1 *per GJ* difference between the forecasts would have a huge impact on the overall economic feasibility on the project.

No Additional Distribution Revenues

106. Enbridge includes over *$4.5 billion* in incremental distribution revenues in its economic feasibility analysis for this project. This is invalid because, as detailed above, the project is not needed in order to address load growth. If the project is not needed to address load growth, the revenue from customer additions cannot be included in the economic evaluation of the project.

Transcript Vol. 6, Sept. 26, p. 6 ln. 19-26 [Compendium, tab 39]

107. The net result of removing the costs and revenues associated with customer additions is a $217.6 million reduction in the net present value of the project.

Application Excerpt re Economic Sensitivity Results (Ex A-3-9, Att.3) [Compendium, tab 42]

Declining or Disappearing Revenue from Shippers

108. Enbridge includes over $471 million in revenues from shippers on Segment A in its economic feasibility analysis. This is based on a 40-year time horizon. Counting these revenues for 40 years is highly speculative and unreasonable for at least three reasons.

Application Excerpt re Economic Sensitivity Results (Ex A-3-9, Att.3) [Compendium, tab 42]

109. First, any number of changes in the demand and supply of gas could reduce or eliminate the demand for shippers on Segment A. Few predicted the recent increases in shale gas production or the resulting losses on the TCPL mainline. Similar changes may occur in the future.

110. Second, there is compelling evidence put forward by the experts for the Council of Canadians ("COC") that shale gas supplies will sharply decline in the next ten years. This evidence will be discussed in detail in the COC's submissions. Although the future forecasts are disputed, in the very least there is considerable uncertainty around the viability of this supply source.

111. Third, it is very possible that the drive to reduce GHG emissions in other jurisdictions will seriously reduce demand for capacity on Segment A. As discussed above, GHG reductions in Ontario will require overall decreases in gas consumption. This is likely the case in other jurisdictions as well.

112. If the revenue from shippers is included only for ten years (until 2024), the net present value of the project would be reduced by $133 million.[8]

Application Excerpt re Economic Sensitivity Results (Ex A-3-9, Att.3) [Compendium, tab 42]
Interrogatory Response I.A3.EGD.ED.44 (Re: Shipper Revenues) [Compendium, tab 43]

Total Impact – Gross Losses for Consumers

113. The result of the above is that consumers will suffer significant losses if the project proceeds. This can be illustrated by (i) examining the expected costs per GJ, (ii) focusing on the TCPL analysis, or (iii) by performing some simple calculations based on Enbridge's economic sensitivity analysis.

[8] The calculation is $667,432,377 (the NPV of the project, base case, from Ex. A-3-9 attachment 3) minus $534,351,214 (the NPV of the project, base case but assuming only 10 years of transportation revenues, from I.A3.EGD (Update).ED.44), which equals $133,081,163.00.

Costs Per GJ

114. During cross-examinations, Union acknowledged that, on average, the impact of switching from long-haul (from Empress) to short-haul (from Dawn) would be as follows:

a. Customers would save $0.48 per GJ ($1.40 in toll savings minus $0.92 from the higher cost of gas from Dawn); and

b. TCPL would lose $1.40 per GJ in revenue.

Transcript Vol. 3, Sept. 17, p. 48 ln. 16-20 & p. 61 ln. 1-5 [Compendium, tab 41]

115. If the TCPL toll savings are taken out of the equation (for the reasons discussed in paragraphs 97 to 100 above), the savings of $0.48 per GJ would become *losses* of $0.92 per GJ. Even if consumers ultimately bear only *half* of TCPL's revenue losses (e.g. because of the settlement terms and/or if TCPL bears part of its losses), consumers would still lose $0.22 per GJ ($0.70 minus $0.92). For consumers just to break even per GJ, TCPL would have to absorb 65.7% of its revenue losses, which is clearly not the case under the settlement agreement.[9] This situation arises because the toll savings must be high enough to overcome the unfavourable Dawn-Empress price differential.

116. The above does not account for the cost of the project. The above losses result only from the fact that the toll "savings" will be more than offset by (i) the price differential between Dawn and Empress and (ii) the additional costs borne by customers to (even partly) make up TCPL's revenue losses. Even if consumers break even on a per GJ basis (e.g. if TCPL bears over 65.7% of its losses), they would still be left paying for a $686.5 million project with no economic benefits.

[9] The relevant calculation is the price differential ($0.92) divided by the toll savings ($1.40). At least 65.7% of the toll savings must be achieved (i.e. not offset by other increases in toll) in order to compensate for the additional $0.92 per GJ cost at Dawn versus Empress.

Enbridge's Economic Sensitivity Analysis

117. Enbridge's own economic sensitivity analysis also shows significant losses if reasonable assumptions are used. If distribution revenues are removed (see paragraph 107 above), a ten-year horizon is used for the revenue from shippers (see paragraph 112 above), and 50% of the purported transportation savings are removed to account for a somewhat less optimistic Dawn-Empress price differential, the project NPV is negative $110,752,039.00.[10]

Application Excerpt re Economic Sensitivity Results (Ex A-3-9, Att.3) [Compendium, tab 42]

118. The above scenario shows a negative NPV even though it does not account for the impact of increased TCPL tolls. If only a small portion of TCPL's losses on the mainline are passed on to consumers such that consumers break even per GJ (see paragraph 115 above), the NPV would be reduced by a further $427,487,268.00 as transportation savings are reduced to zero.

Application Excerpt re Economic Sensitivity Results (Ex A-3-9, Att.3) [Compendium, tab 42]

119. If all of TCPL's losses on the mainline are passed on to consumers, the transportation savings become massive unanticipated losses (equal to the Dawn-Empress price differential multiplied by the total volumes), potentially in the billions of dollars. However, even if none of those losses are passed on to consumers, the project would still be uneconomic if the Dawn-Empress price differential follows Union's or TCPL's predictions.

Application Excerpt re Economic Sensitivity Results (Ex A-3-9, Att.3) [Compendium, tab 42]

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[10] The calculation is $667,432,377 (the NPV of the project, base case, see Ex. A-3-9 attachment 3) minus $217,615,985.00 (the NPV reduction to account for no distribution revenues, see Ex. A-3-9 attachment 3), minus $133,081,163 (the NPV reduction to account for the ten year horizon for shipper revenue, see paragraph above112) minus $427,487,268.00 (the NPV reduction to account for 50% transportation savings, see Ex. A-3-9 attachment 3). Enbridge has confirmed the validity of subtracting NPV values from the base case as has been done here (see transcript Vol. 6, p. 8 to 10).

TCPL Evidence

120. If the Board is not convinced by the above analysis, TCPL's supplementary evidence also contains a detailed economic analysis of Enbridge's project showing massive potential losses. After factoring in the increased TCPL rates that would result from the project, TCPL's evidence forecast net *yearly* losses:

a. $78 million per year based on a $0.51/GJ Dawn-Empress price differential (Enbridge's assumption);

b. $158 million per year based on $0.92/GJ (Union's assumption); and

c. $257 million per year based on $1.50/GJ (historical average per TCPL evidence).

Supplementary Evidence of TCPL, August 16, 2013, p. 8 [Compendium, tab 38]

121. TCPL's evidence was created before the settlement terms were reached. However, the conclusions in the evidence, and the principles behind those conclusions, are even more so valid after the settlement agreement was reached, as discussed below.

<u>The Settlement Agreement does not Make the Project Profitable and is Contrary to the Public Interest</u>

122. The settlement agreement does not make this project profitable and is contrary to the public interest.

Fundamental Economic Problems Persist

123. Most importantly, the settlement agreement does not change any of the underlying fundamental problems with the economics of this project discussed above. In particular, it does not change the fact that the "saved" tolls become lost revenue for TCPL that is recouped from customers though other means. Although TCPL has made some concessions (e.g. the reduced ROE), it is still more or less kept whole, as the following transcript passage shows:

Ms. Chaplin: So I'm going to come back to that again, just to see if I can understand it better, because **my understanding of the agreement with TCPL** and sort of the general expectation **is that TCPL more or less is going to be kept whole as a result of this shift from long-haul to short-haul?**

Mr. Isherwood: **That's correct.**

Ms. Chaplin: **So maybe the monies reallocated are moved around, but there's not really -- not driving costs out of the TCPL system. They're still going to be recovered?**

Mr. Isherwood: That's **correct.** (emphasis added)

Transcript Vol. 3, Sept. 17 (Union Panel 1) [Compendium, tab 41]

124. If TCPL will be kept more or less whole, the projected savings will not materialize. Again, if TCPL is allowed to recoup the revenue it losses on the mainline, the single source of savings evaporate and customers are left with only the unfavourable Dawn-Empress price differential.

Comparatively Minor Benefits Do Not Address the Sheer Magnitude of Expected Losses

125. The benefits of the settlement agreement (e.g. TCPL's reduced ROE) do not come close to addressing the sheer magnitude of the losses expected from the project. Again, the TCPL evidence predicted *yearly* losses of $78, $158 or $257 million, depending on the price differential, for Enbridge customers alone. For Enbridge, Union, and Gaz Métro combined, TCLP estimated losses of between $125, $264, and $439 million, depending on the price differential ($0.51, $0.92, or $1.50, respectively), and again on a yearly basis. In the worst case scenario, the losses would amount to over $2 billion over just five years without *even taking into account the actual costs of the project*.

Supplementary Evidence of TCPL, August 16, 2013, p. 8 [Compendium, tab 38]

126. The settlement agreement would need to create hundreds of millions of dollars in consumer benefits to eliminate the expected losses from the proposed projects. Based on TCPL's calculations, consumers will lose $264 million *per year* if a $0.92 Dawn-Empress price differential is assumed. For consumers to simply *break even* on their gas supply costs, the settlement agreement would need to create $264 million *per year* in consumer benefits.

Supplementary Evidence of TCPL, August 16, 2013, p. 8 [Compendium, tab 38]

127. The settlement agreement would need to create even more in consumer benefits to actually make the project profitable. For consumers to reap the full benefits of the switch from long- to short-haul, the settlement would need to address the entirety of TCPL's forecasted $400 million marginal yearly revenue shortfall resulting from the switch, *without putting those costs on consumers*.

Supplementary Evidence of TCPL, August 16, 2013, p. 4 [Compendium, tab 38]

128. The comparatively minor benefits provided by the settlement agreement (e.g. TCPL's reduced ROE) do not come anywhere close to level needed to allow consumers to break even in their gas supply costs, let alone reach the level needed to make the project profitable. During the hearing, TCPL was questioned extensively on the factors in the settlement terms that made the project economic. The responses were summarized as being (i) a $20 million per year contribution by TCPL, (ii) a decrease in TCPL's ROE, and (iii) a reallocation of the burdens. Those three items do not come close to eliminating the losses discussed above, let alone addressing TCPL's forecasted $400 million marginal yearly revenue shortfall resulting from the switch from long- to short-haul.

Supplementary Evidence of TCPL, August 16, 2013, p. 4 [Compendium, tab 38]
Transcript Vol. 9, Oct. 10, p. 89 ln. 14-28 [Compendium, tab 44]

129. As TCPL continued to be pressed on this subject during the hearing, it ultimately fell back to the position that it could not confirm whether Enbridge's project would result in significant losses:

> Mr. Mondrow: Okay. So you were right before and you're not sure now. Is that what you're telling me?
>
> Mr. Schultz: Well, I think that's probably fair. We said that things have changed. We haven't rerun this analysis, so we don't know what the actual result would be.
>
> Mr. Mondrow: Okay. So you were right before, and you're not sure now?
>
> Mr. Schultz: Yes. Yes.

Transcript Vol. 9, Oct. 10, p. 90 ln. 1-8 [Compendium, tab 44]

130. The comparatively minor benefits from the settlement agreement will not offset the massive gas supply losses forecast in TCPL's evidence, let alone make the project profitable.

The Settlement Agreement Exacerbates the Negative Project Economics

131. Overall, the settlement agreement actually *exacerbates* the economic problems with this project. Prior to the settlement agreement there was a high probability that TCPL would be required to absorb a significant portion of the losses resulting from the switch from long- to short-haul. In its decision in RH-003-2011, the National Energy Board ("NEB") clearly indicated to TCPL that it was at risk of absorbing these losses:

> If larger-than-forecast cost deferrals were to occur, they could represent a materialization of the Mainline's fundamental risks and costs could be disallowed. If costs were disallowed, it would not mean that TransCanada did not have a reasonable opportunity to recover costs, but rather that events did not turn out as forecast or that this opportunity was not seized by TransCanada. **A potential outcome is that the Mainline would suffer a loss – just like any other business that faces competition.**
>
> **NEB Reasons for Decision in File. No. RH-003-2011, p. 3**

132. As noted above, TCPL would need to absorb approximated 65% its losses on the Mainline for customers to simply break even on their gas supply costs (see paragraphs 114 to 116 above). Even if TCPL was required to absorb a lesser percentage of its losses, this would nonetheless provide some benefit to consumers.

133. However, as noted above, the settlement agreement more or less keeps TCPL whole so that it is assured its revenue requirement will be met (see paragraph 123 above). This occurs through mechanisms such as the bridging payments and the increased TCPL tolls. The settlement agreement ensures that consumers cannot benefit from the switch from long- to short-haul because it provides a means for TCPL to recoup its losses on the Mainline from consumers.

Information on the Impact of the Settlement is Insufficient

134. Enbridge's updated evidence regarding the impact of the settlement agreement is insufficient. Enbridge has not quantified the impact of the settlement agreement on an overall cost/benefit analysis of the project, provided an updated DCF analysis or recalculated the profitability index. Its economic evidence therefore does not account for

the payments that will be made to TCPL to compensate it for lost revenue from the switch from long- to short-haul.

135. Enbridge's updated evidence regarding the finalized settlement agreement consists of the responses to Undertakings J9.1 and J6.X. These are addressed below.

136. Undertaking J9.1 provides the expected annual total bill impact by rate class that flow from Enbridge's application *and* from the settlement agreement. According to this interrogatory response, the project is *not* profitable because it will lead to over 2% in rate *increases*.

Enbridge Response to Undertaking 9.1 [Compendium, tab 45]

137. The response to Undertaking 9.1 contradicts Enbridge's continued assertions that its project is profitable. However, it is possible that the response accounts only for the costs, and not the purported benefits from the project. If that is the case, the response does not properly answer the Undertaking, which was worded as follows:

> Now, we wish to better understand the customer rate impacts that will result from the leave-to-construct application and the toll impacts that flow through the settlement agreement, and I haven't been able to find anything that sets out the customer rate impacts.
>
> So are you able to provide anything that would provide us with the expected annual **<u>total bill impact</u>** for charges by rate class that flow **from these applications and the settlement agreement**?
>
> MS. GIRIDHAR: I would have to take an undertaking to do that… (emphasis added)

Transcript Vol. 9, Oct. 10, p. 43 ln. 27 to p. 44 ln. 10 [Compendium, tab 44]

Enbridge Response to Undertaking 9.1 [Compendium, tab 45]

138. The response to Undertaking 9.1 either (1) shows that the project is uneconomic or (2) has not answered the undertaking and has not quantified the costs and benefits of the project and settlement agreement.

139. Enbridge's only remaining evidence on the impact of the finalized settlement agreement is the response to Undertaking J6.X. It also does *not* quantify the impact of the settlement agreement on an overall cost/benefit analysis of the project.

Enbridge Response to Undertaking J6.X [Compendium, tab 45]

140. The response to Undertaking 6.X does note the following two impacts from the Settlement Agreement:

> The toll impacts of the Settlement Agreement provided by TransCanada are a 55% increase in short haul tolls to the Enbridge Franchise and a 19% increase in long haul tolls to the Enbridge Franchise.
>
> …
>
> The annual increase in gas costs resulting from the Settlement Agreement tolls provided above relative to the compliance tolls and using the October 2013 QRAM gas supply portfolio is approximately $66.4 million.

Enbridge Response to Undertaking J6.X [Compendium, tab 45]

141. However, Enbridge does not explain how the incremental $66.4 million in annual costs was calculated or exactly what it includes. It is impossible to verify whether the $66.4 million in annual costs accurately or completely captures the impact of the settlement agreement. Furthermore, Enbridge has not factored this additional $66.4 million in annual costs (or the 55% and 19% increase in short- and long-haul tolls) into a revised overall cost/benefit analysis, DCF analysis, or profitability index calculation.

142. The response to Undertaking J6.X analyzes the purported project benefits based on three Dawn-Empress price differential scenarios. However, this analysis is based on the *pre-settlement agreement* compliance filing tolls.[11] Also, the analysis accounts for the benefits only (i.e. they do not include the project costs) and they are nominal figures (i.e. not in present value).

Enbridge Response to Undertaking J6.X, p. 3 [Compendium, tab 45]

Enbridge Response to Undertaking J4.10 [Compendium, tab 46]

143. Enbridge states that it "has not updated the benefits resulting from the GTA Project using the tolls provided in the Settlement Agreement" because "the differential in tolls is expected to be approximately the same as the differential in compliance tolls." This is smoke and mirrors. It is clearly detrimental to customers if *both* long- and short-haul tolls

[11] This is indicated in the title of the table on page 3. It is also clear from a comparison of the figures in that table with previous data provided in response to Undertaking J4.10. The annualized purported benefits in the table at page 3 of J6.X ($173M, $101M, and $3M per year) correspond to the purported benefits indicated in response to Undertaking J4.10 ($1.733M, $1,010M, and $31M over ten years). These figures *do not* account for the impact of the settlement agreement.

increase as a result of the Settlement Agreement. By Enbridge's logic, the project would still provide the same net benefits if the long- and short-haul rates were increased by an astronomical $1000/GJ, as long as the difference between the rates remains roughly the same.

Enbridge Response to Undertaking J6.X, p. 3 [Compendium, tab 45]

144. The purpose of the above review is to show that Enbridge's updated evidence does not quantify the impact of the settlement agreement on an overall cost/benefit analysis of the project. Enbridge also has not provided an updated DCF analysis or recalculated the profitability index. Therefore, its economic evidence does not account for the toll increases flowing from the settlement agreement that will compensate TCPL for its lost revenue from the switch from long- to short-haul.

Enbridge Response to Undertaking J6.X, p. 3 [Compendium, tab 45]

Enbridge has Failed to Meet the Requirements in E.B.O. 134 and 188

145. Enbridge has failed to meet the guidelines in E.B.O. 134 and 188 because it has not accounted for the settlement agreement tolls in its cost/benefit analysis. The increased tolls resulting from the settlement agreement are an *incremental cost* attributable to this project because they are intended to compensate TCPL for its losses resulting from the switch from long- to short-haul. Again, that switch from long- to short-haul is the very purpose of the project. By failing to incorporate the increased tolls in its cost/benefit analysis (e.g. in its DCF and profitability calculations), Enbridge has failed to meet the Board guidelines.

146. Paragraph 14 of the *Filing Guidelines on the Economic Tests for Transmission Pipeline Applications* (the "*Transmission Filing Guidelines*") expressly require consideration of these kinds of broader impacts of a project:

> Any project brought before the Board for approval should be supported by **an assessment** of the potential impacts of the proposed natural gas pipelines **on the existing transportation pipeline infrastructure** in Ontario, **including an assessment of the impacts on Ontario consumers in terms of cost**, rates, reliability, and access to supplies.

Filing Guidelines on the Economic Tests for Transmission Pipeline Applications (EB-2012-0092), p. 3.

147. According to that paragraph, applicants must assess the impact of a project on existing infrastructure and costs to consumers. The impacts on TCPL fall squarely within the meaning of this paragraph. The impact on “existing transportation pipeline infrastructure” is the decreased demand for the TCPL Mainline. The impact on “Ontario consumers in terms of cost” is the increased tolls that TCPL will levy under the settlement agreement to make up for the decrease in demand. Under the *Transmission Filing Guidelines* these impacts must be assessed. As outlined above, they have not.

148. Some other relevant excepts from the guidelines and rules are as follows:

> The following information will be filed in each rates case … (d) **estimates of the NPV and the benefit-cost ratio** for the Investment Portfolio **using a Societal Cost Test** ("SCT"), defined in the Report of the Board, E.B.O. 169 III, **as an evaluation of the costs and/ or benefits accruing to society as a whole, due to an activity.** (emphasis added)
>
> **E.B.O. 188, Appendix B (Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario), s. 3(d).**
>
> [I]ncremental costs should be used in evaluating the feasibility of system expansion. …
>
> **Filing Guidelines on the Economic Tests for Transmission Pipeline Applications (EB-2012-0092), p. 2**
>
> Where a party becomes aware of new information that constitutes a material change to evidence already before the Board before the decision or order is issued, the party shall serve and file appropriate amendments to the evidentiary record, or serve and file the new information.
>
> **Ontario Energy Board Rules of Practice and Procedure, s. 11.02**

149. These excerpts further obligate Enbridge to update its economic evidence to account for the settlement agreement and increased tolls.

150. Regardless of the above specific excerpts from Board guidelines, Enbridge is required to assess the impact of the increased tolls as a consequence of its basic obligation to assess the net costs and benefits from its project. The increased tolls are an incremental cost directly resulting from this project. Again, they are intended to make up TCPL’s lost revenue on the mainline from the switch from long- to short-haul, which is a core function of this project.

151. Enbridge has not provided any holistic cost/benefit analysis of the project that includes these incremental costs, let alone the kind of detailed DCF analysis required under the rules. It has not met the Board guidelines.

The Settlement Agreement is Contrary to the NEB's Decision in RH-003-2011

152. The settlement agreement is also contrary to the National Energy Board's ("NEB") decision in RH-003-2011. The NEB stated as follows:

> It is TransCanada's responsibility to ensure that the Mainline is economically viable and continues to be an important asset to connect the WCSB to markets in the east. The extent to which the Mainline is used as a supply option for consumers and a market option for producers can only be determined by a functioning free market. **TransCanada must not look to regulation to shield the Mainline from its fundamental business risk. It must address the underlying competitive reality in which the Mainline operates.** (emphasis added)

NEB Reasons for Decision in File. No. RH-003-2011, p. 3

153. Contrary to the NEB's decision, TCPL is looking to regulation – not the market – to protect its business and profit. The utilities and TCPL are asking the Board to sanction an agreement that protects TCPL's interests, but not the interests of consumers. Although the settlement agreement changes the details and the mechanisms, the result would be the same – TCPL would be shielded from losses on the Mainline through *government mandated* rates.

The Settlement Agreement Protects the Utilities at the Expense of the Consumer

154. The history of settlement agreement is further evidence that it is protects the interests of the utilities – not the public interest. Enbridge's application was originally predicated on a Memorandum of Understanding with TCPL ("MOU") which granted a significant portion of the capacity on Segment A to TCPL. As a result of a motion from Union, Enbridge unilaterally terminated the MOU, agreed to increase the size of Segment A, and agreed to an open season on Segment A. TCPL responded with a $4 billion lawsuit. The purpose of the settlement agreement is to resolve this contractual dispute, not to protect consumers.

155. The benefits to TCPL and Enbridge from the settlement agreement include the following: (i) TCPL shareholders are more or less assured that they can recover the costs on the Mainline, (ii) Enbridge shareholders are released from the huge risk of legal costs and liability from the $4 billion lawsuit, and (iii) Enbridge shareholders gain support for a project that would result in $184 million in net income over the next 10 years. Very simply, the settlement agreement protects TCPL and Enbridge shareholders from risk.

156. Although the settlement agreement resolves the disputes between TCPL, Union, Enbridge, and Gaz Metro, it does so at the expense of consumers who are locked into paying for TCPL's stranded asset. Regardless of the outcome of the remainder of this application, Environmental Defence submits that this agreement should not be accepted by the Board because it is not in the interests of consumers.

Summary re Settlement Agreement

157. In sum, the settlement agreement does not make this project profitable and is contrary to the public interest because: (i) it does not alter the underlying problems with the economic feasibility of the project, (ii) any value it adds (e.g. the reduced ROE) pales in comparison to the expected losses resulting from the project, (iii) it actually exacerbates the problem by protecting TCPL from losses on the Mainline, (iv) it relies on government rate-setting rather than the market to shield TCPL from losses, and (v) it protects the utilities from risk at the expense of consumers.

Opportunity Cost from Failing to Implement DSM

158. The last cost of this project is the value of the foregone alternative – in this case DSM. As discussed above, instead of carrying out this project, Enbridge could implement incremental DSM that would bring approximately $1.7 billion in incremental net savings over 10 years. This would be a significant missed opportunity.

Conclusion re Purported Gas Supply Savings and Overall Project Economics

159. For the above reasons (which are summarized in paragraph 95), this project cannot be justified based on alleged gas supply savings. Also, the overall cost of the project is unreasonable in light of the likely significant losses.

Reliability & Flexibility – Pressure Issue and East-West Bottleneck

160. The final purported benefit of the project is reliability. In that regard, Enbridge asserts that its project will:

> b. Reduce operational risks and enhance safety and reliability by:
>
> i. Improving diversity and flexibility of the distribution system through additional looping of single feed XHP lines and providing additional supply sources for the major XHP lines in the GTA Project Influence Area; and
>
> ii. Providing the ability to lower pressures on key supply lines;

Application Excerpt re Purpose Summary, p. 1-2 (Ex A-3-1) [Compendium, tab 2]

161. This purpose can roughly be divided into the goals of (i) reducing the pressure on the Don Valley lines from 37% to under 30% SMYS and (ii) relieving the so-called east-west bottleneck so that additional gas can be sourced from Parkway and moved to the east of the city.

30% SMYS Pressure Issue

162. This project cannot be justified as simply a means to lower pressures on the Don Valley lines. Nor can this benefit justify only the north-south portion of Segment B (which runs in the Don Valley).

163. The pressure issue has only been considered in the context of a larger project to address other purported purposes such as meeting demand growth and shifting from long- to short-haul. Enbridge has not provided the evidence (or the analysis of alternatives) to justify the project on reliability grounds once those other purposes are taken out of the equation.

164. First, Enbridge has not completed a comprehensive assessment of the whether the pressure reduction is (i) truly necessary, (ii) worth the cost, or (iii) the highest priority on Enbridge's network. During cross-examinations, Enbridge acknowledged that it has not:

a. "[C]alculated the likelihood, the mathematical likelihood, of an accident occurring on these lines as a result of this pressure issue";

b. "[C]alculated the probability or the likelihood of, not an accident, but simply service losses arising from this pressure issue"; or

c. "[D]one a comprehensive risk analysis comparing the risks associated with this 30 percent SMYS issue and other risks in the Enbridge system, including a comparison of the likelihood of service losses, the likelihood of accidents, the consequences of those events and the costs of addressing the various risks."

Transcript Vol. 6, Sept. 26, p. 18 ln. 9 to p. 24 ln. 4 [Compendium, tab 40]

165. The lack of more detailed analysis and evidence regarding the pressure issue is particularly problematic seeing as:

a. Enbridge has acknowledged that its system will meet all minimum standards with or without the proposed project;

Transcript Vol. 6, Sept. 26, p. 16 ln. 19 to p. 17 ln. 2 [Compendium, tab 40]

b. The two lines in question have operated at current pressure levels (i.e. over 30% SMYS) since they were built;

Transcript, Technical Conference (June 12, 2013), p. 31 ln. 25 to p. 32 ln. 13 [Compendium, tab 47]

c. There is no evidence that there have been accidents or service losses as a result of this pressure issue for the approximately 40 years these lines have been operating at these levels; and

d. Enbridge and Union each have hundreds of kilometres of pipelines that operate at above 30% SMYS.

Union Undertaking JT4.3
Transcript Vol. 5, p. 106 [Compendium, tab 3]

166. Again, Enbridge has not done the kind of comparative risk and cost analysis necessary to justify this project on the basis of the SMYS pressure issue. Furthermore, the above facts show that the pressure issue is not urgent and need not be remedied by November, 2015.

167. Second, if the SMYS issue must be addressed, Enbridge has not established that the project is the preferred option as opposed to a combination of DSM and increased interruptible volumes.

168. Enbridge assessed the alternatives to this project from the perspective of *all* of its components and drivers. It has not assessed whether each component part is justified in comparison to potential alternatives. In particular, Enbridge has *not* conducted an a separate assessment of whether just the portion of Segment B intended to resolve the SMYS pressure issue could be addressed through another preferable alternative. Instead, Enbridge's logic was that, seeing as it believed it needed the project to address load growth and to increase access to Dawn gas, it could also address the SMYS issue at the same time. However, if those drivers are taken out of the equation, Enbridge has not done a sufficient analysis of alternatives with respect only to this SMYS issue.

169. Furthermore, Enbridge has not considered whether the portion of Segment B related to the SMYS issue could be avoided through a lower cost option involving a *combination* of incremental DSM, additional interruptible service, and operational measures. Although some analysis was completed on DSM as a stand alone alternative, DSM has not been considered as part of a larger option involving, for example, a contract with PEC for interruptible service.

Interrogatory Response I.A4.EGD.ED.18 [Compendium, tab 25]

170. Further still, the analysis of DSM as an alternative to specifically address the SMYS issue is flawed because (i) it is based on Enbridge's inflated demand forecast (which exacerbates the pressure issue) and (ii) Enbridge drastically underestimates the DSM potential, particularly in Toronto's commercial and apartment buildings. According to the

53

Enerlife Model, the DSM potential in Mr. Neme and Mr. Jarvis' evidence provide 650,825 m^3/hr in peak demand savings (at top-quartile efficiency levels) by 2025.[12] This amounts to over 22% of the baseline peak demand for all sectors (commercial, apartment, residential, and industrial).[13]

Interrogatory Response I.A4.EGD.ED.3 [Compendium, tab 11]

171. Even if Enbridge's demand forecast is accepted, DSM can significantly reduce overall demand (see the chart at paragraph 67 above). However, the demand growth forecast by Enbridge (amounting to 296,420 m^3/hr)[14] offsets almost *half* of the potential DSM savings. If the demand growth forecast by Enbridge is factored out, the full 22% overall demand reduction could be achieved.

Interrogatory Response I.A4.EGD.ED.3 [Compendium, tab 11]

172. It is worth noting that the greatest savings are available from large commercial buildings such as those in the downtown area served by Don Valley lines. DSM could be focused in this specific area to provide an even greater impact on Station B.

173. Additional interruptible service could buttress the DSM solution and could be implemented quickly – sooner even than the proposed project. The interruptible service potential is high and includes the PEC generating station. We understand that the possibility of additional interruptible service, including from PEC, will be addressed in more detail in the Green Energy Coalition's submissions.

174. It therefore appears that the SMYS issue can be addressed with a combination of DSM and additional interruptible service. If necessary, Enbridge could also consider additional operational measures or minor capital improvements (such as those used to provide the capacity needed for PEC in 2008).

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[12] See the Enerlife Model provided as an attachment to M.EGD.ED.2 (at BG43 to BG54 in the "Forecast" tab).
[13] The baseline is 2,889,983 m^3/hr per Exhibit I.A4.EGD.ED.3. The calculation is: 650,825.18 (DSM savings) divided by 2,889,983, which equals 22.5%.
[14] The calculation is: 3,346,015 (forecast 2025 demand) divided by 2,889,983 (baseline 2012 demand). See I.A4.EGD.ED.3 for the forecast figures.

175. An alternative focused on DSM and interruptible load would be far more cost-effective than the supply-side solution. DSM actually creates significant *net savings*. In contract, a supply-side reliability investment only creates costs. Interruptible service is also highly efficient because it avoids the need for very high-cost supply side infrastructure that is only needed for at most a few hours per year.

176. In sum, this project cannot be justified simply a means to lower pressures on the Don Valley lines. Nor can this benefit justify just the portion of Segment B intended to resolve with the pressure issue. Enbridge simply has not provided the evidence (or the analysis of alternatives) to justify the project on reliability grounds when the pressure issue is considered in isolation without the other purposes of the project. The evidence strongly suggests that a combination of DSM and interruptible loads would be sufficient.

East-West Bottleneck and Upstream Supply Diversity

177. Enbridge asserts that this project would provide "additional sources of supply," would "[i]mprove supply chain diversity," and would "reduce upstream supply risks." It claims that this is accomplished by relieving the so-called east-west bottleneck so that additional gas can be sourced from Parkway and moved to the east of the city. However, this project will likely decrease rather than increase security of supply.

Application Excerpt re Purpose Summary, p. 1-2 (Ex A-3-1) [Compendium, tab 2]

178. According to TCPL's evidence, 83% of Enbridge's supply contracts rely on the Dawn to Parkway system. The project proposes to even further increase Enbridge's reliance on that supply path for its entire franchise and for the GTA area. Toronto's supply would therefore become *less* diverse. Toronto would also become more vulnerable to a major incident on the Union system and to the uncertainties surrounding shale gas in the U.S. northeast (as discussed by the experts retained by the Council of Canadians). This *reduces* Enbridge's security of supply, rather than increases it. In TCPL's words, "the GTA project fails because it leaves the Enbridge franchise area increasingly dependent on one pipeline system, Union's Dawn-Parkway system."

Supplementary Evidence of TCPL, August 16, 2013, p. 9, 10 [Compendium, tab 38]

179. In the very least, Enbridge cannot point to alleged supply chain diversity as a *benefit* of this project.

DSM IS A FEASIBLE AND MORE COST EFFECTIVE ALTERNATIVE (ISSUE A4)

180. DSM is a feasible, more cost effective, and preferable alternative to the proposed project.

DSM is a Feasible Alternative

181. The feasibility of DSM as an alternative is discussed above:

a. Paragraphs 53 to 76 detail how DSM can easily address GTA demand growth in the short and long term.

b. Paragraphs 91 to 93 detail how entry point diversity (i.e. backup in case of failure at the Parkway Gate Station) can be achieved with only a very short and inexpensive connection between the new Parkway West Gate Station and the Enbridge system. DSM is an alternative to the remainder of the project even though it cannot achieve entry point diversity or replace the Parkway West Gate Station connection.

c. Paragraphs 94 to 159 detail how the purported gas supply cost benefits of the proposed project are illusory. Therefore, the appropriateness of DSM as an alternative does not depend on whether it can achieve the shift from long- to short-haul.

d. Paragraphs 170 to 174 detail how DSM can address the pressure issue on Enbridge's Don Valley lines in concert with additional interruptible volumes.

182. Therefore, DSM can replace the entire project (with the exception of the Enbridge Parkway West connection).

183. In addition, if the Board approves Segment A in order to achieve the shift from long- to short-haul service, DSM can still replace the remainder of the project that is intended to resolve the demand growth and pressure issues (i.e. Segment B, or at least the north-south portion). These submissions have already addressed how DSM can address the particular

drivers for segment B, namely demand growth (paragraphs 53 to 76) and reliability (paragraphs 160 to 179).

DSM is More Cost-Effective and Preferable

184. As detailed below, DSM is a preferable and more cost-effective alternative because:

a. DSM results in net savings;

b. DSM results in many additional benefits to Ontario;

c. DSM costs are fairly distributed; and

d. DSM savings are audited and far less risky.

DSM Results in Net Savings

185. DSM provides substantial net savings.

186. The Total Resource Cost ("TRC") test is intended to capture all of the costs and benefits to society of DSM. Enbridge's DSM programs easily pass the TRC test as they provide significant net benefits. As noted above, the TRC *net* benefits (i.e. with the costs netted out) from the incremental DSM needed to address the demand growth forecast by Enbridge would amount to approximately $140 million per year, or $1.7 billion cumulatively from 2014 to 2025. Although it is difficult to estimate the net benefits without preparing a detailed DSM plan, the above at least provides guidance on the magnitude of the net savings.

Summary of Enbridge's DSM Evidence [Compendium, tab 6]
Transcript Vol. 5, p. 32 - 37 [Compendium, tab 3]

187. The above TRC benefits do not include the avoided costs of additional supply-side capacity, either at a general level or for this specific project. DSM is therefore even more cost-effective once the avoided cost of the project is factored in. We understand that these

avoided costs and the evidence of Paul Chernick will be discussed in more detail in the submissions of the Green Energy Coalition.

Evidence of Paul Chernick (Resource Insight, Inc.), June 28, 2013, Update August 22, 2013

188. DSM is clearly preferable to building all or part of Segment B, which, as a supply-side capital expenditure, is a pure cost.

189. The net benefits are also greater than the purported savings from the switch from long- to short-haul that Segment A is intended to facilitate (which, again, are illusory in any case).

Application Excerpt re Economic Sensitivity Results (Ex A-3-9, Att.3) [Compendium, tab 42]

DSM Results in Many Additional Benefits to Ontario

190. In addition to the $1.7 billion in net TRC benefits, DSM provides many *additional* benefits that are *not* included in the TRC calculation. Those benefits include:

a. Decreased greenhouse gas emission reductions;

Transcript Vol. 7, p. 11 [Compendium, tab 22]

b. Improved corporate productivity and competitiveness;

Enbridge Response to Environmental Defence Interrogatory No. 6 in EB-2012-0394 [Compendium, tab 48]

Transcript Vol. 5, p. 47 ln. 11 to p. 48 ln. 15 [Compendium, tab 3]

c. Higher GDP and government revenues; and

Enbridge Response to Environmental Defence Interrogatory No. 7 in EB-2012-0394 [Compendium, tab 49]

Transcript Vol. 5, p. 48 ln. 27 to p. 49 ln. 16[Compendium, tab 3]

d. More jobs for Ontarians.

Transcript Vol. 5, p. 49 ln. 17 to 22 [Compendium, tab 3]

191. As stated in the transcript excerpts noted above, Enbridge agrees that these are additional benefits of DSM. Again, these benefits are not included in the calculation of the TRC net benefits. These additional benefits are yet another reason why DSM is a preferable alternative.

DSM Costs are Fairly Distributed

192. Ratepayer intervenor groups have previously stated a concern that all ratepayers fund the costs of DSM whereas only the ratepayers participating in the DSM programs receive the benefit. However, that concern does not apply here as DSM will provide benefits to *all* consumers by avoiding the high cost of the pipeline.

193. The same cannot be said for Enbridge's proposed project. The Don Valley portion is only allegedly needed for the small subset of customers served by Station B. However, all Enbridge ratepayers will pay the cost.

194. Furthermore, it is fair that some consumers benefit even more than others from DSM. The design of the program is founded on the principle that those who participate are rewarded because they help save gas and help avoid additional costs like supply-side investments. The selective provision of additional benefits is a necessary consequence of any system that encourages conduct through incentives. This is not unfair.

DSM Savings are Audited and far Less Risky

195. Finally, the savings from DSM are far less risky than the purported gas supply savings from the project. Again, Environmental Defence submits that the savings alleged by Enbridge are illusory. However, even if that submission is not accepted, it cannot be denied that the purported gas supply savings are subject to massive risks relating to (i) who will bear TCPL's revenue losses from the switch from long- to short-haul, (ii) the future price differential between Dawn and Empress, (iii) whether the GTA's demand will grow as forecast, (iv) whether the demand from shippers will decline, (v) whether the U.S. shale gas turns out to be a bubble, and so on.

196. Furthermore, Enbridge unequivocally states that, even if the profitability index turns out to be less than one because of some of those risks, it would still seek to have the entire $686.5 million cost of this project included in rate base and it would not agree to a reduction in its net income from the project. In other words, according to Enbridge's

proposal, it would receive $185 million in incremental net income and not bear any of the risks.

> **Transcript Vol. 6, p. 12 ln. 20-24, p. 13 ln. 21-27 [Compendium, tab 40]**
> **Undertaking Response J6.1 [Compendium, tab 50]**

197. In contract, DSM savings are not subject to those same massive risks. Furthermore, under the DSM guidelines, Enbridge's income incentives from DSM are tied to results. If Enbridge does not meet the DSM targets it will not receive the full incentives.

198. The savings from DSM are not subject to the high economic risks that plague Enbridge's proposed project.

Conclusion re Preferability of DSM

199. For the above reasons, DSM is a more cost-effective and preferable alternative.

Enbridge's Alternatives Assessment was Insufficient

200. Enbridge has the burden to establish that its project is the most preferred alternative. Environmental Defence submits that, even if the Board is not *completely* convinced that DSM is *necessarily* the preferred option, this project should not be approved because Enbridge did not complete a sufficient examination of the DSM alternative and has not established (on the evidence, as is its burden) that its proposed project is preferable to DSM.

201. Enbridge prematurely screened out the DSM alternative because DSM could not achieve *all* of benefits of the project. On cross-examination, Enbridge stated that it screened out DSM because it could not achieve the "multiple objectives" of the project, including the 600 TJ "supply shift in order to get the discretionary services over to short-haul firm." There are two problems with reasoning:

> **Transcript Vol. 5, p. 69-70 [Compendium, tab 3]**

a. First, it ignores the possibility that DSM could avoid *part* of the project at a lower cost (e.g. the portion related to load growth).

b. Second, the analysis is now invalid because it has turned out that the 600 TJ shift from long- to short-haul will result in losses to customers rather than savings. The fact that DSM cannot achieve this 600 TJ shift is no longer an argument against an alternative focused on DSM.

202. Enbridge's back-of-the-envelope analysis of the DSM alternative was also insufficiently robust to satisfy its evidentiary burden or to fully and adequately assess this option. DSM was screened out in one or more screening meetings without any studies or "detailed analysis." *No documentation* was created to justify the decision. Furthermore, *the decision was made without any input from the DSM team*. The DSM team was not present at the screening meetings. This is *far* short of the kind of detailed analysis of alternatives required for a complicated $686.5 million project such as this.

Transcript, Technical Conference (June 13, 2013), p. 165 ln. 16 to p. 166 ln. 24 [Compendium, 23]

Transcript Vol. 5, p. 70 ln. 22-26 [Compendium, tab 3]

Transcript Vol. 7, p. 8 ln. 2-16 [Compendium, tab 22]

203. A proper analysis of DSM as an alternative would have considered:

a. Whether DSM is a feasible alternative to *all* of the proposed project;

b. Whether DSM is a feasible alternative to *any part* of the proposed project;

c. Whether DSM is a feasible alternative on its own or in conjunction with other measures (e.g. interruptible service); and

d. If yes, whether the DSM alternative would be more cost-effective or otherwise preferable.

204. Stated differently, Enbridge should have considered whether DSM is a preferred alternative to *all* or *any part* of the project, either alone or in conjunction with other measures.

205. That analysis was *not* completed. Therefore this application should not be approved.

ENBRIDGE'S STRONG INCOME INCENTIVE TO BUILD THIS PIPELINE

206. Enbridge has an extremely strong income incentive to build this project. From 2015 to 2025, Enbridge shareholders stand to earn $185 million in incremental net income (i.e. profit) as a result of the costs of this project being added to rate base. From 2026 onward Enbridge will continue to earn approximately $14 million a year, declining yearly for depreciation. According to Enbridge, it can earn this net income whether or not its forecasts about the profitability of the project become a reality (i.e. even if the profitability index ends up being below 1).

Undertaking Response J6.1 [Compendium, tab 50]
Transcript Vol. 6, p. 12 ln. 20-24, p. 13 ln. 21-27 [Compendium, tab 40]

207. As an aside, although Enbridge earns incentives from DSM, these are not as significant as, and are shorter-lived than, the net income from capital projects. Furthermore, the DSM incentives are directly tied to results. Enbridge's DSM incentives are aligned with the benefits provided to the public.

208. Enbridge's incentives to build more pipelines are not necessarily aligned with the public interest. In this case, DSM is the preferable option for consumers but for Enbridge's shareholders a new pipeline is the far more profitable option.

209. In light of these strong perverse incentives, Environmental Defence respectfully submits that it is the Board's core role to carefully scrutinize this application and to hold Enbridge to its strict legal obligation to establish that the proposed project is needed and is the best alternative.

NATURAL GAS INTEGRATED RESOURCE PLANNING

210. Regardless of whether the Board approves all or part of this project, Environmental Defence respectfully requests that the Board indicate to the natural gas utilities:

a. That the Board will only approve new supply-side infrastructure if the needs cannot be met at a lower cost by DSM and/or interruptible service; and

b. That, early in the planning process, natural gas utilities should comprehensively assess whether DSM is a more cost-effective or otherwise preferred alternative to *all* or *any part* of a project, either alone or in conjunction with other measures.

211. In contrast to the process followed by Enbridge in this proceeding, Environmental Defence submits that the gas utilities' analysis of DSM alternatives should be conducted early in the planning stages, should be comprehensive, and should at least include a detailed assessment of:

a. Whether DSM is a feasible alternative to *all* of the proposed project;

b. Whether DSM is a feasible alternative to *any part* of the proposed project;

c. Whether DSM is a feasible alternative on its own or in conjunction with other measures (e.g. interruptible service); and

If yes, whether the DSM alternative would be more cost-effective or otherwise preferable.

These are not new requirements. Instead, these are simply a corollary of the requirement that capital projects be truly necessary, the best alternative, and in the public interest. However, in light of Enbridge's failure conduct a thorough and timely analysis, we submit that further direction from the Board is needed.

212. During the hearing, Paul Chernick made the following comments about the need for and benefits of a Integrated Resource Planning:

> Formalizing the IRP process is important if the utility isn't paying attention and somebody needs to basically make them sit down and do their homework.
>
> And that actually could be internally within the company, that top management could say: All these different parts of the company need to talk to one another and turn out a comprehensive analysis that we can follow and we can file with the Board.
>
> Or it could come from -- the direction could come from the Board.
>
> But the important thing is that you not break, or the company not break these issues into separate islands that don't communicate with one another. And it looks like the company has taking the position that: Well, we'll just wait on the pressure issue at station B until it's time to get approval to start digging, to build some looping on the Don Valley Parkway.

> And had they brought that issue to the DSM people and started a targeted program. I think the other witnesses will have a very strong opinion that they could have kept down the loads on that line considerably and avoided any need for expanding the Don Valley Parkway, without scrambling in any way to do it.
>
> That also would have given them more flexibility in terms of reducing pressures on the lines, to the extent that that is something that is important and that they want to do it.
>
> **Transcript Vol. 7, p. 106 ln. 8 to p. 107 ln. 6 [Compendium, tab 22]**

213. Environmental Defence echoes those comments. Again, as detailed above, it is not "too late" for the DSM alternative (see paragraphs 77 to 90 regarding the November, 2015 demand growth issue and see paragraphs 164 to 166 regarding the lack of urgency re the pipeline pressure issue). However, if Enbridge had adequately considered DSM early in the process, some of the issues being addressed at this hearing would have been resolved far earlier or avoided altogether.

CONCLUSION, REQUESTED RELIEF, AND NEXT STEPS

214. For the above reasons, which are summarized in the overview, Environmental Defence respectfully requests an order:

   a. That Enbridge's application be denied (with the exception of the connection to the new Parkway West Gate Station);

   b. That (in the alternative, if the Board approves Segment A,) Segment B and the settlement agreement be denied;

   c. That EB-2012-0394 be resumed to approve a new 2014 DSM plan to eliminate peak demand growth in the GTA by a combination of DSM and enhanced interruptible service;

   d. Direct Enbridge to seek to negotiate an interruptible service contract with PEC in cooperation with IESO and OPA; and

   e. That Enbridge and Union return to the Board, as soon as possible, with a comprehensive assessment of the risks caused by high pressure lines in their franchise

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areas, including whether DSM, enhanced interruptible service and other measures can address these issues.

215. Although it need not form part of the formal order arising from this hearing, Environmental Defence also respectfully requests that the Board indicate to natural gas utilities:

a. That the Board will only approve new supply-side infrastructure if the needs cannot be met at a lower cost by DSM and/or interruptible service; and

b. That, early in the planning process, natural gas utilities should comprehensively assess whether DSM is a more cost-effective or otherwise preferred alternative to *all* or *any part of* a project, either alone or in conjunction with other measures.

All of which is respectfully submitted this 14th day of November, 2013.

PURPOSE, NEED, AND TIMING

Introduction

1. The intent of this section is to provide a summary of the purpose of the GTA Project and the needs met through the construction of the proposed facilities. In Exhibit A, Tab 3, Schedule 8, the justification for bringing forth the GTA Project Application for Leave to Construct to the Ontario Energy Board (the "Board") at this time will be discussed.

2. Segments A and B are described in detail at Exhibit A, Tab 3, Schedule 6. The existing Extra High Pressure ("XHP") infrastructure is further described in Exhibit A, Tab 3, Schedule 2. The GTA Project Influence Area is later described in Exhibit A, Tab 3, Schedule 4. An overview map of the XHP distribution system with the proposed GTA Project facilities is provided in Figure 1. Major pipelines discussed in this Application are also noted on the map, which includes the NPS 36 "Parkway North", NPS 36 Mississauga Southern Link ("MSL"), NPS 30 "Don Valley", and the NPS 26 lines.

Purpose and Need

3. The GTA Project has multiple purposes intended to address multiple needs. At the highest level, the purpose of the GTA Project is to reinforce the XHP system to manage operational risks and meet growth needs, in a prudent manner. The specific elements are detailed below.

4. The GTA Project will:
   a. Meet customer growth requirements over the period from 2015 to 2025 by reinforcing the XHP distribution network;

b. Reduce operational risks and enhance safety and reliability by:
   i. Improving diversity and flexibility of the distribution system through additional looping of single feed XHP lines and providing additional supply sources for the major XHP lines in the GTA Project Influence Area; and
   ii. Providing the ability to lower pressures on key supply lines;

c. Provide entry point diversity by reducing the dependence upon Parkway Gate Station which currently provides more than 50% of the supply to the GTA Project Influence Area and does not have alternate means of supply; and

d. Improve supply chain diversity, reduce upstream supply risks and reduce gas supply costs over the period 2015 to 2025.

5. The following evidence will discuss each of the above elements. Table 1 on the following page provides a summary of the nature of the benefits associated with each element of the GTA Project.

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2012-0433** **EB-2012-0451** **EB-2013-0074**

VOLUME:	**5**	
DATE:	**September 24, 2013**	
BEFORE:	**Cynthia Chaplin**	**Presiding Member and Vice-Chair**
	Marika Hare	**Member**
	Peter Noonan	**Member**

I N D E X O F P R O C E E D I N G S

customer data to derive that peak hour demand and the overall, and what we found is that overall system peak is increasing but the contribution on a per-customer basis is declining. And this has been captured in the load forecast.

MR. STOLL: Thank you. And, Ms. Oliver-Glasford, just one question for you. You've heard Mr. Naczynski. What role does DSM play in its relationship to peak hour design?

MS. OLIVER-GLASFORD: Our DSM framework provides – my apologies.

Our DSM framework provides a broad-based annual savings. That's how it's measured and tracked. Currently there is no verified relationship between DSM efforts and peak load reductions. In fact, it's quite different than the electric side, where they have the data enabling in the programs that do target peak load reduction in the form of demand response and the like.

MR. STOLL: Thank you.

Those are my questions, and I'll offer them up for cross-examination.

MS. CHAPLIN: Thank you.

Mr. Elson, I believe you are first?

MR. ELSON: Thank you. Yes.

MS. CHAPLIN: And we have you for two hours. We would probably take a break no later than 11:00 o'clock, though, but perhaps earlier.

CROSS-EXAMINATION BY MR. ELSON:

MR. ELSON: Thank you. Again, panel, my name is Kent

Elson. I represent Environmental Defence, and I might as well just jump into it. I'm going to start off asking you some questions further to some load growth questions I was asking panel 1.

And if I could ask you to start by referring to the Environmental Defence cross-examination document book number 1; that's the large document book with tabs. That's Exhibit K4.5. Is that the correct exhibit number?

If you could please turn to tab 9?

MR. NACZYNSKI: Mr. Elson, were you going to redistribute those books with all the tabs? I do have a paper copy in front of me here, but if we're going to reference all the various tabs that you've got...

MR. ELSON: I'm afraid that panel 1 has those copies, but perhaps Mr. Stoll can speak to that.

MR. STOLL: Can you just provide the page reference as opposed to the tab reference, then?

MR. ELSON: Yes. So this is page 16 in the document book. This is the response to Environmental Defence Interrogatory No. 5, and if you turn over a page you'll see table 1, which lists the peak load derived historic and forecast.

So my understanding is that table 1 is showing Enbridge's weather-normalized peak hour demand estimates for apartment, commercial, industrial and residential customers, and historically it's only for six years; is that correct?

MR. NACZYNSKI: That's correct.

MR. ELSON: According to this table, the industrial weather-normalized peak hour demand declined by approximately 48 percent, subject to check? That's between 2006 and 2012.

MR. NACZYNSKI: That is correct.

MR. ELSON: And according to this table, the residential weather-normalized peak hour demand declined by three percent over that same period, 2006 to 2012; is that right?

MR. NACZYNSKI: That's correct as well, subject to check.

MR. ELSON: Given those weather-normalized trends, why is Enbridge forecasting that residential and industrial peak hour demands will rise continuously in every winter from 2012-13 to 2024-25?

MR. NACZYNSKI: So the load information and how it's projected -- again, as I've mentioned, we use actual metered consumption from the billing, from our billing system that is weather-normalized, and that is certainly one of the factors that we use.

Also look at our peak day system growth. If we were to pull up schedule A, tab 3, schedule 5, and if we look at the supply numbers that are referenced in that document as well, looking at the weather-normalized peak day information as well, we do observe from -- so that's Exhibit A, tab 3 schedule 5, page 7 of 26.

So the peak hourly information that we incorporate is certainly one of the factors that we're considering, as well as other longer term trends that we’re observing on our system.

Based on that information, during the supply or during the system planning process, we held the loads in our model relatively constant, and then applied the growth to the system knowing that we do anticipate and observe growth in peak hour on our system and peak day, normalized peak day flows.

MR. ELSON: Going back to ED 5, I'm not sure if you answered my question. The question specifically related to the industrial numbers and the residential numbers. And if you look at ED 5, we've done this so that we can put the historic right next to the forecast, and if we're both -- maybe I'll leave it at this, which is to say you would acknowledge that for both residential and industrial, for the historic numbers that you’ve provided, you are showing a decline, whereas in the forecast you are showing a year-over-year increase; is that right?

MR. NACZYNSKI: So I would also like to point out that --

MR. ELSON: Are you saying yes, and then adding more information? You just said "so", and then I didn't hear what your answer was.

MR. NACZYNSKI: My answer is yes, based on the derived historic numbers.

However, I also realized there were some economic changes that occurred over that time, specifically in the industrial areas, that would have certainly resulted in an overall growth in those customers -- or sorry, an overall reduction in the number of those customers. My apologies.

MR. ELSON: Has Enbridge produced any load growth forecasts that consider and compare a number of different growth scenarios, including the possibility of zero load growth?

[Witness panel confers]

MR. FERNANDES: The company has done its best to produce the best forecast available, based on the customer adds that we believe will happen over time.

Mr. Naczynski has talked about how that is converted into peak hour load growth. We have included a reduction factor that attempts to account for potential efficiency gains in new building construction, and all sorts of items.

In terms of producing hypothetical forecasts, we have provided sensitivity, in terms of the project. But the most important thing to point out is that load growth is not the primary driver of the project, as we stated at the outset.

There's a multi-faceted project that has a number of items that we're trying to achieve, in terms of objectives. So focussing in solely on load growth is not something that I think we can do nor should do.

MR. ELSON: That may be information which you wish to convey to the Board, but it doesn’t in any way answer my question, which was whether Enbridge has produced any load growth forecast that consider and compare a number of different growth scenarios, including the possibility of a zero load growth scenario. Has that been done?

MR. FERNANDES: We've done economic sensitivity with no load growth on the system.

MR. ELSON: My question is whether you have -- maybe I'll ask a different question.

Do you have any studies or analyses that estimate the probability of different growth scenarios, including a no volume growth scenario?

MR. NACZYNSKI: We have not completed the analysis assuming no load growth. However, as Craig mentioned, we have considered it for -- as Mr. Fernandes has mentioned, we have considered it for economic purposes.

MR. ELSON: I hate to continue on this very, very small point, but you still haven't answered my question, which is a very, very simple question, which is: Has Enbridge done any studies estimating the probability of different growth scenarios, for example the probability of this scenario that you have presented and another scenario that would show no volume growth?

Have you looked at the probability as between different possible growth scenarios? I believe the answer is no, but I would just like to confirm that that's the case.

MR. FERNANDES: We do not have a probabilistic load forecast, no.

MR. ELSON: Thank you. If I can ask you to refer to tab 11, which is -- I'll give you a page reference. The particular page I'm looking for, which is page 23 of the

Environmental Defence cross-examination document book, which is Exhibit K4.5. That's page 23 of the document book.

This tab contains the Enerlife report that Environmental Defence has put forward as evidence in this proceeding, and I would like to bring your attention to figure 13, which contains peak demand trends.

So what Enerlife has charted here is that the derived historic peak demand from 2007 to 2012, and if you look at footnote 11, this data comes from Enbridge Exhibit A4.EGD.ED 3, which is the response from Environmental Defence, Interrogatory No. 3.

Do you have any concerns with the way that they have charted that historical data here?

MR. NACZYNSKI: With respect to the chart?

MR. ELSON: Yes.

MR. NACZYNSKI: And how the information is presented on that chart? That is consistent and a representation of what was in our response to Environmental Defence No. 3.

MR. ELSON: Thank you. And looking in particular at the dotted line that is flat or declining slightly, this shows the historic peak demand from 2007 to 2012, and that shows a peak demand that is flat or declining; is that right?

MR. NACZYNSKI: Based on that limited data set, that is a -- would appear to be linear trend of those data points.

MR. ELSON: And those were the data points that you provided to Environmental Defence in response to that interrogatory; isn’t that correct?

MR. NACZYNSKI: That’s correct.

MR. FERNANDES: It’s a very short time frame to be extrapolating, from six years' worth of data to over a decade longer into the future.

MR. ELSON: So are you suggesting that the further distant past is more -- gives a more accurate picture than the more recent five or six years that you’ve provided?

MR. FERNANDES: As Mr. Naczynski has already brought up, we did provide trend data in our submission in Exhibit A, tab 3, schedule 5.

MR. ELSON: Now, I guess the issue that I take with some of your earlier data is that in response to Environmental Defence 3, you said, quote:

> "The data has only been provided for 2006 onward as EGD implemented a new load gathering system. Prior to 2004, load gathering was completed on a legacy mainframe system and the archived data is not readily accessible."

So that's my understanding of why you provided only those six years of data; is that correct?

MR. FERNANDES: For the purposes of this response, we provided six years of data based on peak hour. The Exhibit A, tab 3, schedule 5 provides a much longer time frame for peak day.

MR. ELSON: Using the data that you provided for ED 3 and looking at this chart, the line with the squares is what you're forecasting, which is up at the top, and the dotted line that's linear from 2007 to 2012 is the linear trend line from the historic numbers; is that right?

MR. FERNANDES: The green dashed line appears to be linear historical from the 2007 to 2012 time frame.

MR. ELSON: And the red line at the top with squares as data markers is your forecast?

MR. FERNANDES: That's what it appears to be. You've taken the data that Enbridge provided and put it on a graph.

MR. ELSON: Okay. I will move on, and I would like to discuss with you the reduction factor used in your load growth analysis. But before getting into that, I would like to confirm that I have correctly understood how your growth forecast works.

So first of all, your load forecast is centred on a forecast of customer additions; is that right?

MR. NACZYNSKI: That's correct.

MR. ELSON: And, Mr. Naczynski, you were the main person creating this load forecast; is that correct?

MR. NACZYNSKI: I developed the load forecast based on the customer additions forecast that was provided to me, yes.

MR. ELSON: Thank you. So I understand that the basic steps that you took in developing your forecast were as follows.

First, you estimated the number of new customers for each customer type, or your colleague made that estimation;

is that correct?

MR. NACZYNSKI: That's correct.

MR. ELSON: And then you multiplied the number of new customers by an estimated average demand per customer?

MR. NACZYNSKI: That's correct, based on a peak hour anticipated consumption at a design day.

MR. ELSON: Then you added up the forecast demand growth for each customer type to generate what I will call a preliminary forecast of the demand growth from new customers? From the customer additions?

MR. NACZYNSKI: That's correct.

MR. ELSON: And then you reduced that preliminary growth forecast from new customers -- i.e., customer additions -- by a reduction factor?

MR. NACZYNSKI: That's correct, yes.

MR. ELSON: That was the 35 percent reduction factor?

MR. NACZYNSKI: That's correct.

MR. ELSON: And finally, once you had applied that reduction factor to the growth from new customers, you added that to the base, which would be the load from existing customers?

MR. NACZYNSKI: That's correct, yes.

MR. ELSON: So mathematically, the load from existing customers stays constant in the model and the load growth from new customers is just added on top?

MR. FERNANDES: The --

MR. ELSON: Mr. Naczynski, is that correct?

MR. NACZYNSKI: So that is correct. However, note that that 35 percent reduction factor includes more -- at the end of the day is to make sure that we have a forecast we believe is consistent with the historical observed trends in peak day load.

MR. FERNANDES: And I think we provided that response in JT2.29, an undertaking for yourself, Mr. Elson, I believe, where we stated that the reduction factor captures the impact of all of the factors across the existing and incremental loads.

MR. ELSON: So the reduction factor is applied, the 35 percent reduction is applied only to the growth of new customers, but it is intended to capture all of the variables affecting both new customers and existing customers, such as DSM and the like; is that accurate?

MR. FERNANDES: That is correct. We took a total forecast and we netted it down. Mathematically it was taken off of the incremental growth from new customers, but it was intended to cover all the factors that influence our peak load growth across both the existing and new customers.

MR. ELSON: The people at Enerlife took issue with this process, and I would like to refer that to you. This is, again, page 23 of the Environmental Defence cross-examination document book. That's tab 11, Exhibit K4.5. My apologies, that's page 24 of the document book.

And under point C, I'll read you to what their response was. They say:

"The application of the discount factor in the Enbridge load growth forecast model appears to be misleading. The DSM forecast of 12,000 cubic metres per hour reduction each year is 0.4 percent of the peak hourly load in the GTA. The 35 percent discount factor is applied on the incremental new customer growth rate of 1.2 percent each year to account for the DSM load reduction over the entire existing building stock. This leads to the misunderstanding that no amount of DSM could offset growth, since even if a 99 percent discount factor is applied, there will still be a positive growth trend."

Is Enerlife correct in saying that even if there is a 99 percent reduction factor, your model would still show some positive growth? Mr. Naczynski?

MR. NACZYNSKI: If there was absolutely no growth on the system and we believed that there was no growth on the system, we would not have added the load to the system in the manner that we've done.

The reality is that we do believe there is growth on the system, and thereby we reduce the load that was simply being added to our modelling for network simulation purposes, to the load that was being added.

MR. FERNANDES: If the argument is with the mechanics of how we applied our judgment to our forecast, we believe the net forecast is correct.

MR. ELSON: The question is whether if the reduction factor was 99 percent, your model would still show some positive growth; is that correct?

MR. FERNANDES: You're taking the modelling literally. We looked at longer-term trends, and we reduced our growth forecast.

MR. ELSON: I'm going to ask you some questions about what underlies this 35 percent and how you came up with it and what it is supposed to include.

But for now, just mechanically, would you agree that if it was a 99 percent reduction factor, your model would still show some positive growth? Is that correct?

MR. FERNANDES: If we believed there was no load growth on the system, Mr. Naczynski has already stated that we would have had that in our forecast.

The exact mechanics of how we applied it, you are correct. That's a mathematical certainty.

MR. ELSON: I think the answer was yes, with some other information; is that correct?

MR. FERNANDES: Yes.

MR. ELSON: Thank you.

So now getting into the details of what the reduction factor is intended to include, one of the things it's intended to capture is the impact of DSM on demand growth; is that right?

MR. FERNANDES: I think if we can go back to JT2.29, which was, again, an undertaking, we fully articulated that there are a number of factors that influence peak load growth on the distribution system, one of which is the effects of energy efficiency. And there are a multitude of others, and our load growth forecast captures them all.

MR. ELSON: So the reduction factor would include -- I'm trying to separate some of those out. One of the things it would include is the impact of your, of Enbridge's, DSM programs; is that right?

MR. FERNANDES: We believe we've captured all of those factors in our load growth forecast.

MR. ELSON: So another one would be the impact of customer losses through building demolition? That's another factor that's intended to be accounted for in this reduction factor; is that right?

MR. FERNANDES: Along with other items, such as a trend towards much larger and taller buildings.

MR. ELSON: It's also intended to capture improved efficiencies occurring outside of Enbridge's DSM programs?

MR. FERNANDES: That's correct.

MR. ELSON: And it's intended to capture the impact of more stringent building codes on new and existing buildings; is that correct?

MR. FERNANDES: Building codes on new buildings and renovations.

MR. ELSON: Yes.

MR. FERNANDES: On existing buildings. Correct.

MR. ELSON: So basically it's supposed to account for everything except for your customer additions?

MR. FERNANDES: Based on the customer additions that we forecast over this particular forecast horizon, we intentionally wanted to ensure we had a conservative load growth forecast. So we applied an additional factor to bring our load growth down, and it and was intended over the entire forecast horizon specifically for this project.

MR. ELSON: So in other words, the reduction factor captures all of the factors, except for the incremental customer load from new additions.

It's supposed to capture everything; it's an overall number that is supposed to capture everything?

MR. FERNANDES: We tried to capture everything in our load growth forecast. We applied a reduction factor; I think you've heard how we applied it, and you may have some issues with the mechanics.

But it is intended to capture everything, all of the forces that are impacting our load growth. And it is specific to the GTA. It is specific to this particular forecast horizon.

So one of the items that Mr. Naczynski could describe better is the fact when we do our system design and planning, we need to geographically distribute that load in order to size the system.

So this was kind of a marriage of a top-down forecast of other known factors, and it was the way that we applied it to geographically distribute it.

MR. ELSON: Could you turn to page 3 of the Environmental Defence document book, which is tab 3 as well?

To assist in this cross-examination, we've prepared a table summarizing Enbridge's peak load forecast. This was based on the numbers provided to us by Enbridge in response to ED 3 – that is Environmental Defence Interrogatory No. 3.

We sent the Excel file to you, so you could confirm that we prepared the table correctly, and I believe that your counsel has confirmed that you don't have any issues with the way we have reproduced this data; is that correct?

MR. NACZYNSKI: That's correct.

MR. ELSON: I would like to refer you to the column showing the 35 percent reduction factor amount, and that's the second column.

Looking at this column, the reduction factor reduces the demand growth forecast by approximately 12,000 cubic metres per year. Is that number correct?

MR. NACZYNSKI: It reduces the overall net system load that we'd be modelling by the amount indicated here, the approximately 12,000.

MR. ELSON: So overall, your load growth forecast is reduced by 12,000 cubic metres per year as a result of this reduction factor?

MR. FERNANDES: I think the way I would describe it is we had current existing load. There are some additions and there are some subtractions, and we have a net load.

So the subtractions were approximately 12,000, as you've stated.

MR. ELSON: So that's what the -- I'm just trying to get a number what the 35 percent reduction factor amounts to, and I believe that number is 12,000 cubic metres. Is that right?

MR. NACZYNSKI: That's correct, and we would be forecasting to add between 22,000 or 23,000 cubes to our system at a peak hour.

MR. ELSON: Thank you. Now, in response to Environmental Defence Interrogatory No. 14, Enbridge estimated that the peak demand reduction from its DSM programs would be roughly 12,000 cubic metres per year -- and I'll direct this question to the DSM folks on the panel. Is that the right number in ED 14?

MS. OLIVER-GLASFORD: Can we bring it up? Is that your page 4 in this book?

MR. ELSON: No, ED 14 is at page -- well, I guess it is also on our page 4. But if you would like to see where -- your response to ED 14 is at page 25 of our document book.

MS. OLIVER-GLASFORD: Yes, that is accurate, based on an illustrative example that we prepared to fulfill your request.

MR. ELSON: In other words, the 35 percent reduction factory applied to your load forecast is roughly equal to the forecast demand reduction that you're expecting from your DSM programs. They are both 12,000 cubic metres, is that right?

MS. OLIVER-GLASFORD: They are roughly the same. This one is twelve, and I think yours is closer to thirteen. But as I said, it was for illustrative purposes and we don't have any verified link between annual and peak and DSM.

MR. ELSON: It seems to me that the reduction factor only accounts for your DSM programs, and therefore doesn't factor in other factors that would result in lower growth, such as building demolition, changes to the building code, and customer-driven improvements and the like, because it happens that your reduction factor comes out to the same amount as what you are expecting from your DSM programs. Would you agree with that?

MR. FERNANDES: No.

MR. ELSON: So can you explain how your reduction factor accounts for other factors, even though it happens to be the same as the anticipated reduction from your DSM programs?

MR. FERNANDES: First of all, it's not the same.

MR. ELSON: Well, it’s roughly the same.

MR. FERNANDES: So now you are talking roughly. So it's roughly in the same order of magnitude. But your focusing exclusively on certain factors and you’re excluding others.

So there are changes in economic growth that drive usage patterns and peak load requirements, and there's also a trend towards larger buildings being built. And we do have that on the record in our Exhibit A, tab 3, schedule 4.

Toronto has a very large number of tall buildings being built, so taking the total number in isolation without looking at the finer details about what types of customers are being added is important, in terms of our overall load forecasts, and the company believes that we have an appropriate forecast.

MR. ELSON: Regardless of what the reduction factor includes or doesn't include -- and I'll have to leave that to argument about whether they are roughly accurate, because I believe the numbers show that they are -- sorry, roughly equivalent, which I believe they are.

Maybe I should get a better grasp about how you derive this reduction factor. Is it correct to say that Enbridge estimated the 35 percent reduction amount to account for a number of factors that were not accounted for in its existing customer additions model, such as DSM, building demolitions, larger buildings and the like?

MR. FERNANDES: That's correct. Given the scale of the project, we took extra diligence in looking at our load forecast.

MR. ELSON: So in other words, after coming up with your preliminary customer additions demand forecast, you thought the numbers were too high and needed to be reduced to account for other factors; is that about right?

MR. FERNANDES: The way I would describe it is compared to smaller reinforcements, we had additional data available to us, and we utilized that appropriately to ensure that we had the most accurate load growth forecast available.

MR. ELSON: Who decided on the figure of 35 percent?

Was that you, Mr. Naczynski?

MR. NACZYNSKI: The 35 percent was done in conjunction with the project team, including Mr. Fernandes.

MR. ELSON: Can you provide any additional information on how it was derived? For example, can you explain that X percent of the reduction factor is attributable to DSM, Y percent is attributable to building demolitions, and Z percent is attributable to there being larger buildings?

Can you provide that sort of detail with respect to the reduction factor?

MR. FERNANDES: If we can go back to JT 2.29, I think we've provided the response.

MR. ELSON: I think answer is no; is that correct? You can't provide that additional detail?

MR. FERNANDES: Well, it's important to understand how the company does its load forecasting, and the different types of forecasts that it produces for various purposes.

For system design, the data availability is not the same as what you would typically see on the electric system. And I think it would be helpful for parties to take a look at interrogatory A3.EGD.Staff.15.

We have a fairly lengthy preamble that describes the different types of forecasts. And it describes how we forecast annual demand, for instance, and what its useful purposes are. It describes how we forecast peak day demand and how we use it to -- in our supply plan. And it also describes how we forecast peak hour, which is used for system planning.

So I think, to your response, it's very difficult to disaggregate that, because it was a top-down adjustment. And there's simply no data to support or understand at the micro level, and it's a consequence of how we meter in our particular system. Most of our customers have meter readings only occurring six times a year.

So the data that you're looking for is simply not available.

MR. ELSON: So you're not able to -- I'm sorry, I'm going to have to repeat the question because that was a long answer, and I'm not sure where to find the specific answer to my question. You are not able to break apart this reduction factor and explain what percent is attributable to DSM or what percent is attributable to building demolitions and the like; is that correct?

MR. FERNANDES: No, we're not able to.

MR. ELSON: Thank you. I guess it would be fair to say Enbridge developed a broad-brush estimate without an underlying model or detailed calculations, like we were just discussing?

MR. FERNANDES: I think those are almost the exact words that I used in the technical conference when we had this discussion.

MR. ELSON: So yes is the answer?

MR. FERNANDES: Correct.

MR. ELSON: I'm going to move to some questions about greenhouse gas reduction policies and their potential impact on the load growth forecast. Could you turn to tab 15 of the Environmental Defence document book, please? That's page 31. I'm actually going to ask you to refer to the end of that document, which is page 36 in the document book.

This document is the government of Ontario's Action Plan on Climate Change. It's from 2007. And according to this tab:

> "The government of Ontario's greenhouse gas reductions goals are as follows: a six percent reduction in our greenhouse gas emissions by 2014 relative to 1990 levels, a 15 percent reduction in our GHG emissions by 2020 relative to 1990, levels, and an 80 percent reductions in our GHG emissions by 2050 relative to 1990 levels."

Are you aware of these targets?

MR. FERNANDES: Yes. You have provided them to us.

MR. ELSON: Were you aware of these targets before I have provided them to you?

MR. FERNANDES: Yes.

MR. ELSON: Now, your DSM people were aware; were you aware of them, Mr. Fernandes?

MR. FERNANDES: I was aware that the Ontario government has a greenhouse gas policy. I have to admit I'm not well versed in the details of it.

MR. ELSON: And, Mr. Naczynski, were you aware of these targets?

MR. NACZYNSKI: Similar to Mr. Fernandes, I was aware of a policy by the provincial government, but not of the specific targets.

MR. ELSON: If you could turn over the tab in our document book to -- which is tab 16 which is page 37, according to this tab, in 2010 natural gas consumption was responsible for 34.5 percent of Ontario's total energy-related GHG emissions. And that comes from a table that's at page 40 of the document book.

I believe you confirmed this number in the recent DSM proceedings, but I would just like to ask you to confirm it again. Do you agree that that is an accurate estimate?

Again, that's 34 percent of Ontario's total energy-related GHG emission being related to natural gas.

MS. OLIVER-GLASFORD: We certainly don't have information on the energy mix, but all other things being equal, yes, they seem reasonable.

MR. ELSON: Ms. Oliver-Glasford, is it reasonable to assume that, in order to achieve the 2050 GHG emission reduction goals, that Ontario's total natural gas consumption would need to be significantly reduced?

MS. OLIVER-GLASFORD: I think mathematically that concept sounds reasonable, but since this document was done in 2007 and -- even 1990 energy mix, I'm not an expert in what the energy mix was at that time.

MR. ELSON: I take it, though, that you don't have any studies or analysis to show that Ontario can achieve its 2050 GHG reduction targets without total natural gas consumption declines; is that right? You don't have any studies that would show that?

MR. FERNANDES: Our studies would typically focus on our franchise, not on the entire province of Ontario. So we do not.

MS. OLIVER-GLASFORD: I would like to add to that that we do have a climate change policy that has two components, where we're addressing our own GHG emission reductions at the facilities and taking a leadership role in that, and also working with others to help them reduce their GHG emission reductions.

MR. ELSON: That's reducing GHGs in your operations; is that right? That's not talking about the GHGs that are produced from using gas that you sell to your customers?

MR. FERNANDES: You mean our customers' production of greenhouse gases?

MR. ELSON: Yes. Is that correct?

MR. FERNANDES: We have to focus on our own operations.

MR. ELSON: Of course. If you could turn to the next tab in our document book, that starts at page 43. This is an excerpt from the government of Ontario's 2012 climate change progress report. And if you could turn to page 12 of the document, which is page 55 of the document book, I'm afraid I didn't manage to sidebar these numbers, but on page 55 of the document book you'll see table 6. Do you all have that table in front of you?

It's also up on the screen. Does the Board Panel and the witness panel both have the table in front of you?

MS. CHAPLIN: Yes.

MR. ELSON: If you could move down to the "Industry Sector," there's an initiative listed, which is the natural gas demand side management programs.

And you'll see that the government of Ontario is projecting reductions of 0.6 megatonnes for 2014 and one megatonne for 2020.

Are you aware of those numbers, Mr. Naczynski?

MR. NACZYNSKI: I was not aware of these numbers until receiving this document.

MR. ELSON: And moving down a line to "Buildings," "Buildings" include three initiatives including natural gas demand side management programs, and the government of Ontario is projecting a reduction of 1.6 megatonnes by 2014 and 2.9 megatonnes by 2020.

And again, were you aware of these forecasts by the government of Ontario?

MR. NACZYNSKI: Similar to above, I was not aware of these until now.

MR. ELSON: These would be net reductions from 1990 greenhouse gas emission levels; is that right, Ms. Oliver-Glasford?

MS. OLIVER-GLASFORD: Sorry, can you repeat the question?

MR. ELSON: These reductions would be net reductions from 1990 levels?

MS. OLIVER-GLASFORD: It's not clear to me from looking at that, this one table. My apologies. Maybe it is listed as an assumption somewhere.

MR. FERNANDES: I think also net reductions for the entire province that the Enbridge franchise is only a part of.

MR. ELSON: Yes, of course. This document, I should maybe discuss the background with you a little bit. This is the climate change progress report from the government of Ontario. This is a document produced pursuant to its climate change action plan, and its action plan is -- has created targets based on 1990 GHG emission levels.

So perhaps, subject to check, you could agree that these would be net reductions from 1990 levels.

MR. FERNANDES: Subject to check, I think we can agree with that.

MR. ELSON: Thank you. Mr. Naczynski, when you created your load forecast, did you expressly consider and incorporate these projections?

MR. NACZYNSKI: As I've already mentioned, my load forecast is based on peak hour consumption, or on a design day condition in the City of Toronto. It's not based on annual forecast number.

So specifics about GJ -- greenhouse gas emissions to be reduced over -- annual basis was not considered.

MR. ELSON: I guess what I'm asking is whether you considered the fact the government of Ontario is planning on making net, or achieving net GHG emission reductions with respect to industry and buildings that are fairly significant.

Did you consider that as part of your load forecasting process?

I don't think you could have, because you weren't aware of these numbers prior. But I'd just like to confirm that that wasn't part of the forecasting model.

MR. NACZYNSKI: I think that certainly would be obvious that, no, that was not included in it.

MR. ELSON: Could you turn back to page 10 of this report? That's page 53 of the document book, Environmental Defence's cross-examination document book.

This table, table 5, indicates the current gap between the projected GHG reductions that we were looking at just now, and the targets. Do you see that there? Are you with me with this table?

MR. NACZYNSKI: On the screen, yes.

MR. ELSON: Thanks. You can see that the gap for 2020 is 28 megatonnes; that's four rows down, I think, in the last column.

MR. NACZYNSKI: We see that.

MR. ELSON: And so even if the projected natural gas GHG reductions we just discussed are attained -- in other words, even if the industrial- and the buildings-based initiatives are achieved -- there would still be a very large gap, is that right?

Perhaps the DSM experts might be the best people to answer that question.

MS. OLIVER-GLASFORD: I haven't reviewed this document in detail to verify it, and I would also say I'm not sure how the projections have been developed. You know, certainly GTA area, if we're talking about this particular project, it's a completely different growth profile, I would imagine, than this rest of the province.

So I just don't know how to be able to credibly verify these numbers and the gaps.

MR. ELSON: Perhaps I'll show tell you numbers. If you look at the column for 2020, it says that the projected reductions are 42 megatonnes. And if you move down, it says that the gap is 28 megatonnes.

Do you see those numbers there? So we have projected 42, and gap of 28?

MS. OLIVER-GLASFORD: Yes, I do.

MR. ELSON: And over on page 12, which is what we were just looking at, which is page 55 of the document book, all of these initiatives for 2020, at the bottom right-hand corner of that table, they amount to 41.3 megatonnes in reductions. So those are the projected.

So in addition to that 41.3, there will still be a significant gap. That's what the document is predicting, subject to check?

MR. FERNANDES: Subject to check, that's correct for the province as a whole.

MR. ELSON: Thank you. When Enbridge created it's load forecast, did it expressly consider the possibility that the government of Ontario would look to the natural gas sector for even further greenhouse gas reductions than it is currently forecasting, in order to meet its projected gap of 28 megatonnes?

MR. FERNANDES: I don't believe we speculated on future policy by the Ontario government.

MR. ELSON: Thank you. I would like to move on to some other topics.

I have some other load-growth-related questions, but perhaps I'll save those to the end.

I would like to move more into a discussion of DSM, and just to give you a bit of a road map, I'm going to ask you about the DSM potential if Enbridge continues with its same, what I will call a technology-based approach. I'm going to ask you some questions about a different approach, set out in the Enerlife model, which you could call a performance-based approach, or a benchmarking approach.

I'm going to ask you about some of the benefits of DSM, and some of the analysis that Enbridge has done of DSM as an alternative.

So starting with the first topic, which is the DSM potential based on a technology model, could you turn to tab 4 of the ED cross-examination reference book, which is page 4?

This table is entitled "Summary of Enbridge's DSM Evidence", and again I believe your counsel has confirmed that we've accurately reproduced this data; is that correct?

MS. OLIVER-GLASFORD: Yes.

MR. ELSON: I'm going to go through some of these numbers with you.

The first column of data is the peak demand reduction from forecast DSM, and this is Enbridge's rough estimate of the peak demand reduction in the GTA area that would result if its existing 2014 DSM budget is forward continued forward into the future; is that correct?

MS. OLIVER-GLASFORD: Okay. I'm just going to refer to Exhibit I.54.EGD.ED.14, please, yes. So does everybody have that in front of them?

MR. ELSON: That's at page 25 of our document book, if that makes it easier to turn up.

MS. OLIVER-GLASFORD: I'm just going to reference the caveat that we've put forward in developing those numbers, which you had asked us for. So we wanted to be helpful.

But just as a reminder, they are illustrative and the assumptions, and we used a linear conversion from peak day – sorry, peak hour to peak day, and then peak day to annual figures -- or vice versa, rather. But in practice, that conversion factor will not be linear.

So there is kind of one caveat that I want to pull out, and we also assumed a static cost effectiveness when we did our assumptions on the costs.

MR. ELSON: Thank you. And you provided -- you made your best-efforts estimate. This is the best estimate you could come up with; is that right?

MS. OLIVER-GLASFORD: That’s correct.

MR. ELSON: Just for your reference, in our table here back at page 4, I have noted in the source that someone looking at this chart should note the assumptions and the data caveats listed on page 2 of ED 14. So there is a reference in there, because we do acknowledge that some assumptions had to be made.

So the amount -- I guess what I'm trying to get is these numbers right here are Enbridge's rough estimate of the peak demand reduction that would result if your 2014 DSM programs were continued on into the future; is that right?

MR. FERNANDES: I believe the question asked us to use, and we did use best efforts to try and convert what our 2014 DSM program, what impact it would have on peak load.

MR. ELSON: Yes.

MR. FERNANDES: So if you want to take that, because it was provided on a best-efforts basis to show the relative magnitude and use it as a future projection, you should note the caveats.

MR. ELSON: Okay. Thank you. The next column over is Enbridge's best-efforts rough estimate of the incremental peak demand reduction that would be necessary to avoid load growth in the GTA area; is that correct?

MR. FERNANDES: That is correct.

MR. ELSON: And that amount is 25,000 cubic metres per hour?

MR. FERNANDES: Correct, as per that table.

MR. ELSON: Moving to the next table down, the first column is the forecast DSM budget for the GTA area. Now, this is Enbridge's rough estimate of the portion of Enbridge's DSM budget that is allocated to the GTA area; is that right?

MS. OLIVER-GLASFORD: Yes, that's correct, based on consistent dollars from today.

MR. ELSON: And that's approximately $15.5 million in 2014, and then rising incrementally from there?

MS. OLIVER-GLASFORD: Correct.

MR. ELSON: What's the reason for the numbers increasing year over year? Even though the anticipated demand reduction stays constant?

MS. OLIVER-GLASFORD: The numbers increase based on the inflation factor that we use in our DSM framework.

MR. ELSON: Thank you.

And the next column over is Enbridge's rough estimate of the incremental DSM budget that would be necessary to avoid load growth; is that right? That's incremental budget?

MS. OLIVER-GLASFORD: Yes, that's correct, again with the caveat of linear cost-effectiveness.

MR. ELSON: And in 2014 that's approximately $33.7 million?

MS. OLIVER-GLASFORD: Correct.

MR. ELSON: So the next column to the right is a rough estimate of the incremental net TRC benefits that would result from just the incremental programs, and that would be approximately $140 million per year; is that right?

MS. OLIVER-GLASFORD: Yes, that would be correct as well, noting that when we project out in DSM there are a lot of caveats in terms of net-to-gross ratios, you know, costs, all those sorts of things that we have to consider adjustment factors on programs that are factored into these numbers, as well.

MR. ELSON: Of course. And these are net benefits, meaning that from an overall perspective, the present value of the savings from the incremental DSM measures such as avoided gas, water, and electricity costs would be over $140 million higher than the present value of the cost of the measures; is that right, Ms. Oliver-Glasford?

MS. OLIVER-GLASFORD: Yes, that is correct, but it should be noted that that TRC calculation does not include the cost of incentives to get that avoided cost benefit.

MR. ELSON: But that's the TRC societal benefit analysis; is that correct? It's the TRC analysis that would be done under the DSM guidelines?

MS. OLIVER-GLASFORD: Correct.

MR. ELSON: And the intent of that is to determine the net benefits to society as a whole?

MS. OLIVER-GLASFORD: Correct.

MR. ELSON: Now, why doesn't this number increase by inflation? Is that -- why would you have applied inflation to the DSM budget but not the incremental TRC benefits?

MS. RAMSAY: We didn't apply an inflation factor because the estimation of incremental net TRC benefits going forward had so many assumptions behind it. And we don't necessarily think that there's a linear relationship as we go forward and get deeper and deeper savings in a very targeted area, that it would be a linear relationship.

MR. ELSON: So perhaps your -- if you're getting declining returns, it would offset the inflation; is that about right? So you didn't include inflation there?

MS. RAMSAY: You could put it that way.

MR. ELSON: The next column over provides the cumulative TRC benefits. So over the 12 years, the net benefits -- that is, the savings minus the costs -- would equal about $1.6 billion, and that's in the bottom right-hand corner of the table; is that correct?

MS. RAMSAY: Yes, but just to remind us that that does not include the cost of the incentive. The incentive is paid to the customers, to encourage those societal benefits.

MR. ELSON: It does include total cost of the measures, of the efficiency measure; is that right?

MS. RAMSAY: No. It includes the incremental cost of the measure over and above a standard piece of equipment.

MR. ELSON: I guess maybe I'll ask you: Has this been calculated in accordance with the DSM guidelines?

MS. RAMSAY: Yes.

MR. ELSON: Could you turn to tab 20, please, which is page 61 of the document book? This tab contains a report by Marbek, excerpts of a report by Marbek entitled, "Natural Gas Energy Efficiency Potential: Update, 2008." And it provides an estimate of the DSM potential for Enbridge's residential, commercial and industrial sectors.

Does Enbridge believe that the overall conclusions in this report are generally sound and accurate?

MS. OLIVER-GLASFORD: Overall, we support this study. They do have, as well, in the study and I -- subject to check. I can't recall the page, but they also have put caveats, as well, on some of the analysis.

MR. ELSON: If you can turn to page 74 of the document book, that's -- actually, my apologies, 72 of the document book. That's page 10 of the report. I'm going to ask you some questions about the chart in Exhibit 2.1.

This chart shows forecast of natural gas consumption in the Enbridge service area over time for a number of different DSM scenarios; is that right?

MR. FERNANDES: That is correct. It should be noted, however, that that is annualized demand, and this is a facilities application that's dependent on peak hour.

MR. ELSON: Thank you. And the top line is the reference case. That is, the forecast growth with no DSM; is that right, Ms. Oliver-Glasford?

MS. OLIVER-GLASFORD: That's my understanding, yes.

MR. ELSON: Now, I'm directing my questions to you not as any derision to you, Mr. Fernandes, but just asking your DSM experts, of course.

And the next line down is a scenario with a DSM budget of $20 million; is that correct?

MS. OLIVER-GLASFORD: Yes, that's correct.

MR. ELSON: Now, it's a bit hard to read, but the next two lines down are almost touching and next to each other, very close to the third line. And they are the scenarios with 40- and $60 million DSM budgets?

MS. OLIVER-GLASFORD: That looks to be right.

MR. ELSON: And in these last two scenarios with 40- and $60 million budgets, Marbek forecasts overall declining annual growth; is that correct?

MS. RAMSAY: The potential study considered the period from 2007 to 2017. It was not intended to forecast beyond 2017. It was intended to assess what the technical, economic, and achievable potential for DSM programs would be in the franchise area up to 2017.

MR. ELSON: Yes, of course. It's not projecting up to 2025, but the trend from 2002 to 2017. In the reference case, you have significant increasing demand, and then in the $40 million budget and $50 million budget scenarios, you have a decreasing trend in demand.

And I just want to confirm with you that I'm reading this chart correctly.

MS. OLIVER-GLASFORD: Yes, you are reading it correctly and those numbers are for the whole franchise. So not just this area.

MR. ELSON: Thank you. Could you turn to tab 11, which is the Enerlife report?

MS. OLIVER-GLASFORD: Could you provide a page reference?

MR. ELSON: My apologies, it’s page 19. In specific, I would like to refer you to the next page, which is page 20, and I'm going to read this paragraph to you and just ask you a basic question.

The authors of this report say, and I'm quoting from infrastructure, there's an entirely different risk situation there.

MR. ELSON: I guess my question was the -- well, I'll move on. I think that's a sufficient answer.

I'll ask you about some of the other benefits of DSM in addition to those that are accounted for in your TRC test. Could you please turn to tab 21 of the Environmental Defence document book, which is page 75? This is an interrogatory. It's IR No. 6 from Enbridge's most recent DSM case.

And in this interrogatory, we put to Enbridge a report from the Canadian Council of Chief Executives, and in that report there was a conclusion that:

> "Fundamentally, however, Canada needs to begin with a renewed commitment to energy conservation. We must use existing and future energy supplies as efficiently as possible, embracing the maxim that the cheapest form of energy is the unit that is not used. Better conservation practices will help insulate Canadians from volatile energy prices, reduce costs for public institutions such as hospitals, and improve the international competitiveness of Canadian companies."

In response to that, Enbridge said that Enbridge generally agrees, and I'm reading from page 76:

> "Enbridge generally accepts that a sustained focus on energy efficiency assists with the long-term environmental sustainability and economic

"competitiveness of the province."

And it also concludes that:

"Energy efficiency helps customers lower their overall energy usage, which in turn reduces one input cost for businesses."

Would Enbridge stand by its response to this interrogatory in this proceeding as well?

MR. FERNANDES: The company does believe in sustainability, so yes.

MR. ELSON: In particular, would you agree that a sustained focus on energy efficiency assists with the economic competitiveness of the province?

MR. FERNANDES: We would agree with that, and say that efficiency in general helps with competitiveness of the province.

MR. ELSON: And that's in part because it reduces one input cost for businesses.

If you could turn over to tab 22, which is page 82 of the Environmental Defence cross-examination document book, this is Interrogatory No. 7 from the DSM case.

And we asked Enbridge about Canadian companies needing to increase productivity and investment, and about a report by Dr. Ernie Stokes quantifying the economic benefits of natural gas DSM in terms of increased GDP, increased employment, decreased deficits and the like.

And I'm going to read the response that Enbridge provided. Enbridge said:

"Mark Carney's remarks that increased investment results in increased productivity appear reasonable. It is the understanding of the company that pervasive economic theory does suggest that higher productivity may lead to higher wages, profits and government revenues. Enbridge believes that when a business participates in DSM programs and invests in energy efficiency upgrades, all other things being equal, it may see increases in productivity. While Enbridge cannot specifically predict the future impacts of DSM on overall productivity and GDP, it believes that DSM initiatives can be a factor in elevated productivity and thus, GDP."

Does Enbridge still believe in those statements?

MS. OLIVER-GLASFORD: Yes, I do.

MR. ELSON: Thank you. Would Enbridge agree, or would you agree, Ms. Oliver-Glasford, that Enbridge's DSM programs create jobs in Ontario, including energy contractors and the like?

MS. OLIVER-GLASFORD: That's certainly something that's been discussed. And I would agree that there's probably jobs created through DSM, yes.

MR. ELSON: Most of the dollars spent through Enbridge's DSM programs would be spent in Ontario; is that right?

MS. OLIVER-GLASFORD: We wish there were more DSM evaluation companies in Ontario, but that said, most of the

DSM dollars would stay in the province.

MR. ELSON: Most would be spent in Ontario; is that -- thank you.

And much of the savings from DSM programs come from avoided gas costs, which is money that would have largely gone to natural gas producers and places outside the province, such as the US northeast; is that a fair statement?

MR. FERNANDES: I believe it's fair to say that the commodity portion would by and large come from outside of the province, not specifically the US northeast.

MR. ELSON: That was just an example; but yes?

MR. FERNANDES: Yes.

MR. ELSON: On the other hand, most of the savings from this proposed pipeline come from gas supply benefits which would require a shift of dollars away from TCPL and gas producers in western Canada, towards gas producers in the US northeast; is that correct?

MR. FERNANDES: The economic benefits presented in the project, one of the benefit streams has to do with changes in our transportation contracts that shift from long-haul discretionary services to short-haul firm contracting.

MR. ELSON: I would like to move onto a different area, which is, you know, again, a no-growth scenario. I have just a couple brief questions on this point.

I believe on Thursday, Mr. Fernandes, you stated that Enbridge allocated approximately 800 tJs per day of segment A to Enbridge's distribution needs in the GTA area; is that correct?

MR. FERNANDES: That is correct.

MR. ELSON: Is that the amount that would be needed to address forecast load growth?

MR. FERNANDES: The 800 terajoules a day the project proposes to bring in on segment A, the distribution system at Albion station, is made up of 600 terajoules a day that would be shifted from long-haul discretionary transport contracts to short-haul firm.

The other 200 terajoules a day is existing gas flows that's come into Parkway from upstream providers that is being shifted from the suction side to the discharge side, in order to move it further into the distribution system at Albion, and that would allow – you know, the distribution system capacity is available for future load growth of additional 200. But the gas supply plan as presented doesn't have that future growth included in it.

MR. ELSON: So would you say that 200 tJs is the amount that is needed to address load growth? I'm trying to figure out an amount of this pipe that is allocated, or that we can think of as being necessary for load growth. Would 200 tJs be a fair estimate?

MR. FERNANDES: I believe the number that’s presented in our market forecast section is 190 terajoules per day over the forecast period.

MR. ELSON: And the current proposal is a 42-inch pipe for segment A?

MR. FERNANDES: That is correct.

MR. ELSON: So let's say that there wasn't any load growth from today forward, and the 200 tJs per day was not needed for load growth. What size would the pipe need to be to address the remaining purposes of the project, but not load growth?

MR. FERNANDES: We believe the 42-inch pipe size is appropriate.

MR. ELSON: I know you do. I'm asking how much you could decrease that if you weren't accounting for load growth.

I understand it's probably not going to be a large amount, but it would be helpful to have that estimate, if we were to take growth out of the scenario.

MR. FERNANDES: If you were to leave off 190 terajoules per day in requirements over that forecast period, the company would still be proposing 42-inch pipeline.

We believe that it's required for building out the capacity for market access from Parkway through to Maple. We have the results on the record of our open season of over 932 terajoules a day, plus the company's requirements.

We don't believe an NPS 36, which would be the next standard pipe size lower, is in the interests of either distribution or transmission ratepayers in the long run.

MR. ELSON: So you think that the 42 could be used completely just for transmission purposes and for shifting your supply input, so you that can achieve the gas supply savings? You don't need it for demand growth; is that right?

MR. FERNANDES: No, you said in a no-load-growth scenario. We have load growth, and that is what we're projecting.

MR. ELSON: I'll ask the question from the other side. If the only thing that you were attempting to address was load growth, how large would that pipe need to be?

Now, I am not including gas supply benefits, or shifting from Victoria Square to Parkway. If you just needed it for load growth, how big would the pipe need to be?

MR. FERNANDES: I think it's already on the record that if we were looking at a load-growth-only scenario, with none of the other limitations of the system being addressed, that we would be looking at expanding the north-south section of segment B only.

However, that is not what the company is proposing, because of the other important limitations on our system.

MR. ELSON: In other words, if it was load growth only, you wouldn’t need segment A, and you wouldn't need the east-west portion of segment B; you would just need the north-south portion of segment B; is that right?

MR. FERNANDES: Under the hypothetical situation where we were looking to only address load growth, that is correct.

MR. ELSON: Thank you. And now with respect to the north-south portion, is that size -- could that be decreased, if you were only addressing load growth and weren't addressing other issues such as the SMYS pressure issue?

MR. FERNANDES: I think Mr. Naczynski will be able to fill in a little bit more. It's theoretically possible, but under the consideration where it is intended to tie into an existing NPS 36, that would create all sorts of operational issues for us.

NPS 36 has been the most common pipe size for us to expand the backbone of our extra high pressure grid over the last two decades, and the reasons are is that is that’s the most economic size for capacity for a distribution system.

MR. ELSON: Thank you. I would like to ask some questions in relation to Environmental Defence document book number 2 -- which isn't actually much of a document book; it's actually just one document.

I believe that copies were provided to Panel members and Mr. West, I think, has copies there. So if you could turn them up, that would be much appreciated.

MR. MILLAR: We'll give that an exhibit number. K5.1.

EXHIBIT NO. K5.1: ENVIRONMENTAL DEFENCE CROSS-EXAMINATION MATERIALS, BOOK 2

MR. ELSON: As you can see, this document was recently released by the Ministry of Energy, and it relates, of course, to electricity. But I would like to ask you some questions based on it, in relation to natural gas, of course.

And this is the document entitled "Conservation First,

a Renewed Vision for Energy Conservation in Ontario".
Two pages in, you have Minister's message, and Minister says:
"Conservation is the cleanest and least costly energy resource and offers consumers a mean to reduce their electricity bills."
My question is simple, which is: Do you believe that that statement would apply also to natural gas?
MS. OLIVER-GLASFORD: Yes, we would agree with that statement for natural gas.
MR. ELSON: Thank you. On the next page over, in the underlined portion, it says:
"Reducing or shifting electricity use avoids the need for new generation as well as transmission, reduces strain on the electricity system, and improves the efficiency of the power grid."
Would you agree that the same is true with respect to natural gas -- of course acknowledging that instead of new generation, it's new supply, and instead of the electricity system, it would be the Enbridge pipeline system as well as the transmission system?
MR. FERNANDES: We do agree that energy efficiency is important; it's for our customers. However, I don't think we can agree with that analogy, in particular with respect to the limitations that we described at the beginning of our testimony.
So I don't think there's a role in efficiency in terms of providing diversity of path, or operational flexibility

within our system in addressing some of the supply consequences that we currently face within our system.

So I'm not saying that energy efficiency is not a social good. Enbridge is strongly supportive of that. But I don't think you can draw the conclusion across the board from an electrical for a natural gas system.

MR. ELSON: Now your specific application before the Board today has some unique aspects to it, and I'm not asking any questions about those unique aspects. I'm asking a question on a general level and perhaps I can break it down, which is to say: Would you agree that conservation can reduce the need for new pipelines by reducing demand?

MR. FERNANDES: Conservation can certainly help in reducing annual demand. We're not as certain about what it's direct impact on peak hour, and therefore on facilities.

But we believe it does have an impact, it's just not as certain.

MR. ELSON: If you could turn to the last page? This talks about the vision outlined in this paper with respect to electricity, and it says:

> "Ontario's vision is to invest in conservation first before new generation, where cost-effective."

And further down, the underlined portion:

> "Conservation should be the first resource considered in meeting Ontario's electricity

needs. Cost-effective conservation brings environmental, economic, and system benefits."

Would you agree that gas conservation also brings environmental, economic, and system benefits?

MR. FERNANDES: We do agree with that, and we do agree that it should be used where cost-effective.

MR. ELSON: Do you agree that gas conservation should be the first option considered before supply-side transmission and distribution investments?

MR. FERNANDES: It depends on the objective. As we stated, we have some very important system limitations in this particular case. We're looking for diversity.

Some of the items, such as providing a second feed into the downtown core, I don't see how energy efficiency could possibly do that. We also have considerations of reducing the pressure on our oldest, highest-stress lines, which is dealing with aging infrastructure. And I don't believe that energy efficiency can have a significant impact on those requirements.

MR. ELSON: Perhaps I'll revise my question. Would you agree that gas conservation should be the first option considered before supply-side transmission and distribution investments that are intended to address load growth?

MS. OLIVER-GLASFORD: Yes, they should be considered. However, I would note in Exhibit M, GEC.EGD.6, attachment A, the RAP report that outlines the US experience with efficiency as a transmission and distribution system resource, first of all, again, I think it's very important to point out that these are electricity-centric documents.

Electricity and gas are fundamentally different with how we can impact those peak demands, and also the impacts, if there is some sort of outage event, with getting people up and running again.

But that said, in that report, in the executive summary, (iii), you know, even National Grid, Rhode Island would agree that when you are doing these kind of focused geo-targeted offsets, you want to make sure that you don't have any other drivers other than load growth. And, you know, as I've heard Mr. Fernandes say, there is other drivers for this project other than load growth.

MR. ELSON: Ms. Oliver-Glasford, would you agree that Enbridge should pursue all feasible and cost-effective DSM -- i.e., with a TRC greater of one -- before seeking permission for new supply infrastructure intended to meet growing demand?

MS. OLIVER-GLASFORD: We have a responsibility to our customers to balance out various stakeholder input into what is an appropriate budget and approach to our DSM planning. And over a number of years through a very transparent and inclusive process, I believe we're at that appropriate point.

MR. ELSON: Going forward, would Enbridge agree to strive to eliminate load growth through DSM if it could do so with cost-effective programs with a positive TRC benefit-cost ratio?

MS. OLIVER-GLASFORD: I believe we would certainly

MR. ELSON: Current average use.

MR. FERNANDES: Just like we hold dollars constant into the future for the economic feasibility, we hold the other rates and inputs constant as well. And that ensures that you have consistency in terms of calculations for comparability.

MR. ELSON: Thank you, and my final few questions are in relation to Enbridge's examination of DSM.

Does Enbridge believe it is required, as part of this application, to provide evidence that is sufficient to establish whether DSM is a feasible or preferable alternative to the project?

MR. FERNANDES: I believe we already have.

MR. ELSON: And you believe that's a requirement of this application?

MR. FERNANDES: We included it because we thought it was relevant.

MR. ELSON: I would like to ask you a few questions about the studies in the examination that Enbridge did to assess DSM as an alternative.

I believe I had the answers from you, Mr. Fernandes, at the technical conference, but I want to just confirm that my understanding is correct.

I believe, Mr. Fernandes, you said at the technical conference that DSM was screened out in 2011; is that correct?

MR. FERNANDES: That is correct.

MR. ELSON: And that was done at a meeting?

MR. FERNANDES: That was done over a course of several.
MR. ELSON: And no documentation was created?
MR. FERNANDES: I believe we have documentation.
MR. ELSON: I believe that at the technical conference, I asked for documentation and you said that none existed.
So perhaps I'll ask for the documentation that was created when DSM was screened out as an alternative. Could you provide that?
MR. FERNANDES: The screening process involved a number of parties internal to the company, across a wide variety of functional areas, and they went through a series of workshops in order to screen through potential alternatives, looking at all of the limitations.
So there is a large body of work. Some of it is not easily producible, but I think we can provide some presentation material on check points and approvals, if that would be --
MR. ELSON: I do not want all of your screening analysis of all your alternatives.
What I'm looking for is a document that was created in 2011 at one of these meetings that describes why DSM was screened out.
My understanding from the technical conference -- you said there was nothing to provide. So if there is something to provide, if you could provide it by way of undertaking it would be appreciated.

MR. FERNANDES: So specific to DSM, those were working meetings. There is mention in discussion on looking at DSM, but I -- I could look at the documentation. I don't think there's a lot of detail.

As we described in the technical conference, when we looked at the limitations that we're looking to address, or the objectives of the project, it was an order of magnitude that we looked at with respect to DSM.

When we look at what we -- you know, our DSM group has provided some desktop assumptions stating that we can get approximately 12 10^3m^3 reduction in peak load hour based on our present DSM programs. And we look at the order of magnitude of the things that are trying to be achieved, such as the 600-terajoule shift, it's orders of magnitude, factors of 30 or 60 times, in order to achieve something like that at DSM. And in terms of those working meeting discussions with a broader group, we screened it out as being something that can't possibly be achieved.

MR. ELSON: So I think what you are referring to there is the 30 percent SMYS criteria. And what you would need is 20-fold increase in DSM to meet the 30 percent SMYS criteria. So you decided in a meeting: We shouldn't even bother looking at DSM. Is that an accurate description?

MR. FERNANDES: We looked at it. We understood the rough order of magnitude. It's not just the pressure reduction. The pressure reduction would give you -- I believe it's about a 20X order of magnitude, but the supply shift in order to get the discretionary services over to short-haul firm is 3X that.

So there's multiple objectives that would state that you can't possibly do this with energy efficiency measures. So it was screened out.

MR. ELSON: So you screened it out because it couldn't achieve your gas supply benefits and it couldn't achieve your pressure reduction --

MR. FERNANDES: And it couldn't achieve the second feed into downtown Toronto, or the flexibility or diversity within the extra high-pressure system.

So there's multiple objectives that, while energy efficiency is good and we recognize it can have an impact on load growth, it can't possibly achieve those other objectives.

And what we tried to articulate in the technical conference, that one of the reasons why Enbridge wanted to look at all these together is because several of those objectives dealing with those limitations on our current system are coincident. So it's much better for us to look at them in aggregate, to ensure that we can bring out any economies that are available to address them all.

MR. ELSON: So you didn't undertake any studies or reports of DSM or a detailed analysis, because you were able to rule it out as an option to address all of the purposes early on in the process; is that right?

MR. FERNANDES: That's correct.

MR. ELSON: And Enbridge didn't produce any studies or reports to analyze whether DSM might satisfy only one or two of the project purposes? It was just screened out because it couldn't address all of them; is that right?

MR. FERNANDES: It's a much more detailed discussion than that. I wouldn't portray it that way.

Effectively -- I think we've already gone through this -- when we looked at the solutions, DSM was screened out fairly early in the process, but in terms of having an impact on the facilities, the load growth portion, as we stated, is dependent -- if we were to do it alone, is dependent on the north-south piece of our segment B.

And our segment B is connecting a 36-inch pipeline to a 36-inch pipeline within our system. The operational limitations that that would place in things like our integrity management programs for in-line inspection, among other things, the economies of scale of using larger parameter pipe meant that there would be no capability to downsize the facilities, either.

So it's not quite as simplistic But we basically screened it out because it does not have an impact on the facilities in order to meet the objectives of the project.

MR. ELSON: Thank you. I have no further questions.

MS. CHAPLIN: Thank you. We will rise now for our break for 30 minutes.

--- Recess taken at 11:16 a.m.

--- On resuming at 11:48 a.m.

MS. CHAPLIN: Please be seated. So next on my list is CME and CCC. Ms. Dullet, I believe you’re -- and the estimate we were given, the commitment we were given was thirty minutes.

CROSS-EXAMINATION BY MS. DULLET:

MS. DULLET: I won’t be longer than that.

Good morning, I am Kim Dullet, here on behalf of the CME, and I also have some questions to ask on behalf of the CCC this morning.

The majority of my questions relate to DSM. More specifically, we are interested in EGD's perspective on the evidence that has been filed in these proceedings by GEC and ED.

To that end, I would first turn to Exhibit L.EDG.GEC.2, which is the evidence of Chris Neme and Jim Grevatt.

So my first question. At page 4 of the evidence, the report states that EGD has never really considered DSM as a potential peak capacity resource. Is this something that EGD could do, essentially use DSM to avoid or defer capital investments required for peak demand?

MS. OLIVER-GLASFORD: We would have to do extensive studying in order to understand the relationship between peak and annual for all of the technologies and for DSM overall.

MS. DULLET: Is that why it hasn't been done to date?

MS. OLIVER-GLASFORD: Certainly up to this point, our DSM framework and discussions have emphasized broad-based equal access programs, DSM programs for our customers.

MS. DULLET: Okay. If we look at page 7 of the same report, at the very bottom of the page -- and I'll read out

MR. FERNANDES: Yes, we are.

MR. POCH: And your concern is about the winter peak?

MR. NACZYNSKI: That's correct.

MR. POCH: Can you identify – are there other areas of the system that are operating above 30 percent SMYS, other than the ones you've identified specifically for this -- trying to address in this project?

[Witness panel confers]

MR. NACZYNSKI: Enbridge has a number of what we characterize as higher stress lines and I believe, subject to check, about 280 kilometres of pipeline above 30 percent SMYS.

MR. POCH: Do you have projects that you are applying this Board to change that for those other pipelines?

MR. NACZYNSKI: What you're referring to there is some of the design philosophy and guidelines that Mr. Thalassinos can speak to. But certainly what I can say is that certainly directionally, Enbridge is seeking to be able to operate those lines at lower pressures.

MR. POCH: But you're not proposing to build to get around the problem, if you can't otherwise deal with it?

MR. NACZYNSKI: When the system or ability to manage the system reaches a point where -- for example, in this case, we have challenges meeting peak, peak hourly pressure constraints on the system, one of the requirements that my team and system analysis would look at is what infrastructure we require to not only to meet our load growth or other challenges on the system, but also

EB-2012-0451, EB-2012-0433, EB-2013-0074
Filed by Environmental Defence on: 2013-09-16
Cross-Examination Document Book

Hourly Gas Demand in the GTA Area
(July 1, 2011 - June 30, 2012)

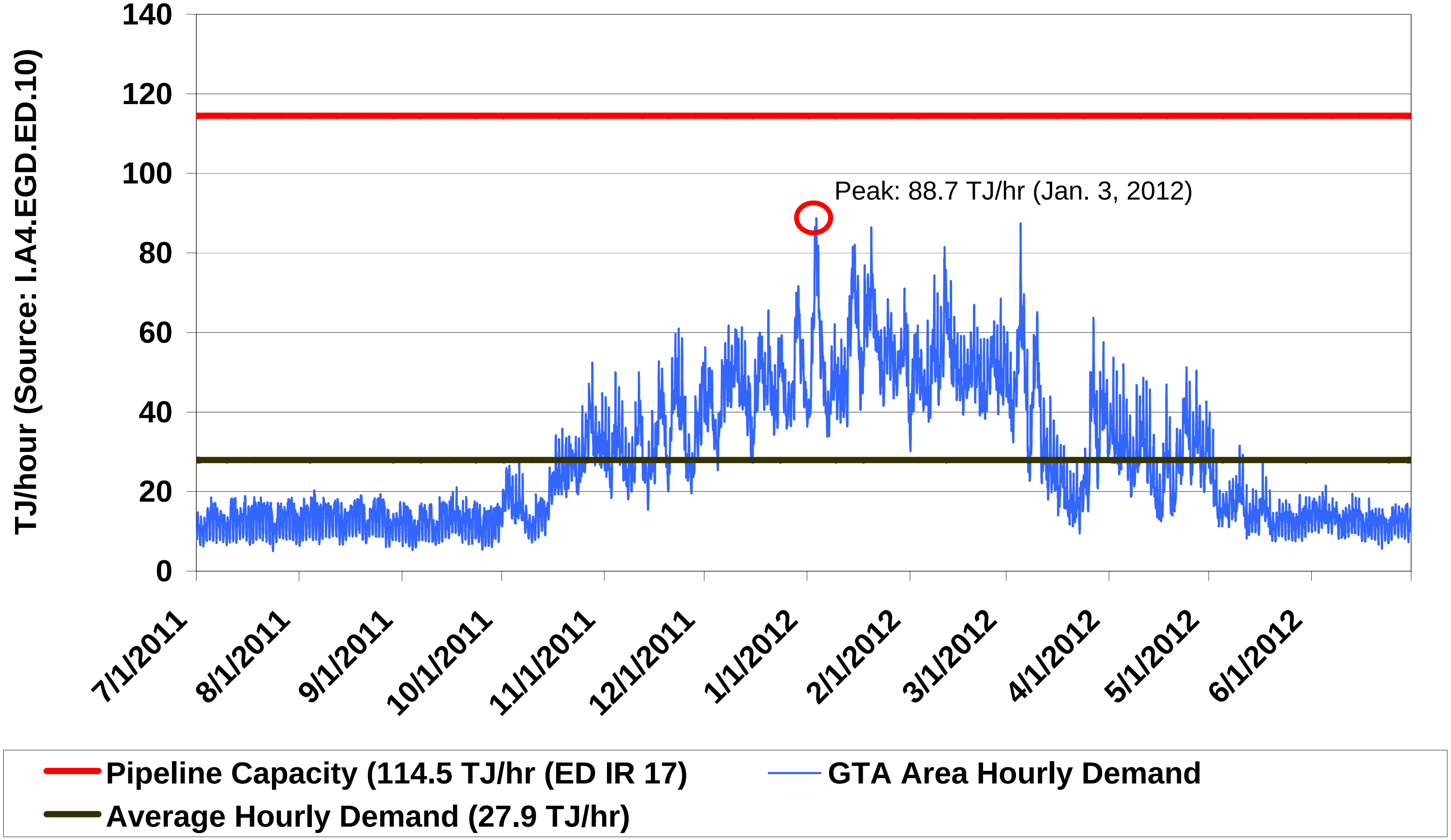


Table 1: Summary of Enbridge's Peak Load Forecast Calculations

		Demand from New Customers (Before Reduction Factor)[1]	35% Reduction Factor Amount[2]	Demand from New Customers (After Reduction Factor)[3]	Base (i.e. Demand from Existing Customers)[4]	Forecast Peak Demand[5]
	Year	m³/hr				
Baseline	2011-2012			46,793		2,889,984
Forecast	2012-2013	33,691	11,792	21,899	2,889,984	2,911,883
	2013-2014	32,908	11,518	21,390	2,911,883	2,933,273
	2014-2015	33,565	11,748	21,817	2,933,273	2,955,090
	2015-2016	35,282	12,349	22,933	2,955,090	2,978,023
	2016-2017	35,812	12,534	23,278	2,978,024	3,001,302
	2017-2018	35,223	12,328	22,895	3,001,302	3,024,197
	2018-2019	35,238	12,333	22,905	3,024,197	3,047,102
	2019-2020	35,351	12,373	22,978	3,047,102	3,070,080
	2020-2021	35,594	12,458	23,136	3,070,080	3,093,216
	2021-2022	35,842	12,545	23,297	3,093,216	3,116,513
	2022-2023	35,842	12,545	23,297	3,116,513	3,139,810
	2023-2024	35,842	12,545	23,297	3,139,810	3,163,107
	2024-2025	35,842	12,545	23,297	3,163,106	3,186,403
	Total	456,029		296,419		

Sources and caluclations:

[1] Calculation: Demand from New Customers (After Reduction Factor) divided by 0.65

[2] Calculation: Demand from New Customers (After Reduction Factor) minus Demand from New Customers (Before Reduction Factor)

[3] Source: I.A4.EGD.ED.3 (TOTAL ADD).

[4] Calculation: Forecast Peak Demand minus Demand from New Customers (After Reduction Factor).

[5] Source: I.A4.EGD.ED.3 (TOTAL LOAD).

Table 2: Summary of Enbridge's DSM Evidence

DSM Required to Offset Growth in the GTA Area

	Peak Demand Reduction from Forecast DSM (m^3/hr)[1]	Incremental Peak Demand Reduction needed to Offset Growth (m^3/hr)[2]	Total Peak Demand Reduction needed to Offset Growth (m^3/hr)[3]
2014	12,000	25,000	37,000
2015	12,000	25,000	37,000
2016	12,000	25,000	37,000
2017	12,000	25,000	37,000
2018	12,000	25,000	37,000
2019	12,000	25,000	37,000
2020	12,000	25,000	37,000
2021	12,000	25,000	37,000
2022	12,000	25,000	37,000
2023	12,000	25,000	37,000
2024	12,000	25,000	37,000
2025	12,000	25,000	37,000

Incremental DSM Budget and TRC Benefits From Incremental DSM Needed to Offset Growth

	Forecast DSM Budget for the GTA Area[4]	Incremental DSM Budget Needed to Offset Growth (Yearly)[5]	Incremental net TRC Benefits (Yearly)[6]	Incremental net TRC Benefits (Cumulative)[7]
2014	$ 15,824,016	$ 33,730,415	$ 140,654,152	$ 140,654,152
2015	$ 16,140,496	$ 34,405,024	$ 140,654,152	$ 281,308,304
2016	$ 16,463,306	$ 35,093,124	$ 140,654,152	$ 421,962,456
2017	$ 16,792,572	$ 35,794,987	$ 140,654,152	$ 562,616,608
2018	$ 17,128,424	$ 36,510,886	$ 140,654,152	$ 703,270,760
2019	$ 17,470,992	$ 37,241,104	$ 140,654,152	$ 843,924,912
2020	$ 17,820,412	$ 37,985,926	$ 140,654,152	$ 984,579,064
2021	$ 18,176,820	$ 38,745,645	$ 140,654,152	$ 1,125,233,216
2022	$ 18,540,357	$ 39,520,557	$ 140,654,152	$ 1,265,887,368
2023	$ 18,911,164	$ 40,310,968	$ 140,654,152	$ 1,406,541,520
2024	$ 19,289,387	$ 41,117,188	$ 140,654,152	$ 1,547,195,672
2025	$ 19,675,175	$ 41,939,532	$ 140,654,152	$ 1,687,849,824

Sources and calculations:

[1] Source: I.A4.EGD.ED.14 (Note the assumptions and data caveats listed on pg. 2)

[2] Source: JT2.36, p. 8

[3] Calculation: "Peak Demand Reduction from Forecast DSM" plus "Incremental Peak Demand Reduction needed to Offset Growth"

[4] Source: I.A4.EGD.ED.14 (Note the assumptions and data caveats listed on pg. 2)

[5] Calculation: "Total GTA Area DSM Budget Needed to Offset Growth (from JT2.20)" minus "Forecast GTA Area DSM Budget (from I.A4.EGD.ED.14)"

[6] Source: JT2.20

[7] Calculation: Cumulative tally of the yearly totals

UNDERTAKING JT2.27

UNDERTAKING

TR 2, page 149

To provide declining average use trends per customer and per sector. Include equation used for regression

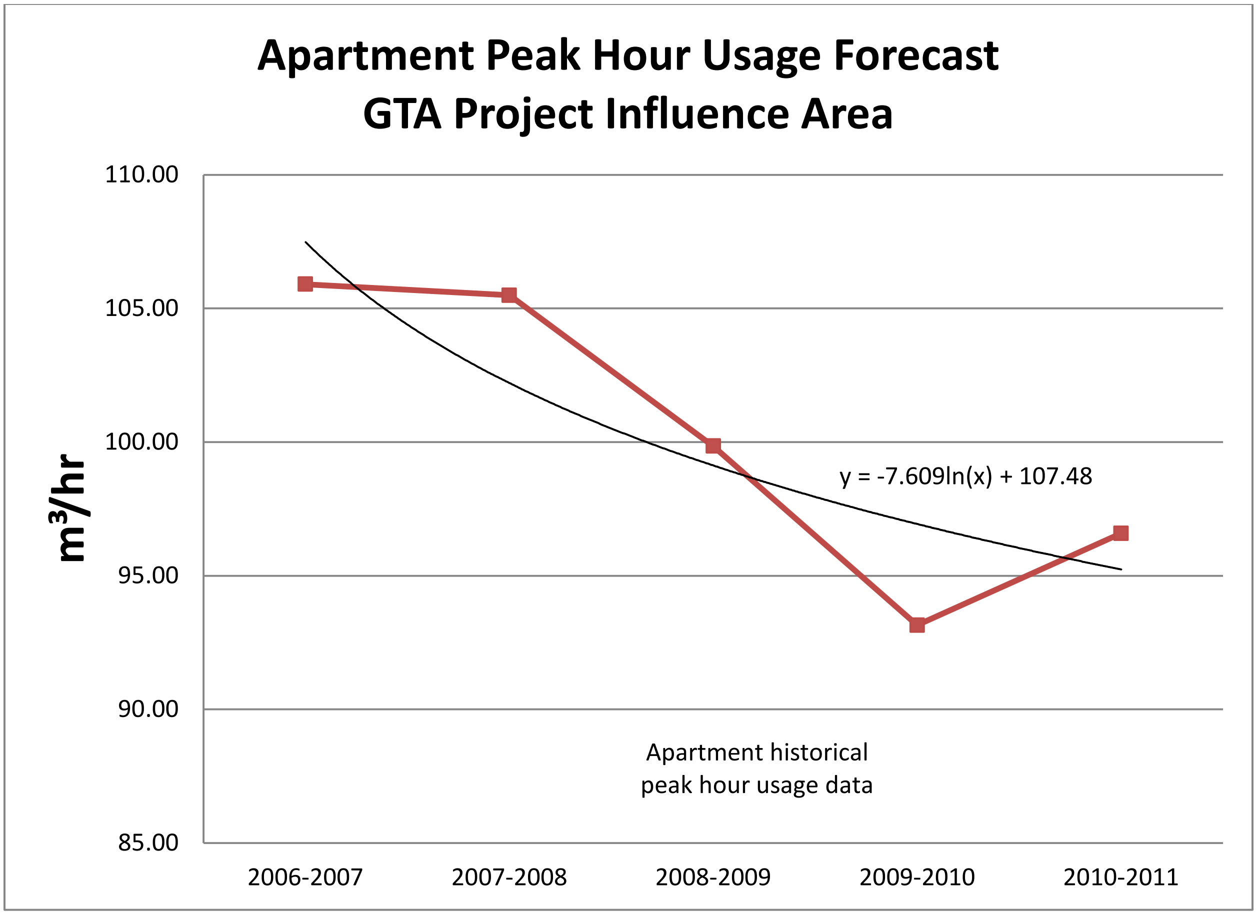
RESPONSE

The figures provided on the following pages illustrate the declining peak average usage trends for each sector. The average peak hourly usage forecast was prepared by collecting five years of load gathering data and using lograrithmic trend lines.

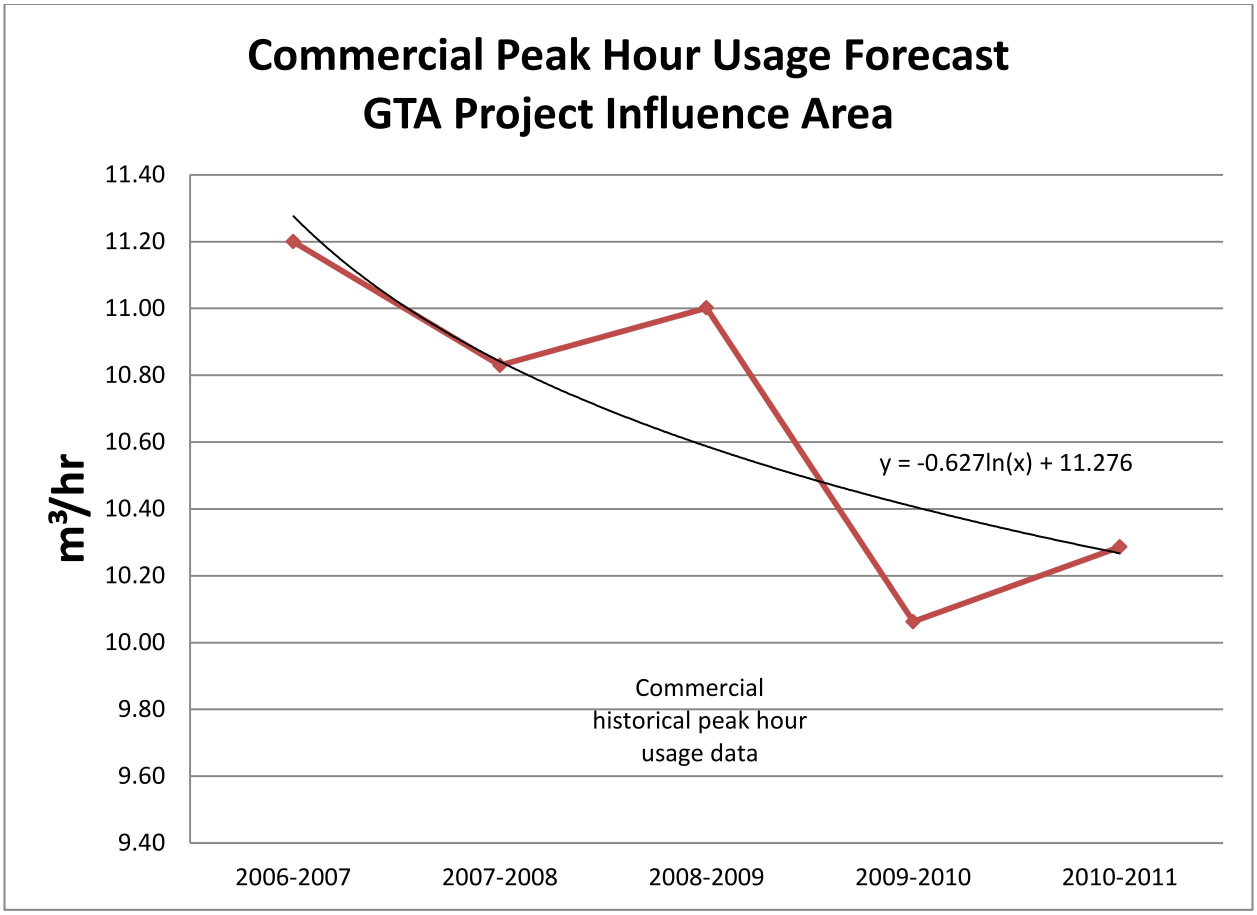
5 years historical data: *2006, 2007, 2008, 2009, 2010*
4 types of customers: *Apartment, Commercial, Industrial, Residential*

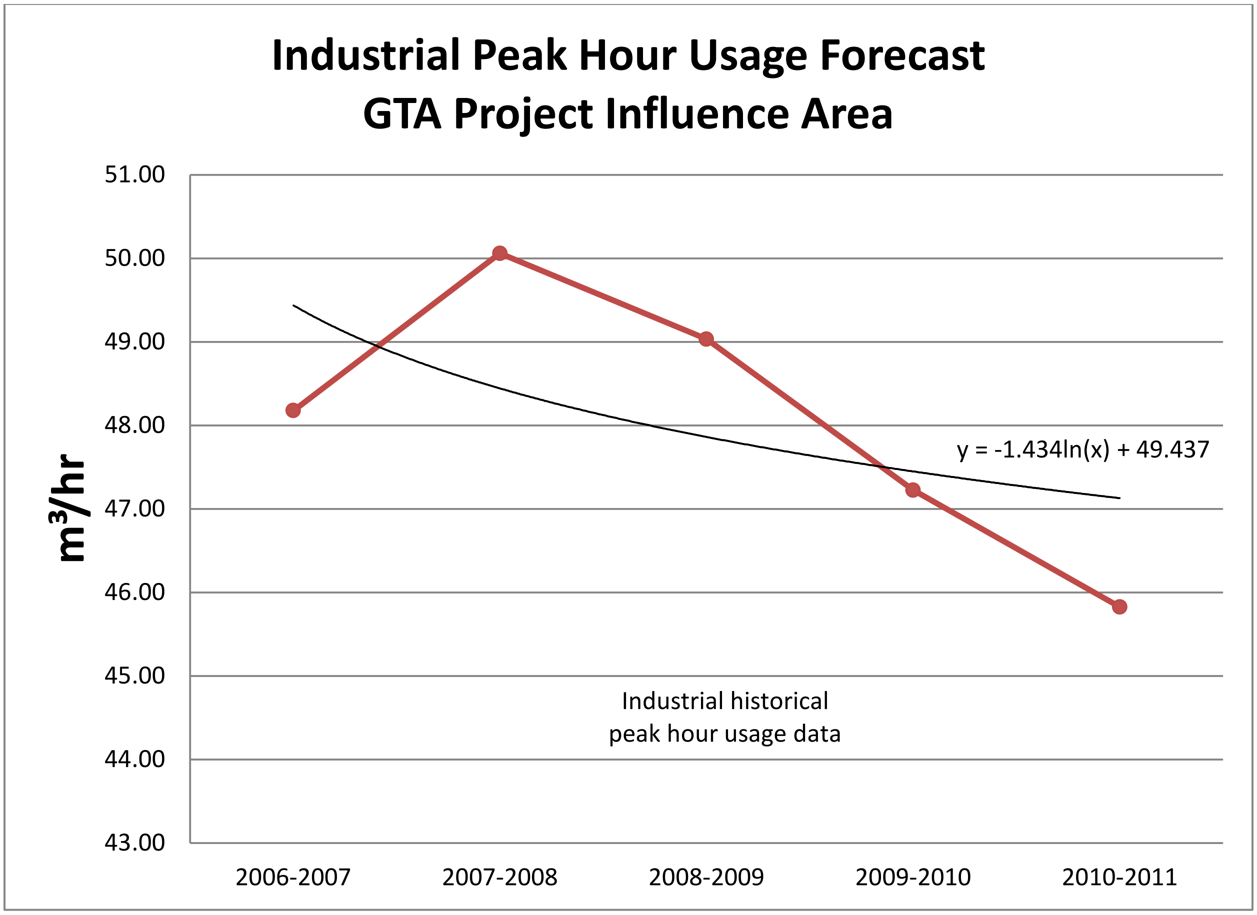
Data has only been provided for 2006 to 2010 as Enbridge implemented a new load gathering system. Prior to 2004, load gathering was completed on a legacy main frame system and the archived data is not readily accessible. From 2004 to 2006 there were numerous changes in customer classifications which make year to year comparisons irrelevant due to changing base data. The load presented excludes unbundled customers. A description of the load gathering process for network planning purposes can be found in the response to Environmental Defence Interrogatory #12 found at Exhibit I.A4.EGD.ED.12.

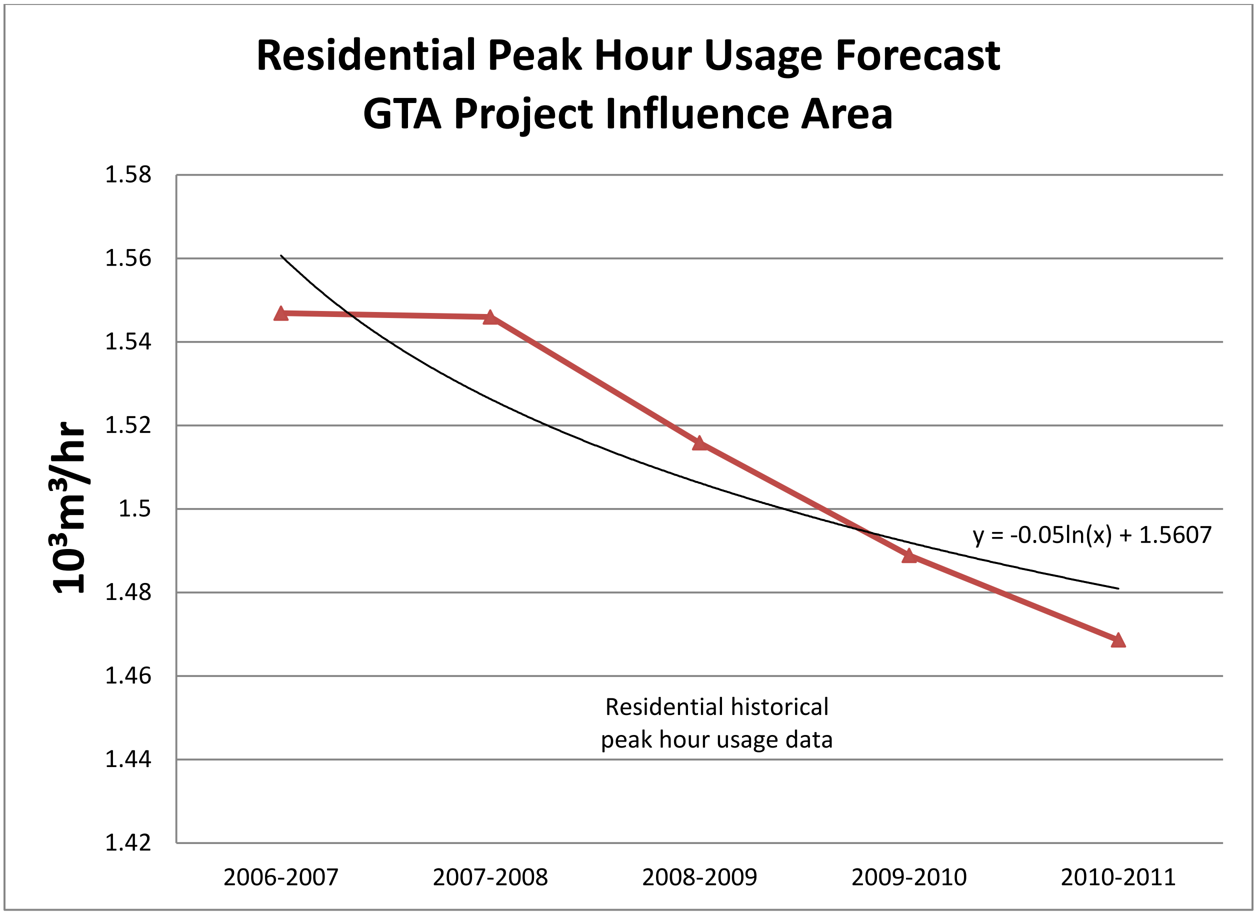
Witness: E. Naczynski


Apartment Peak Hour Usage Forecast
GTA Project Influence Area
110.00
105.00
100.00
95.00
90.00
85.00
m³/hr
y = -7.609ln(x) + 107.48
Apartment historical
peak hour usage data
2006-2007
2007-2008
2008-2009
2009-2010
2010-2011

Filed: 2013-06-18
EB-2012-0451
Exhibit JT2.27
Page 3 of 5




Industrial Peak Hour Usage Forecast
GTA Project Influence Area
m³/hr
51.00
50.00
49.00
48.00
47.00
46.00
45.00
44.00
43.00
y = -1.434ln(x) + 49.437
Industrial historical
peak hour usage data
2006-2007
2007-2008
2008-2009
2009-2010
2010-2011



Witness: E. Naczynski

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #12

INTERROGATORY

Issue A4: "What are the alternatives to the proposed facilities? Are any alternatives to the proposed facilities preferable to the proposed facilities?"

Reference: Ex. A, Tab 3, Schedule 4, page 1

Please fully describe the methodology and assumptions for Enbridge's annual residential, commercial, apartment and industrial customer load growth forecasts from 2013 to 2025 inclusive in the GTA Project Influence Area. Please provide all written analyses and spreadsheets justifying the forecast.

RESPONSE

The Company does not measure peak hourly or daily consumption for the vast majority of its customers. Peak hourly load growth is derived from actual customer consumption volumes extracted from Enbridge's billing system. The customer consumption volumes are used to derive the peak hourly consumption forecast.

An extract of 24 months of actual customer consumption volumes and corresponding temperature readings are used in a mathematical regression to determine the base load and heat load for each customer. The base load and heat load are aggregated to sector (residential, apartment, commercial, industrial) within each municipality every year. These two values collectively result in peak hourly consumption estimates that are applied accordingly within the study area for the forecast period. A summary of peak hour consumptions broken down by customer sector and municipality is included in the response to Environmental Defence Interrogatory #13 found at Exhibit I.A4.EGD.ED.13. The customer additions forecast has been provided in the response to Environmental Defence Interrogatory #2 found at Exhibit I.A4.EGD.ED.2. A summary of total load in the influence area and by customer sector is included in the response to Environmental Defence Interrogatory #13 found at Exhibit I.A4.EGD.ED.13.

The network analysis model also factors in the declining average use consumption trend. The declining average use is calculated through a mathematical regression using the last five years of derived peak hourly consumption estimates by municipality by, customer sector. This declining average use values are then applied to forecast customer additions throughout the study period. The network analysis models are refreshed on an annual basis to factor in updated values for peak hourly consumption.

For the purposes of the GTA Project an additional reduction factor was also applied to the future load additions. This reduction factor is explained in Environmental Defence Interrogatory #13 found at Exhibit I.A4.EGD.ED.13 part c).

SUMMARY OF INPUTS

Incremental Customer Additions

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Residential	12,277	12,607	13,034	13,148	13,331	13,535	13,748	13,748	13,748	13,748
Commercial	1,291	1,327	1,250	1,253	1,250	1,261	1,269	1,269	1,269	1,269
Apartment	71	71	69	69	68	67	67	67	67	67
Industrial	3	3	2	2	2	2	2	2	2	2
Total	**13,642**	**14,008**	**14,355**	**14,472**	**14,651**	**14,865**	**15,086**	**15,086**	**15,086**	**15,086**

Average Annual Volume per Customer

($10^3 m^3$)	
Residential	2.568
Commercial	20.230
Apartment	154.877
Industrial	109.481

Total Cumulative Volumes*

($10^3 m^3$)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential	15,764	47,715	80,638	114,255	148,254	182,750	217,782	253,087	288,392	323,696	341,349
Commercial	13,058	39,540	65,606	90,924	116,242	141,640	167,231	192,903	218,575	244,247	257,083
Apartment	5,498	16,494	27,336	38,022	48,631	59,086	69,462	79,839	90,216	100,593	105,781
Industrial	164	493	766	985	1,204	1,423	1,642	1,861	2,080	2,299	2,409
Total	**34,484**	**104,241**	**174,346**	**244,187**	**314,332**	**384,900**	**456,118**	**527,690**	**599,263**	**670,835**	**706,621**

Note* 50% effectivity considered for the first year of customer additions

Savings on Gas Transportation

($s)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Savings	**24,283,396**	**148,930,993**	**154,482,286**	**192,335,965**	**161,419,071**	**156,859,561**	**156,743,050**	**157,109,580**	**157,360,615**	**161,395,219**	**161,094,879**

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #5

INTERROGATORY

Issue A4: “What are the alternatives to the proposed facilities? Are any alternatives to the proposed facilities preferable to the proposed facilities?”

Reference: Ex. A, Tab 3, Schedule 4, page 4, Table 1

Please provide for each year from 2000 to 2025 inclusive the actual/forecast *total peak hour* demands (TJ/hour) and average peak hour demands (GJ/hour) of Enbridge’s: a) residential; b) commercial; c) apartment; and d) industrial customers in the GTA Project Influence Area. Please also provide the total peak hour demands for all of these customers for each year from 2000 to 2025 inclusive. Please also provide a further breakdown of the commercial customers by subsets such as offices, retail, hospitals, schools, etc.

RESPONSE

Peak load by sector is not measured on an hourly or daily basis. The Company does derive some of this data for network planning purposes as per the response to Environmental Defence Interrogatory #12 found at Exhibit I.A4.EGD.ED.12.
The information provided below is the historical data as used for network planning.

Table 1 (please see attachment) provides a summary of the historical and forecast derived peak load in m^3/hr from 2006 to 2025. This table shows peak load by customer type for all customers in the GTA Project Influence Area.

The Company does not have further breakdowns of the commercial sector for peak demand.

Data has only been provided for 2006 onward as EGD implemented a new load gathering system. Prior to 2004, load gathering was completed on a legacy main frame system and the archived data is not readily accessible. From 2004 to 2006 there were numerous changes in customer classifications which make year to year comparisons irrelevant due to changing base data. The load presented excludes unbundled customers.

The conversion from m^3 to GJ as found in the EGD rate handbook is 37.69 MJ/m^3

Witness: E. Naczynski

Table 1

PEAK LOAD (m3/hr)	Derived Historic						Forecast												
	2006-2007	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Apartment	410758	414932	404701	400992	410716	424455	428717	432326	436452	440674	444881	448893	452855	456806	460711	464600	468490	472380	476270
Commercial	896792	900775	916271	905314	902621	1112231	1119742	1126892	1134299	1142224	1150310	1157861	1165411	1172925	1180485	1188071	1195658	1203244	1210830
Industrial	352178	358798	336968	311336	324351	184774	184791	184807	184906	185008	185052	185094	185135	185175	185229	185282	185335	185388	185442
Residential	1203076	1225376	1230241	1220411	1205503	1168523	1178633	1189248	1199433	1210117	1221059	1232348	1243700	1255174	1266791	1278559	1290326	1302094	1313862
TOTAL LOAD	2862804	2899882	2888182	2838054	2843190	2889984	2911883	2933273	2955090	2978023	3001302	3024197	3047102	3070080	3093216	3116513	3139810	3163107	3186403

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #3

INTERROGATORY

Issue A4: "What are the alternatives to the proposed facilities? Are any alternatives to the proposed facilities preferable to the proposed facilities?"

Reference: Ex. A, Tab 3, Schedule 4, page 4, Table 1

Please provide for each year from 2000 to 2025 inclusive the actual/forecast average: a) peak hour (GJ/hour), b) peak day (GJ/day) and c) annual demands (GJ/year) of Enbridge's **incremental**: i) residential, ii) commercial, iii) apartment and iv) industrial customers in the GTA Project Influence Area. Please also provide the aggregate peak hour, peak day and annual demands of each of these customer classes and all of Enbridge's GTA Project Influence Area customers for each year from 2000 to 2025 inclusive.

RESPONSE

Peak load by sector is not measured on an hourly or daily basis. The Company does derive some of this data for network planning purposes as per I.A4.EGD.ED.12. The information provided below is the historical data used for network planning.

Table 1 (please refer to Attachment) provides a summary of the derived peak load in m^3/hr from 2006 to 2025. This table shows peak load by customer type in the GTA Project Influence Area for both incremental and total load added, as well as total load for all customers in the GTA Project Influence Area.

Table 2 (please refer to Attachment) provides all the same data as Table 1 but has converted the hourly data to daily.

Data has only been provided for 2006 onward as EGD implemented a new load gathering system. Prior to 2004, load gathering was completed on a legacy main frame system and the archived data is not readily accessible. From 2004 to 2006 there were numerous changes in customer classifications which make year to year comparisons

Witness: E. Naczynski

irrelevant due to changing base data. The load presented excludes unbundled customers.

The conversion from m^3 to GJ as found in the EGD rate handbook is 37.69 MJ/m^3.

Witness: E. Naczynski

Table 1

PEAK LOAD (m3/hr)		Derived Historic						Forecast												
		2006-2007	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Apartment	Base		410758	414932	404701	400992	410716	424455	428717	432326	436452	440674	444881	448893	452855	456806	460711	464600	468490	472380
	Add		4174	-10231	-3709	9723	13740	4262	3609	4126	4223	4207	4012	3962	3950	3905	3890	3890	3890	3890
	Total	410758	414932	404701	400992	410716	424455	428717	432326	436452	440674	444881	448893	452855	456806	460711	464600	468490	472380	476270
Commercial	Base		896792	900775	916271	905314	902621	1112231	1119742	1126892	1134299	1142224	1150310	1157861	1165411	1172925	1180485	1188071	1195658	1203244
	Add		3984	15496	-10957	-2693	209610	7511	7150	7407	7925	8086	7551	7550	7513	7561	7586	7586	7586	7586
	Total	896792	900775	916271	905314	902621	1112231	1119742	1126892	1134299	1142224	1150310	1157861	1165411	1172925	1180485	1188071	1195658	1203244	1210830
Industrial	Base		352178	358798	336968	311336	324351	184774	184791	184807	184906	185008	185052	185094	185135	185175	185229	185282	185335	185388
	Add		6620	-21830	-25632	13015	-139577	17	16	100	102	44	42	41	40	54	53	53	53	53
	Total	352178	358798	336968	311336	324351	184774	184791	184807	184906	185008	185052	185094	185135	185175	185229	185282	185335	185388	185442
Residential	Base		1203076	1225376	1230241	1220411	1205503	1168523	1178633	1189248	1199433	1210117	1221059	1232348	1243700	1255174	1266791	1278559	1290326	1302094
	Add		22301	4865	-9830	-14909	-36979	10110	10615	10185	10684	10941	11290	11352	11474	11617	11768	11768	11768	11768
	Total	1203076	1225376	1230241	1220411	1205503	1168523	1178633	1189248	1199433	1210117	1221059	1232348	1243700	1255174	1266791	1278559	1290326	1302094	1313862
TOTAL ADD			37078	-11700	-50128	5137	46793	21899	21390	21817	22933	23278	22895	22905	22978	23136	23297	23297	23297	23297
TOTAL LOAD		2862804	2899882	2888182	2838054	2843190	2889984	2911883	2933273	2955090	2978023	3001302	3024197	3047102	3070080	3093216	3116513	3139810	3163107	3186403

Table 2

PEAK LOAD (m3/day)		Derived Historic						Forecast												
		2006-2007	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Apartment	Base		8215167	8298645	8094030	8019841	8214310	8489106	8574342	8646519	8729035	8813487	8897622	8977861	9057107	9136116	9214211	9292008	9369805	9447603
	Adds		83478	-204615	-74189	194470	274795	85236	72177	82516	84452	84135	80239	79246	79009	78095	77797	77797	77797	77797
	Total	8215167	8298645	8094030	8019841	8214310	8489106	8574342	8646519	8729035	8813487	8897622	8977861	9057107	9136116	9214211	9292008	9369805	9447603	9525400
Commercial	Base		17935832	18015504	18325421	18106283	18052415	22244617	22394838	22537842	22685973	22844479	23006204	23157230	23308228	23458493	23609707	23761430	23913152	24064875
	Adds		79673	309916	-219137	-53869	4192202	150221	143004	148131	158505	161725	151026	150999	150265	151214	151723	151723	151723	151723
	Total	17935832	18015504	18325421	18106283	18052415	22244617	22394838	22537842	22685973	22844479	23006204	23157230	23308228	23458493	23609707	23761430	23913152	24064875	24216597
Industrial	Base		7043569	7175964	6739356	6226720	6487024	3695482	3695820	3696135	3698126	3700156	3701039	3701878	3702700	3703507	3704580	3705643	3706706	3707769
	Adds		132396	-436608	-512636	260303	-2791542	338	315	1991	2031	883	839	823	807	1073	1063	1063	1063	1063
	Total	7043569	7175964	6739356	6226720	6487024	3695482	3695820	3696135	3698126	3700156	3701039	3701878	3702700	3703507	3704580	3705643	3706706	3707769	3708832
Residential	Base		24061512	24507526	24604829	24408227	24110055	23370469	23572662	23784959	23988667	24202347	24421171	24646969	24874006	25103483	25335820	25571175	25806530	26041885
	Adds		446014	97304	-196603	-298171	-739587	202193	212297	203708	213680	218824	225798	227037	229477	232336	235355	235355	235355	235355
	Total	24061512	24507526	24604829	24408227	24110055	23370469	23572662	23784959	23988667	24202347	24421171	24646969	24874006	25103483	25335820	25571175	25806530	26041885	26277240
TOTAL ADD			741560	-234003	-1002565	102733	935869	437989	427794	436346	458668	465566	457901	458105	459559	462718	465938	465938	465938	465938
TOTAL LOAD		57256079	57997639	57763636	56761071	56863804	57799673	58237662	58665455	59101801	59560469	60026036	60483936	60942041	61401600	61864318	62330255	62796193	63262131	63728068

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #4

INTERROGATORY

Issue A4: “What are the alternatives to the proposed facilities? Are any alternatives to the proposed facilities preferable to the proposed facilities?”

Reference: Ex. A, Tab 3, Schedule 4, page 4, Table 1

Please provide for each year from 2000 to 2025 inclusive Enbridge’s actual/forecast total number of residential, commercial, apartment and industrial customers in the GTA Project Influence Area.

RESPONSE

Total Customers by Sector

	Apartment	Commercial	Industrial	Residential
2004	4,424	68,606	4,773	777,117
2005	4,471	69,885	4,792	796,860
2006	4,497	71,388	4,798	816,062
2007	4,540	73,351	4,805	832,492
2008	4,543	74,848	4,807	849,520
2009	4,564	76,250	4,807	863,284
2010	4,600	77,449	4,812	873,205
2011	4,675	78,626	4,812	884,673
2012	4,701	79,543	4,816	893,936
2013	4,729	80,563	4,823	904,728
2014	4,803	81,718	4,824	916,831
2015	4,872	82,918	4,827	928,500
2016	4,943	84,208	4,830	940,776
2017	5,014	85,535	4,833	953,383
2018	5,083	86,785	4,835	966,418
2019	5,152	88,037	4,837	979,565
2020	5,220	89,288	4,839	992,896
2021	5,287	90,549	4,841	1,006,431

The Company uses multiple data management systems for specific purposes. The Company has not historically tracked information for sub-areas such as the GTA Project Influence Area. To present historical information for the GTA Project Influence Area,

Witnesses: F. Ahmad
M. Suarez

customer numbers have been derived based on one or more data systems to determine the proportion of GTA Project Influence Area customers to the total customers within Areas 10, 20, and 30 in the franchise (within which the GTA Influence Area resides). Forecasts of customer growth for the GTA Influence Area are layered on derived historical numbers and are denoted in the shaded areas.

Witnesses: F. Ahmad
M. Suarez

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #9

INTERROGATORY

Issue A4: "What are the alternatives to the proposed facilities? Are any alternatives to the proposed facilities preferable to the proposed facilities?"

Reference: Ex. A, Tab 3, Schedule 4, pages 8 & 9

Enbridge states that the "total forecast peak day demand, shown in Table 3, is the incremental load growth plus the load required by the existing customer base."

a) Does Enbridge's forecast assume that the demand from existing buildings will increase, decrease, or remain constant? Please explain why.

b) For each year from 2014 to 2025, please provide the forecast *total peak hour* demands (TJ/hour) and average peak hour demands (GJ/hour) from: a) the above-described incremental load growth from new customers, and b) Enbridge's existing customer base in the GTA Project Influence Area. Please also break out your results by residential, commercial, apartment and industrial customers.

c) Please also provide the requested data in a table covering only the period from 2015 to 2025. This will assist in comparing the data with Enbridge's load forecast at Exhibit A, Tab 3, Schedule 4, which covers only the 2015 to 2025 period.

RESPONSE

a) The Company utilizes peak hour demand rather than annual demand for network planning purposes. Forecast peak hourly loads for existing customers are assumed to be constant for network planning. Incremental customers by sector are assumed to have lower peak hourly demands based on the year added as per the load gathering process described in the response to Environmental Defence Interrogatory #12 found at Exhibit I.A4.EGD.ED.12. Efficiency gains for the system as a whole are incorporated in the incremental peak demand through the reduction factor as per the response to Environmental Defence Interrogatory #13 found at Exhibit I.A4.EGD.ED.13.

Witness: E. Naczynski

Enbridge Gas Pipeline Hearing EB-2012-0451

Evidence concerning Demand Side Management Potential in GTA

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Wen Jie Li

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Enerlife Consulting

June 28, 2013, Updated September 11, 2013

Executive Summary

This report estimates the Demand Side Management ("DSM") potential for commercial and apartment customers in the GTA area, summarizes the DSM estimates for residential and industrial customers prepared by the consultants retained by the Green Energy Coalition ("GEC"), analyzes the potential DSM against load growth, estimates the present value of the commodity cost savings associated with the efficiency measures, and provides comments on Enbridge's load forecast model. The terms of reference provided to us by Environmental Defence appear at Appendix A to this report.

We conclude that all load growth in the GTA area can be completely offset through commercial and apartment DSM and that overall demand can be significantly *reduced* with the addition of residential and industrial DSM.

Enbridge estimates that its DSM programs will deliver in the order of 12 10^3 m^3 per hour (9 TJ/day) peak demand reduction savings each year. Enbridge also advises that additional peak demand reduction of 25 10^3 m^3/hr (18 TJ/day) is required each year to offset customer load growth. Therefore, a total of approximately 37 10^3 m^3/hr (27 TJ/ day) in peak demand reduction is required.

The forecast annual average peak demand reduction potential through DSM presented in this evidence yields a total of 50 10^3 m^3/hr (37.7 TJ/day) at the top quartile level, which is considered readily attainable in the timeframe involved. The average annual peak hourly reduction presented in the Enerlife model and by the GEC's witnesses is summarized as follows:

Table I. DSM Potential in the GTA Area

Customer Sector	**DSM Potential (10^3 m^3/hr)**
Commercial (Per Enerlife Model, Top-Quartile Attainment)	31.0
Apartment (Per Enerlife Model, Top-Quartile Attainment)	11.3
Sub Total	**42.3**
Residential (Per Chris Neme)	5.6
Industrial (Per Marbek Report and Chris Neme's Analysis)	2.1
TOTAL	**50.1**

Median-quartile attainment would achieve 18.8 10^3 m^3/hr (14.2TJ/day) for commercial customers and 4.9 10^3 m^3/hr (3.7TJ/day) for apartment customers. The total present value of the avoided commodity costs at 2015 for attainment of the median performance target is $743 million and for the top quartile target is $1,108 million.

The Performance-Based Model presented in this evidence for calculating commercial and apartment DSM potential is derived from Enerlife's substantial and growing database of actual energy performance data for buildings. The approach is consistent with a growing number of provincial and national programs. [1] It takes a different approach from the DSM Potential Study conducted for Enbridge in 2009 by Marbek Resources Consulting Inc.[2] Rather than relying on technologies, assumed penetration levels and engineering calculations, the Performance-Based Model analyzes actual, benchmarked energy use of different building types and establishes the potential savings due to all buildings reaching intensity levels already achieved by one half (median) or one quarter (top-quartile) of the peer group.

Simply bringing high gas use intensity buildings down to meet median base and heating energy levels of existing buildings yields overall percentage savings in the order of 19% for commercial and 12% for apartment buildings. Going further to meet top-quartile performance levels raises the potential to over 32% for commercial buildings and almost 29% for apartments.

It should be noted that attainment of today's top quartile gas use is by no means the greatest savings level that can be planned for and expected within the timelines in question. By definition, one quarter of existing buildings are already performing at or better than this level. Energy efficiency initiatives such as REALpac's 20 by '15 Target and TRCA's Town Hall Challenge and Greening Health Care programs use top quartile gas use to set energy targets.

Measures to improve efficiency in high gas intensity buildings go beyond those included in Marbek's DSM Potential Study and are typically site-specific equipment repairs, upgraded control of buildings systems, and testing, tuning and rebalancing of heating plant and systems. Such projects show generally good Total Resource Cost ("TRC") test values, can be implemented quite quickly, and serve to improve building performance as well as energy efficiency. They require a systematic approach to identify target buildings, engage owners, isolate the inefficiencies, implement the necessary improvements and verify the results.

Enbridge is already starting down the path on this new, data-driven performance-based conservation programming with its Energy Compass and Run It Right programs. The company has also gained experience in this space through its sponsorship of and participation in Toronto & Region Conservation's programs and CivicAction's Race to Reduce. In order to deliver the substantial additional natural gas savings identified herein in an efficient and expedient manner, additional focus and expanded scope should be applied to these new programs. Working with other parties, Enbridge can readily identify and target the largest gas savings potential customers in each sector, and support them in understanding and achieving the considerable energy and cost savings potential in their buildings.

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[1] Examples include: Ministry of Education's Utility Consumption Database; REALpac's 20 by '15 Target and Benchmarking; Toronto & Region Conservation's Energy Efficiency Programs of The Living City; Government of Canada's Canadian launch of EPA's Portfolio Manager; CivicAction's Race to Reduce; Ontario Government's Green Energy Act reporting

[2] Exhibit I.A4.EGD.ED.14, Attachment

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[2] Exhibit I.A4.EGD.ED.14, Attachment

Part One - Natural Gas DSM Potential in the GTA – Enerlife Model

1.0 Performance-based DSM Forecast Methodology

Enerlife's model to forecast natural gas DSM potential in the GTA is based on established performance from a large multi-year database of energy use by buildings, direct project experience with successful high energy performing buildings and leadership of peer-reviewed initiatives aimed at determining conservation potential by defining how much energy individual buildings need. This differs from the DSM forecast model provided by Enbridge that points to a technology-centric view of DSM programs, rather than a performance-based one. This approach leads to a systematic approach to identifying buildings with savings potential and solution-based measures, often operational, that lead to quicker and greater gas savings.

Enerlife's Performance-based Forecast Model is supported by multi-year national pilot projects conducted by Enerlife on behalf of the Canada Green Building Council in the following building sectors: commercial office, government and utility administration, K-12 schools, retail bank branches, universities and municipal arenas. The pilots proceeded in parallel with and informed the technical development of the LEED standard for Existing Buildings: Operations & Maintenance.

These pilots were incredibly successful, and set the stage for the remarkable pace of market transformation which has taken place since they were completed. They brought awareness of opportunities to green existing buildings, engaged markets and generated interest in building performance. Enerlife's energy benchmarking and target-setting methodology introduced through the pilots has been adopted by the market, as evidenced by the REALpac 20 by '15 energy target, REALpac's Energy Benchmarking program, the reporting of energy intensity distribution of BOMA BESt certified buildings, Greening Greater Toronto's Race to Reduce awards, and others.

1.1 Data sets

For the commercial and apartment building sectors, we have assembled the largest full-year Canadian building data set in our online Green Building Performance System (GBPS) from the years 2009-2012. The GBPS employs IPMVP[3] methodology to weather-normalize gas consumption from different climatic regions to a common Toronto degree day base.

1.2 Building Sector Potential Savings

The graph below is illustrative of the benchmarking results for offices, schools, hospitals, retail, recreation and apartments respectively.[4] Each figure includes the size of the data set, indicates the range of base and heating gas use intensity (m3/ft2), and shows the overall percentage gas savings resulting from reaching median and top-quartile gas consumption levels.

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[3] International Performance Measurement and Verification Protocol

[4] The rest of the benchmarking results are in Appendix B

Figure 1 Example of Building Sector Benchmarking Results

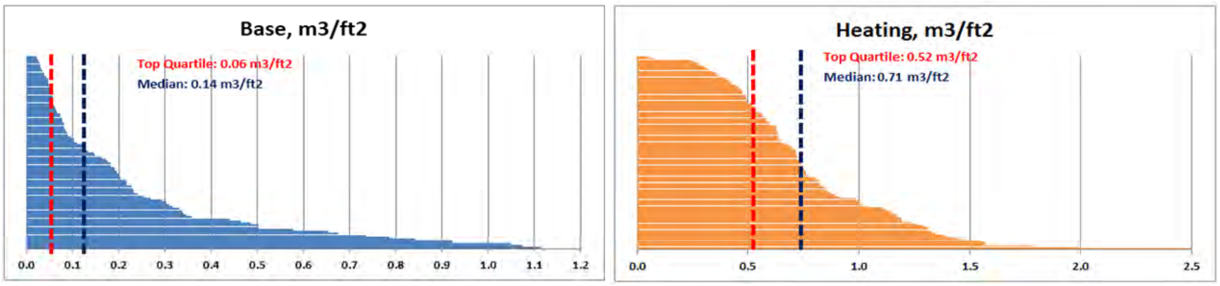
Sector: Office Buildings

Number of buildings: 123

Total building area, ft2: 42,000,827

Gas usage	Savings potential, % at the attainment of	
	Median	Top Quartile
Base	47%	72%
Heating	23%	39%
Total	**27%**	**44%**

Based on 2010 data weather-normalized to Toronto. Data centres have been excluded.



Part Two – Load Forecast Model

The Performance-Based Model was prepared in order to more completely represent the effects of DSM on the peak hour demand forecast. The model applies the DSM savings projected in this report to the baseline (2011-2012) consumption, and then adds the full impact of new customer load growth (as projected by Enbridge) to the net usage. The model includes DSM projections for residential and industrial sectors based on the 2009 DSM report and the analysis completed by the GEC experts.

2.1 Annual DSM Savings Potential

The following table summarizes the total savings potential by sector, illustrating the difference if the median target is reached and the top quartile target.

Figure 2 Total Sector Savings Potential

Conservation Potential

Apartment			Commercial			Industrial			Residential		
Base	Heating	Total	Base	Heating	Total	Base	Heating	Total	Base	Heating	Total
Median Target											
12%	13%	13%	38%	16%	19%	15%	15%	15%*	5.25%	5.25%	5.25%**
Top Quartile Target											
23%	30%	29%	54%	28%	32%	15%	15%	15%*	5.25%	5.25%	5.25%**

Marbek study of DSM potential indicates the economic potential is 919 million m^3 in the industrial sector by 2017 (i.e. within 10 years, given when they started their analysis). That is relative to a baseline of 2671, or a 34.4% savings. They estimate that they can get 43% of that amount in their financially unconstrained scenario and also in their $40 million annual budget scenario, for a total savings of 14.7%.

*** Evidence provided in "DSM Potential in GTA" report by Chris Neme and Jim Gravatt is the basis for the residential savings potential by 2025.*

The present value of the avoided commodity costs for attaining the median performance target is $743 million and for the top quartile target is $1,108 million, using a 5.88% discount rate[5] and commodity costs used by Enbridge.[6]

Enbridge's current DSM programs capture 0.6% of their annual volume[7], while the Performance-based Model forecasts capturing 1.2% of the annual volume for the median target and up to 1.9% for the top quartile target as savings.

Commercial Sector breakdown

The following table summarizes the DSM Potential results for the five commercial building types presented in Part One to produce weighted average percent savings for commercial buildings as a whole.

Figure 3 Apartment and Commercial Sectors Savings Potential

Database by Sector:	Buildings	Total building area, Mft2	Savings potential, % at the attainment of					
			Median			Top Quartile		
			Base	Heating	Total	Base	Heating	Total
Office	123	42.0	47%	23%	**27%**	72%	39%	**44%**
Schools	212	12.0	44%	17%	**21%**	63%	32%	**37%**
Hospitals	77	36.2	22%	12%	**18%**	52%	25%	**41%**
Retail	84	0.7	72%	26%	**37%**	87%	42%	**53%**
Recreation	20	1.4	56%	12%	**32%**	79%	29%	**52%**
Apartments	122	25	12%	13%	**13%**	23%	30%	**28%**

2.2 Peak Hourly Demand Savings

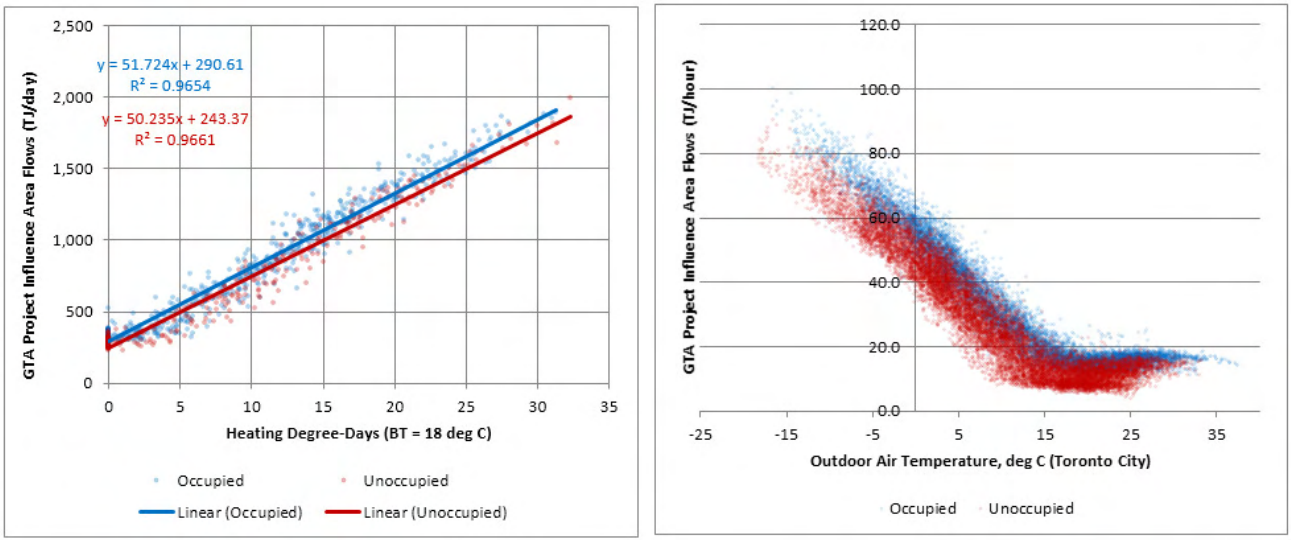
The Peak Breakdown worksheet of the model presents the hourly gas consumption data in 2010, 2011 and 2012 as provided by Enbridge for the GTA Project Influence Area (TJ/hour), relative to outdoor temperature. The analysis yields the breakdown of the base (16%) and heating (84% extrapolated to 41 HDD) on the Peak Breakdown worksheet. This is used to derive the impact of annual DSM savings on the system peak demand.

[5] The model uses the same discount rate as Enbridge uses for the Economic Feasibility. Exhibit E, Tab 1, Schedule1, Attachment, Page 1 of 5.

[6] Exhibit A, Tab 3, Schedule 5, Attachment Page 4 of 5.

[7] Calculated from current DSM estimate from Enbridge Exhibit I.A4.EGD.ED.25, Page 6 of 6.

Figure 4 Peak Hourly Demand



2.3 Peak Hourly Demand Forecast

The previous Peak Breakdown numbers inform the Peak Hourly Demand Forecast graphs below. Since this breakdown is not known for each sector, the same breakdown is used for Apartment, Commercial, Industrial and Residential. The base, heating and total DSM percentage potential for each of the four sectors originate from the Savings Model median and the top quartile scenarios. This also includes Enbridge's breakdown of the total peak demand (m3/hr) for each of the four sectors. Finally, the forecast percent attainment of the total potential is determined for each year from 2011 to 2025 to yield the peak demand reduction for each year.

This model incorporates the incremental gas demand over this period due to new customers coming on stream as projected by Enbridge.[8] However it should be pointed out that performance-based conservation plays an important role in setting design metrics and standards for new buildings, and that significant improvements can be expected over current design practice due to incorporating these into Enbridge's High Performance New Construction program. The potential impact on demand is unknown and was not included in the model.

The graphs below illustrate the variance between Enbridge's forecast of the impact of DSM on peak hourly demand and our performance-based forecast of the impact of DSM for the GTA Project Influence Area and individual building sectors. Included are:

- Baseline (2011-2012) which presents the actual historical peak demand data and simply projects 2011-2012 consumption through to 2025
- Baseline with Full Load Growth as provided by Enbridge

[8] Exhibit 1.A4.EGD.ED.2, Page 1 of 1

- Baseline with Discounted Load Growth which is Enbridge's forecast including the 35% reduction factor
- Baseline with Performance-based Forecast DSM (Median) and Full Load Growth
- Baseline with Performance-based Forecast DSM (Top Quartile) and Full Load Growth

Figure 5 GTA (all sectors) Peak Demand Forecast Model

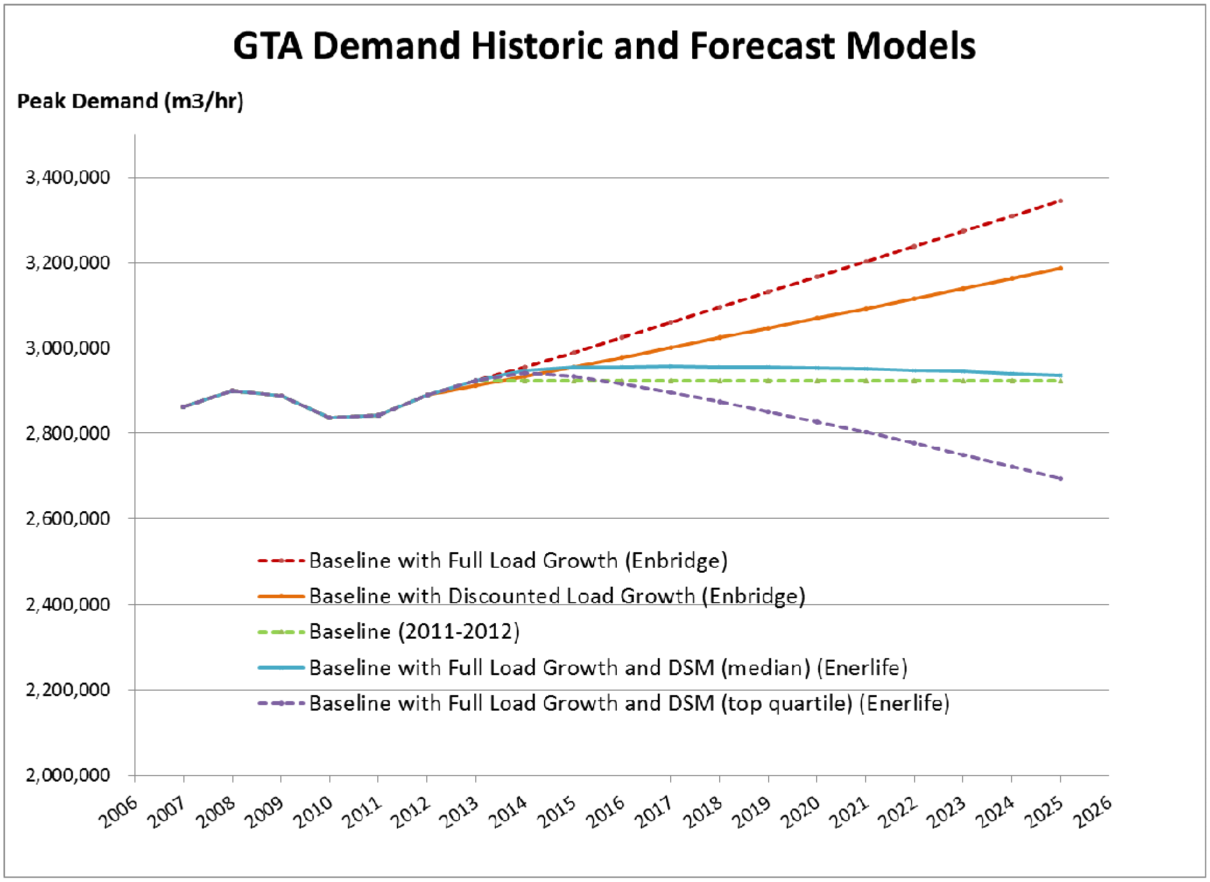


Figure 6 Comparison of savings and increases in gas use by 2025 from 2011 Baseline in the GTA Demand Historic and Forecast Models

% Increase by 2025 from 2012 Baseline	Apartment	Commercial	Industrial	Residential	Total
Enbridge's Full Growth Model	18.8%	13.6%	0.6%	19.1%	15.8%
Enbridge's Discounted Growth Model	12.2%	8.9%	0.4%	12.4%	10.3%
Enerlife's Forecast with Full Growth and DSM (median)	3.7%	-8.3%	-14.5%	12.9%	1.6%
Enerlife's Forecast with Full Growth and DSM (top quartile)	-15.8%	-22.6%	-14.5%	12.9%	-6.7%
% Reduction by 2025 from Enbridge's Full Growth Model					
Enerlife's median DSM	-12.7%	-19.3%	-15.0%	-5.2%	-12.2%
Enerlife's top quartile DSM	-29.1%	-31.9%	-15.0%	-5.2%	-19.5%

Part Three – Performance-based conservation

3.1 Performance based conservation

Performance based conservation begins with identifying high energy intensity buildings through benchmarking and then works systematically towards identifying and fixing the particular inefficiencies causing the high use in each building. The nature of the inefficiencies runs the range of errors in design and construction, through equipment deterioration over time, to changes in use and operation of the building, and poor performance of controls and automation systems. It is the compound effect of these problems that leads to gas use levels in some buildings which is 3 to 5 times what is needed and already achieved by comparable, more efficient buildings.

Fixing these problems requires a systematic methodology. The work involved in equipment repairs and replacement, right-sizing and rebalancing, refurbishment and re-programming, typically provides relatively short payback periods.

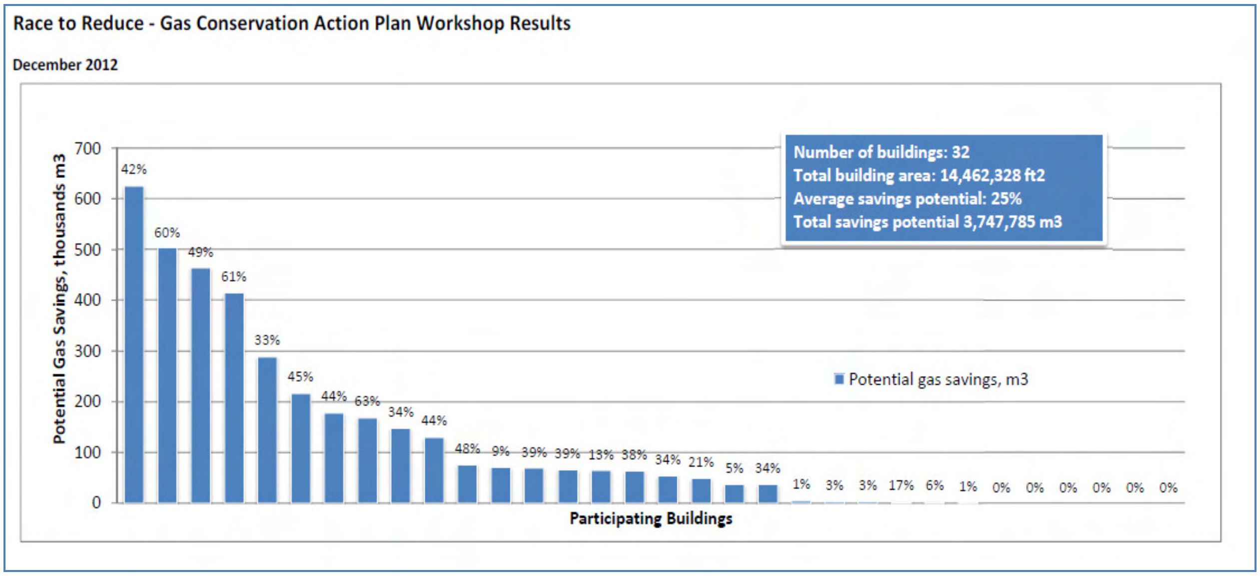
Part Four – Achieving the Additional DSM Savings

4.1 Identify Top Savings Potential Buildings

Performance-based conservation begins with identification of buildings with the greatest potential for savings and level of reduction possible. Enerlife piloted this approach in 2012 on behalf of Enbridge, through a workshop provided to Race to Reduce participants that addressed 31 commercial office buildings with a total area of over 14 million square feet.[9]   Benchmarking and target-setting identified the range of gas savings potential shown in the chart below. The analysis for each building was provided to the participant in a standardized energy assessment report. The workshop then provided training in which specific measures were indicated to achieve the targeted savings in each building, enabling each participant to produce their own customized gas conservation action plan, and enabling Enbridge Energy Solutions Consultants to follow up with technical and incentive support to deliver the savings.

[9] Enbridge Energy Efficiency Workshop, November 23rd, 2012

Figure 12 Commercial office building gas savings potential[10]



This illustrates the importance of identifying buildings in each sector with the greatest potential gas savings. Some buildings have significant gas reduction potential while others have little or none at all. Applying a similar approach across each building sector will enable Enbridge to focus its efforts on customers and buildings with the greatest DSM potential, and help them identify the specific actions and measures which will achieve the savings results.

Our proposed plan envisages Enbridge targeting building owners of large buildings and large portfolios of buildings, based on their gas savings potential identified through benchmarking and target-setting. Commercial building owners already collaborate in energy efficiency initiatives such as REALpac Energy Benchmarking, BOMA BESt, Race to Reduce and Greening Health Care, which support awareness and engagement. Once owners are engaged and their buildings assessed, technical support can be provided by Enbridge assisting them in identifying contributing factors to high gas use, implementing necessary improvements and verifying that savings are achieved and maintained over time. Enbridge was unable to provide the requested breakdown of numbers of customers accounting for the largest gas consumption.1

However, consistent with this strategy, we have refined our recommended approach to market engagement and penetration using gas savings potential data for commercial buildings from our database. The strategy is illustrated below, which lays out the first four years of a 12-year market engagement program. The following 8 years of the program would build on this foundation to achieve the modeled top-quartile gas savings of 822 million M3/year in 2025.

[10] Labelled percentages in the graph indicate the gas savings potential for each individual building.

The proposed strategy is to engage buildings in each year of the program with a combined 75 million M3/year of gas savings potential so, by the end of 11 years, the required 2025 top quartile total of 822 million M3/year (as presented in the model) will be achieved.

The first year of the program would target owners of large buildings – typically hospitals, major commercial and government office buildings and hotels, and universities. Our database contains 26 such buildings in the GTA (including office buildings in the Enbridge workshop for the Race to Reduce as shown in Exhibit L.EGD.ED.1, Figure 12, Page 13) owned by 20 different organizations with identified potential savings totaling 24 million M3/year. Based on this, the program would aim to engage approximately 60 owners and identify approximately 80 high gas savings potential buildings to achieve the target engagement of buildings with combined potential for 75 million M3/year.

We estimate our database contains fewer than 20% of the large gas savings potential buildings in the GTA. The market engagement program would engage these buildings and other readily identified owners to meet the first year's target. Gas savings would be realized over the following 2-3 years.

The second year would target buildings with 200,000 M3/year of gas savings potential. Our database of office, government and commercial office buildings contains 25 of these buildings with a combined gas savings potential of 6.6 million M3/year. To meet the aims of the program requires approximately 300 of these buildings. However, large portfolio owners, such as school boards, municipalities and retail chains, would be targeted first so the number of owners to engage is proportionately less (estimated at 50).

The subsequent year of the program would target buildings with 10,000 M3/year gas savings potential, requiring engagement of 500 buildings and 50 new customers (given that some customers engaged in years one and two will have buildings already identified in this range). The fourth year would focus on buildings with 50,000 M3/year gas savings potential, for which we estimate 1000 buildings and 50 new customers. Successful execution of this proposed strategy for the first four years will establish the relationships, processes and capabilities required in subsequent years of the program.

Table 1 Market Penetration Model for Commercial Sector

	Year 1	**Year 2**	**Year 3**	**Year 4**
Gas savings engaged (M3)	75 million	75 million	75 million	75 million
Potential savings per building M3/yr.	> 500,000	> 200,000	> 100,000	> 50,000
# of targeted buildings/year	80	300	500	1000
# of new participants/yr.	60	50	50	50

Target customers	Commercial landlords; major hospitals; universities; major hotels; government	School boards (high schools); municipalities; colleges; large retail; other hospitals, hotels etc	Other retailers; long-term care operators	Banks (branches); school boards (primary schools);

The Apartment sector also has large buildings, large portfolio owners, and collaborative programs in place (including the Federation of Housing Providers of Ontario, and the City of Toronto Tower Renewal Office) so a similar model would apply. A s.

Lower penetration rates are projected in the model for Residential and Industry, but the principles of performance-based conservation may be useful in these sectors as well.

4.2 Finding and Fixing Inefficiencies

Identifying and addressing inefficiencies requires a savings focused approach to DSM. Trained people with similar skill sets to energy analysts, commissioning agents and energy efficiency engineers focused on getting to energy savings as quickly as possible are needed to work with building operation staff. Outcomes-based strategies and incentives prioritize scheduling optimization, ventilation and air flow testing and savings opportunities that use lower cost technology such as zone dampers and variable frequency drives. These typically can be implemented quickly and have short paybacks.

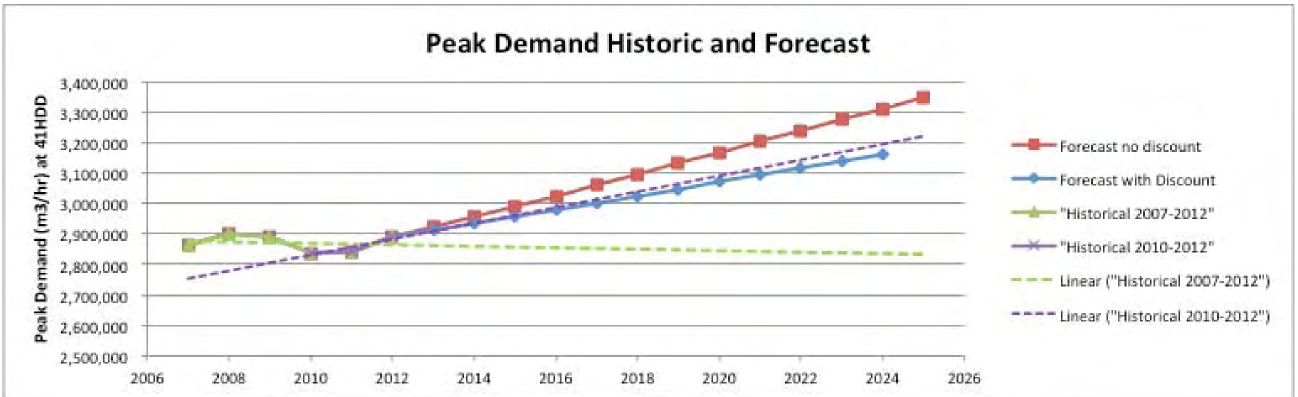
Part Five - Enbridge Peak Demand Forecast Model

5.1 Assessment of Enbridge's Load Growth Forecast Model

Enbridge's argument for a proposed new pipeline to serve the GTA is partially based on the need for additional capacity to meet increased peak hourly demand. To support this, they provided a Peak Load Growth Forecast discounted for gas savings from DSM programs. Due to the short length of review time, we are unable to provide a complete assessment of the load forecast but have the following observations:

a. Insufficient trend information to base projection

Figure 13 Peak Demand Trends



The derived historic peak demand (weather-normalized to 41HDD)[11] from between 2007 and 2012 shows no net growth overall. However, Enbridge's forecast indicates an increase in demand. This is consistent with a shorter data period (2010 to 2012). Given the erratic growth patterns within the Industrial and Commercial sectors during this time, three years would seem insufficient to base a forecast upon. [12]

As illustrated below, the industrial sector demand dropped by 43% between 2011 and 2012 while the commercial sector demand increased by 23% in the same period with no significant increase in the number of customers. Overall there was little total demand growth. This would indicate the difficulty in forecasting future growth based on so little trend data.

Table 2 Number of Customers by Sector (historical)

	Apartment m^3/hr	Commercial m^3/hr	Industrial m^3/hr	Residential m^3/hr	Total m^3/hr
2007	410,758	896,792	352,178	1,203,076	2,862,804
2008	414,932	900,775	358,798	1,225,376	2,899,881
2009	404,701	916,271	336,968	1,230,241	2,888,181
2010	400,992	905,314	311,336	1,220,411	2,838,053
2011	410,716	**902,621**	**324,351**	1,205,503	2,843,191
2012	424,455	**1,112,231**	**184,774**	1,168,523	2,889,983

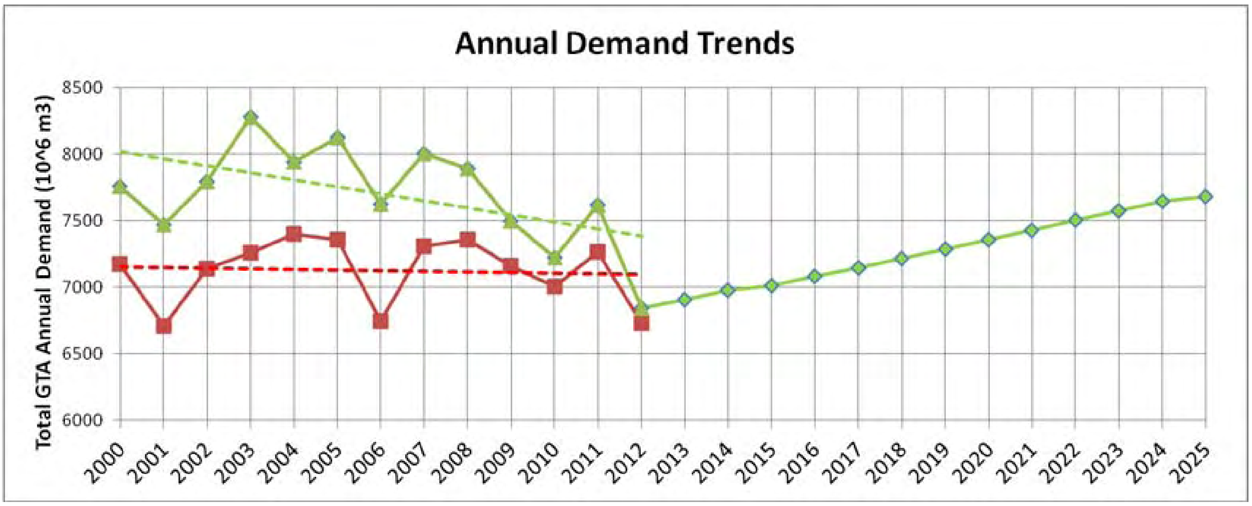
b. Forecast inconsistent with historical peak demand trends

Based on historical annual demand trends, demand has been declining over the past decade but Enbridge has forecast substantial demand growth in the future. As can be seen in the graph below, it

[11] Exhibit I.A4.EGD.ED3
[12] EXHIBIT I.A4.EGD.EGC.ED.3

appears Enbridge provided total GTA annual demand data from two sources. The green line is from actual volumes[13] and the red is measured at the gate station[14]. Neither indicates a growth in demand, while the annual demand is forecast to grow consistently. During the historical period (2004 to 2012) the growth rate of the number of customers is similar to the forecasted customer growth rate, yet there was no peak demand growth. Enbridge uses linear interpolation between annual consumption to derive peak hourly data, which supports the correlation between annual volume and peak hourly demand. Based on this, there is no historical correlation between an increase in number of customers and significant peak demand growth as forecast.

Figure 14 Annual Demand Trends - historic and forecast



c. Inaccurate application of the discount factor

The application of the discount factor in the Enbridge Load Growth Forecast model appears to be misleading. The DSM forecast of 12 10^3m^3/hr reduction each year is 0.4% of the peak hourly load in GTA. The 35% discount factor is applied on the incremental **new** customer growth rate of 1.2% (35 10^3m^3/hr) each year, to account for the DSM load reduction over the entire **existing** building stock. This leads to the misunderstanding that no amount of DSM could offset growth, since even if a 99% discount is applied there will still be a positive growth trend.

It would be more accurate to apply the discount factor directly to the total peak load. The Performance-based DSM model proposed in this report applies it this way, and if DSM reaches 3 times the current level there will be no net growth.

[13] JT2.36 using “actual volumes from Franchise Areas 10, 20, 30 from the billing system to proxy for volumes in the GTA Project Influence Area” for the historical information, and the “2013 Board-approved average use were applied to GTA Project influence area customer growth forecasts to project total annual demands”
[14] Exhibit I.A4.EGD.ED.25, “measured at the gate station”

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #14

INTERROGATORY

Issue A4: "What are the alternatives to the proposed facilities? Are any alternatives to the proposed facilities preferable to the proposed facilities?"

Reference: Ex. A, Tab 3, Schedule 4, page 8

a) For each year from 2014 to 2025 inclusive, please state the forecast impact of DSM on peak hourly demand and total annual demand in the GTA Project Influence Area, both yearly and cumulative, based on the "reduction factor" used by Enbridge in its forecast. For each year, please also estimate Enbridge's DSM budget needed to achieve the DSM reductions assumed in the forecast.

b) Please state the amount of DSM, in addition to that assumed in Enbridge's forecast, that would be needed to meet Enbridge's customers' needs in the GTA Project Influence Area in each year from 2014 to 2025 inclusive (i.e. to ensure that minimum system requirements with respect to capacity and pressure are met) without the proposed new Enbridge pipelines.

c) Has Enbridge estimated the potential for incremental DSM in addition to the amount assumed in its forecast? If yes, please state this potential for each year from 2014 to 2025 inclusive. Please also provide all the reports, studies and analyses that support these estimates and state when this research was commenced and was completed.

d) For each of the above, please also provide the requested data in a table or tables covering only the period from 2015 to 2025. This will assist in comparing the data with Enbridge's load forecast at Exhibit A, Tab 3, Schedule 4, which covers only the 2015 to 2025 period

RESPONSE

a) Enbridge reports DSM using annual figures and does not communicate, measure, or interpret DSM reductions on a peak day or peak hour basis. For illustrative

Witnesses: T. Maclean
F. Oliver-Glasford
J. Ramsay

purposes, the Company has converted its annual results into peak hour and peak day reductions using several theoretical assumptions. The assumptions include:

- the use of a linear conversion ratio to derive peak day from annual figures and peak hour from peak day;
    - o In practice the conversion ratio will not be linear and will vary between DSM measures and customer segments
- the use of a factor to apportion the amount of the whole franchise-wide DSM which is attributable to the GTA Project Influence Area; and
- static cost effectiveness as conservation budgets increase (i.e. each incremental m^3 saved is priced at the same as the first m^3).

Because of the theoretical and simplified nature of the assumptions built into the numbers, the charts below should only be used to illustrate the relative magnitude of the data.

Franchise-wide DSM		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Peak Hour Demand Reductions (10^3m^3)	Yearly	24	25	25	25	25	25	25	25	25	25	25	25	25
	Cumulatively	24	49	73	98	122	147	171	196	221	245	270	294	319
Peak Day Demand Reductions (10^3m^3)	Yearly	600	614	614	614	614	614	614	614	614	614	614	614	614
	Cumulatively	600	1,214	1,828	2,442	3,056	3,670	4,284	4,898	5,513	6,127	6,741	7,355	7,969
Annual Demand Reductions (10^3m^3)	Yearly	74,353	76,049	76,049	76,049	76,049	76,049	76,049	76,049	76,049	76,049	76,049	76,049	76,049
	Cumulatively	74,353	150,402	226,451	302,501	378,550	454,599	530,648	606,697	682,747	758,796	834,845	910,894	986,943
Annual Province-wide DSM Budget		$32,380,295	$32,966,700	$33,626,034	$34,298,555	$34,984,526	$35,684,216	$36,397,901	$37,125,859	$37,868,376	$38,625,743	$39,398,258	$40,186,223	$40,989,948

GTA Influence Area DSM		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Peak Hour Demand Reductions (10^3m^3)	Yearly	12	12	12	12	12	12	12	12	12	12	12	12	12
	Cumulatively	12	23	35	47	59	70	82	94	106	118	129	141	153
Peak Day Demand Reductions (10^3m^3)	Yearly	288	295	295	295	295	295	295	295	295	295	295	295	295
	Cumulatively	288	583	877	1,172	1,467	1,762	2,056	2,351	2,646	2,941	3,236	3,530	3,825
Annual Demand Reductions (10^3m^3)	Yearly	35,689	36,504	36,504	36,504	36,504	36,504	36,504	36,504	36,504	36,504	36,504	36,504	36,504
	Cumulatively	35,689	72,193	108,697	145,200	181,704	218,207	254,711	291,215	327,718	364,222	400,726	437,229	473,733
GTA Influence Area DSM Budget		$15,542,541	$15,824,016	$16,140,496	$16,463,306	$16,792,572	$17,128,424	$17,470,992	$17,820,412	$18,176,820	$18,540,357	$18,911,164	$19,289,387	$19,675,175

As shown in the GTA Project Influence Area DSM table above, the impact of the Company's forecasted 2014 DSM reduction on peak hour demand is 12 10^3m^3/hr.

In comparison, the peak load demand reduction as calculated using the reduction factor impact is 13 10^3m^3/hr.

Witnesses: T. Maclean
F. Oliver-Glasford
J. Ramsay

b) In the table below are estimates of the DSM reductions that would be necessary in the GTA Project Influence Area in order to meet the Company's customers' growth needs from 2014 to 2025 inclusive (i.e. to meet a 'growth only' scenario) without the pipelines proposed, holding all other factors constant.

Enbridge asserts that the enormous DSM reductions required to meet customers' needs without the proposed pipeline far exceed any realistic or achievable level.

The data below assumes that the realm of available natural gas savings in the GTA Project Influence Area is unlimited and that cost effectiveness is static. The Company knows this not to be the case. Furthermore, significant portions of the Company's results are achieved through industrial customers of whom there are limited quantities. It is for these reasons among others that conservation was discounted as a non-viable option to offset the GTA Project.

DSM Required to Offset Growth in the GTA Project Influence Area		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Additional Annual DSM Needed in GTA (10^3m^3)		77,811	77,811	77,811	77,811	77,811	77,811	77,811	77,811	77,811	77,811	77,811	77,811
Total Franchise-wide Annual DSM Needed (10^3m^3)		153,860	153,860	153,860	153,860	153,860	153,860	153,860	153,860	153,860	153,860	153,860	153,860
Total DSM Budget Needed	Yearly	**$66,697,115**	**$68,031,057**	**$69,391,679**	**$70,779,512**	**$72,195,102**	**$73,639,004**	**$75,111,785**	**$76,614,020**	**$78,146,301**	**$79,709,227**	**$81,303,411**	**$82,929,479**
	Cumulatively	**$66,697,115**	**$134,728,173**	**$204,119,851**	**$274,899,363**	**$347,094,466**	**$420,733,470**	**$495,845,255**	**$572,459,275**	**$650,605,576**	**$730,314,802**	**$811,618,214**	**$894,547,693**

c) The Company completed a DSM Potential Study in 2009. (The study commenced in 2008.) The Potential Study covered the period 2008 through 2017 using the base year of 2007. The Study Report was filed with the 2012 DSM Plan (EB-2011-0295, Exhibit B, Tab 2, Schedule 7).

d) Please see the table above for 2015 to 2025.

Witnesses: T. Maclean
F. Oliver-Glasford
J. Ramsay

natural gas demand during the heating season and at peak or near-peak weather conditions. Increases in the number of temperature insensitive customers will not only increase demand during peak and near-peak conditions but also during off-peak periods as well.

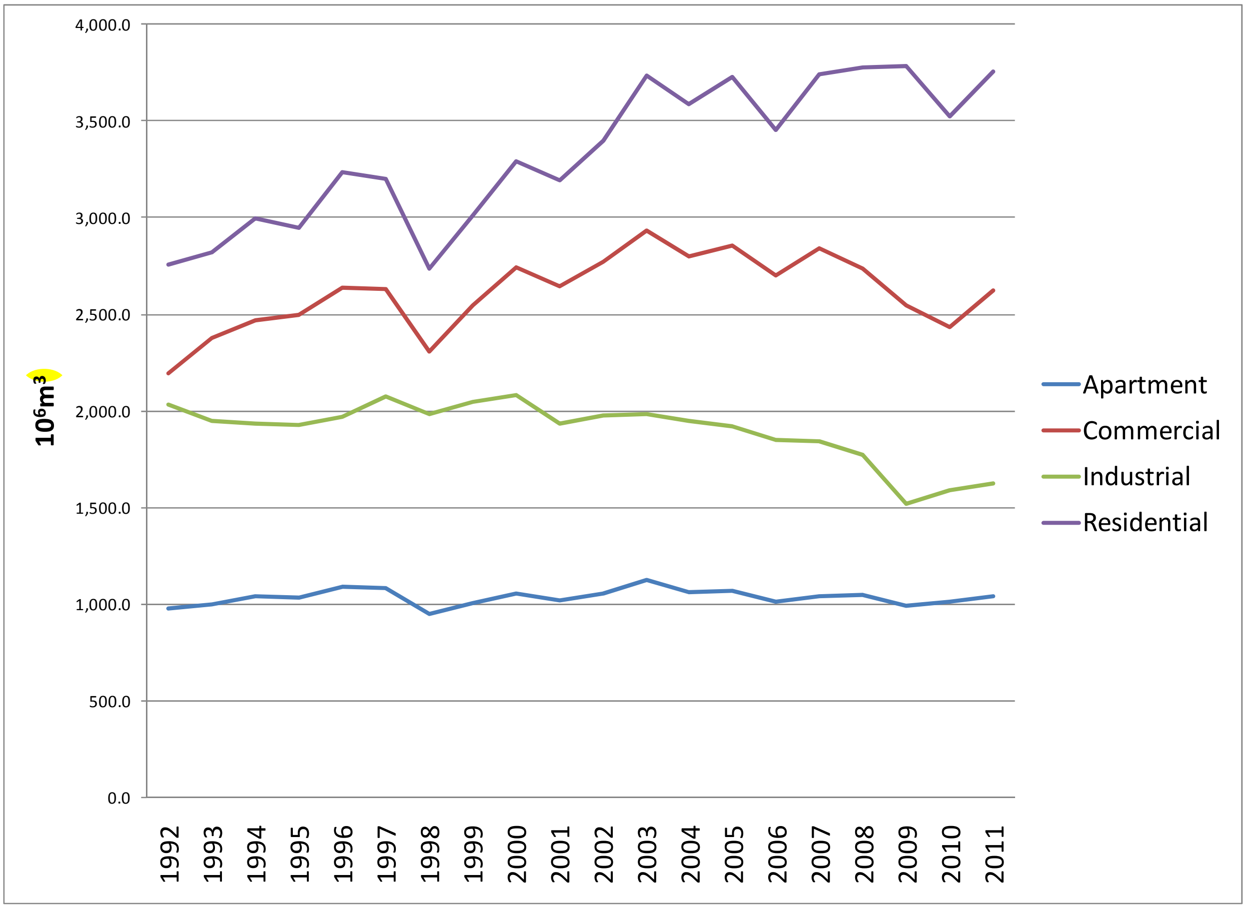
5. Over time changes and trends in these variables will impact the total amount of natural gas demand each year as well as the shape of the demand profile within any particular year or day.

Trends in Annual Demand[1]

6. Since 1992 annual gas demand in the Central Weather Zone has increased. However, trends in annual demand differ from sector to sector. The apartment, commercial, and residential sectors have, on average, experienced increased demand for natural gas whereas the industrial sector has, on average, experienced a decline in demand for natural gas. Figure 1 on the following page shows total annual demand, by sector, by year for the Central Weather Zone[2].

[1] Annual demand trends by sector are discussed using billing system data since daily send out volumes cannot be attributed to any particular sector. Data are presented for the Central Weather Zone as illustrative of the trends that have been experienced within the GTA Project Influence Area. The Central Weather Zone is comprised of the Metro, Western, Central and Northern areas of the Enbridge franchise area. The Enbridge CDA is also referenced in this evidence. The Enbridge CDA is comprised of the Central Weather Zone and the Niagara Weather Zone.
[2] Data presented in Figure 1 are un-normalized volumes.

Figure 1: Natural Gas Demand – Central Weather Zone



7. Temperature sensitive residential demand has increased from 35% of total demand in 1992 to 42% of total demand in 2011 for the Central Weather Zone. Industrial demand as a percentage of total demand on the other hand has declined. In 1992 industrial demand comprised 26% of total demand for the Central Weather Zone. In 2011 this figure declined to 18% for the Central Weather Zone. These trends in annual demand are largely a result of customer additions and changes in customer mix over time in addition to macroeconomic factors.

8. Table 1 below provides the number of customers, as measured by unlocked customers, for the Central Weather Zone for the years 1992 and 2011.

Table 1: Unlocked Customers by Sector, Central Weather Zone

(000's)	Apartment	Commercial	Industrial	Residential	Total
1992	4.6	83.6	7.0	753.8	849.0
2011	5.6	114.3	5.9	1,378.4	1,504.1

9. In 1992 temperature sensitive residential customers comprised approximately 89% of the total customer stock in the Central Weather Zone. By 2011 this percentage had increased to approximately 92%. The number of industrial customers has declined, primarily as a result of economic factors.

10. The trends observed in apartment, commercial, and residential customer growth are largely a result of extended periods of economic growth and more recently a favourable housing market and interest rate environment. The continual addition of customers in these three sectors has increased natural gas demand. Growth in demand for these sectors has been partially offset by energy conservation and the Company's DSM programs.

11. The trends in industrial customer sector are due in part to an appreciation of the Canadian dollar, natural gas price volatility experienced in the early 2000's, a general shift from domestic production to production overseas, a shift towards a more service oriented economy in Ontario, and more recently slow economic growth. Loss of industrial customers has in part lead to a decline in natural gas demand for this particular sector.

12. Temperature sensitive customer demands are seasonal during the year whereas industrial customer demands are relatively flat (i.e., base load) throughout the year.

The implications of these demand trends on natural gas supply and the Company's gas supply portfolio are more fully discussed in the sections that follow.

Peak Day Demand Trends

13. Enbridge has an obligation to serve its customers and meet their demands for natural gas in a safe, reliable, and cost effective manner. Enbridge constantly evaluates its gas supply portfolio to ensure this is the case. Ensuring that the gas supply portfolio is able to meet demand on the crucial peak day, or day of highest demand, is extremely important. In light of the demand trends discussed above and changes in the natural gas market it is reasonable to expect that the composition of the gas supply portfolio utilized by the Company to meet natural gas demand has changed. Over time the Company has reduced distance of haul in order to serve an increasingly temperature sensitive demand profile. The reduction in distance of haul has also been driven by diversity and economic considerations.

14. Figure 2 and Figure 3 on the following pages show normalized peak day demand for the Central Weather Zone and the GTA Project Influence Area[3].

[3] Peak day demand is normalized to a Design Criteria of 41.4 DDs for Figure 2 and 41 DDs for Figure 3. 41.4 DDs are used for gas supply planning purposes for the Central Weather Zone whereas 41 DDs are used by System Analysis & Design when planning distribution facilities for the areas within the GTA Project Influence Area.

Figure 2: Normalized Peak Day Demand – Central Weather Zone (PJs)

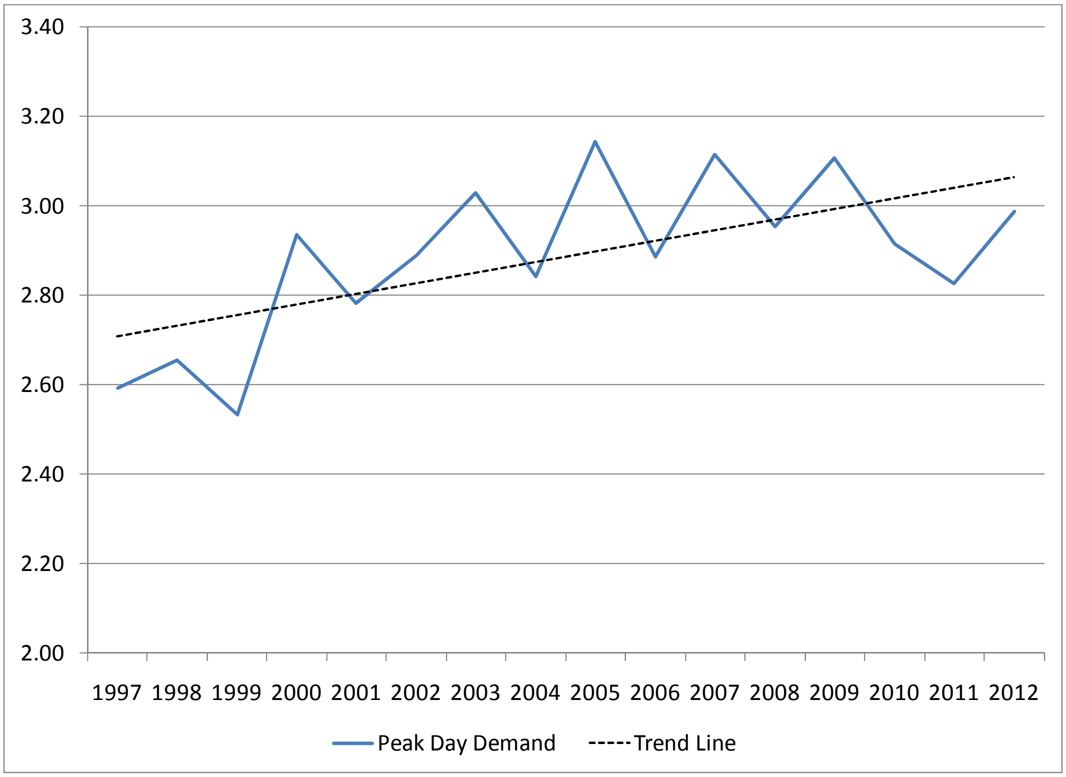
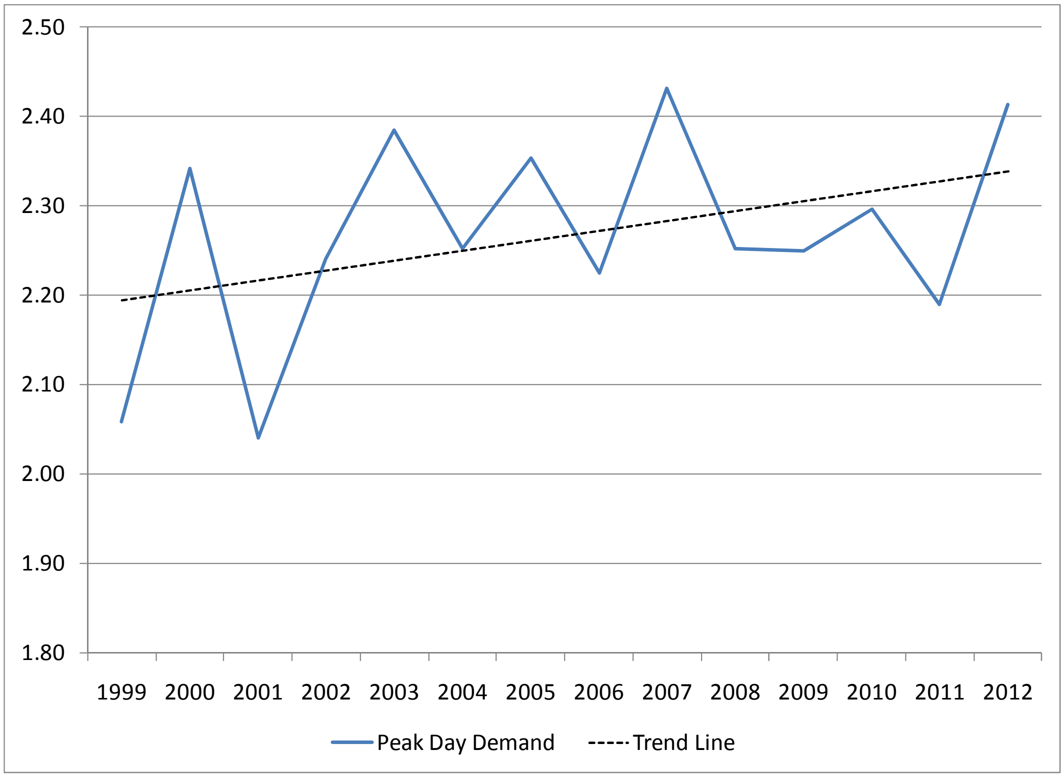


Figure 3: Normalized Peak Day Demand – GTA Project Influence Area (PJs)



15. On average peak day demand for the Central Weather Zone has increased by 1.2% per year since 1997. The comparable figure for the GTA Project Influence Area is 1.5% per year since 1999.

16. Figure 4 and Figure 5 on the following pages show the ratio of normalized peak day demand to average day demand for the Central Weather Zone and the GTA Project Influence Area[4].

[4] Data in Figure 4 and Figure 5 have been normalized to the same Design Criteria used to normalize the data in Figure 2 and Figure 3.

Figure 4: Ratio of Peak Day Demand to Average Day Demand – Central Weather Zone

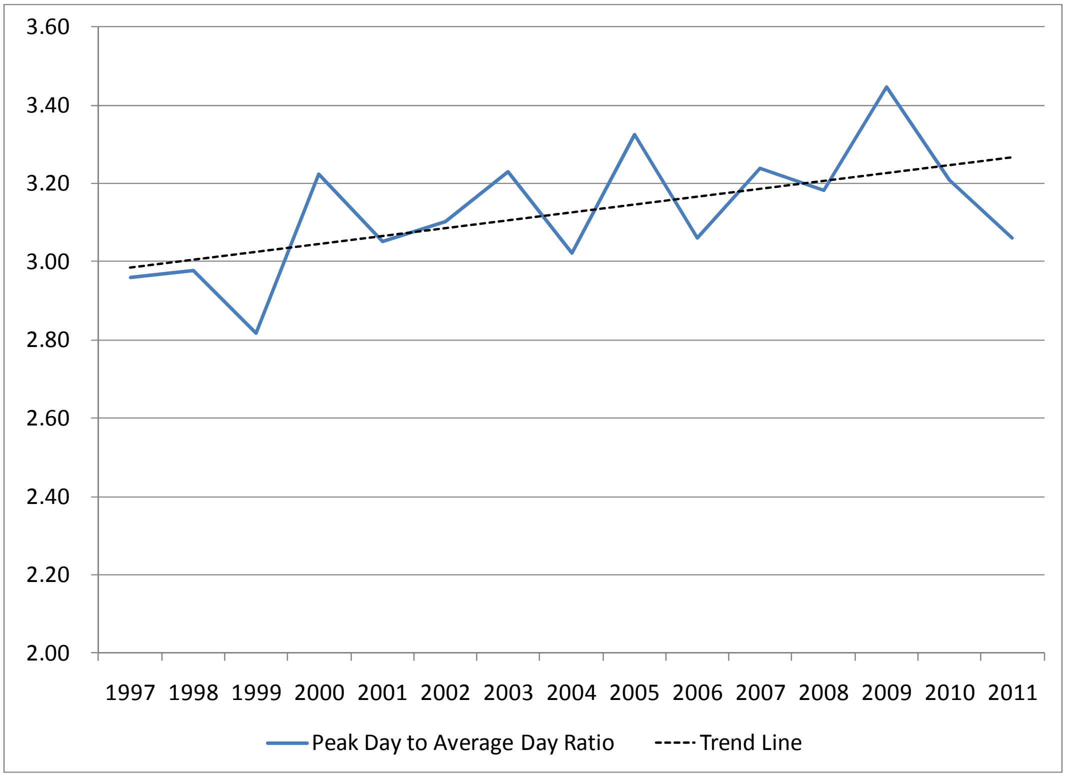
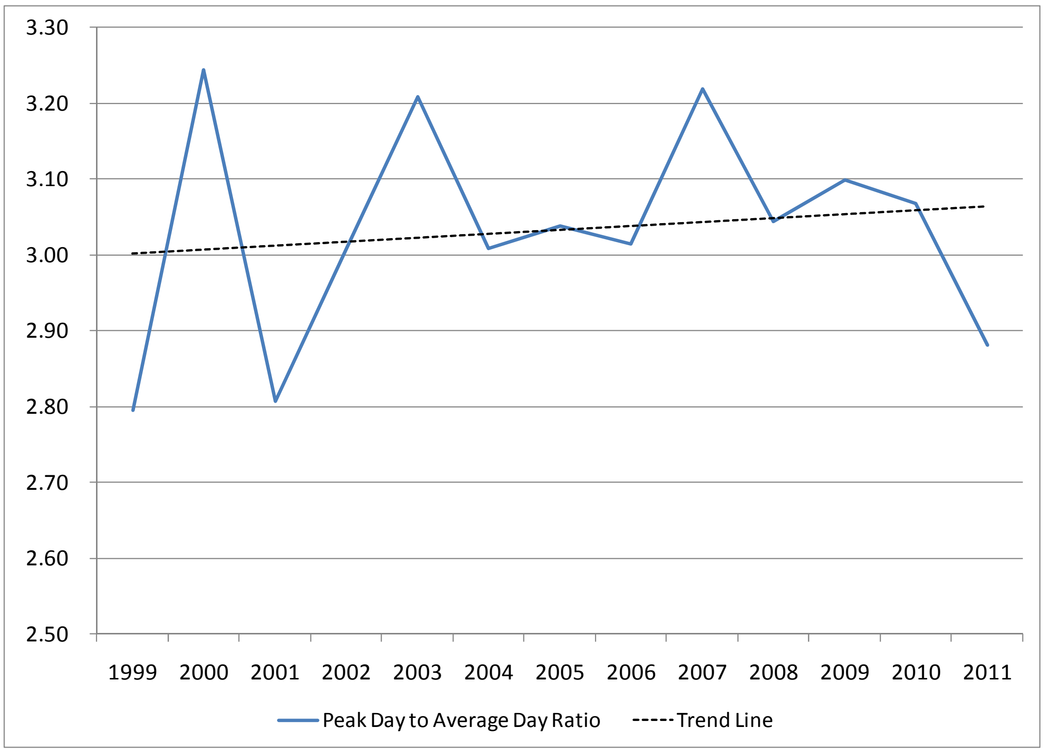


Figure 5:Ratio of Peak Day Demand to Average Day Demand – GTA Project Influence Area



17. The ratio of peak day demand to average day demand for the Central Weather Zone and the GTA Project Influence Area show an increasing trend over time indicating the distribution system load factor has tended to decline over time.

18. The trend of increases in peak day demand is a result of the demand trends discussed above. While industrial demand has declined, the continued addition of temperature sensitive customers to the distribution system has, on average, increased peak day demand over time. Likewise, the increase in the ratio of peak day demand to average day demand is largely a result of changes in the mix of customers with the majority of customer additions being temperature sensitive residential customers. Residential customer additions and the loss of industrial

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TR 2, page 156

To advise how EGD's 0.65 reduction function was calculated with an explanation discussing all the factors it considers including DSM.

RESPONSE

There are a number of factors that influence peak load on the distribution system over time. Some factors, such as GDP growth or a trend to larger buildings which are taller and denser than historical multi-residential construction, would tend to push the peak load higher. Other factors, such as energy efficiency improvements to the existing building stock or installed base of equipment, or changes to Building Codes on new construction and renovations, would be expected to decrease peak load. The Company forecast includes all of the above items.

The Company did a comparison of the load growth forecast (aggregated by sector, by geography, over the project forecast horizon as explained in the response to Environmental Defence Interrogatory #12 found at Exhibit I.A4.EGD.ED.12) to the historical send-out trend on peak day normalized to design conditions. As a result the Company applied a reduction to the forecast of increased peak system loads. The reduction factor captures the impact of all of the factors listed above across the existing and incremental loads.

The table below shows the comparison of the previous period normalized peak day demand for the GTA Project Influence Area and the forecast without and with the reduction factor that was included in the project forecast.

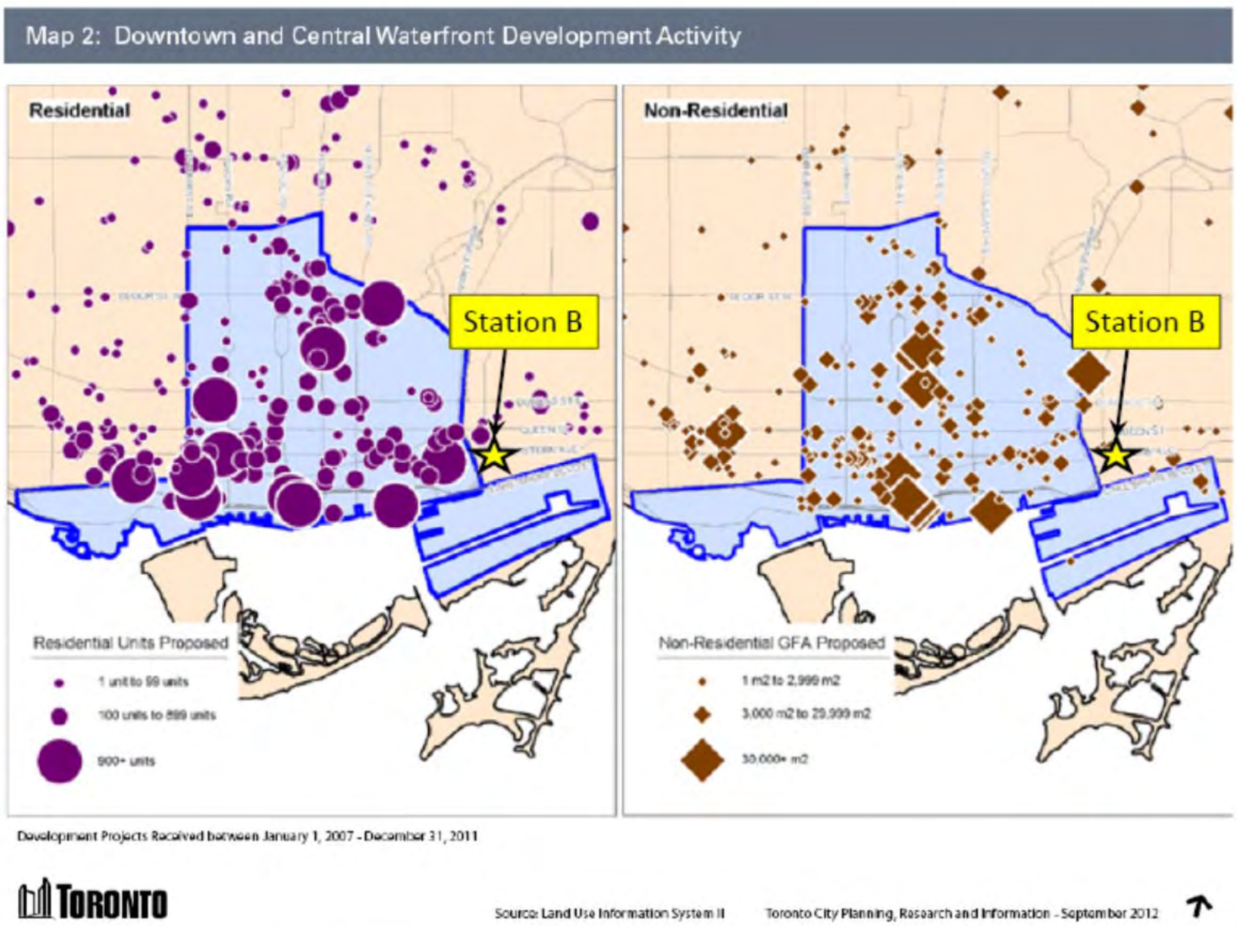
Period	# of Years	Total Growth (GJ/d)	Total Growth (%)
1999-2012 [1]	13	406,923	19.5
2013-2025 forecast (No reduction factor)	13	334,736	13.9
2013-2025 forecast (with reduction factor)	13	217,578	9.0

1 - Normalized peak day demand regression on customer count

Witness: C. Fernandes

Figure 3[3]: Development projects received by the City of Toronto

(2007 to 2011, yet to be built)



Load Growth

9. Pipelines and facilities are sized based on the forecasted total peak hourly consumption, which is calculated from the customer additions forecast and the peak hourly consumption estimate. For each municipality identified in the Influence Area, the peak hourly consumption estimate was calculated for each customer type based

[3] "Profile Toronto", October 2012 Issue. The location of Station B is overlaid on the figure.

on the five years of historical peak hour consumption. The data was regressed with temperature information to determine peak hourly gas consumption at a 41 DD. A reduction factor was then applied to account for efficiency gains through Demand Side Management ("DSM") and customer losses through building demolition. Large volume customers, such as power plants, are evaluated on an individual basis to determine replacement capacity requirements and therefore excluded from the customer additions forecast. The calculated peak hourly consumption value for each customer sector for each municipality was applied to customer additions forecast.

10. The total forecast peak day demand, shown in Table 3, is the incremental load growth plus the load required by the existing customer base. Gas demand and supply is further described in Exhibit A, Tab 3, Schedule 5.

Ontario

Go Green

Ontario's Action Plan On Climate Change

August 2007

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GO GREEN:
ONTARIO'S ACTION PLAN ON CLIMATE CHANGE

INTRODUCTION: WHY GO GREEN?

Scientists, and most notably, the United Nations Intergovernmental Panel on Climate Change (IPCC) have shown that the earth's climate is changing dramatically, and human industrial activity and the burning of fossil fuels are largely to blame. Before the Industrial Revolution, the carbon dioxide (CO_2) concentration in the earth's atmosphere was about 280 parts per million.

We are now at about 380 parts per million. At 380 parts per million, coral reefs are dying, glaciers are melting, seas are rising and an estimated 35,000 people died in the 2003 European heat wave. According to the IPCC, without significant action to reduce emissions, CO_2 concentrations may reach 750 parts per million this century.

Partly, this is because molecules of CO_2 remain in the atmosphere for up to 200 years. Which means the CO_2 molecules produced by the first cars, the Wright brothers' plane and the first coal-fired electricity plants may still be airborne.

Climate change is a crisis we caused together, and a responsibility we all share, together. So it's important we act, not only because we can't ignore the science, not only because we bear the responsibility, and not only because we have an obligation to our children.

We must also act, because this environmental crisis is also an economic opportunity. As a province with a strong manufacturing sector, plenty of natural resources, and a smart, educated, skilled workforce, there are opportunities for Ontario.

We don't have to choose between a strong economy and a healthy environment. Faced with the challenge of climate change, the only way to have a strong economy is to go green. And the only way to go green is to have a strong economy.

Go Green: Ontario's Action Plan on Climate Change is Ontario's *greenprint* for creating solutions, here, together. The time for imagining is over. Ontario is going green – now.

ONTARIO'S ACTION PLAN

Go Green: Ontario's Action Plan on Climate Change includes some of the most comprehensive, forward-looking steps on the environment that Ontario has ever contemplated.

We're setting firm targets and goals that we will meet together — not only for the distant future, but for right now, too.

Go Green will improve the way we live and travel in southern and central Ontario, the way we heat and light our homes, and the way we encourage and support businesses and industries that think green.

Through *Go Green*, your government is making green choices. But this plan will also enable everyone to make better, greener choices that will save money and help the economy. It will give Ontario's businesses the tools they need to go green and thrive – and offer opportunities for new, green business to take root and grow in our province.

Go Green is a five-point action plan:

- **Green Targets –** We have set short-, medium- and long-term targets for reducing Ontario's greenhouse gas emissions, starting now and continuing through mid-century. And we're setting out the measures to achieve these targets – new regulations, conservation, a phase-out of coal-fired power plants and much more renewable energy. From phasing out inefficient light bulbs to rebates for energy audits to provincial sales tax breaks for energy efficient products, there are new programs and incentives for Ontario consumers, businesses, and municipalities to get green.

- **MoveOntario 2020 –** We're launching the largest transit investment in Canadian history – a $17.5 billion plan that includes 52 rapid transit projects in the GTA and Hamilton, the country's largest urban area. It calls for 902 kilometres of new or improved rapid transit, creating 175,000 jobs during construction.

- **Creating Jobs by Going Green –** The *Next Generation Jobs Fund*, a new $650-million program, will secure the next generation of high-paying jobs for Ontarians by supporting businesses' commercial development, use and sale of clean and green technologies and businesses right here in Ontario.

- **Green Power –** A $150 million investment will help Ontario homeowners fight climate change, conserve energy and adopt green technologies. In addition to a world leading standard offer for renewable energy, we have set long-term targets to double the amount of electricity from renewable sources by 2025. In the short term we have gone from 10 to nearly 700 windmills, in place or planned. And we now have a standard offer for clean energy to enable power users to improve their efficiency through cogeneration (combined heat and power electricity production). We are removing other barriers that prevent more widespread use of cogeneration.

- **Grow Green –** In addition to the Greenbelt Act, which ensures there will always be nature and open spaces around our most populated areas, 50 million new trees will be planted in southern Ontario by 2020. Under the Places to Grow Act, we are growing more sustainable, energy-efficient, transit-friendly communities and we are setting strong targets to make sure we are achieving our goals. We're also bringing in new programs to promote locally grown Ontario food – the best in the world.

ONTARIO’S GREEN TARGETS

Go Green: Ontario’s Action Plan on Climate Change sets ambitious but realistic targets:

Together, we will reduce Ontario’s greenhouse gas emissions to 6 per cent below 1990 levels by 2014 – a reduction of 61 megatonnes relative to business-as-usual.

By 2020 Ontario will reduce greenhouse gas emissions to 15 per cent below 1990 levels – a reduction of 99 megatonnes relative to business-as-usual.

By 2050 we will reduce greenhouse gas emissions to 80 per cent below 1990 levels.

These reduction targets won’t be easy to achieve, but they are achievable – and they’re worth it. These targets put Ontario among the leaders in addressing climate change. No place in Canada is committed to producing more real reductions than Ontario.

If the federal government does its part by introducing an emissions trading system for industry compatible with other markets — an effective regime with real caps on emissions, real reductions over time and with the same 1990 baseline used by most of the international community — Ontario will achieve these targets even sooner.

ENVIRONMENTAL DEFENSE INTERROGATORY #5

INTERROGATORY

Issue 1: "Is the 2014 DSM Budget ($32.2M) reasonable and appropriate? Should the Board determine that the DSM budget for 2014 should be increased, what are the implications and required next steps."

Interrogatory No. 1-ED-5 Greenhouse Gas Emission Reductions

Reference: Ex. B, Tab 1, Schedule 2, page 1-3

Attached is a table containing a breakout of Ontario's energy-related greenhouse gas ("GHG") emissions in 2010 prepared for Environmental Defence and submitted in EB-2012-0337 (Exhibit K 1.5, Tab 4). In that proceeding, Union Gas agreed that the estimates in that table look reasonable.[1]

Also attached for your reference is a report from the Environmental Commissioner of Ontario which lists Ontario's GHG emission reduction targets as follows:

i) 6% below 1990 levels by 2014 (to approximately 165 megatonnes or Mt);
ii) 15% below 1990 levels by 2020 (to approximately 150 Mt); and
iii) 80% below 1990 levels by 2050 (to approximately 35 Mt).[2]

The Environmental Commissioner report states that "[the] government, itself, has projected a 30 Mt gap by 2020."[3]

a) Does Enbridge believe that the estimates in the attached table appear to be reasonable? If not, please provide alternative estimates.

b) According to the attached table, natural gas was responsible for 34.5 percent of Ontario's total energy-related GHG emissions in 2010. When the coal phase-out is complete and the Pickering nuclear station comes to an end of its life, is it more likely than not that the greenhouse gas emissions from natural gas-fired power plants will rise as a proportion of the total (all other things equal)?

[1] Transcript, EB 2012-0337, Vol. 1, January 31, 2013, p. 92, lns. 1-9.
[2] Environmental Commissioner of Ontario, *A Question of Commitment: Annual Greenhouse Gas Progress Report 2012*, http://www.eco.on.ca/uploads/ Reports-GHG2/20 I 2/Climate-Change-Report-20 I 2.pdf, page 12.
[3] *Ibid*. p. 14.

c) Is it reasonable to assume that a cost-effective strategy to achieve Ontario's 2020 GHG emission target will require a significant increase in the energy efficiency of Ontario's natural gas consumption'?

d) Are GHG emission reductions given a dollar value and factored into the TRC analysis for DSM programs?

RESPONSE

a) While Enbridge has not made any inquiries into the accuracy of the figures, the estimates in the attached table appear reasonable.

b) Yes (all other things being equal) the proposition seems reasonable. Enbridge is however neither qualified nor in a position to comment on the Provincial Governments overall long term plans for operating power generation plants. It therefore cannot comment on whether it is reasonable to assume that 'all other things' will be equal. When the coal phase-out is complete and the Pickering nuclear station comes to an end of its life, greenhouse gas emissions from natural gas-fired power plants will be determined by how often and which of the gas-fired power plants are dispatched in a new supply mix environment.

c) Natural gas energy efficiency contributes towards Ontario's pursuit of its GHG targets. Again, the Company is neither qualified nor in a position to comment on matters of overall Provincial Policy and Strategy as it pertains to Ontario's GHG emission target.

d) No value for CO_2 is included in the TRC equation.

Schedule A to Interrogatory No. 1-ED-5

Table of Ontario's Natural Gas-Related & Other Greenhouse Gas ("GHG") Emissions in 2010

Percent of Ontario's Total 2010 Energy-Related GHG Emissions from Certain Sources		
#	GHG Emission Source	Percent
1	Natural Gas Power Plants	8%
2	All Natural Gas Consumption	34.5%
3	Coal-Fired Power Plants	9%
4	Transportation	45.6%

Sources and Calculations

1. Ontario's total natural gas consumption in 2010 was 24,264.58 million cubic metres.[1]

2. Emission Factors for Natural Gas[2]:

    a) Carbon Dioxide: 1879 g/cubic metre
    b) Methane: 0.037 g/cubic metre
    c) Nitrous Oxide: 0.033 g/cubic metre

3. Natural Gas Consumption Emissions (m3 of gas multiplied by emission factors)

    a) Carbon Dioxide: 45,593,145.82 tonnes
    b) Methane: 897.79 tonnes
    c) Nitrous Oxide: 800.73 tonnes

4. IPCC Global Warming Potentials – 100 – Year Time Horizon (Second Assessment Report)[3]

    a) Carbon Dioxide: 1
    b) Methane: 21
    c) Nitrous Oxide: 310

5. Natural Gas Consumption GHG Emissions (Carbon Dioxide Equivalent)

    a) Carbon Dioxide: 45,593,145.82 tonnes
    b) Methane: 18,853.59 tonnes

[1] Statistics Canada, Catalogue 57-601, *Energy Statistics Handbook*, Tables 6.6 & 6.7, http://www.statcan.gc.ca/pub/57-601-x/2012001/tablelist-listetableaux6-eng.htm.
[2] Environment Canada, *GHG Emissions Quantification Guidance: Fuel Combustion*, http://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=AC2B7641-1.
[3] Environment Canada, *Global Warming Potentials*, http://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=CAD07259-1.

c) Nitrous Oxide: 248,226.3 tonnes
d) Total 45,860,225.71 tonnes

6. Ontario's Natural Gas Consumption GHG Emissions (45,860,225.71 tonnes) as a percent of Ontario's Total Energy-Related GHG Emissions (133,000,000 tonnes):

   34.5%[4]

7. Ontario's transportation-related GHG emissions as a percent of Ontario's Total Energy-Related GHG Emissions in 2010:

   45.6%[5]

8. Ontario's coal-fired electricity-related GHG emissions as a percent of Ontario's Total Energy-Related GHG emissions in 2010:

   9%[6]

9. Ontario's natural gas-fired electricity-related GHG emissions as a percent of Ontario's Total Energy-Related GHG emissions in 2010:

   8%[7]

   These emissions are a sub-component of Ontario's total Natural Gas Consumption GHG emissions.

[4] Calculated as 45,860,225.71 divided by 133,000,000. Ontario's total energy-related GHG emissions in 2010 were 133,000,000 tonnes. Environment Canada, *National Inventory Report 1990-2010 Part 3*, Table A14-12.
[5] Environment Canada, National Inventory Report 1990-2010 Part 3, Table A14-12.
[6] Environment Canada, National Inventory Report 1990-2010 Part 3, Table A14-12; and Environmental Commissioner of Ontario, *A Question of Commitment: Annual Greenhouse Gas Progress Report 2012*, (December 2012), page 21.
[7] Environment Canada, National Inventory Report 1990-2010 Part 3, Table A14-12; and Environmental Commissioner of Ontario, *A Question of Commitment: Annual Greenhouse Gas Progress Report 2012*, (December 2012), page 21.

Related GHG Figures

Ontario's GHG Emission Reduction Targets[8]

1. 6% below 1990 levels by 2014 (to approximately 165 megatonnes or Mt);
2. 15% below 1990 levels by 2020 (to approximately 150 Mt); and
3. 80% below 1990 levels by 2050 (to approximately 35 Mt).

GHG Emissions Gap

According to the Government of Ontario, in the absence of additional policy action, Ontario's GHG emissions in 2020 will be 30 Mt greater than its target.[9]

[8] Environmental Commissioner of Ontario, *A Question of Commitment: Annual Greenhouse Gas Progress Report 2012*, page 12.
[9] Environmental Commissioner of Ontario, *A Question of Commitment: Annual Greenhouse Gas Progress Report 2012*, page 14.

Climate Vision | Climate Change Progress Report

Ontario

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Technical Appendix A

Introduction

This technical appendix provides details on the province's greenhouse gas (GHG) emissions and changes in emission levels since 1990.[1] In addition, it also provides an update on the province's forecasted emission levels out to 2020, including the impact of policies on progress toward the province's emission targets.

How Ontario Measures its GHG Emissions

Ontario's definition of GHG emissions aligns with the definitions used to prepare Environment Canada's National Inventory Report 1990–2010: Greenhouse Gas Sources and Sinks in Canada (NIR), published in April, 2012. Each year, Environment Canada submits its updated NIR to the United Nations Framework Convention on Climate Change (UNFCCC) Secretariat. Historical GHG emissions in this progress report are taken from the latest NIR, which covers the period from 1990 to 2010. The data cover most activities in Ontario's economy that influence GHGs but do not include impacts relating to land use and forestry at this time. The NIR is organized into numerous categories that are defined by UNFCCC reporting protocols and therefore do not match categorizations by other sources of economic, industrial, energy and emissions data. For this appendix, the categories are rolled up into six key economic sectors (see Table 1).

TABLE 1
ONTARIO EMISSION SECTOR DESCRIPTIONS

ECONOMIC SECTOR	DESCRIPTION
Transportation	Emissions from the consumption of fossil fuels such as diesel, gasoline and propane consumed by passenger and commercial vehicles including road, rail, marine and air travel
Industry	Emissions from industrial processes and the use of fossil fuels such as coke, natural gas and coal are produced from a range of industries including mining, oil and gas extraction, manufacturing, mineral and chemical production, construction and paper and wood products production
Buildings	Emissions from the use of fossil fuels such as natural gas in residential, commercial and institutional buildings for heating and water
Electricity	Emissions from electricity and heat generation produced from the combustion of fossil fuels such as coal and natural gas
Agriculture	Emissions generated by enteric fermentation, manure management and fertilizer application
Waste	Emissions generated by solid waste disposal on land, wastewater handling and waste incineration

NB: Emissions from the pipeline transportation of petroleum products are included in the Industry sector.

1 All figures in this appendix are rounded, which may therefore not produce the exact results indicated for totals, ratios, etc.

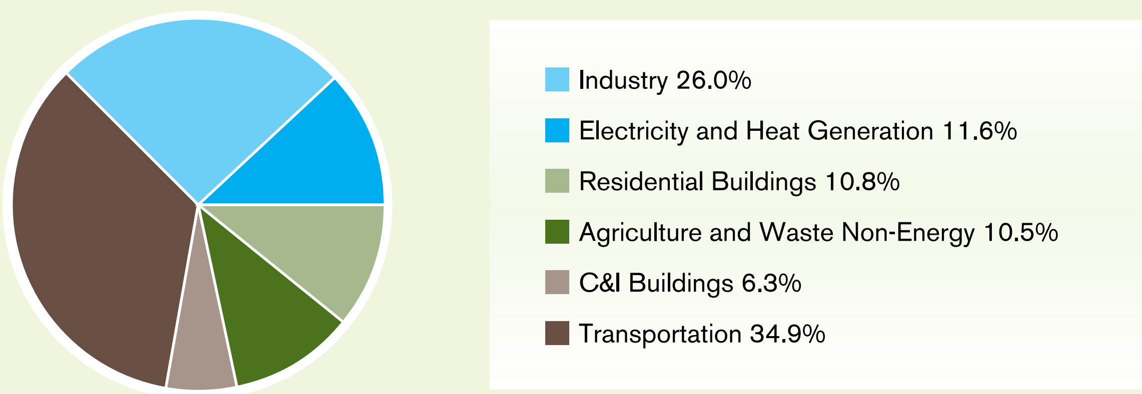
Changes in NIR

Environment Canada is continually working to refine the data and methods used to estimate national and provincial emissions. These refinements often lead to re-calculation of GHG emission estimates for the whole time period of the NIR, dating back to 1990. This means that our 1990 base year emissions and historical trends can change from year to year, influencing our emission forecasts and the assessment of our progress to targets. These changes are well documented in the NIR and are typically minor but in recent years, some changes in the industrial sector methods have had a pronounced impact on Ontario emission estimates.

Sources of Ontario's GHG Emissions

GHG emissions result from virtually all aspects of Ontario's society and economy but primarily from how we produce and consume energy. Ontario's 2010 emissions are estimated to have been 171 megatonnes (Mt) of carbon dioxide equivalent (CO_2 eq), with sectoral shares shown in Figure 1.

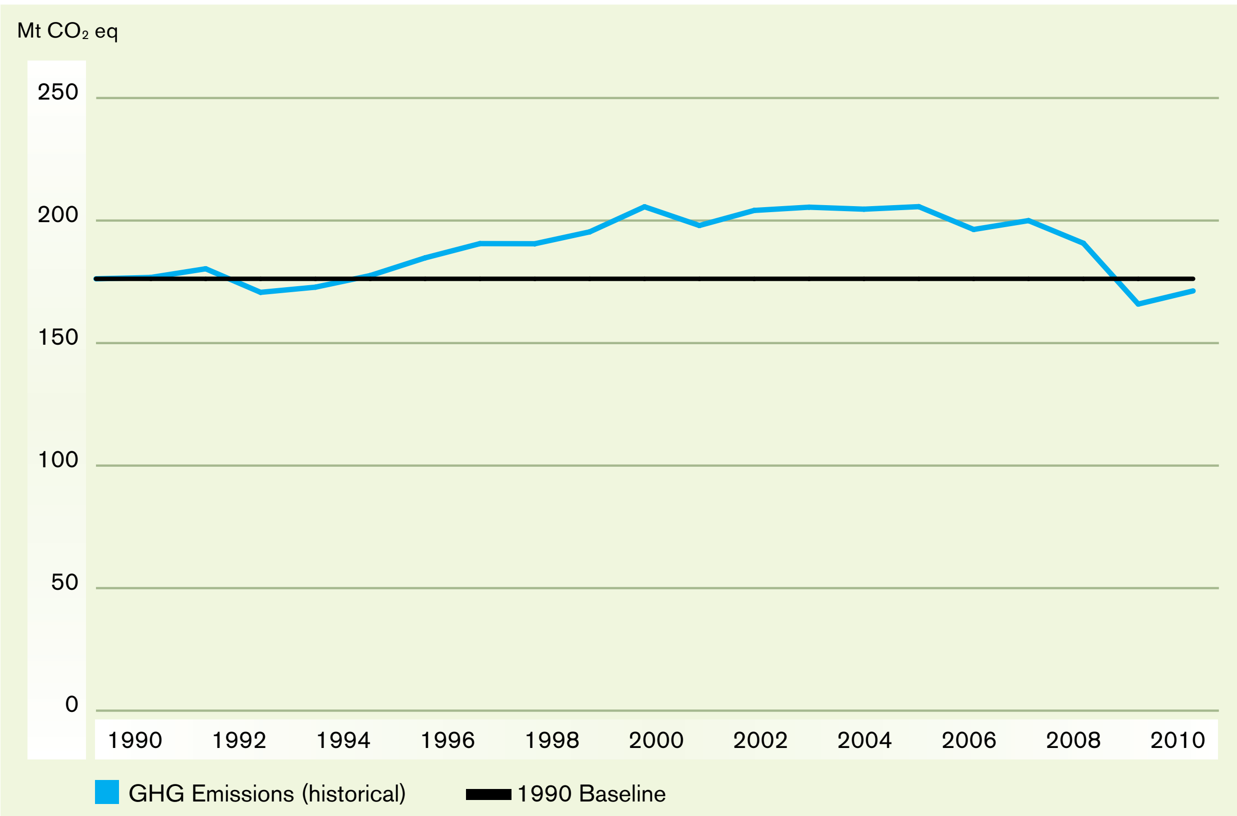
FIGURE 1
2010 GHG EMISSIONS BY SECTOR



Long-Term Trends in Ontario's Emissions (1990–2010)

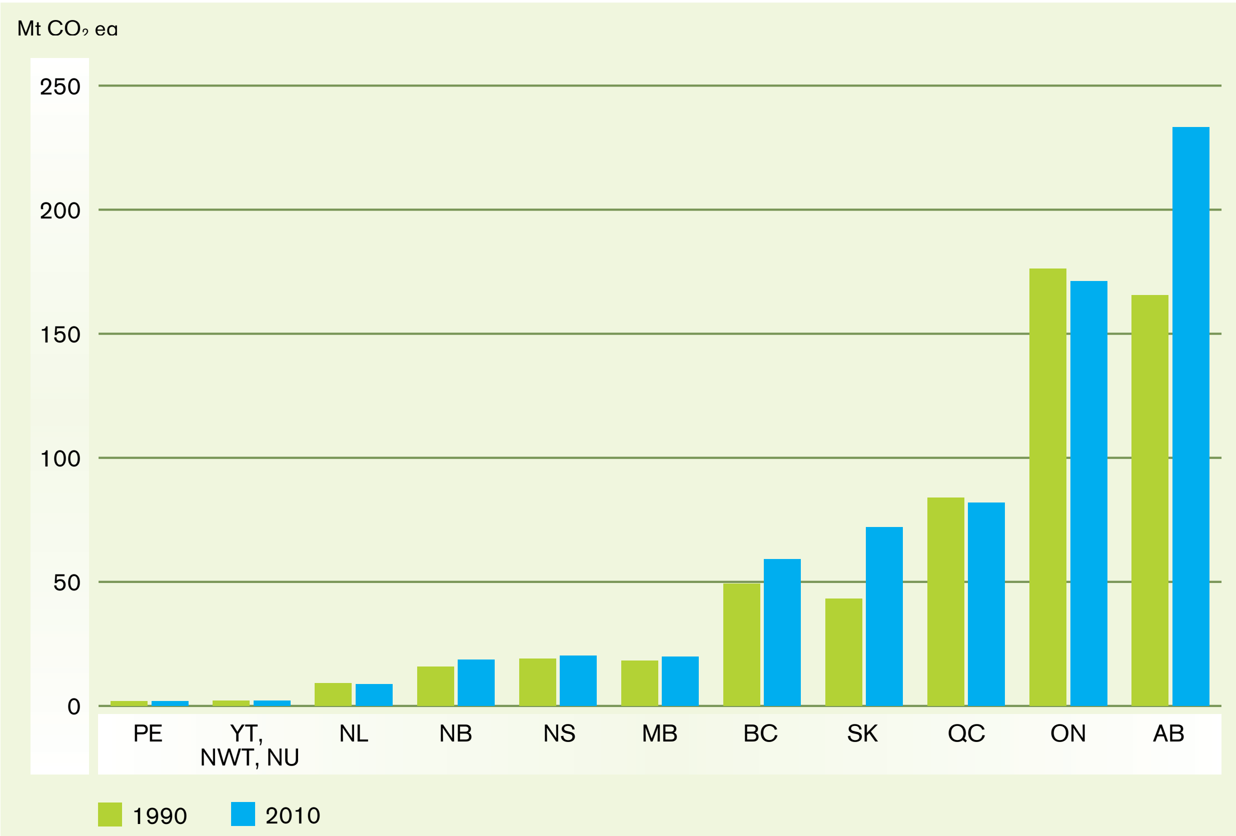
Between 1990 and 2010, Ontario's total annual emissions dropped by three per cent, from 176 Mt of CO_2 eq to 171 Mt of CO_2 eq. Figure 2 shows that, while total emissions increased fairly steadily in the first half of this period, more recent annual emission levels have fluctuated in response to changes in the economy, weather, energy demand and technologies used by industry, electricity generation, transportation, and consumer products.

FIGURE 2
ONTARIO'S GHG EMISSIONS, 1990–2010



In contrast to Ontario's stable to declining emissions, the national trend is increasing emissions. In 2010, Canada's GHG emissions totalled[2] 695 Mt CO_2 eq, which represents an increase of 18 per cent since 1990. However, increases since 1990 have varied significantly across Canada. Similar to Ontario, Quebec's emissions decreased by two per cent while Saskatchewan realized the highest increase in emissions (67 per cent) (see Figure 3). In absolute emissions since 1990, the most growth has occurred in Alberta (68 Mt) while the greatest decrease has occurred in Ontario (5 Mt).

FIGURE 3
TERRITORIAL AND PROVINCIAL GHG EMISSIONS, 1990 AND 2010

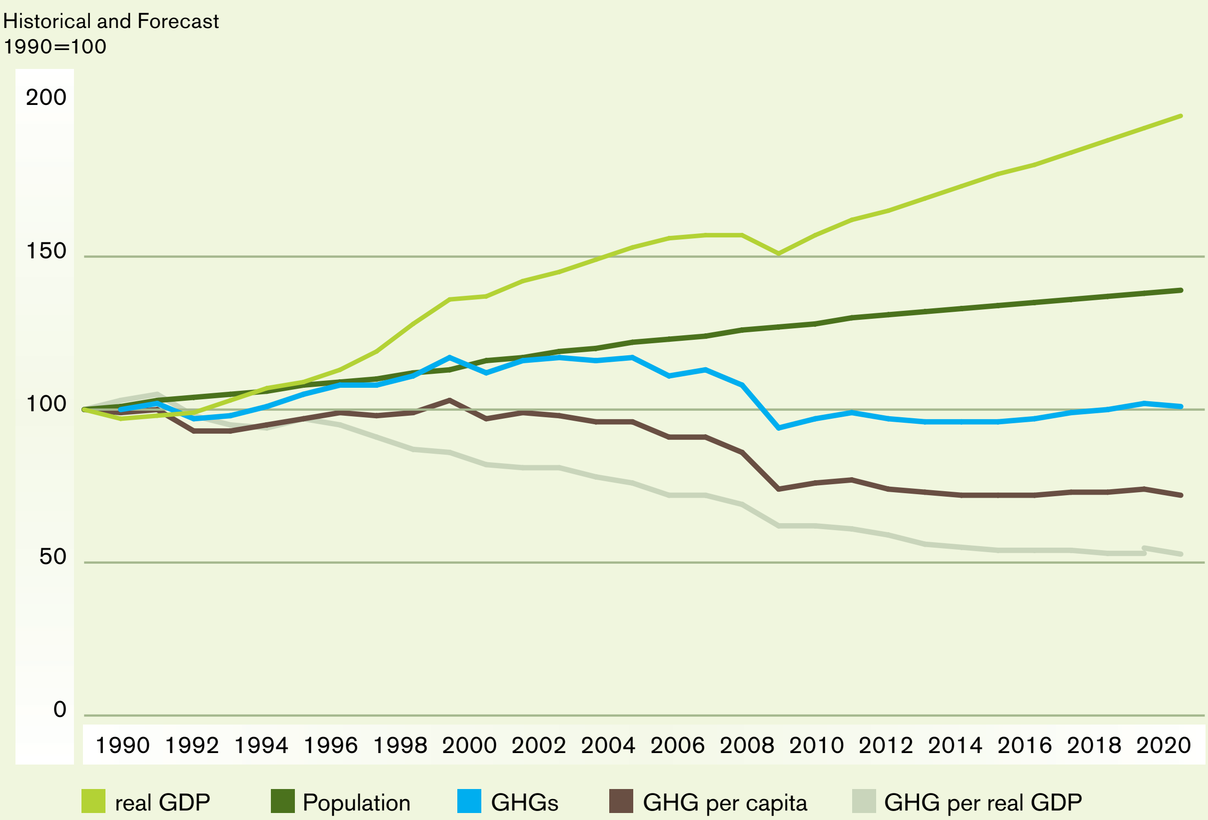


2 In June 2012, British Columbia released their Greenhouse Gas Inventory Report 2010, in which they identified a significant discrepancy in the "Fossil Fuel Production and Refining" line item of the 1990-2010 NIR. As the discrepancy was due to a data automation issue that was not identified before the NIR was published, this appendix uses a revised estimate for B.C. (and therefore total Canadian) emissions: an increase of 3037.5 kiltotonnes CO2 eq in 2010.

TABLE 2 EMISSION CHANGES BY SECTOR (ONTARIO)	
ECONOMIC SECTOR	DESCRIPTION
Transportation 1990: 45.5 Mt 2010: 59.8 Mt Change: +31%	Road transportation was responsible for the greatest increase in Ontario's emissions between 1990 and 2010. This long-term increase can be attributed to 30 per cent growth in the on-road vehicle population and the increased consumer preference for SUVs, vans and pick-ups (which more than doubled over this period) over smaller passenger vehicles. Higher emissions also reflect the national trend toward just-in-time delivery, requiring more transportation per product.
Industry 1990: 63.2 Mt 2010: 44.5 Mt Change: -30%	Significant improvements in energy efficiency since 1990 have resulted in greenhouse gas reductions as industries responded to increased energy costs and global competitiveness.
Buildings 1990: 26.3 Mt 2010: 29.2 Mt Change: +11%	Long-term increases in this sector are due to economic changes and population growth. Emissions from commercial and institutional buildings have increased 18 per cent due to a shift in the provincial economy from a manufacturing base to a diversified service industry including finance, insurance and real estate. Residential emissions increased by seven per cent while the population increased by 28 per cent.
Electricity 1990: 25.1 Mt 2010: 19.8 Mt Change: -21%	Emissions in Ontario's electricity and heat generation sector grew between 1990 and 2000 (an increase of approximately 70 per cent). Significant decreases after 2007 (40 per cent by 2010) have been achieved primarily through the phasing out of coal-fired generation, increasing of renewables and conservation initiatives in the industrial, residential and commercial sectors.
Agriculture 1990: 10.0 Mt 2010: 10.3 Mt Change: +4%	Emissions from agriculture have remained relatively constant with slight fluctuations resulting from a combination of changing tilling and nutrient management techniques and livestock levels.
Waste 1990: 6.2 Mt 2010: 7.6 Mt Change: +24%	Waste emissions increased primarily due to increases in landfill gas which is generated from waste disposed in landfill sites both recently and in past decades.

It is important to note that, while Ontario's total emissions decreased by three per cent between 1990 and 2010, both emissions per capita and emissions for each dollar of real Gross Domestic Production (GDP) have declined by a much greater amount (24 percent and 38 per cent respectively; see Figure 4). This indicates an ongoing trend towards a lower-carbon economy and society, which our modelling suggests will continue.

FIGURE 4
EMISSION INTENSITIES INDICES



Ontario's intensities are significantly lower than most provinces. Table 3 shows 2010 emissions per capita and per dollar of real GDP across Canada.

TABLE 3
PROVINCIAL/TERRITORIAL GHG INTENSITIES

PROVINCE/ TERRITORY	GHG INTENSITY (Mt/$B GDP)	RANK (GHG INTENSITY)	GHG PER CAPITA (t/CAPITA)	RANK (GHG PER CAPITA)
YT, NWT, NU	0.18	1	18.99	7
QC	0.34	2	10.37	1
ON	**0.37**	**3**	**12.95**	**2**
BC	0.41	4	13.04	3
MB	0.53	5	16.05	5
PE	0.57	6	13.67	4
NL	0.59	7	17.33	6
NS	0.79	8	21.54	8
NB	0.88	9	24.68	9
AB	1.55	10	62.70	10
SK	2.12	11	69.05	11

NB: GDP is measured in 1997 dollars.

Short-Term Trends in Ontario's Emissions (2007–2010)

Between 2007 (when the Climate Change Action Plan was first released) and 2010, Ontario's emissions decreased by 14 per cent – a decline of 29 Mt. Table 4 shows emissions decreased across all major sectors. The electricity sector saw a 40 per cent reduction in emissions, the largest decrease. The second largest decrease was in the industrial sector where emissions fell by 23 per cent. These reductions are largely attributable to reduced coal-fired electricity generation and a decline in both output and emission intensity in energy-intensive industries. Both residential and commercial buildings also reduced their emissions from heating, despite increases in total floor space. This is due to ongoing successful natural gas demand management programs, and the residential retrofit program; however, economic activity likely affected these emissions as well.

TABLE 4 CHANGES IN ONTARIO'S EMISSIONS (2007–2010) (MT CO_2 EQ)			
SECTOR	2007	2010	VARIATION (2007–2010)
Transportation	58.0	59.8	3%
Industrial	58.0	44.5	-23%
Buildings	33.0	29.2	-12%
Electricity	33.0	19.8	-40%
Agriculture	10.0	10.3	4%
Waste	7.9	7.6	-4%
Total	**200.0**	**171.3**	**-14%**

Emission Modelling Overview

Reporting on the progress of Climate Change Action Plan initiatives and projecting future GHG emissions are essential to understanding Ontario's progress towards meeting its action plan targets. It should be noted, that emission forecasts are only one measure of progress on climate change actions. Decarbonization is achieved through steady, ongoing reductions in the key drivers of energy use (particularly fossil fuels) and non-energy emissions. Incremental progress in these areas is best assessed by looking at a variety of indicators – quantitative ones like emission forecasts, but also changes in emission intensities, building densities, vehicle kilometres travelled, etc. – along with qualitative assessments of the nature and resilience of socioeconomic changes. Finally, most of the important initiatives (public transit infrastructure, building energy efficiency, vehicle efficiency improvements, and land use) take decades until their peak impacts are felt.

Ontario's approach to modelling GHG emissions is updated periodically to incorporate the latest data available and refinements based on best practices. In addition, the projections of emission reductions are adjusted as required to incorporate changes to programs or policies. This modelling uses the most recent NIR data (April 2012) from Environment Canada and economic and demographic forecasts from February 2012 by Informetrica.

This information was used to create:

1. A Business-as-Usual (BAU) projection – a projection that assumes underlying historical emission trends continue (excluding the anticipated future impact of emission reduction initiatives, both planned and already underway), while taking account of the current economic outlook for Ontario;

2. A Climate Change Action Plan projection – a projection that includes the anticipated future impact of emission reduction initiatives (both those that are underway and those that are committed to and sufficiently developed to reasonably estimate their impacts).

Third-Party Validation

To provide confidence in the province's long-term forecasts, Ontario has had its emissions forecasting methodology and assumptions validated by an independent third party. In 2009, Ontario was the first jurisdiction to undertake a validation of its forward-looking emission reduction forecasts. The process of completing a validation is intended to ensure that the methodologies, data sources and assumptions used to develop the projected GHG emissions under the action plan are reasonable and align with best practices where available. For this report, Ontario retained Navius Research Inc., who concluded that Ontario's estimates are a fair representation of those expected using current best practices in GHG emissions forecasting and evaluation of GHG mitigation programs (see Appendix C for assurance statement).

Updated Emissions Projection

Since the release of the last climate change progress report, the province's emission forecasting model has been updated to reflect the best available information.

The government is now projecting that the suite of initiatives will achieve approximately 90 per cent of the reductions needed to meet the 2014 target. The forecasts show a slight improvement over those in the last report (see Table 5). Changes in forecasted emissions reflect revisions to modelling[3], changes to the BAU scenario (see below) and new data on program participation and effectiveness.

TABLE 5
PROGRESS TO TARGETS

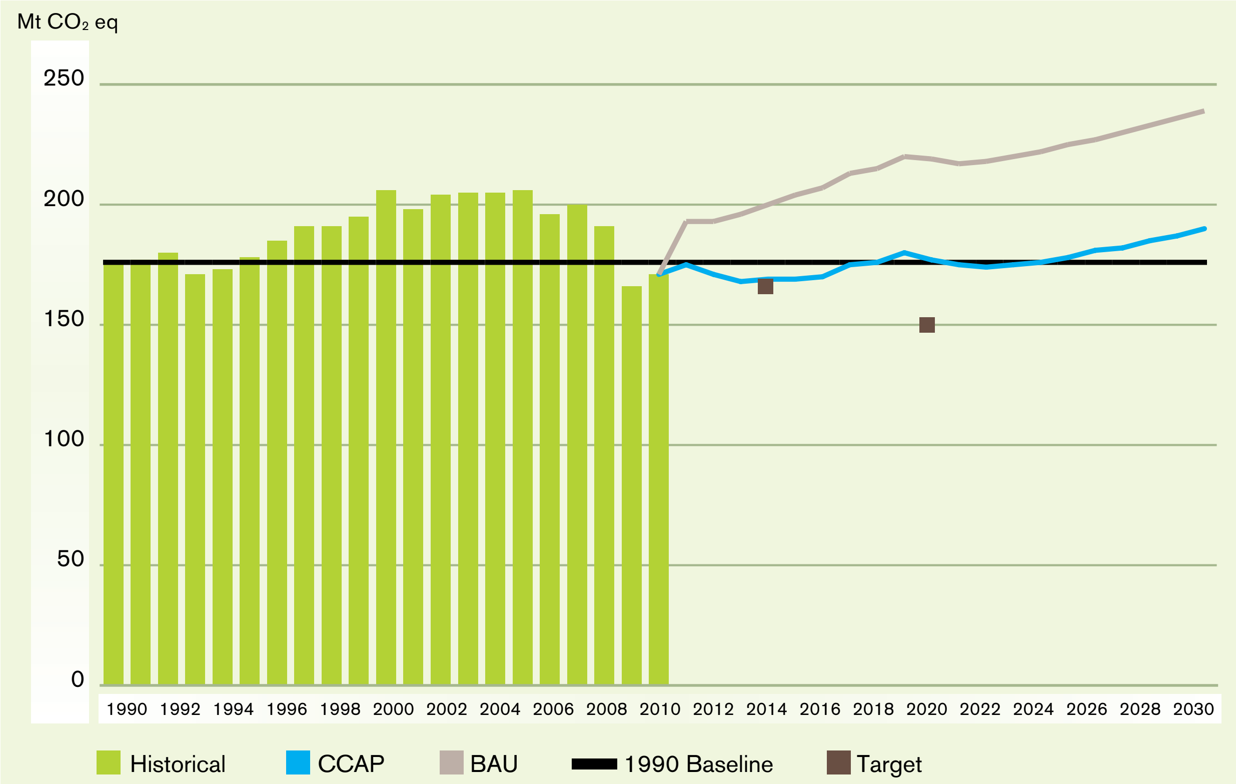
2012 REPORT	2014	2020
Projected Reductions (Mt)	31	42
Progress to Target	91%	60%
Gap (Mt)	3	28
2011 REPORT	**2014**	**2020**
Projected Reductions (Mt)	27	39
Progress to Target	88%	57%
Gap (Mt)	4	30

Updating the BAU

The province's BAU scenario has been updated to reflect more recent emission and energy use data, revisions to historical data from Environment Canada and Natural Resources Canada, revised economic and demographic forecasts and refinements to the underlying model.

3 The most significant methodological change was in how ethanol in blended gasoline is both reported and forecast. In the last report, the NIR data used did not account for ethanol in motor gasoline and the model did not forecast emission reductions from higher ethanol blending due to Ontario's ethanol regulation (although in place at the time). A change to using an average of historical emission factors of coal in generating electricity also significantly increased the BAU emissions from electricity, as recommended by the validator.

FIGURE 5
FORECASTED GHG EMISSIONS



Initiative Impacts

The province's suite of initiatives represent a combination of distinct GHG reduction efforts, such as provincial regulation requiring methane from landfills to be captured, and clusters of related efforts aimed at achieving a common goal, such as the phase-out of coal-fired electricity generation and related renewable generation and conservation activities. The initiatives cross all of the emission sources and economic sectors and represent a blend of short-, medium- and long-term emission reductions. The initiatives include activities that are both within and outside the direct control of the Ontario government and include federal policies that are closely interrelated with provincial initiatives.

TABLE 6
EMISSION REDUCTIONS BY INITIATIVE (SECTOR TOTALS)

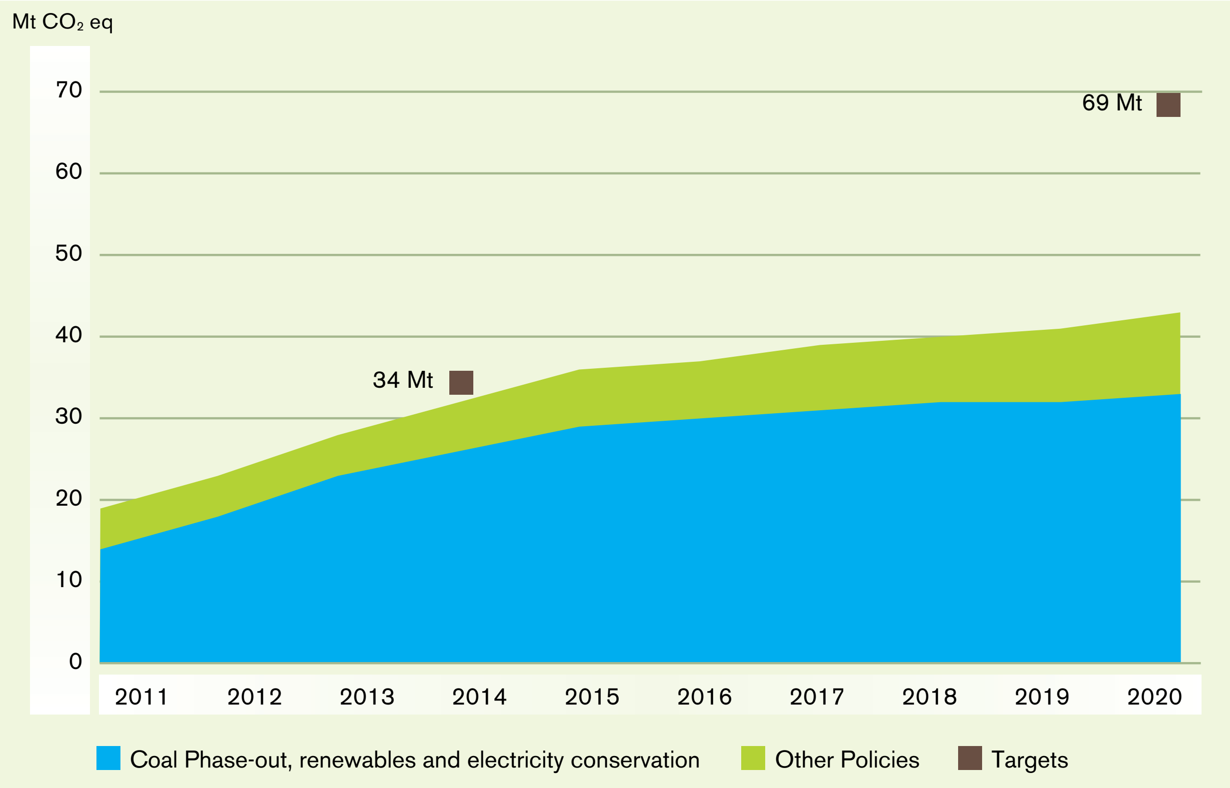
SECTOR	INITIATIVE	PROJECTED REDUCTIONS (MT) 2014	2020
Transportation	• The Big Move regional transportation plan and Growth Plan for the Greater Golden Horseshoe[4] • Passenger vehicle efficiency regulations • Freight truck speed limiter regulation • Municipal hybrid bus purchase and Green Commercial Vehicle Programs • Ontario ethanol regulation	1.9	3.9
Industry	• Natural gas demand side management programs	0.6	1.0
Buildings	• The Growth Plan for the Greater Golden Horseshoe • Natural gas demand side management programs • Building Code changes	1.6	2.9
Electricity	• Long-Term Energy Plan: Coal phase-out; the Feed-In Tariff; residential, commercial and industrial conservation programs; and related electricity policies	24.8	31.6
Agriculture and Waste	• Biogas Financial Assistance Program • Landfill gas capture regulation	1.8	2.0
	All initiatives	30.6	41.3

NB Emission reductions for all initiatives together may differ from the sum of individual initiative reductions due to interaction between them.

Phasing out coal-fired electricity generation and replacing it with renewable power, natural gas, refurbished nuclear and energy conservation has by far the largest impact in the near future (see Figure 7). After 2020, however, impacts from initiatives in the transportation and building sectors will increase relative to those from the electricity sector because of the time required for construction (transit projects) and turnover (vehicle fleets, housing stock).

4 The regional transportation plan is an official long-term plan, produced by Metrolinx. However, capital projects are approved and funded individually as the plan is implemented over 25 years and may be subject to change. Therefore, modelling for this initiative is inherently more uncertain than for other initiatives.

FIGURE 7
REDUCTIONS BY SOURCE



Uncertainty

The reductions presented in this report, linked to the government's GHG emission reduction measures, are based on a single set of economic, demographic, energy, and policy assumptions. As with any modelling of this kind, there are significant uncertainties inherent in this projection.

As a rough example, if in 2020 both real GDP and population were one per cent higher than forecasted, the projected non-electricity emissions would be approximately 1.5 Mt greater (almost one per cent of non-electricity emissions). This change is a generalized effect. The increase could be significantly higher or lower depending, for example, on whether energy-intensive manufacturing output is higher than the service sector. Electricity emissions are sensitive to weather – more frequent hot summer afternoons (especially combined with higher GDP) would increase emissions much further.

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2012-0433** **EB-2012-0451** **EB-2013-0074**

VOLUME:	**7**	
DATE:	**September 27, 2013**	
BEFORE:	**Cynthia Chaplin**	**Presiding Member and Vice-Chair**
	Marika Hare	**Member**
	Peter Noonan	**Member**

I N D E X   O F   P R O C E E D I N G S

MR. BRETT: Well, that's interesting, but if you don't have any analyses of the extent to which the changes in the building codes and the rigour with which they have been enforced and the administration of those codes, if you don't have that kind of analysis, it must be somewhat difficult to build in an authoritative factor for the effect of those codes into your load forecast, would it not?

[Witness panel confers]

MR. FERNANDES: I think we can look at what the process that was used, and Mr. Naczynski can speak a little bit more to that. But we do take actual data into account and project that forward. So for instance, things like a change in 2009 we believe is incorporated into the load forecast that we've used.

MR. BRETT: All right. Ms. Ramsay, you were with Enbridge up until about a year ago; is that right?

MS. RAMSAY: Until -- officially until earlier this year; that's correct.

MR. BRETT: All right. And you're a senior advisor in their DSM group, have been for some time?

MS. RAMSAY: Since earlier this year, correct.

MR. BRETT: Yes, but prior to that you were involved with the DSM effort at Enbridge, if I'm not mistaken.

MS. RAMSAY: Yes, from 2000 onwards.

MR. BRETT: Right. And yesterday we heard about a number of meetings that were held in 2011 and perhaps 2012. We heard from Mr. Fernandes and Mr. Naczynski about these internal meetings that were held at Enbridge to plan the GTA project, and at those meetings one of the decisions that was taken was that DSM -- the DSM program as practised by Enbridge wouldn't have any relevance to the GTA project so it should not be considered as part of the solution.

Now, my question to you is, were you at those meetings, or was anybody else from the DSM group at those meetings?

MS. RAMSAY: I was not at the meeting.

MR. BRETT: You were not. Mr. Fernandes, was anybody -- I take it you were at those meetings as a GTA project leader.

MR. FERNANDES: I was; correct.

MR. BRETT: Was anybody from the DSM group at those meetings on a continued basis or regular basis?

MR. FERNANDES: No, they were not.

MR. BRETT: Okay. Mr. Naczynski, you yesterday spoke a little about -- just before I get into that -- I'll come back to you in just a moment, sir. But there was some discussion yesterday about a statement made in the document which is entitled "Conservation First". And I think that Mr. Elson referred to this.

"Conservation First" is a document that was put out recently this summer really by the provincial government. Are you folks in the DSM group in particular aware of that document? It was put out as sort of an add-on to the draft long-term energy plan.

MS. OLIVER-GLASFORD: Yes, we're aware of that back for a moment, just to finish that point off, Ms. Ramsay, your -- I apologize, I need to refresh my memory on that quote, but effectively, when the 169 decision was made and for several years thereafter, you would agree with me that the externality, the external benefits were quantified? Social external benefits were quantified as part of the benefit? And then at some point, at some later date, that part of the analysis, as I understand it, was discontinued. Does that ring a bell?

If it doesn't, you can just tell me, if you are not aware of it.

MS. RAMSAY: Well, I think we need to be careful with terminology. It wasn't social benefits. The --

MR. BRETT: It was external environmental benefits, as I understand it.

MS. RAMSAY: No, external environmental benefits were never included. They were considered early on in EBO-169 and there was a major study in terms of trying to quantify what those external environmental benefits would be, but in the end the Board decided on using the TRC test, not the societal cost test, and environmental externalities have never been included in our calculations.

MR. BRETT: In the very early years you used to calculate CO_2 reduction impacts, as I understand it.

MR. RAMSAY: We calculate the --

MR. BRETT: Both Union and Enbridge had threshold numbers that they use to make those calculations. Now, are you saying to me that the Board never, even in its earliest

--- Recess taken at 10:08 a.m.

--- On resuming at 10:38 a.m.

MS. CHAPLIN: Please be seated.

Are there any preliminary matters before the panel is introduced and sworn? No? Okay. Is it Mr. Elson or Mr. Poch going --

MR. POCH: We're going seriatim. We've combined in the interests of speeding the hearing along, and as the panel will be aware, the witnesses did have an opportunity to interlace their efforts at some -- to some limited extent.

So if I could just introduce Mr. Chernick, Mr. Paul Chernick, and Mr. Chris Neme, and ask that they be sworn, and perhaps my colleague can do the same.

MR. ELSON: I could, of course, introduce Ian Jarvis and Wen Jie Li from Enerlife Consulting and ask that they be sworn.

ENVIRONMENTAL DEFENCE/ GEC – PANEL 1

Ian Jarvis, Affirmed

Wen Jie Li, Affirmed

Chris Neme, Affirmed

Paul Chernick, Affirmed

EXAMINATION-IN-CHIEF BY MR. POCH:

MR. POCH: Mr. Neme, perhaps we'll start with you. You're the author of Exhibit L.EGD.GEC.2 and their related interrogatory responses?

MR. NEME: Yes, I am.

MR. POCH: And you adopt them in your evidence in this proceeding?

MR. NEME: I do.

MR. POCH: Your curriculum vitae appears as L.EGD.GEC.4; correct?

MR. NEME: Yes.

MR. POCH: I see you've worked in numerous jurisdictions in the United States, Canada, and Europe?

MR. NEME: That's correct. Approximately 25 different states.

MR. POCH: Is your microphone on?

MR. NEME: Okay. Sorry. Approximately 25 different states, several Canadian provinces, and several different countries in Europe.

MR. POCH: And I note that you've filed testimony, by my count I think, at least 18 cases before this Board, and appeared as an expert witness before this Board on numerous occasions?

MR. NEME: That's correct.

MR. POCH: And your expert testimony in those cases has been on matters of conservation policy, program design, program delivery, and evaluation in both electricity and gas cases? Am I correct?

MR. NEME: That's correct.

MR. POCH: I understand you're familiar with Enbridge's DSM programs as a result of your participation in DSM collaboratives and as an appointee of the various intervenor groups to the audit committees over the years and, most recently, to the technical advisory committee?

MR. NEME: Yes, I've been involved in the various collaborative consultative processes, going back to the very first DSM efforts in 1995. I've been on one or both of the two utilities' audit committees, I think every year but one since the year 2000, and I currently serve on the Enbridge audit committee and on the technical evaluation committee, in both cases elected as a representative of the broader stakeholder group.

MR. POCH: All right. And when you say "elected", you're saying elected by the breadth of intervenors?

MR. NEME: Correct.

MR. POCH: Thank you.

Madam Chair, I would ask that Mr. Neme be qualified as an expert in the area of conservation policy, program design, program delivery, and evaluation.

MS. CHAPLIN: Are there any questions or submissions from counsel?

MR. STOLL: I talked to Mr. Poch beforehand. I have no issues with that qualification.

MR. POCH: Mr. Chernick, you are the author of -- Madam Chair, is that acceptable to you?

MS. CHAPLIN: It is. Thank you, Mr. Poch.

MR. POCH: Most importantly. Mr. Chernick, your evidence is L.EGD.GEC.1 and related IRs, correct?

MR. CHERNICK: Yes. Yes, it is.

MR. POCH: And you adopt that as your evidence in this proceeding?

MR. CHERNICK: I do.

MR. POCH: And your CV appears as L.EGD.GEC.4? Am I correct?

MR. CHERNICK: Yes.

MR. POCH: And I see you've testified in over 250 occasions on utility issues before various regulatory, legislative, and judicial bodies, including in five Canadian provinces; is that correct?

MR. CHERNICK: Yes.

MR. POCH: And you filed testimony or appeared as an expert witness before this Board on approximately a dozen occasions?

MR. CHERNICK: Something like that, yes.

MR. POCH: Am I correct that your expert testimony has centred on matters of regulatory economics and with respect to integrated resource planning?

MR. CHERNICK: Yes.

MR. POCH: And assuming my friend has no objection, Madam Chair, I would ask that Mr. Chernick be granted status as an expert witness in those two areas.

MR. STOLL: I don't have any objection.

MS. CHAPLIN: The Board accepts him.

MR. POCH: Thank you.

Perhaps I'll carry on with chief for these witnesses before my friend begins.

Mr. Neme, let me start with you again. On the stand on Tuesday Ms. Ramsay for Enbridge stated that some years ago the company stopped including the distribution component of avoided costs in its cost-effectiveness screening for DSM, and she indicated that it was her recollection that that had been discussed with other parties in the stakeholder collaborative process. Do you have a recollection of such discussions?

MR. NEME: No, I do not. As I indicated, I have been pretty intimately involved in those discussions for quite some time. I don't attend -- I haven't -- wouldn't claim to have attended every single consultative meeting, but I did confer with Mr. Millyard, who usually attends them when I don't, and he had no recollection of that conversation either.

MR. POCH: Had you been aware of such a proposal would you have objected?

MR. NEME: Yes, I would have, for several reasons. First, as I understood Ms. Ramsay's explanation, the underlying rationale for excluding the capital costs of distribution upgrades from avoided costs didn't make sense. Her explanation was that because the company has the opportunity to earn incentives -- or rewards for shareholders, if you will -- if they make the capital investment, that it would be inappropriate to include the avoided costs for those things in cost-effectiveness screening when at the time the utility was earning shareholder incentives for DSM based on the magnitude of the TRC net benefits.

And implied in that was that there might be some sort of double-collecting by shareholders of incentives, and almost by definition there couldn't be. Either the company would build a distribution project and earn its rate of return on that project or, if it did enough DSM to defer the project, it wouldn't build the project or it would build it later, and would instead earn a shareholder incentive related to the net benefits associated with that deferral. It's one or the other.

That's one problem. The other is that by then excluding the benefits of deferral of capital projects on the distribution system, the avoided costs inherently understate the economic benefits of DSM. That means that it might have rendered some efficiency measures or programs that might have been considered for implementation to be cost-ineffective when they really were cost-effective. It kind of distorts that whole view of things.

And then I guess finally the point I would make is that in the most recent natural gas DSM guidelines adopted by the Board, the Board made clear that avoided capital costs ought to have been included.

MR. POCH: All right. The company also said through its witnesses that they feel they can't count on DSM to address capacity issues, because they don't have data on the relationship between annual energy savings and peak-hour savings. How do you respond to that?

MR. NEME: I would say several things. First, although the company devoted some portion of its discussion of DSM as an alternative to the potential that some efficiency measures might actually exacerbate peak, when pressed on the issue it became clear that it's a very small number of measures which, by my estimation, account for a de minimus portion of the savings that the company has historically been getting across its whole portfolio.

Secondly, so we know that the vast majority of efficiency measures that they promote through their programs will provide benefits both annually and at the time of peak. It's probably true that some of those measures will provide disproportionately more benefit on peak than annually, some less benefit on peak than annually, and others, particularly measures like more efficient heating equipment, the ratios are probably pretty proportional.

So on average, absent better information, it's a reasonable assumption to assume that proportionality exists.

Now, I will also add that to the extent one wanted to test this further and to the extent the company would have discomfort with that kind of assumption, there are well vetted, off-the-shelf building simulation, hourly building simulation modelling tools, that are used across the industry to assess impacts not just annually, but at different times of the day and in different seasons for different types of efficiency measures.

But one doesn't need to go out and extensively meter everything to get a good insight into the question of what the impacts might be at different times of the day for different types of measures. That analysis could have been undertaken.

MR. POCH: The company says that your comparison -- in particular they made a particular point that your comparison to Vermont Gas savings levels was perhaps misleading because Vermont Gas numbers, according to Enbridge's witnesses, are gross savings whereas Enbridge's are net. And Ms. Ramsay, I think, indicated that there would be a 35 percent difference in Enbridge's case between net and gross, and that if you compared Enbridge's gross to the Vermont numbers, they would be roughly similar. How do you respond to that?

MR. NEME: I would say a couple of things. First of all, she's incorrect. The Vermont Gas numbers are indeed intended to be net numbers.

MR. POCH: Let me just stop you there. Did you verify that after --

MR. NEME: I did.

MR. POCH: Thank you.

MR. NEME: I did. And then I guess the second thing I would say is that even if that weren't true, there's a big problem with potentially comparing Enbridge's gross values to the gross values of some of the other utilities that I've cited in my evidence.

And the reason for that is that Enbridge's programs, particularly those targeted to the commercial and industrial sectors, offer very low financial incentives to their customers. And while, to be sure, the level of financial incentives are not the only thing that affect what is commonly called free ridership -- the number of customers that would have done it anyway -- it is also true that the lower your incentive as a fraction of incremental cost, in general the higher the free rider rate will be.

And Enbridge's financial incentives to their commercial and industrial customers are much lower than the range of utilities that I've looked at. In some cases they are five -- the other utilities are offering three, five, 10 time greater financial incentives per unit of savings than Enbridge is.

MR. POCH: I take it from that that these other utilities would tend to have much smaller spread between net and gross?

MR. NEME: That's correct.

MR. POCH: Now, the company also said that, apparently to support the proposition that it would be difficult to achieve conservation, that they had underspent their budget in some years, or at least in one year. How do you respond to that?

MR. NEME: The notion that because you might have underspent your budget in one or two years, that that might somehow indirectly imply that you couldn't prudently spend more, makes no sense.

When you are -- when you start the year with a fixed budget, whether it's 10, 20, 50, $80 million a year, whatever it is, you design your programs -- in the financial incentives you offer, the types of markets you go after, et cetera -- you design your programs with that in mind.

So if you are -- if you have a relatively -- if you have a $20 million budget, you are going to design your programs, you're going to make sure that your financial incentives are such that the payment per customer multiplied by your expected participation would get you somewhere in the ballpark of $20 million. Now, if you'd had a $50 million budget, you would have designed everything quite differently.

Then you get later in the year, and everybody's plans when they run DSM programs are always somewhat imperfect in terms of the accuracy of their forecast of how many participants they are going to get in each of various different markets. You're trying to -- as you approach December 31st, the analogy might be you're trying to land that airplane on a runway, so that you are right in under the budget while still getting as much savings as you possibly can. And sometimes you don't land it exactly so that it stops right at the edge of the runway. You might land a little bit earlier or – especially if you're being a little bit conservative.

So again, the notion that you would -- because in a year or two you might slightly underspend your budget, that that implies that you couldn't spend more, it just doesn't make sense.

MR. POCH: On the residential retrofits specifically, the company says that your forecast implies a 16 percent market penetration rate for residential retrofits over the 10- to 12-year period. And that raised a red flag for them, given, as they indicated, they understood that significant past market penetration had been achieved by the federal ecoENERGY program and by high housing prices. How do you respond to that?

MR. NEME: Well, I say a couple things. First, I've looked -- I have tracked -- I've tracked the progress of the EnerGuide for Homes program and the ecoENERGY program that succeeded it for quite a number of years. I've looked at the data. And recognizing that some of the participants in those -- in that program would have done whole building retrofits and some of them would have just replaced heating or cooling equipment, it's hard to say exactly what portion of the market has been treated with whole retrofits through the program, but it's probably reasonable to assume that it's on the order of five to six percent of the eligible market.

So that leaves still a quite significant amount of headroom.

And then I would also point, then, to the fact that, as noted in my evidence, there are a number of jurisdictions that are now or have in the recent past achieved market penetration rates on the order -- or comparable to and in some cases even a little higher than the one and a half percent per year that I assumed could be ramped up to over the course of three years.

So I'm not saying this would be a slam dunk, an easy thing they could do in their sleep. It would certainly require some work, but other jurisdictions have done it, including Ontario, for that matter, where the -- at its peak the ecoENERGY program achieving market penetration rates on the order of two percent or better.

Ramping up to one and a half percent ought to be achievable.

MR. POCH: Ms. Oliver-Glasford said that the company's current residential retrofit program is trending at a negative TRC, not cost-effective. Would it make sense to pursue a significant expansion of residential retrofits if that was the case?

MR. NEME: Well, first I'll observe that -- I did read that statement in the transcript on Tuesday, but I'll observe that there's actually no empirical evidence on the record to support that statement. The only empirical evidence on the record on this program relates to the filing that the company did for its 2013 and 2014 DSM programs, which suggested the program would, in fact, be TRC-positive, it would be cost-effective.

The second thing I would say is that that even in that filing where the program was TRC cost-effective, roughly half of the costs of the program were associated with what you might call -- well, with non-incentives, with utility overhead, by which I mean not just administration management costs, but marketing and training and whatever other market development activities they needed to pursue. That's quite a high percentage.

Now, it may be that part of the reason that percentage is quite high is that it's the early days of the program, and certainly as you move to scale to the kind of market penetrations that I'm talking about in my evidence, the amount of that non-incentive cost -- or the portion of the non-incentive cost as a fraction of the total TRC cost would significantly decline, which would make the program even more cost-effective.

And I guess I would say two other things as well. The first is that you have to understand that the utility's pursuing a specific design to its program. It's not necessarily the design that I would have preferred and probably quite dissimilar from the design that a lot of the leading, more aggressive programs are pursuing.

And then lastly, all of the cost-effectiveness analyses that have been done to date, as was noted earlier, have been done without any avoided costs associated with deferred capital investments on the distribution system. And as Mr. Chernick has indicated, there is a significant value to such deferrals, so that would also tend to make the programs more cost-effective.

So for all of those reasons I believe it's eminently reasonable to assume that an aggressive residential retrofit program would be perhaps not -- in terms of the ratio, not quite as cost-effective as some of the industrial efficiency programs, but nevertheless quite robust, certainly sufficiently robust from a TRC cost-effectiveness perspective.

MR. POCH: All right. Thank you.

Mr. Chernick, turning to you, both Ms. Ramsay and Mr.

Fernandes sought to compare the budget costs of the pipeline proposals in this case to the budget cost of DSM program expansion as proposed by both Mr. Neme and by the Enerlife witnesses. Is that an appropriate comparison?

MR. CHERNICK: That comparison would only be appropriate if it nets out the benefits of the alternatives. The construction of 7-B-2, the north-south portion, for example, is primarily motivated by concerns with meeting load growth and maintaining adequate pressure at station B.

The proposed DSM programs would maintain the adequate pressure and also reduce Enbridge's requirements for purchases of gas commodity, pipeline capacity, and storage capacity, defer other Enbridge infrastructure projects, and contribute to reducing greenhouse gas emissions and thus meeting the province's greenhouse gas targets.

The DSM programs would more than pay for themselves in savings just of commodity and capacity, with the avoided facilities costs and greenhouse gas benefits being on top of that.

So even if the DSM program budget cost somewhat more than the pipeline, the net cost to the DSM would be much lower than the pipeline.

MR. POCH: All right. And on those extra benefits of GHG reduction, do you have any insight into whether the provincial greenhouse green reduction target of 80 percent by 2050 from 1990 levels is feasible without reductions in natural-gas use?

MR. CHERNICK: Yes. In response to the company's pointing to this as being a provincial target, rather than one specific to them, or to the gas industry, I looked at the data from the 2012 Ontario Greenhouse Gas Progress Report. The provincial target for 2050 is an 80 percent reduction from the 176 megatonnes of emissions in 1990 to about 35 megatonnes by 2050.

As of 2010 emissions were 171 megatonnes, just a little bit under the 1990 value. And from the page 40 of ED's cross document book, there's data that shows that about 26 percent of that 171, or 45 megatonnes, were from non-generation natural gas; that is, natural gas that's going through the LDCs to end-use customers.

So even in the unlikely event that all the other emissions were eliminated, including all the natural gas used in electric generation, all the coal, all the oil, all the transportation, Ontario can't meet its greenhouse gas target unless the non-generation natural-gas use is reduced by least 23 percent, because it's now about 45 megatonnes, and the total allowed is 35.

And of course, you're not going to meet a zero target for everything else, so the reduction would have to be even more than the 23 percent.

MR. POCH: All right. Now, the issue that has been discussed in this case about whether Portlands Energy Centre could be interrupted or curtailed or, as Mr. Quinn put it, offered a demand response incentive to deal with extremely cold weather, has come up, and the question is weren't retained to look at the question of whether segment A is -- or the Union projects are justified, to the extent they are justified on the gas savings argument. And all that was before the term sheet may have changed the landscape?

MR. CHERNICK: Yes. I was asked to look at the feasibility and benefits of avoiding additions through load reductions. And since the justification for segment A and some of the other facilities had to do with switching gas supplies, it really wouldn't have been affected by load reductions. And as I said in my direct, I therefore didn't take a position on those.

As -- I understand now that there is question about the magnitude of those savings, but that's beyond the scope of my testimony.

MR. POCH: Thank you very much. Those are my questions. Thank you, Madam Chair.

EXAMINATION-IN-CHIEF BY MR. ELSON:

MR. ELSON: Mr. Jarvis, you and your firm prepared a report and some interrogatory responses for this proceeding; is that correct?

MR. JARVIS: That is correct.

MR. ELSON: Do you adopt your report and your interrogatory responses as your evidence in this proceeding?

MR. JARVIS: Yes, we do.

MR. ELSON: And Mr. Jarvis and Ms. Jie Li's CVs have been filed. I believe there is a copy on the dais. And I don't believe it's necessary to mark them as an exhibit because they are already filed.

And I will go through some of your qualifications briefly.

Mr. Jarvis, you are a professional engineer?

MR. JARVIS: That's correct.

MR. ELSON: In particular, you are trained as a mechanical engineer?

MR. JARVIS: Mechanical engineer, yes.

MR. ELSON: Up until 1984, so I guess that was 1976 to 1984, you were a partner and director at Engineering Interface Limited?

MR. JARVIS: That's correct.

MR. ELSON: Could you briefly describe your role in some of the activities that you undertook there?

MR. JARVIS: I was responsible for the newly formed existing buildings division. We did some of the pioneering work around energy analysis of existing buildings. The -- I think part of the highlight of that work -- and this was some of the beginnings of regression analysis and looking for meaning in utility billing data, in monthly billing data -- we presented our findings in Stockholm in 1981 at the International Energy Agency, the first time that kind of conversation had taken place, and has really taken root since. And I think the greatest tribute we had was to be retained by Walt Disney World over the course of that period to actually tackle the energy efficiency in the pavilions down in Florida.

So it was quite pioneering work. It was a good time.
MR. ELSON: After Engineering Interface Limited, I guess up until 1999 you worked for Rose Technology Group. Now, I said "worked for" and that's not the right term. You were the president, chair and chief executive officer; is that right?
MR. JARVIS: I became that position in the early '90s, yes. In fact, we formed Rose Technology Group as a consulting firm in 1984. Consumers Gas acquired the company in 1985, with the aim of turning it into an energy performance contracting firm. There was a real interest in that time in this new breed of financing and guaranteeing the savings of projects.
And we bought the company back as a management team in 1993, from British Gas at that time, that owned Consumers. Also in that period of time, we expanded the company across Canada into the United States, and looked at well over a hundred projects, well over a thousand buildings where we were engineering, analyzing, engineering, retrofitting and guaranteeing the savings in those facilities.
Again, the highlight for us was probably winning the Ohio University contract against all North American competition in 1998.
We sold the company to Synergy Corporation in 1999.
MR. ELSON: What kind of staff would you have been overseeing in that?
MR. JARVIS: In 1999 we had around 200 staff in eight offices across Canada and in the United States, and

revenues of $52 million.

MR. ELSON: And your business, in a nutshell, was finding savings from energy efficiencies for your consumers; is that right?

MR. JARVIS: Finding and financing savings and guaranteeing the results of the financing could be secured, yes.

MR. ELSON: Then you founded Enerlife Consulting in 2001?

MR. JARVIS: Correct.

MR. ELSON: Could you describe some of your work with Enerlife?

MR. JARVIS: So the Enerlife, we created, building on the experience coming out of Rose Technology Group and I guess a growing understanding that it wasn't so complicated retrofitting buildings. Achieving high levels of energy efficiency simply required integration of good operations and good design and good projects, and our intention within Enerlife was to create programs to take that knowledge and spread it across a fairly wide basis, so in a range of commercial building sectors to find partners to run programs, and essentially to help people improve themselves or help building owners improve themselves, and we still grounded that in working with a number of major building owners on -- directly on projects where we were, if you like, proving the concept and proving the metrics and proving the targets by working directly with individual owners.

MR. ELSON: And so how many years have you been in the business of finding energy efficiency savings for companies and for organizations?

MR. JARVIS: Do I have to answer that, Madam Chair? I guess three decades is what sort of slips off the tongue these days, yes.

MR. ELSON: Madam Chair, I ask that Mr. Jarvis be accepted as an expert in natural-gas demand-side management, and I can advise that I've spoken to counsel for Enbridge, who I don't believe has any objections to that.

MR. STOLL: I don't have any objection.

MS. CHAPLIN: Mr. Jarvis is accepted as a witness on that basis. Thank you.

MR. ELSON: Thank you. And Madam Chair, with respect to Ms. Jie Li, she is here largely in a supporting role for Mr. Jarvis, and we don't propose that she provide opinion evidence on her own accord, and therefore I don't propose to qualify her as an expert. Again, Enbridge agrees with this approach, and I believe it would be a more efficient way of proceeding, and therefore I would propose to move into a direct examination, subject to any objections from the Board.

MS. CHAPLIN: That's fine. Thank you.

MR. ELSON: Mr. Jarvis, I would like to ask you some questions about Enbridge's critiques of your model, but perhaps before jumping into that we could go over an extremely brief summary of your evidence, and I would ask if you and the Board could turn up page 8 of your report. And your report happens to be conveniently located in Enbridge's compendium, and so I apologize if I'm stealing Mr. Stoll's thunder, but perhaps it would be appropriate to mark that as an exhibit.

MR. MILLAR: K7.1.

EXHIBIT NO. K7.1: MR. JARVIS'S REPORT

MR. ELSON: The Enerlife report is at tab 2 of the Enbridge compendium, conveniently reproduced in colour. And if you could refer in specific to page 8. Is it possible to pull that up on the screens as well? Thank you.

Page 8 shows figure 5 from your report, which I believe is a key way to summarize the results. Could you describe what the solid blue line and the dotted purple lines in this chart represent?

MR. JARVIS: Yes. The solid blue line is the median projection, the forecast natural-gas load growth, assuming median attainment, in terms of gas-efficiency performance in all buildings with the data we presented for commercial and apartment building sectors and Mr. Neme's evidence with residential and industrial.

MR. ELSON: And the purple line?

MR. JARVIS: The dotted purple line is the attainment of top quartile performance, which would project a reduction in gas throughput over time.

MR. ELSON: And so those two lines include the commercial and apartment data that you have calculated, and you have also factored in the residential and industrial numbers from Chris Neme; is that correct?

MR. JARVIS: That is correct.

MR. ELSON: Could you explain to the Board whether and why you might think that top quartile results are attainable?

MR. JARVIS: Yes. The data we've been working with, certainly going back to 2006, but more substantially since 2008, with national programs with a focus on Ontario, because that's where we're based, has been collecting a lot of benchmarking information which is presented in the report that we provided, and when this was first published in 2006 for schools, so a project that the OPA funded, that was the first, I guess, shock to everybody, including ourselves, in terms of the kind of ranges for quite similar schools, in terms of just how much energy they were using, so the highlights from that particular study were across 42 new schools all built within the past seven years.

Electricity range was three to one. The natural-gas range was four to one, between the best and the worst, the least efficient. And water consumption was a five-to-one range. And that really put the cat among the pigeons, in terms of what is going on out there, and that really began all of this work that's been progressing since through national pilot projects.

So the quartile levels have since become the standard that we've used, so the REALpac Race to Reduce where there's a white paper published. It was a peer-reviewed paper that we prepared for the Real Property Association of Canada, for the commercial office building landlords. The methodology and the metrics and the target-setting is set out within that. More recently the town hall challenge was developed for national town and city halls. The methodology again, peer-reviewed, is settled within there.

But I think for our own work, when we're working on individual projects, we've yet to -- we've yet to find a building that will not meet and exceed those targets. We work more generally to the top decile level.

So I think the gas targets presented in these numbers have been pretty well road-tested, and to date we've not found a condition within buildings, notwithstanding the comments about the marathon runners and so on, we've yet to find buildings that cannot reach those kind of target levels.

Within our programs more and more participants are meeting and exceeding those levels as well, so it's a bit of a moving target, but it's been going on now for well over five years, and I think the process is quite robust.

MR. ELSON: Enbridge's opinion is that the targets in your model are not attainable because they say your database is self-selected and "not indicative of what is happening in our marketplace". Could you respond to that, including with respect to the representativeness of your sample?

MR. JARVIS: Yes. We look at that quite a bit. Around 72 percent, I think, when looked at this last night, 72 percent of the buildings that we have in our data set are in Ontario, and we can't readily extract it, but we think that the majority of those buildings are in the GTA, so we think they are representative of the GTA, but when we put the data set across Canada together, there are no apparent regional differences, you know. The schools in British Columbia, even though it's milder, when you adjust for weather differences, seemed to be just as inefficient as schools in Ontario, and so on and so on.

So we don't see regional differences. But we do do correlation. So as of a few months ago the federal government has rolled out a portfolio manager in Canada so we now have access to national data, a national database, and we've -- we were asked by Natural Resources Canada earlier this year to somewhat road-test portfolio manager for hospital and school sectors, and we're finding that the median hospital, you know, with the Energy Star 50 score hospital, is pretty similar to the median hospital with our data set, similar with schools, and similar when we're running office buildings the same way.

So we think data sets, once they reach a certain critical mass, they become pretty reliable. They don't move that much over time as you add more building. So we're pretty confident in the -- that the data we're presenting is representative both of Ontario and of the GTA area that this is subject to.

MR. ELSON: And of course, your data set includes a large number of GTA-area buildings; is that right?

MR. JARVIS: That is correct. I think the largest group of buildings within there would be GTA, and the largest buildings -- the largest group of buildings and the largest buildings would be in the GTA.

MR. ELSON: It was also stated that your forecast numbers are more of a technical potential and are not practically achievable. Could you respond to that as well?

MR. JARVIS: Yes, we saw that comment, and I guess it surprised us a little bit. We completely understand and respect the history of DSM in Ontario and across North America, in terms of, when there weren't large data sets available to base projections and forecasts and business cases on, it made perfect sense to use engineering calculations, and it served the province well, and it's got us to this point.

The idea of it somehow moving to real empirical data, where you can look at the actual performance of buildings and make adjustments for material differences and then identify the savings that way, as opposed to projecting engineering calculations, we've always seen it, and I guess the folks that we talked to have always seen that this is moving us to a higher level of accuracy, a high level of dependability, and it also provides a management focus. In other words, every building now has a potential gas savings attached to it that can be presented to the owner, that can be used on an ongoing management basis.

So we were surprised to feel -- or to hear the thought maybe this whole movement towards data and benchmarking that's got illustrated by, again, Energy Star in Canada and Green Energy Act, this move towards data-, evidence-based projection of savings potential and targeting for individual buildings would be less rigorous. I believe this is far more rigorous and by far the most accurate way of moving forward.

MR. ELSON: Thank you. Enbridge also suggested that you wouldn't be able to sign up enough participants because the participants would not want to invest in energy efficiency or wouldn't be able to for one reason or another.

Based on your years of experience in the energy-efficiency industry, what would you say to that?

And I should add that other members of the panel are free to respond as well if they have comments, but I'm directing this in particular to Mr. Jarvis.

MR. JARVIS: I think there's a few answers there. One is the level of interest, significantly in part to the efforts of Enbridge. And I think they've been very forward-looking in terms of how they have caught onto some of the engagement programs going on out there. So they have been very actively involved with the Race to Reduce, for example, that has, I think, more than 60 percent of all the commercial office space in the Greater Toronto Area working together to meet energy efficiency targets.

So the level of engagement there is quite remarkable.

Within greening health care, Toronto Region Conservation Authority has more than 20 percent of Ontario hospitals working together to achieve energy efficiency.

Similar programs with municipalities and schools. You may be aware the City of Toronto's Tower Renewal Office has a program they call STEP that's engaging high-rise apartment building owners, working together on similar things.

So our read is that there's never been as much interest as there is right now. People out there are really, for a whole bunch of reasons -- primarily to save money -- are really interested in getting into energy efficiency.

So that's the first part, is the level is there. And again, credit to Enbridge for being a significant player in kind of moving that forward.

I think the second piece of that conversation is that the biggest savings potential is with the large building owners. And they're quite accessible and they are ready to move right now. So whether they're retail chains or Toronto Community Housing or school boards or commercial office landlords, they are already engaged. They're already looking for things. What they're really looking for is technical support to help them quantify the savings, which target-setting does, performance-based does, and then go find the savings.

And I think that's the challenge for all gas utilities today, is to develop that internal technical ability, when you see a building's using three times as much gas as it should be, to be able to help the owner walk through in a systematic way, find those savings and deliver those savings. That's the big step forward. That's the big transition.

The final thing I'll say, we talk to a lot of small buildings owners, as well, who are resource-limited, who don't have much technical capability in-house. There isn't one of them that isn't keen to save money.

So once small building landlords, small apartment landlords, small office landlords, once you can present them with the magnitude of the savings opportunity, if it's $23,000 a year for them, for some of them that's a fortune. And they have contractors out.

So again, it's not hard to imagine the kind of capability that Enbridge has already, that it be directed towards helping those owners find the contractors, the service providers that can track down and deliver those savings. So it's simply a matter of adopting these targets, these -- identifying high potential buildings, and helping the industry of building owners work together to track them down and deliver them.

So we think the interest is there and Enbridge will never underspend its budget again.

MR. ELSON: I guess one of the difference is that you would be approaching buildings that are specifically identified beforehand as being particularly inefficient, so that you would be able to guarantee a certain amount of savings; is that right?

MR. JARVIS: That is correct. And you would be approaching at a much more senior level. So as long as your approaching building owners with a suite of incentive programs -– you know, I'll do this for variable -- there's no senior manager within a commercial landlord or school board that's -- that you'll get passed down to the facilities department to talk to them.

When you talk to a major building owner about the ability to save $4.3 million a year, now you've got the attention of the CFO.

And part of our presentation here is I think Enbridge is in the process of and needs to accelerate the development of that kind of key account executive capability, that you can identify that potential and you can knock on the right door to get that business case established.

MR. ELSON: Thank you. It was also noted that 93 percent of Enbridge's largest 42 customers have actually done something in the past seven years with Enbridge and its DSM portfolio.

Can you explain whether this fact impacts your confidence in your model, including your expected ramp-up, and why or why not?

MR. JARVIS: I think it kind of supports the model. So many of those buildings would also be in the data that we presented, which is the targets based on 2012 actual natural gas consumption.

So the fact that they have done a few things is illustrative of the fact that they are interested, so that there's no lack of interest out there, that relationships have been created between Enbridge and some of those building owners. That's a good thing, so you are not knocking on a cold door.

But the big part of the conservation potential still exists in most of those buildings. And that's what this approach aims to target.

MR. ELSON: My last question is this. There was an analogy that was made earlier, and I'll read a quote:

> "If you look at folks that want to be healthy, you can't assume that the top quartile that are running marathons and doing triathlons, that everybody can get to that level."

Is that a valid analogy, and can you explain why or why not? That would be an analogy of people's health and the energy efficiency levels in buildings in the downtown GTA area.

MR. JARVIS: I think the diagnostic aspect of what we're talking about is a wonderful analogy to health. Essentially what this is saying is that every building is not equal, and having, if you like, medical staff having to go and check everybody in the whole community to see if they have high blood pressure or heart problems or lung cancer or whatever is impractical. And the medical analogy is we've developed tests, we've developed ways of kind of measuring readily available things so we can identify the individuals who have particular need for whatever treatment we have in mind.

too early, too late":

"A common utility strategy for delaying alternatives to the utility's preferred strategy until the utility can claim it's too late to implement the alternatives."

Is that your suggestion, that this is occurring here?

MR. CHERNICK: I can't read the minds of Enbridge's staff, current or past, so I don't know what's intentional and what's accidental.

It certainly would be consistent with that kind of approach. It's also consistent with an interpretation that says they just never really took DSM seriously, never thought of it as being related to a need for facilities additions, ignored it, didn't bother raising the issue with the DSM -- the supply planners didn't raise the issue with the DSM planners, the DSM planners didn't drag the appropriate information out of the supply planners.

And so whether it's deviousness or limited competence, I can't really say.

MR. POCH: Very fair. Thank you. Those are my questions, Madam Chair.

MS. CHAPLIN: Thank you.

QUESTIONS FROM THE BOARD:

MS. CHAPLIN: I have just one brief area of questions, which I believe are probably best directed to Mr. Chernick and Mr. Neme, but, Mr. Jarvis and Ms. Li, that would be fine if you have anything to add.

Would I be correct in saying that sort of the cumulative message of your evidence is that if Enbridge had undertaken sort of formalized integrated resource planning, it would be able to achieve the objectives it's seeking to achieve through DSM measures rather than supply-side measures? Is that a fair characterization?

MR. CHERNICK: I would start by saying I'm not sure how important formalized is.

Formalizing the IRP process is important if the utility isn't paying attention and somebody needs to basically make them sit down and do their homework.

And that actually could be internally within the company, that top management could say: All these different parts of the company need to talk to one another and turn out a comprehensive analysis that we can follow and we can file with the Board.

Or it could come from -- the direction could come from the Board.

But the important thing is that you not break, or the company not break these issues into separate islands that don't communicate with one another. And it looks like the company has taking the position that: Well, we'll just wait on the pressure issue at station B until it's time to get approval to start digging, to build some looping on the Don Valley Parkway.

And had they brought that issue to the DSM people and started a targeted program. I think the other witnesses will have a very strong opinion that they could have kept down the loads on that line considerably and avoided any need for expanding the Don Valley Parkway, without scrambling in any way to do it.

That also would have given them more flexibility in terms of reducing pressures on the lines, to the extent that that is something that is important and that they want to do it.

It wouldn't necessarily deal with the issue of importing additional gas from the United States and bringing it in through Parkway.

Chris, do you have more to say about that?

MR. NEME: No. I think that's a fair summation.

MS. CHAPLIN: And perhaps you have references to this in your evidence, and if you do, then if you could just point me to them, but what is your general knowledge or experience with other gas utilities that undertake this sort of, if not formal integrated resource planning, then an equivalent consideration of supply-side and demand-side alternatives when doing overall system planning?

Is it common, uncommon? Are there some specific instances that you can point us to?

MR. NEME: Well, again, I think that the -- I'll say a couple things in response.

The first is that I don't know that we know the extent to which that kind of integrated resource planning happens on the gas side. I have not done that analysis on the gas side across the continent to try to determine how often it happens and where and what the experience has been. I have done on the electric side, and it is -- the principles apply equally well.

And the only example, as I mentioned earlier, that I'm aware of where there has been some use of demand-side investment to defer capital investment associated with construction projects, was with Vermont Gas, but that's probably largely because it's my own home state.

My colleague that co-authored the testimony with me used to run all their DSM programs, so he had intimate, firsthand knowledge of it being done.

So I think there's an extensive record, published record, on this now on the electric side. There isn't that same published record on the gas side, but again, the principles ought to apply equally well.

And one of the things we've learned on the electric side is that to make it happen -- you know, Con Edison in New York on the electric side is the poster child for this. They do this -- they have done it for longer, and they have done it much better and much more extensively than any other utility that I'm aware of in North America.

And I've had dozens of conversations with the folks there about how this works and why it works well, and I probably asked about a dozen times, Well, so how did you get started on this? What caused this to start happening?

And I never really got an answer until finally someone told me that they went to their regulators with an expansion plan that the regulators said was too expensive, and they told them to go back and come up with a different answer. And that kind of regulatory pressure forced them to begin looking at alternatives.

And now they have evolved to the point where this is institutionalized within the company.

And I think there's -- we had the same experience in Vermont, where there was a large transmission-line project where the regulators concluded in the end that the utility came forward with it too late for adequate consideration of alternatives, and ended up approving the projects -- the transmission project in saying, But you will never do this again, and you are not required to do ten-year plans for any transmission, and for that matter, they've extended to distribution system upgrades, and you will work with the efficiency utility to integrate your forecast with theirs and do least-cost analysis on everything on an ongoing basis.

So in both of those cases it was -- it took some regulatory pressure, partly in response to proposals that were too late, to change the culture of what was happening, and conceptually the same may be true. I see no reason why the same wouldn't be true on the gas side.

MR. CHERNICK: And sort of a more direct answer to a piece of your question, there are a number of utilities and, for that matter, a number of jurisdictions that require utilities to file integrated resource plans. How well-integrated those are really varies, I'm sure, but you can find documents with that title or something very similar, that forecast of loads and resources.

And to the extent that resources, including major pipeline additions, are noted in the forecasts, they can then be targeted for -- by DSM efforts.

It's hard for the DSM collaborative, for example, to focus on those issues if they just never hear that there's a project floating five or ten years out until it's right on top of them.

MS. CHAPLIN: Thank you. Those are the Board's questions. So this witness panel is excused with the Board's thanks.

Mr. Stoll, would Enbridge's panel number three be ready to start today?

MR. STOLL: No, it's not ready for today. We were going to do that on Monday.

MS. CHAPLIN: Okay. All right. Then -- so just looking ahead, we are certainly hoping to complete this proceeding between Monday and Tuesday. I had noted on my, what I believe is my most recent hearing plan -- did, I think, contemplate Enbridge panel three -- oh, starting on Monday. Sorry, my mistake. So we will be working to complete the proceeding in those two days.

Are there any matters before we adjourn now for the -- Mr. Rubenstein?

MR. RUBENSTEIN: Through you, I was wondering if we could ask the utilities -- they were -- my understanding, they scheduled us on the 1st that the joint panel would sit. And there was an expectation that the number -- some idea of the numbers that would flow out of the terms sheet would be presented before that, as parties would like to

VT INCEPIT FIDELIS SIC PERMANET
Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2012-0433**
EB 2012-0451
EB-2013-0074

VOLUME: **Technical Conference**

DATE: **June 13, 2013**

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E X H I B I T S

also would want to just make clear for the record and everybody in the room here that the 10 terajoule shortfall is point specific at station B at that control point; whereas the volumes that I/we have quoted are total system.

MR. ELSON: So moving on to ED.19, this actually relates to a question that David asked earlier, which was when Enbridge started analyzing DSM as a possible alternative and what was done, and if you could provide written materials.

And I heard you say this morning that you looked at a rough order of magnitude of what DSM was achievable. I believe those were your words. And could you provide the memo or whatever analysis was done at that time so that we could take a look at it?

And by "that analysis", the question probably was not clear enough for an undertaking. Could you provide your analysis from when you first screened out DSM, your internal memo or report or whatever was created at the time?

MR. FERNANDES: We could write up the response that was given, but just to be clear, looking at DSM as a potential alternative to meet the objectives of the project, we have an order of magnitude estimate of existing DSM programs being -- on annual basis, providing approximately 8 or 9 tJs per day, but we have other factors -- sorry, 8 or 9 tJs per day specific to the entire GTA project influence area, but we have other needs on the project to be able to swing 600 tJs.

MR. ELSON: I'm just asking about the original analysis that you did and whether you can provide a copy of that. I do understand what you are saying on the evidence here.

Are you able to provide an undertaking to provide the original analysis when you screened out DSM as an alternative, some sort of document that would have a data on it and be either one page or ten pages? I don't know what it is, but if you could provide it, that would be appreciated.

[Witness panel confers]

MR. FERNANDES: So in response to this, we don't have anything to provide. When we're undertaking to take a look at a project, it is common for you to explore many possible alternatives but using rules of thumb to rule out certain alternatives in order to preserve resources and time.

So the order of magnitude was simply so large that we did not consider it in detail.

MR. ELSON: So there's no document?

MR. FERNANDES: No, there is not.

MR. ELSON: When was that decision made?

MR. FERNANDES: In 2011.

MR. ELSON: I presume in a meeting?

MR. FERNANDES: Correct.

MR. ELSON: Moving on to ED.42, Enbridge's response to this interrogatory included a category entitled "Other" that accounts for about two-thirds of the customers and half of the volume. Would you be able to provide a further

We can't disaggregate our reduction factor. We applied it intentionally to ensure we were having a continued downward trend in our forecast.

MR. ELSON: So I guess your reduction factor of 0.65 was based on an assumption of X amount of DSM, and I'm asking you to recalculate the reduction factor assuming double that DSM. Maybe you're saying you cannot do that.

I don't really see how -- why you couldn't, but if you can't, then I guess there's no answer. But maybe we should move on. Is that possible to do?

MR. FERNANDES: We could make a number of assumptions and calculate something, but I don't think it actually adds value, because it's not in keeping with what the company did in terms of creating the reduction factor for its forecast.

MR. ELSON: It might be helpful to me and it may also be helpful to David, so if I could have an undertaking for you to take best efforts and see what you come up with, that would be appreciated. If there's caveats and you include those in the answer, that would be appreciated.

MR. FERNANDES: We will do that.

MR. ELSON: Thank you.

MR. WASYLYK: JT2.31.

UNDERTAKING NO. JT2.31: TO MAKE BEST EFFORTS TO UPDATE REDUCTION FACTOR OF 65 PERCENT, ASSUMING DSM DOUBLES.

MR. ELSON: Moving onto ED.14(a), again, these are GEC's questions. Can Enbridge analyze its DSM portfolio to develop a more accurate estimate based on the types of measures installed of what peak day and peak hour savings are? Is it possible to do that?

[Witness panel confers]

MS. OLIVER-GLASFORD: Union, that was our best effort to try and understand what the load profiles would be. We don't have definitive studies that show what the load profiles are for each technology. We've talked about this desktop analysis. So my hope is that would be helpful in kind of gaining some of that perspective.

MR. ELSON: Thank you.

MS. OLIVER-GLASFORD: But I think beyond that, we can't. Yes, we don't have anything further.

MR. ELSON: Thank you. Moving onto ED.18, at one point in the evidence or in the interrogatory responses there's reference to a 20-fold increase in DSM necessary, but then in ED.14 there is that table which suggests that DSM could increase, I believe, two-fold, in order to deal with load growth issues.

I'm wondering if you could explain the difference between that 20-fold increase -- I believe that's related to addressing the SMYS pressure issues -- as opposed to the increase as indicated on table 14 -– sorry, the table as part of IR 14, ED's IR 14.

MR. FERNANDES: You are correct. In the one case, the 200 percent increase in DSM -- slightly more than that -- it was to offset the remaining load growth, whereas in ED.18 it's to offset that year's load growth, in addition to accounting for the pressure reduction on the Don Valley line.

MR. ELSON: That's to bring it down from 36 to 30 so it's within SMYS? That's the 20-fold?

MR. FERNANDES: So that would increase the required offset to be a factor of 20-fold.

And I should note as we had in our preamble, noting that that would also have to be heavily concentrated in the influence area from Victoria Square. So it's not necessarily a generalized reduction in load that would have to occur; it would have to be the fairly heavily concentrated in the -- I guess we've now decided that it's peach-coloured area in the figure that we were looking at earlier.

MR. ELSON: That's actually a very important issue that I will need to get back to before the end of this, but I would like to continue on with the GEC questions, of which there is only one or two more.

For ED.20, in referring to the growth-only component of the GTA project, does Enbridge mean that if growth was the only project driver, this component would not be added if growth was eliminated by DSM?

MR. FERNANDES: No, that is incorrect. We were referring to a hypothetical situation, where the only need for the company was to address system load growth.

If that were the case -- and I have to be clear it is not -- if we were looking at a load growth-only scenario and nothing else, the amount of reinforcement required for the system is actually relatively small. And it does entail, as per the interrogatory response, going from Sheppard to McNicoll at an approximate cost of 40 to $50 million, is what we have done a desktop estimate on.

But again, that is a totally hypothetical situation, because that's not the only issue the company is trying to address.

MR. ELSON: So in that hypothetical situation, to defer the growth-only component of the project, is that what you would need, the amount of DSM that you indicated in ED.14? Or more or less than that?

MR. FERNANDES: That is correct. ED.14 lists the amounts of DSM using all of the assumptions, as noted, that would reduce our load growth forecast to essentially zero.

MR. ELSON: Thank you. ED.39, Enbridge says that 48 percent of its customers are in the GTA, but not 48 percent of its industrial customers. Could you provide the portion of Enbridge's total residential, apartment, commercial and industrial sales that are in the GTA, and could you provide those separately for each customer type?

And actually, you know, it might be best, just so it can be clear, to provide both the proportion by sales and also the proportion just by customer numbers.

MS. OLIVER-GLASFORD: We can provide you that as an undertaking.

MR. ELSON: Yes, of course. Thank you.

MR. WASYLYK: JT2.32.

UNDERTAKING NO. JT2.32: THE PORTION OF EGD'S TOTAL

RESIDENTIAL, APARTMENT, COMMERCIAL AND INDUSTRIAL SALES IN THE GTA

MR. ELSON: ED.41(a), you responded that there's 25 full-time reps on DSM. Are these full-time? Are these FTEs?

MS. OLIVER-GLASFORD: Yes, they are.

MR. ELSON: Thank you. And ED.41(c), GEC requests that you provide a table with the number of custom projects by year, separately showing commercial, multi-family, industrial, and the totals. Is that something you could produce?

MR. MacLEAN: Yes, we could undertake to produce what you just requested by custom project.

I would like to go back and correct the previous answer, though.

MR. ELSON: Yes?

MR. MacLEAN: You stated the question in terms of how many people do we have deployed on DSM. The response that was previously given was actually just for the commercial marketplace.

MR. ELSON: So let's deal with that undertaking, perhaps, first and give that a number, if that's okay.

MR. WASYLYK: Yes, so that's going to get JT2.33.

UNDERTAKING NO. JT2.33: TO PROVIDE A TABLE WITH THE NUMBER OF PROJECTS BY YEAR – INDUSTRIAL AND TOTAL

MR. ELSON: How many full-time reps are there on DSM overall?

MR. MacLEAN: I would have to get back you to on the exact number, which changes slightly from year to year, because there are a few people that aren't full-time on it. So we allocate portions of the time, based upon other things that they are doing.

But rough order of magnitude would be approximately 70 -- the equivalent of approximately 70 people employed by the company on DSM activity. The majority of those would be on the sales or marketing side.

MR. ELSON: Is that approximately 70 FTE customer reps?

MR. MacLEAN: What I'm suggesting is that the majority of those forces would be on marketing or sales activity. I would have to get back you to on the exact number, but it would be in the neighbourhood of 50 out of the 70 would actually be field sales or marketing forces.

MR. ELSON: That's sufficient. And if you go back and look at it and find that you want to provide a more accurate figure, I'll leave that up to you.

I would like to -- so that's it for the GEC questions. I would like to go back to the discussion of the peach area, and in particular, further to Environmental Defence Interrogatory 25, I believe -- no, 24.

In Interrogatory ED.24, we had asked that if load growth were to be addressed by DSM, where would that DSM need to be located and could it be located anywhere in the GTA project influence area.

Where would that DSM need to be located in order to address load growth issues only? And I'm not talking about the SMYS, I'm not talking about shifting from one gate station to the other; just load growth. Where would that DSM need to be located?

MR. FERNANDES: It's a difficult question to answer, but generalized, we have growth throughout the area, so I would assume that we would need load reduction throughout the area.

MR. ELSON: That answer is sufficient. The reason I ask it is that we're going to be providing some DSM evidence, and I don't want to go through that process for, then, Enbridge to come back and say: Well, actually, it would all have to be around station B.

My understanding from your answer is that it wouldn't all need to be around station B, and that it would be okay if it was distributed over the general GTA project influence area. Is that what you seem to be saying?

MR. FERNANDES: Well, the system right now has a point of system constraint at station B. So the effective area which is most likely going to deal with that point of minimum system pressure would be within the peach area, not necessarily localized to station B, but it's anywhere from station B back to its supply point.

MR. ELSON: So would DSM that's located in the peach area in a sense have a...

MR. FERNANDES: A larger impact.

MR. ELSON: A larger impact?

MR. FERNANDES: That's correct.

MR. ELSON: Would you be able to provide the numbers in table 14 that you gave us, you know, how much DSM we would need if it was just in the peach area?

I mean, I don't know if we need to go down to this level of specificity. I want to head off this issue before we produce our evidence and before --

MR. NACZYNSKI: So maybe I can help a little bit. So the challenge or the issue with maintaining minimum system pressures at station B, obviously any DSM activities that were targeted specifically in the downtown core that would specifically reduce flows through station B would obviously have the greatest impact.

The further upstream the system you go, the more you may need. So if we were looking at the aggregated peach area and there were additional -- if it was distributed evenly throughout the system.

So if you were able to provide enough DSM that was in the downtown core to negate all load growth, you would need less DSM in the downtown than you would need as you worked your way up the system.

So, for example, that 10,000 terajoule deficit I was referring to, if that all was at station B, that would support your deficit there. As you move up the system, you will need more.

MR. FERNANDES: So it's geographical dependent, but it's not easy to state exactly a number.

MR. NACZYNSKI: It will be within the peach area, but the further down the pipeline you go, the more concentrative an impact it will have.

MR. ELSON: There's a table. Actually, we were referring to 18 tJs as being the need; is that correct?

MR. NACZYNSKI: That's correct.

MR. ELSON: The incremental need.

MR. NACZYNSKI: That's correct.

MR. ELSON: If there were 18 tJs of DSM spread out over the city, would that be sufficient to meet -- adjust the load growth?

MR. NACZYNSKI: Over the entire city?

MR. ELSON: Over the influence area.

MR. NACZYNSKI: So the answer would be no, because that would be distributed throughout the entire influence area, not specifically concentrated at the area of where we're having the system constraint.

MR. ELSON: How many tJs would you need over the entire influence area?

MR. NACZYNSKI: So you are suggesting that I would ratchet down the loads on the overall system and reduce the -- on a system of 2.4 petajoules, what would be the percentage reduction of 2.4 petajoules to produce that, to alleviate the constraint at station B?

MR. ELSON: I'm not suggesting that. I'm trying to figure out how many tJs of DSM you would need and where that would need to be the located so we can produce evidence.

Would all of the 18 tJ need to located within the peach area?

[Witness panel confers]

MR. NACZYNSKI: DSM activities could be distributed throughout. Depending on where it is concentrated in the system, it will have varying degrees of effect.

MR. ELSON: That's my understanding, because - and correct me if I'm wrong - the load growth forecast is based on load growth throughout the system?

MR. NACZYNSKI: That's correct.

MR. ELSON: So that would mean the DSM could conceivably be located throughout the system?

MR. NACZYNSKI: That's correct. Although realizing I already have a capacity deficit at a particular point, as well, already today.

MR. ELSON: I'm sorry, could you repeat that?

MR. NACZYNSKI: I've already -- as I've mentioned and is in evidence already right now, we're referring to a 10 terajoule supply deficit at station B. So we would need to obviously overcome that, and then apply the DSM. That would reduce the overall system growth.

MR. ELSON: I understand that, but in terms of -- I believe what we've come to is that because the growth is calculated based on the entire influence area, you could have DSM throughout the influence area. I believe that was where we concluded.

MR. NACZYNSKI: That's an absolute fair statement.

MR. ELSON: Thank you. So those are more my questions of clarification. The remainder are interrogatory responses that we didn't feel were complete. Those are listed in our letter of June 11th, 2013.

MARBEK
Resource Consultants Ltd.

Natural Gas
Energy Efficiency Potential: Update 2008

Residential, Commercial and Industrial Sectors
Synthesis Report

Submitted to:

Enbridge Gas Distribution

Submitted by:

Marbek Resource Consultants Ltd.

September 2009

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2. SUMMARY OF STUDY FINDINGS

The study findings confirm the existence of significant remaining cost-effective natural gas DSM opportunities in the Residential, Commercial and Industrial sectors within Enbridge's service area.

2.1 TOTAL NATURAL GAS SAVING POTENTIAL

As presented previously in Section 1, the study estimated natural gas savings potential from two perspectives.

- **Potential Savings in Future Natural Gas Consumption –** This perspective estimates the reductions in future natural gas consumption based on the aggregate impact of DSM measures implemented over the study's 10-year time period.
- **Potential DSM Program TRC Benefits –** This perspective estimates the total lifetime savings due to those measures installed in (only) a given milestone year (i.e., 2012 or 2017). This is the method employed in the calculation of net TRC benefits and is part of the DSM program portfolio design process.

The savings associated with each perspective are summarized below.

2.1.1 Potential Savings in Future Natural Gas Consumption

Exhibits 2.1 and 2.2 provide a summary of the total annual natural gas consumption levels contained in each of the forecasts addressed by the study.[6]

Exhibits 2.3 and 2.4 provide a summary of the potential natural gas savings under each of the potential scenarios; in each case savings are presented in both volumetric (m^3) and percentage terms. In each case the savings shown are annual and are based on the aggregate impact of measures installed in prior years within the period when compared to the Reference Case consumption levels.

As illustrated in Exhibits 2.1 to 2.4, inclusive, Achievable Potential savings increase only marginally beyond the $40M scenario. Based on the Achievable Potential workshop results, few additional savings were identified in the $60M scenario and Financially Unconstrained scenarios, while maintaining a positive TRC.

[6] Note: Actual results may not be linear as shown in Exhibits 2.1 and 2.2.

Exhibit 2.1: Graphic of Forecast Results for the Total Enbridge Service Area – Annual Natural Gas Consumption

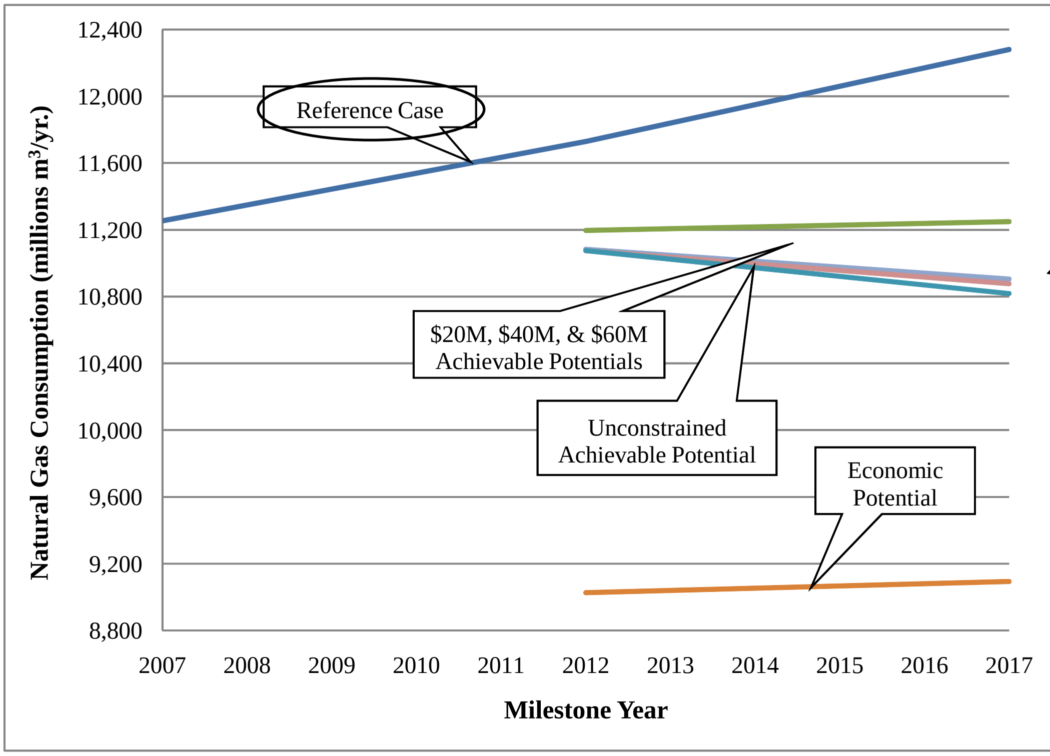


Exhibit 2.2: Total Annual Natural Gas Consumption, by Milestone Year and Forecast Scenario, 3 Sectors

Milestone Year	Total Annual Natural Gas Consumption, All Sectors (million m^3/yr.)					
	Reference Case	Economic Potential	Achievable Potential			
			$20M Scenario	$40M Scenario	$60M Scenario	Financially Unconstrained
2007	11,254					
2012	11,728	9,026	11,197	11,083	11,076	11,076
2017	12,280	9,093	11,249	10,905	10,877	10,818

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #18

INTERROGATORY

Issue A4: "What are the alternatives to the proposed facilities? Are any alternatives to the proposed facilities preferable to the proposed facilities?"

Reference: Ex A, Tab 3, Schedule 7, page 3

Please explain why Enbridge believes that "[c]onservation efforts… cannot be expected to replace the capacity within the system due to the lowering of pressures on large diameter, higher pressure lines."

RESPONSE

Enbridge believes that the magnitude of conservation required to replace the capacity within the system due to the lowering of pressures on large diameter, higher pressure lines is too large to be achievable. Based on estimates consistent with those shown in the response to Environmental Defence Interrogatory #14 found at Exhibit I.A4.EGD.ED.14, the DSM requirement needed to lower the pressure as proposed in the NPS 26 and NPS 30 Don Valley line would be a greater than a 20-fold increase in the GTA. In addition to the sheer scale of the conservation that would be required, the certainty of achieving the conservation targets is unknown. Magnitude and certainty make conservation a non-viable option for replacing capacity as a result of lowering pressures in existing infrastructure.

The primary purpose of the application is for increased safety and reliability in the delivery of natural gas, as stated in Exhibit A, Tab 3, Schedule 1. Enbridge is of the opinion that even if load growth and lowered capacity were offset by efficiency gains, which we do not believe is a reasonable assumption, that the proposed facilities would not be significantly altered, as they are required to meet the other objectives of the project.

Witnesses: T. MacLean
F. Oliver-Glasford
J. Ramsay

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO ENVIRONMENTAL DEFENCE INTERROGATORY #34

INTERROGATORY

Interrogatory No. A.1-ED-34   Reference: Ex. A, Tab 3, Schedule 1, Page 5 & 6

The second purpose for the project is described at pages 5 and 6 of Exhibit A, Tab 3, Schedule 1, and is summarized as follows at page 2:

> "4. The GTA Project will: …
>
> > b. Reduce operational risks and enhance safety and reliability by:
> >
> > > i. Improving diversity and flexibility of the distribution system through additional looping of single feed XHP lines and providing additional supply sources for the major XHP lines in the GTA Project Influence Area; and
> > >
> > > ii. Providing the ability to lower pressures on key supply lines;"

a) Please identify and describe all minimum system standards relating to operational risks, safety, and reliability that Enbridge will fail to meet if this project is not built.

b) If customer growth requirements could be completely met through DSM alternatives, would the project be necessary to meet minimum system standards relating to operational risks, safety, and reliability? Please explain your answer and identify and describe any such minimum system standards.

c) If customer growth requirements could be completely met through DSM alternatives, could certain portions of the project be avoided or deferred while still meeting minimum system standards relating to operational risks, safety, and reliability? Please explain and justify your answer.

RESPONSE

(a) Enbridge operates all of its pipelines facilities to meet or exceed minimum codes, regulations, and standards. There are no minimum standards relating to operational risk, safety and reliability that will not be met if this project does not proceed.

Witnesses: C. Fernandes
N. Thalassinos

(b) The Company does not believe that load growth can be met through efficiency gains, please refer to Environmental Defense Interrogatory #20 at Exhibit I.A4.EGD.ED.20. The project is not justified based on meeting minimum safety standards. The project addresses many needs as identified in Exhibit A, Tab 3, Schedule 1, Paragraph 4 of the pre-filed evidence. With regards to operational risk and safety specifically, the TSSA recently released the Oil and Gas Pipeline Systems Code Adoption Document Amendment FS-196-12 which directs companies such as Enbridge to implement risk reduction activities for higher risk assets. This project is consistent with the directives of the Code Adoption Document.

(c) The Company does not believe that load growth can be met through efficiency gains, please refer to Environmental Defense Interrogatory #20 at Exhibit I.A4.EGD.ED.20. In order to meet all of project objectives, there are no sections of this project that could be deferred. The justification for the project is multi-faceted as explained in Exhibit A, Tab 3, Schedule 1, Paragraph 4 of the pre-filed evidence. The project in it's entirely is required to achieve these objectives.

Witnesses: C. Fernandes
N. Thalassinos

Environmental Defence Response to
Enbridge Gas Distribution Inc. Interrogatory #15

Reference: Exhibit L.EGD.ED.1, Page 5, paragraph 1

a. In the TRC equation, incentives are not factored into determining the TRC ratio. Please estimate the incentive costs required to drive the median performance target.

b. Please estimate the total DSM budget that would be required (including all program costs and overhead costs, etc.) to achieve the "median performance target" and the "top quartile performance target"?

c. If possible, please calculate the Program Administrator Cost Test to achieving the median performance. If it is not possible, please state why.

d. Please provide your calculations and assumptions for the responses to (a) – (c).

Response:

a. The incentive costs would be $76,440,000 to reach the median performance target. By the end of 2025, median gas savings for Commercial and Apartment sectors would be 637 106 m3 per year. We project $0.12 per m3 average incentive rate to drive this target, allowing for graduated and time limited incentives to drive progress to targets within this timeframe, which equals the amount above.

b. We estimate the DSM budget over the course of the program as follows:

	MEDIAN TARGET	**TOP-QUARTILE TARGET**
Account Management	$11,000,000	$11,000,000
Technical Support	$63,700,000	$111,300,000
Marketing and Sponsorship	$3,300,000	$3,300,000
Incentives	$76,440,000	$133,560,000
TOTALS	$154,440,000	$259,160,000
Average Annual Cost	$14,040,000	$23,560,000
Total Gas Savings m3 (2015-2030)	6,912,000,000	12,072,000,000
Average Cost/m3	$0.022	$0.021

c. The PAC Test to achieve the median performance for Commercial and Apartment sectors as shown above is as follows:

Avoided Supply Cost (discounted) from 2015-2030	$841,000,000 (see model)
Incentive Costs	$76,440,000 (see above)
Program Costs	$78,000,000 (see above)
Net Savings	$686,560,000

d. Key assumptions are as follows:

Account Management	$1,000,000/year for 11 years
Technical Support	$0.10 per m3/year savings
Marketing and Sponsorship	$300,000/year for 11 years
Incentives	$0.12 per m3/year savings
Life of Savings	2015-2030

Environmental Defence Response to Board Staff Interrogatory #1

Reference: Exhibit L.EGD.ED.1, Executive Summary, Page 2 of 24

Please provide the estimated cost investments into DSM that would be required in order to meet the forecast annual average peak demand reduction potential.

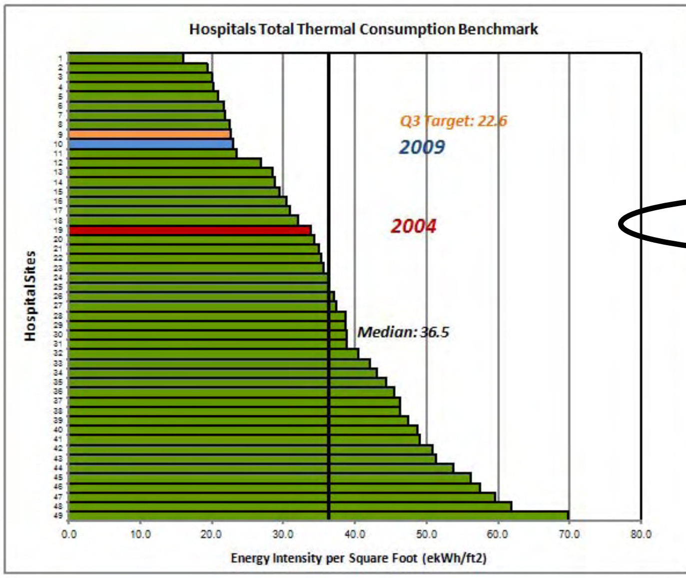
Response:

With the moderate contributions from Residential and Industrial sectors forecast in the model (35% of total 2025 savings at the median and 24% at the top quartile), only median level savings is required in Commercial and Apartment sectors to avoid net load growth to 2025 (see the model). The estimated cost investments into DSM by Commercial and Apartment building owners over the 12 year period to meet the median 2025 savings level (637,000,000 m3/year) is $475,000,000. The present value of associated gas savings from 2014 to 2030 (5 years after the end of the proposed program) is $841,000,000.

The estimated cost investments to meet the top-quartile savings level for Commercial and Apartment sectors (1,113,000,000 m3/year) is $1,350,000,000. The present value of savings over the same period 2014 to 2030 is $1,518,000,000. The payback for building owners on this investment is in the order of 3 years which is within the acceptable range for most owners.

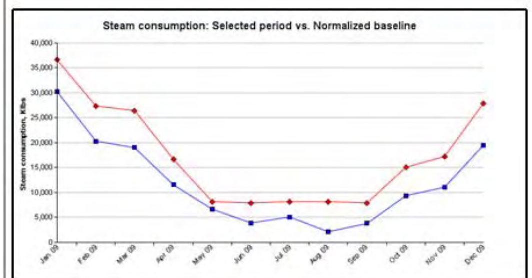
Actual cost investments for performance-based natural gas conservation programs are lower than most people expect. Incentive application reports prepared for EGD for the years 2006-2009 for Greening Health Care hospitals show (in aggregate) owner investment costs of $989,500 over the 4 years with recorded total gas savings of 7,336,000 M3/year. Using a 5 year measure life yields an average of DSM cost of 2.5 cents per M3. In fact, many of the buildings have been maintaining and improving on achieved savings for longer than 5 years, and owners expect the savings to continue indefinitely.

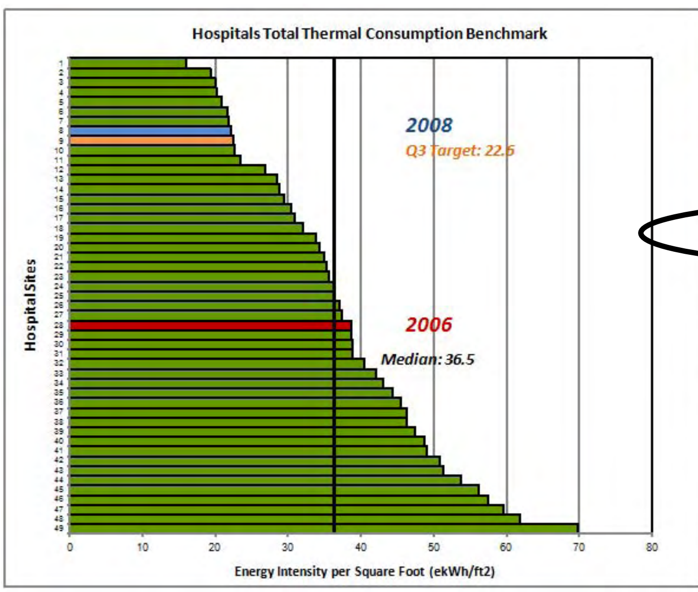
The following examples help illustrate the positive economics. The two hospital facilities have worked towards meeting the top-quartile performance target, and are now sharing their experience and inspiration with other hospitals in the Greening Health Care program. The major downtown hospital worked for five years to achieve these results. The cancer centre took two years to reach the target.



Major Downtown Toronto Hospital

Savings Summary	
Building area	950,000 ft2
Total thermal % reduction	31.3
Gas equivalent (m3/year)	2,676,680
Capital cost of measures	$699,635
Annual cost savings ($0.175/M3)	$468,419





Regional Cancer Centre

Savings Summary	
Building area	100,000 ft2
Total thermal % reduction	39.9
Gas savings (m3/year)	490,766
Capital cost	$105,000
Annual cost savings ($0.175/M3)	$85,884

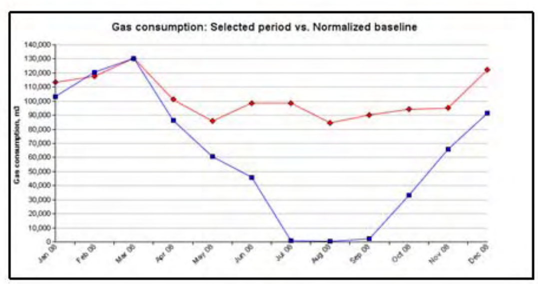


Table 3: Total forecast peak day demand for the Project Area (2015 to 2025)

Year	Peak Day Demand	
	10^3 m^3/hour	TJ/day
2015	3093	2443
2016	3117	2462
2017	3141	2480
2018	3165	2499
2019	3189	2518
2020	3213	2536
2021	3237	2555
2022	3261	2574
2023	3285	2593
2024	3309	2612
2025	3333	2631

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #17

INTERROGATORY

Issue A4: "What are the alternatives to the proposed facilities? Are any alternatives to the proposed facilities preferable to the proposed facilities?"

Reference: Ex A, Tab 3, Schedule 8, page 1

Please state the peak hour (TJ/hour) or peak day (TJ/day) demand in the GTA Project Influence Area that would cause the pressure at Station B in the 2015/2016 heating season to drop below minimum system requirements.

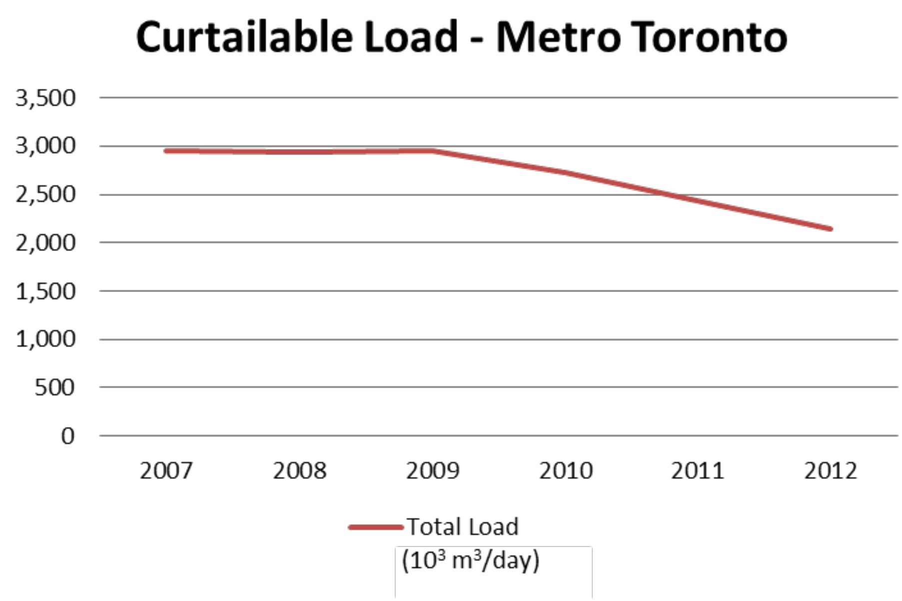
RESPONSE

As summarized in Exhibit A, Tab 3, Schedule 4, Table 3, forecast peak load will drop the system below minimum system pressure required by winter 2015/16. Specifically a forecast load of 3037 10^3m^3/hr would cause the XHP system to drop below the minimum system pressure required.

Witness: E. Naczynski

it a practical and economic alternative already contract for interruptible service. Finally, this runs counter to the trend in curtailment over the last five years, as shown in Figure 1.

Figure 1: Historical Curtailable Load within Metro Toronto /u



Liquefied Natural Gas ("LNG")

6. LNG was considered to provide the additional peaking capacity required for the system, offsetting the need for other infrastructure. Although benefits could be achieved through this type of facility, obstacles to finding an appropriate site area are significant. Given the current location of minimum system pressure at Station B, the site would need to be in close proximity to this area in order to minimize the need for other infrastructure. Location of an LNG facility would require significant setbacks, particularly one that could handle the large demand of the GTA. If a facility was sited outside of the GTA, a corresponding pipeline with associated takeaway capacity would then be required to connect to the GTA XHP grid as a

Subject: RE: EB-2012-0451 - GTA Pipeline - Interruptables
From: Scott Stoll <sstoll@airdberlis.com>
Date: 10/21/2013 6:29 PM
To: 'Kent Elson' <kent.elson@klippensteins.ca>

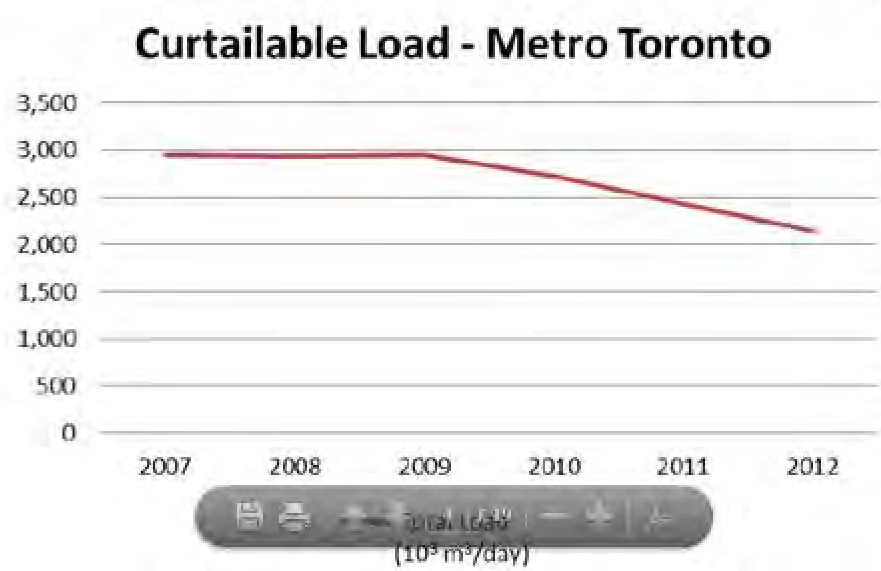
I trust this helps.

See below for the location of the reference to the total curtailable load in the influence area. In 2012, the load was about 100 $10^3 m^3$/hr (based on a 20 hour day).

Updated: 2013-06-03
EB-2012-0451
Exhibit A
Tab 3
Schedule 7
Page 4 of 19
Plus Attachment

it a practical and economic alternative already contract for interruptible service. Finally, this runs counter to the trend in curtailment over the last five years, as shown in Figure 1.

Figure 1: Historical Curtailable Load within Metro Toronto /u



From: Kent Elson [mailto:kent.elson@klippensteins.ca]
Sent: October-21-13 7:57 AM
To: Scott Stoll
Subject: Re: EB-2012-0451 - GTA Pipeline - Interruptables

Scott,

That is helpful, but what I was trying to get at is the amount of interruptables (m3/hr) in the GTA project influence area. Is that the same as the number provided (for the downtown core), or higher?

Best,

Kent

Kent Elson, LL.B.
Klippensteins, Barristers and Solicitors
160 John Street, Suite 300
Toronto, Ontario M5V 2E5
tel.: 416-598-0288 ext. 106
fax: 416-598-9520

On Sun, Oct 20, 2013 at 11:42 AM, Scott Stoll <sstoll@airdberlis.com> wrote:

Kent:

Erik checked and the IT volumes in the downtown core that he was referring to are 47,500 m3/hr.

I trust this is sufficient.

Scott

Scott Stoll

T 416.865.4703
F 416.863.1515
E sstoll@airdberlis.com

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Suite 1800 • Box 754
Toronto ON • M5J 2T9 • Canada
www.airdberlis.com

AIRD & BERLIS LLP
Barristers and Solicitors

From: Kent Elson [mailto:kent.elson@klippensteins.ca]
Sent: October-18-13 5:09 PM
To: Scott Stoll
Subject: EB-2012-0451 - GTA Pipeline - Interruptables

Hello Scott,

During the hearing on September 27, 2013, Mr. Naczynski said that he would validate his estimate that there are 50,000 cubic metres of interruptable volumes in the GTA influence area. Has he been able to look into that and confirm whether his estimate was accurate? If his estimate is off, could you put the correct number on record by way of a letter (because no undertaking number was assigned)?

The reference is on page 36 of the transcript from September 27, 2013: "MR. NACZYNSKI: So let me -- subject to check, the amount of interruptible volumes are approximately 50 10^3 m^3 cubic metres on a peak hour. We'll validate that for you."

Thank you and hope you have a nice weekend.

Kent

--
Kent Elson, LL.B.
Klippensteins, Barristers and Solicitors
160 John Street, Suite 300
Toronto, Ontario M5V 2E5
tel.: 416-598-0288 ext. 106
fax: 416-598-9520

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #24

INTERROGATORY

Issue A4: "What are the alternatives to the proposed facilities? Are any alternatives to the proposed facilities preferable to the proposed facilities?"

Reference: Ex. A, Tab 3, Schedule 4, page 1 & 2

Enbridge's growth forecast relates to the "GTA Project Influence Area." This is described by Enbridge as "the areas of the Enbridge distribution network where growth had a direct impact on the pressures at the current point of minimum system pressure, located at Station B."

a) Please provide a map indicating the detailed boundary of the GTA Project Influence Area.

b) Please describe the boundary of the GTA Project Influence Area using street names and intersections.

c) Assuming that the load growth to be addressed by the proposed facilities were to be instead addressed by targeted DSM (and assuming that this is possible), could that DSM be implemented in any of the 152 smaller geographic areas inside the larger GTA Project Influence Area? For example, would targeted DSM need to be predominantly located in an area nearby to station B or in areas served by proposed segment B?

d) If targeted DSM would need to be located in a sub-area inside the larger GTA Project Influence Area, please:

   i. Provide a map and detailed written description of that DSM sub-area,

   ii. Explain why the project can be justified based on all growth within the GTA Project Influence Area but demand reductions in this same area could not address load growth issues, and

   iii. Provide additional set answers to Environmental Defence's interrogatory numbers 2-15, 17, 25, and 26 based on this DSM sub-area (i.e. with necessary modifications to provide responses with respect to this sub-area rather than the entire GTA Pipeline Project Influence Area.

Witness: E. Naczynski

RESPONSE

a) Please see the Attachment for a map with the boundaries of the GTA Project Influence Area.

b) Please see the Attachment for a map with the boundaries of the GTA Project Influence Area.

c) Enbridge does not believe that targeted DSM can eliminate the need for some or all of the proposed facilities as described in the response to Environmental Defence Interrogatory #20 found at Exhibit I.A4.EGD.ED.20.

d) Enbridge does not believe that targeted DSM can eliminate the need for some or all of the proposed facilities as described in the response to Environmental Defence Interrogatory #20 found at Exhibit I-A4.EGD.ED.20.

Witness: E. Naczynski

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
BOMA INTERROGATORY #25

INTERROGATORY

Issue: A.1

(a) Schedule 1, Paragraph 7 states – The growth in the downtown core is supplied primarily through Station B.

(b) What portion of Station B is used to supply PEC and what portion is used, and will be used, to supply the increased load in the downtown core?

(c) Is more gas required at Station B to supply the downtown core, or greater pressures, or both? Please explain fully.

   (i) Please describe the operations of Station B in detail.

   (ii) Describe the equipment located there, with diagrams.

   (iii) Describe the importance of Station B in serving the Portlands Energy Centre.

(d) A, Sch 1, p14

   (i) How much additional gas can be moved across the XHP distribution system as a result of the construction of Segments A and B on peak day, an average winter day, an average summer day?

   (ii) Please indicate in which pipelines, new and existing, will incremental gas be moved across the XHP system, and how much gas (TJ/day), and using the segments of pipelines and stations listed below.

   (iii) Please provide the amounts of the proposed capacity increase to the Albion, Keele/CNR, Buttonville, and Jonesville stations.

   Station B – The east-west portion of Segment B from Keele/CNR station to Buttonville station.

   NPS 36 Parkway North from Parkway (or Parkway West) to Albion.

Witness: E. Naczynski

NPS 36 from Albion east to Keele/CNR station.

NPS 30 line from Lisgar to Albion, and from Albion to Keele/CNR.

NPS 30 from Don Valley Buttonville to Shepherd.

NPS 30 from Shepherd to Jonesville, and Jonesville to Station B.

(iv) What will be the resulting changes in maximum operating pressures and actual operating pressures for each of these lines relative to what they are today, once Segments A and B are constructed? What will be the changes in operating pressure of each of these lines?

(v) Please provide a copy of the Enbridge operating system, annotated to make it intelligible to the informed layperson.

RESPONSE

a) No question listed.

b) Please see the response to BOMA #23 in Exhibit I.A1.EGD.BOMA.23.

c) Please see the response to BOMA #23 in Exhibit I.A1.EGD.BOMA.23.

d)

(i) The following table shows the estimated capacity at Station B before and after the proposed project. All capacities listed are absent of any supply restrictions.

	2015 Existing System and Pressures (10^3m^3/hr)	**2015 With Reinforcements and Pressure Reductions (10^3m^3/hr)**	**Capacity Increase (10^3m^3/hr)**	**Capacity Increase (TJ/D)**
DD41 Station B Capacity Design Day	(15) Capacity Deficit	210	225	170
DD28 Station B Capacity Average Winter	198	397	199	150
DD0 Station B Capacity Summer	396	725	330	249

Witness: E. Naczynski

ONTARIO ENERGY BOARD

FILE NO.: **EB-2012-0433**
EB-2012-0451
EB-2013-0074

VOLUME: **4**

DATE: **September 19, 2013**

BEFORE:	**Cynthia Chaplin**	**Presiding Member and Vice-Chair**
	Marika Hare	**Member**
	Peter Noonan	**Member**

I N D E X   O F   P R O C E E D I N G S

the current peak demand and load profile in the GTA area. Then I'll ask some high-level questions about Enbridge's load forecast. The remainder of my questioning, I think, will be bumped to panel 2, but we'll see how far I can get today. And then I have some questions about project economics, and about, lastly, the pressure issue, the SMYS pressure issue.

So to begin, I'd like to refer to Environmental Defence's cross-examination document book. And I believe the witness panel has a copy, and that I have provided copies for the Board Panel as well. Are they on the dais there?

MR. MILLAR: They're not, but I'll bring them up. It's Exhibit K4.5.

EXHIBIT NO. K4.5: CROSS-EXAMINATION DOCUMENT BOOK OF ENVIRONMENTAL DEFENCE

MR. ELSON: Thank you. And this will be the document book that we will be using for panel 2, so I would ask if you could hold on to it, and for the witness panel, if I could take copies back so that I can give it to the next witness panel.

So as the basis for my questions regarding the load forecast, first I'd like to get a picture of the current load profile and the peak demand in the GTA area.

So I'd ask if you could please turn to tab 1 of Environmental Defence's cross-examination document book. This tab contains a chart showing the hourly gas demand in the GTA area based on the data provided to us in response to Environmental Defence Interrogatory No. 10 to Enbridge. I provided this chart and the underlying Excel spreadsheet to your counsel, and my understanding is that you don't have any concerns with how it was created, but I will ask you on the record, would you agree that this is an accurate depiction of the data in ED IR 10?

MR. FERNANDES: I believe it's an accurate prediction of actual flows on the system for those dates.

MR. ELSON: Thank you.

And I will just go through the table to explain it. The red line at the top of the chart is at 114.5 tJ per hour. And this represents the point at which the system will fall below minimum system pressures; is that right?

MR. FERNANDES: I haven't done the conversion, but I believe you're correct.

MR. ELSON: Thank you. And the blue line represents the actual hourly demand for this period; is that correct?

MR. FERNANDES: I believe the data that you've charted was the actual flows on the system.

MR. ELSON: Thank you. And the black line at 27.9 tJ per hour represents the average hourly demand.

MR. FERNANDES: I'm assuming you've done the math correctly.

MR. ELSON: Thank you. Looking at this chart, would you agree, of course, that the demand for gas is extremely peaky?

MR. FERNANDES: I believe that's part of our evidence, that we do have a seasonal peaking demand in our franchise.

MR. ELSON: Of course. And you'd of course agree that the vast majority of time the demand is far below the overall capacity?

MR. FERNANDES: I would agree with that, as would be the temperature compared to our design conditions.

MR. ELSON: And you would agree that the peaks are short-lived and few in number.

MR. FERNANDES: Again, I would agree that that is true, as is true with the weather.

MR. ELSON: That's all I have on the load profile. I just wanted to get that picture before moving on to the load forecast.

If you could turn, please, to the response to Environmental Defence interrogatory 25, which is at tab 5 of the document book, and specifically at page 6, based on the numbering of the document book.

Now, table 1 provides the actual peak hour, peak day, and annual demands for the GTA project influence area; is that correct? I'm looking at the response to A on page 6 of the document book, and it is described at the top saying:

"Table 1 provides actual peak hour, peak day, and annual demands for the GTA project influence area."

Is that correct?

MR. FERNANDES: That is correct.

MR. ELSON: Correct. Thank you. So the bottom row on this table shows the actual annual demand for natural gas document book? And this is in part where some of these annual numbers come into play.

Tab 8 is Exhibit E-1-1, page 8. This is -- from the application, that is. This is the summary of inputs for the project economics.

And I understand from this that Enbridge is forecasting that its total number of customers in the GTA project influence area will grow by 131,000 in the next 10 years; i.e., that is to 2023, subject to check. Would you agree with that?

MR. FERNANDES: I'm sorry, can you repeat the question?

MR. ELSON: The question is whether you would agree that Enbridge's forecasting that it's total number of customers in the GTA project influence area will grow by 131,000 customers over the next 10 years; i.e., to 2023, subject to check.

That number comes from adding up the incremental customer numbers in this table here. Am I reading this table correctly?

MR. FERNANDES: No, that's correct.

MR. ELSON: And is forecasting that there will be a net increase in the GTA project influence area's annual demand for natural gas of approximately 599 million cubic metres in the next ten years -- that's to 2023 -- and that number comes from adding up the total volumes.

Subject to check, am I reading this table correctly as well?

MR. FERNANDES: I think you're doing the math on the table correct. But that's not a forecast of what we expect the incremental volumes in the GTA to be. It's simply the economic feasibility requirement. In terms of the customer adds going into that economic feasibility requirement, it's standard process to use the most recent customer volumes by category so that comparisons can be done on a consistent basis. It's not actually a forecast.

MR. ELSON: So the economic analysis is based on that number, though. Is that not right? These are the inputs for your economic analysis of the project?

MR. FERNANDES: I think we can bring the detailed questions to the economics panel, but the numbers that you see here are based on the fact that you use the most recently approved numbers for your economic feasibility, in terms of usage per customer. So they're not a forecast, they're just a consistent methodology in order to present economic feasibility.

MR. ELSON: So these numbers are the input -- I mean, I'm looking at the title of this document, which is the summary of inputs. These numbers are the inputs for your economic feasibility analysis; is that correct?

MR. FERNANDES: These are used in the economic feasibility forecast. But I would -- sorry, economic feasibility parameters that were presented, but I wouldn't -- it's not a forecast.

MR. ELSON: So if these numbers were to change, that would impact your economic feasibility analysis; is that customer additions whatsoever.

And as you can see, the net present value is a $449 million value, with a profitability index of 1.75. Is that -- I believe that's what you were referring to?

MR. ELSON: No. I'm referring to a scenario where you still have customer additions, but despite the fact that you have customer additions, your growth is either constant or declining, and in that scenario, even though you have additional customers, my understanding of how you would do a cost-benefit analysis of a project like this is that you could not attribute those additional distribution revenues from additional customers to this project, because this project isn't needed to hook those customers up; is that correct?

I'm seeing you nodding there.

MR. FERNANDES: This scenario 6 that I just referred to takes away all of the incremental distribution revenues from the incremental customer adds, along with the associated capital of attaching them to the system.

So I believe this is the scenario that you're referring to.

MR. ELSON: I guess the difference between scenario 6 and what I'm talking about is that there would in fact be customer additions. Simply, you couldn't attribute those customer additions to being a benefit of this project.

So scenario 6, maybe the numbers will work out to be the same, but I'm talking about a no-growth scenario where you do have customer additions but you can't attribute their additional revenue as being a benefit from this project.

MR. FERNANDES: That is scenario 6. We have not attributed any revenue from customer additions, nor have we included any costs associated with attaching those customers, assuming the justification for attaching them, their revenue, would recover that.

This is completely outside of the project. So scenario 6 has no customer additions.

MR. ELSON: So I guess scenario 6 is then consistent with our scenario, where there are customer additions. It's just not being incorporated into the math; is that what you're saying?

MR. FERNANDES: That is correct. That's what I'm saying.

MR. ELSON: Okay. So we'd like to do some of our own calculations to look at the economics of this project, based on a no-growth scenario.

The number that you have here for the total upfront capital, is that a present value figure? I'm looking again, I'm sorry, at Exhibit A, tab 3, schedule 9, attachment 3.

MR. FERNANDES: The total upfront capital as described in the exhibit is a constant dollar value, 2013.

MR. ELSON: So that would be equivalent to a PV?

MR. FERNANDES: Correct.

MR. ELSON: And the forecast total transportation savings further down the line here, which is 1.7 billion,

Environmental Defence Response to
Board Staff Interrogatory #2

Reference: Exhibit L.EGD.ED.1, Executive Summary, Page 2 of 24

Please discuss the increase in market penetration (i.e. increase in participants) that would need to be realized in order for the forecast annual average peak demand reduction potential to be achieved.

Response:

Our proposed plan envisages EGD targeting building owners of large buildings and large portfolios of buildings, and using benchmarking and target-setting to identify their buildings with the highest potential for gas savings. Commercial building owners already collaborate in energy efficiency initiatives such as REApac benchmarking, BOMA BESt, Race to Reduce and Greening Health Care, which can help a great deal with awareness and engagement. Once owners are engaged, and their buildings assessed, technical support can be provided by EGD to assist them in identifying specific reasons for high gas use in each building, implementing the necessary improvements and verifying that savings are achieved and maintained over time.

EGD was unable to provide the requested breakdown of numbers of customers accounting for the largest gas consumption.[1]

However, consistent with the strategy stated above to focus engagement on customers with large buildings and large portfolios of buildings, we have refined our recommended approach to market engagement and penetration using gas savings potential data for commercial buildings from our database. The strategy is illustrated by Table 1 below, which lays out the first four years of a 12-year market engagement program. The following 8 years of the program would build on this foundation to achieve the modeled top-quartile gas savings of 822 million M3/year in 2025.

The proposed strategy is to engage buildings in each year of the program with a combined 75 million M3/year of gas savings potential so that, by the end of 11 years, the required 2025 top-quartile total of 822 million M3/year (as presented in the model) will be achieved.

Year One would target owners of large buildings – typically hospitals, major commercial and government office buildings and hotels, and universities. Our database contains 26 such buildings in the GTA (including office buildings in the Enbridge workshop for the Race to

[1] Exhibit JT2.36, Page 6 of 13, Page 13 of 13

Reduce as shown in Exhibit L.EGD.ED.1, Figure 12, Page 13) owned by 20 different organizations with identified potential savings totaling 24 million M3/year. Based on this, Year One would aim to engage in total about 60 owners and identify about 80 of their high gas savings potential buildings to achieve the target engagement of buildings with combined potential for 75 million M3/year.

We estimate that our database contains less than 20% of the large gas savings potential buildings in the GTA. Thus, the Year One program would engage and analyze these and other readily identified major owners to meet the year one target. The realization of the gas savings would then roll out over the following 2-3 years.

Year Two would lower the threshold to buildings with 200,000 M3/year of gas savings potential, of which our database of office, government and commercial office buildings contains 25 with combined gas savings potential of 6.6 million M3/year. Extrapolation for this size of buildings requires engagement of about 300 buildings to meet the 75 million M3/year goal. However, large portfolio owners, such as school boards, municipalities and retail chains, come into play so the number of targeted owners is proportionately less (estimated at 50).

Year Three lowers the threshold again to buildings with 10,000 M3/year gas savings potential which we estimate will require engagement of 500 buildings and 50 new customers (given that some customers engaged in years one and two will have buildings already identified in this range). Year 4 lowers the threshold to 50,000 M3/year, for which we estimate 1000 buildings and 50 new customers will be required.

Table 1 Market Penetration Model for Commercial Sector

	Year 1	**Year 2**	**Year 3**	**Year 4**
Gas savings engaged (M3)	75 million	75 million	75 million	75 million
Potential savings per building M3/yr.	> 500,000	> 200,000	> 100,000	> 50,000
# of targeted buildings/year	80	300	500	1000
# of new participants/yr.	60	50	50	50

Target customers	Commercial landlords; major hospitals; universities; major hotels; government	School boards (high schools); municipalities; colleges; large retail; other hospitals, hotels etc	Other retailers; long-term care operators	Banks (branches); school boards (primary schools);

Successful execution of this proposed strategy for the first four years will establish the relationships, processes and capabilities required in subsequent years of the program.

The Apartment sector also has large buildings, large portfolio owners, and collaborative programs in place (including the Federation of Housing Providers of Ontario, and the City of Toronto Tower Renewal Office). We anticipate that a similar model would apply.

Lower penetration rates are projected in the model for Residential and Industry, but the principles of performance-based conservation may be useful in these sectors as well.

Environmental Defence Response to Board Staff Interrogatory #3

Reference: Exhibit L.EGD.ED.1, Executive Summary, Page 2 of 24

Please discuss the timeframe needed to ramp up EGD's current DSM plan to one that achieves the forecast annual average peak demand reduction potential.

Response:

The response to OEB Staff-2 indicates the nature and scale of the further development of EGD's DSM programs needed to achieve the forecast savings. Enbridge already has many of the required relationships with programs and owners, and the technical foundations of Energy Compass and Run It Right. It would seem that the program development to support the proposed market penetration strategy could begin immediately, meet the annual engagement targets laid out in OEB Staff-2, and be completed over 3-4 years. This would include:

- Account managers engaging senior level executives at high profile, large building owner and management corporations
- Gas target-setting capability
- Consideration of time-limited premium incentives for reaching targets
- Technical capacity for identifying causes of high gas use in high potential buildings

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #35

INTERROGATORY

Interrogatory No. A.1-ED-35 Reference: Ex. A, Tab 3, Schedule 1, Page 6-8

The third purpose for the project is described at pages 6 to 8 of Exhibit A, Tab 3, Schedule 1, and is summarized as follows at page 2:

> "4. The GTA Project will: …
>
> > c. Provide entry point diversity by reducing the dependence upon Parkway Gate Station which currently provides more than 50% of the supply to the GTA Project Influence Area and does not have alternate means of supply."

a) The Parkway Gate Station currently provides approximately 58% of the supply to the GTA. Is this degree of reliance on a single gate station contrary to certain minimum system standards? If yes, please identify and discuss those standards.

b) Please list all municipalities in (i) Ontario and (ii) Canada with a population of 250,000 and over that receive over 50% of its supply from a single gate station.

c) If Union Gas builds its proposed loss of critical unit (LCU) compressor and Enbridge builds its proposed connection between the proposed Parkway West Gate Station and Enbridge's Parkway North pipeline, to what degree would this mitigate the risk of customer losses resulting from an outage at the Parkway Gate Station?

RESPONSE

a) Enbridge is not aware of any minimum standards with respect to reliance on a single gate station specifically.

Witnesses: C. Fernandes
E. Naczynski

b) Enbridge does not track reliance on gate stations outside of its franchise territory. Enbridge notes that the GTA Project Influence Area has almost one million customers and population that is significantly larger than one million. The number of customers connected to a single integrated gas distribution network is relevant, given the restoration process and timelines associated with outages.

Ottawa also has more than 50% of its demand served through a single gate station.

c) As per Exhibit A, Tab 3, Schedule 6, paragraph 38, the construction of the proposed Parkway West Gate station and associated facilities would allow for a complete shutdown of the existing Parkway Gate Station while still maintaining supply to the distribution system.

Witnesses: C. Fernandes
E. Naczynski

ENBRIDGE GAS DISTRIBUTION INC.
UNION GAS LIMITED

Greater Toronto Area Project
Parkway West Project
Brantford-Kirkwall / Parkway D

EB-2012-0451
EB-2012-0433
EB-2013-0074

SUPPLEMENTAL EVIDENCE

Of

TRANSCANADA PIPELINES LIMITED

August 16, 2013

1. INTRODUCTION

This supplementary evidence is filed in order to respond to the amendments to Enbridge's GTA Project application filed on July 22, 2013 (the "Amended Application").

This evidence will:

- describe the history of TransCanada's involvement in Enbridge's GTA Project through the Memorandum of Understanding ("MOU") that governs Segment A as an Enbridge/TransCanada joint project;
- explain why, without the MOU, Segment A should be viewed as solely for Enbridge's distribution needs and thus at NPS 42 is far over-sized in the Amended Application;
- describe why the savings that Enbridge and Union claim for their respective projects, in the new circumstances of the Amended Application, will not be realized, and why those predictions of savings are inaccurate and unreliable, and why the projects are likely to represent net costs rather than savings; and
- describe the misrepresentation by Union and Enbridge of the status of gas supplies available from the Western Canadian Sedimentary Basin, and why the projects, in the new circumstances of the Amended Application, could be well served without the need to access higher-cost supplies at Dawn.

2. BACKGROUND AND CURRENT STATUS

2.1 History of the GTA Project

The Board will recall that when Enbridge originally filed for leave to construct the GTA Project (the "Original Application"), Segment A of the project was an NPS 36 pipeline that commenced at a proposed new connection with Union, the Parkway West Gate Station, and proceeded easterly to Enbridge's Albion station.

In its February 12, 2013 amendment to the Original Application, Segment A was approximately 6.5 kilometers shorter because it began closer to Albion at TransCanada's proposed Bram West interconnection. It was also re-sized to an NPS 42 pipeline. The change was the result of collaboration between Union, Enbridge and TransCanada regarding facilities in the Parkway corridor, with the objective of reducing the costs and environmental impacts of construction in the corridor, as instructed by the Board in its EB-2011-0210 decision.

The discussions among the parties resulted in a binding Memorandum of Understanding (MOU) dated January 28, 2013, between Enbridge and TransCanada. This MOU resulted in the revision to the route and capacity of Segment A described above. Segment A will be used by TransCanada to transport volumes for its shippers (which includes Enbridge, Union and Gaz Métro) as part of the integrated TransCanada system. In the MOU, the objectives of Enbridge and TransCanada are described as follows:

(a) to provide greater certainty with respect to the efficient development of natural gas infrastructure in the GTA and on TransCanada's Parkway to Maple path;

(b) to optimize use of existing natural gas transportation infrastructure in and around the GTA and TransCanada's Parkway to Maple path to meet the capacity needs of the Parties' current and future respective customers;

(c) to plan for future infrastructure to meet medium and long term needs in a coordinated fashion in order to manage rate impacts upon the current and future customers of both Parties;

(d) to ensure reliability and adequacy of the Parties' respective services and gas transportation systems for customers; and

(e) to manage infrastructure costs and potential risk of redundant infrastructure and other risks that may negatively impact either Party or its customers.

When Enbridge filed its February 12th amendment, the intention of Enbridge and TransCanada was that the two parties would be joint owners of Segment A. The MOU included a "transportation by other" (TBO) option if the parties could not make the joint-ownership objective work. The TBO option was designed to mimic joint ownership, in that TransCanada was obliged to contract for all of the transportation capacity on Segment A for at least 15 years, and to pay Enbridge the remaining book value of Segment A if it did not renew the transportation contract through to the end of the economic life of the line. TransCanada also had a right-of-first-refusal to purchase Segment A.[1] When the parties confronted the challenges that could arise from both the OEB and the NEB having jurisdiction over Segment A, they agreed that the TBO option was the appropriate one, and TransCanada so-elected pursuant to the MOU.

It is TransCanada's intent today and always has been to use its capacity on Segment A on an open access basis to serve customers wishing to move gas on the Mainline. TransCanada does not hold any capacity on any pipeline for its own use: all of TransCanada's TBO entitlements are held for the benefit of whichever shippers contract for transportation services on the Mainline, and the same will be true for TransCanada's capacity on Segment A.

On June 21st, Union and Gaz Métro brought a motion to stay the Application (and for various related orders) on the basis that the MOU was not compliant with the Board's Storage and Transportation Access Rule. At the Technical Conference Enbridge disputed this contention, but before the Union/Gaz Métro motion could be heard, Enbridge agreed to the relief sought in the motion, purported to terminate the MOU, and agreed to amend its application. Accordingly, the motion was withdrawn.

In the July 22nd version of the Application, the commencement of Segment A has reverted to Parkway West, TransCanada has no right or obligation to utilize Segment A capacity, but Segment A remains an NPS 42 pipeline.

TransCanada's original evidence in this proceeding was premised on the February 12th version of Enbridge's GTA Project. The parts of that evidence that are not premised on the MOU remain valid; this supplementary evidence addresses the further Amended Application.

[1] See MOU Schedule D, "Term & Termination"

2.2 Related Litigation

The substance of the July 22nd changes to the Application is contained in Exhibit A-1-9, which is Schedule 9. Paragraph 2 of this exhibit begins: "The reason for this update is the termination of a Memorandum of Understanding ("MOU") with TransCanada that provided exclusive access to capacity on the Segment A pipeline of the GTA Project."

It takes two parties to make a contract, and without an applicable termination clause, it takes two parties to terminate it. TransCanada has commenced an action in the Ontario Superior Court for specific enforcement of the MOU. The July 22nd amendment to the GTA Project is entirely inconsistent with the terms of the MOU. TransCanada has put Enbridge on written notice that if it proceeds with the GTA Project otherwise than in accordance with the MOU, it does so at its peril. TransCanada has given notice to Union and Gaz Metro that they too proceed in the face of TransCanada's contractual rights in relation to Segment A.

In Enbridge's response to Exhibit I.A1.EGD (Update). GEC.50-a is a notice of an open season by Union and Gaz Métro for a pipeline to transport gas from Albion to the Mainline at or near Vaughan. The premise of the Amended Application and of the Union compression and looping applications being considered in these proceedings is that there will be available capacity on Segment A above the Enbridge distribution requirements and an interconnection between whatever pipeline takes gas from Albion, to the Mainline near Vaughan. That premise is the subject of a contested proceeding before the National Energy Board.

Accordingly, all of the leave to construct applications combined in these proceedings are contingent on the outcome of regulatory and judicial litigation.

3. Transmission System Expansion Guidelines ("Guidelines")

Neither Union nor Enbridge is in compliance with the Guidelines as they apply to their respective projects. Both LDCs have failed to provide a complete and accurate assessment of the impact of their respective proposed facilities on existing infrastructure and on Ontario consumers. In TransCanada's original evidence filed July, 2013, in Section 6.0, TransCanada discussed the Guidelines and its general view on the impact that these projects would have on existing transportation pipeline infrastructure in Ontario. TransCanada stated that it would continue to analyze these impacts.

Union, Enbridge and Gaz Métro have all calculated the "savings" that they submit will accrue to their customers if these applications are approved. TransCanada has reviewed these calculations and while TransCanada has serious concerns with some of those calculations, the major deficiencies are:

(1) they do not in any way take into consideration the impact that the approval of these applications will have on TransCanada's existing infrastructure and the consequential impact that they will have on Ontario consumers (savings arising from a project are only transitory if they become increased expenses in subsequent years); and

(2) the projected savings are premised on differences between gas commodity costs at Empress and at Dawn that are optimistic and inherently unreliable.

The major impact that the approval of the Union and Enbridge applications (the “Applications”) will have on TransCanada is in the loss of revenue from long-haul firm transportation (FT) service from Empress. If these applications are approved, the three LDCs have all stated that they will dramatically reduce their currently contracted FT volumes for service from Empress to their franchise areas. These reductions will be replaced with a roughly commensurate amount of short-haul service. The loss of revenue from the reduced long-haul service is roughly eight times the revenue from the replacement short-haul service.

As the Board is aware, Ontario consumers have historically paid increased TransCanada tolls, off-setting the short-term savings that the Ontario LDCs have realized by switching from long-haul to short-haul service on the Mainline. As TransCanada explained in its originally filed testimony, the RH-003-2011 Decision leaves higher Mainline tolls as the default outcome when TransCanada’s cumulative revenue deficiency in the Toll Stabilization Account (TSA) is disposed of at the end of the multi-year fixed tolls period, scheduled for December 31, 2017. While there is a risk that the NEB will require TransCanada to absorb some, or all of a revenue deficiency, if this does not happen, the savings that Enbridge and Union (and Gaz Métro) hope to realize with lower transportation costs will evaporate and Ontario consumers will have paid for more expensive Dawn-sourced gas to no benefit resulting in a net loss.

If the projects proceed TransCanada’s revenues will decline by approximately $455 million per year, based only on the first phase of the proposed Union / Gaz Métro bypass[2]. The replacement revenue from short-haul service would be approximately $55 million per year. Thus the net revenue reduction experienced by TransCanada would be approximately $400 million per year.

Another impact on Ontario consumers is that some pipeline company, TransCanada or another, must incur the costs required to build the facilities necessary to provide the increased replacement short-haul service on which the Applications are premised. If TransCanada builds a new pipeline from Albion to the Maple area the capital cost would be approximately $310 million, and it can be expected that any other pipeline company would incur roughly the same costs. These are costs for redundant infrastructure, and must be deducted from any savings hoped to be achieved from the creation of such infrastructure.

In summary, the cumulative negative impact on TransCanada’s revenues between November 1, 2015 and December 31, 2017 from the loss of long-haul revenues—and thus the potential exposure of Ontario gas consumers when TransCanada’s TSA is disposed of after that date—will be approximately $960 million, including carrying costs. In considering the exposure of Ontario gas consumers to the costs of the applied-for projects, the unavoidable cost of the redundant facilities (estimated above to be approximately $310 million) must be added, and this for the dubious savings claimed by the LDCs as discussed below.

This issue is further explored in Section 5 below.

[2] The first phase of the proposed Union / Gaz Métro bypass is from Albion to Vaughan. The proposed second phase is to continue the bypass to Maple, which will result in even larger potential lost Mainline revenues, potentially to be paid by Ontario gas consumers on the disposition of the TSA.

4. Segment A is oversized

If Enbridge does not rely on the MOU to justify the sizing of Segment A, then its only known need is for the reinforcement of Enbridge's distribution system, and the appropriate size of Segment A is NPS 24.

Enbridge has failed to consider any potential Segment A pipe sizes smaller than NPS 36 and has recently amended its application to reflect an NPS 42 pipeline. Enbridge has quoted the capabilities of these pipe sizes as 1600 TJ/d (NPS 36) and 2000 TJ/d (NPS 42) (Exhibit I.A3.EGD (Update).TCPL.23) but has not provided sufficient data for a third party to verify these numbers. Taking these capabilities as provided, it seems obvious that NPS 36 and especially NPS 42 are significantly oversized for Enbridge's market requirement of 800 TJ/d. Enbridge has stated that GTA demand above 800 TJ/d "will be met through other supply paths" (Exhibit I.A3.EGD (Update).TCPL.24).

Given the refusal of Enbridge to provide the data with which the appropriateness of pipeline sizes smaller than NPS 36 can be considered by the Board, TransCanada has completed its own calculations on the capability of Segment A.

TransCanada has previously determined that in the context of the configuration contemplated in the MOU, that the capacities of Segment A with NPS 36 and NPS 42 pipe are 1600 TJ/d and 2000 TJ/d respectively. As these are exactly the same capacities as those quoted by Enbridge, TransCanada expects that Enbridge has used these same values to indicate the capacity of Segment A of these two pipeline diameters. However these calculations (i.e. both those of TransCanada and of Enbridge) are based on the requirements of TransCanada's integrated system. These requirements include a pressure at Parkway of 6000 kPa (870 psi) to account for area transient effects, and a pressure requirement of 4800 to 5000 kPa (700-725 psi) at Albion. Neither of these requirements would apply for a Segment A that is being used exclusively for Enbridge's distribution needs.

For a Segment A that is only for Enbridge's 800 TJ/d requirements, TransCanada has calculated that NPS 24 pipe is more than sufficient. First, TransCanada understands that Union's new compression, which includes loss of critical unit protection, will provide Enbridge with a pressure of 6450 kPa (935 psi) at Parkway West. Second, Enbridge has quoted the Maximum Operating Pressure (MAOP) of the system to which Segment A connects at Albion as 3344 kPa (485 psi) (footnote in Exhibit A, Tab 3, Schedule 3, Page 4 of 25). Based on these two values, TransCanada has calculated the capability of an NPS 24 at approximately 950 TJ/d, which is more than sufficient for Enbridge's requirements. TransCanada has calculated that if the Segment A pipe size was to remain at NPS 36 or NPS 42, the resulting pressure at Albion would be 6230 kPa and 6340 kPa respectively. To arrive at Albion with a higher than required distribution pressure as suggested by Enbridge (Exhibit I.A3.EGD (Update).TCPL.24) is overbuilding of either Segment A, Union compression or both.

Enbridge has stated (Exhibit I.A3.EGD (Update).TCPL.23(e)(i)) that "in the event that there are no shippers for the transportation service under Rate 332, the Company proposes to allocate the entire revenue requirement of Segment A to its distribution customers". Enbridge has declined to provide the difference in cost between NPS 24 and NPS 42 pipe, and so TransCanada has performed the calculations. TransCanada has estimated that approximately $135 million extra would be borne by distribution customers with an NPS 42 line.

As Enbridge has declined to provide it, the table below shows TransCanada's calculations of capability of a Segment A pipeline that is only connected to the Enbridge system, based on the pressure assumptions described above.

Table 4.1 Hydraulic Design Conditions and Resulting Pipe Capability

Inlet Pressure	6450 kPa
Outlet Pressure	3344 kPa
NPS 24 Capability	950 TJ/d
NPS 30 Capability	1725 TJ/d
NPS 36 Capability	2780 TJ/d
NPS 42 Capability	4100 TJ/d

As Enbridge has declined to provide it, the table below shows an estimate of Segment A costs. This shows a $135 million dollar difference between the NPS 24 and NPS 42 cost.

Table 4.2 First Year Rate Base Addition for 27.4 km of Segment A

	27 km Parkway West to Albion Cost	Information Source
NPS 24	$ 178 million	TransCanada estimate
NPS 30	$ 224 million	TransCanada estimate
NPS 36	$ 267 million	Exhibit I.A3.EGD (Update).TCPL.23
NPS 42	$ 313 million	Exhibit I.A3.EGD (Update).TCPL.23

5. LDC savings calculations

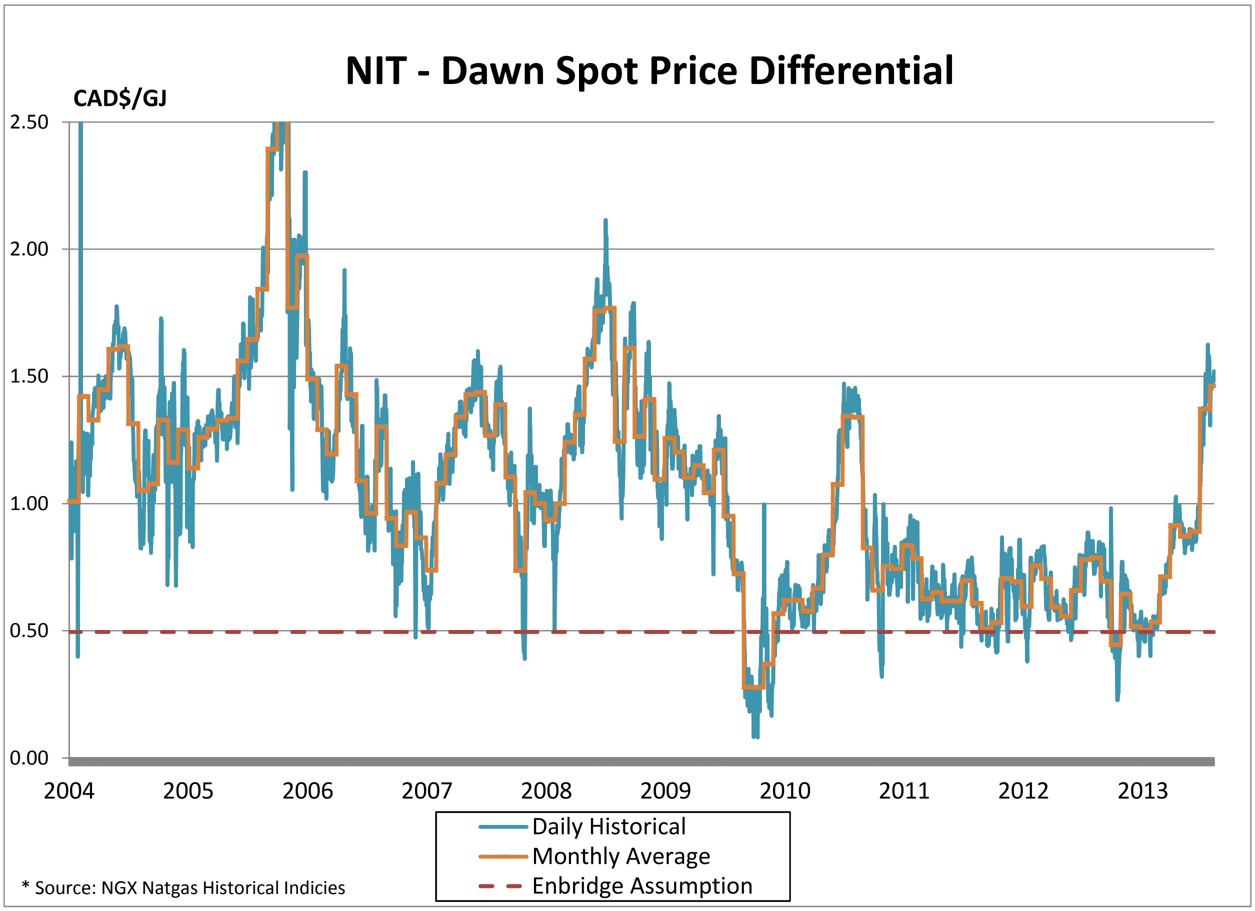
Union, Enbridge and Gaz Métro have provided evidence as to the savings that they hope to achieve if these projects proceed. Union and Enbridge have provided some detail of the derivation of the projected savings; Gaz Métro has provided very little detail.

In this case, the LDCs are proposing to reduce their purchases of gas at Empress by approximately 767,000 GJ/d and increase their purchases of gas at Dawn (and perhaps Niagara in Enbridge's case) by an equivalent amount. Gas is currently more expensive at Dawn than at Empress, so all other things being equal, the short term savings achieved by any of the LDCs is determined by deducting the higher commodity cost at Dawn relative to Empress from the lower tolls that the LDCs hope to pay from Dawn to their markets relative to the toll from Empress to their markets.

When looking ten years into the future, as the LDCs do in this case, informed observers will differ, sometimes by a considerable amount, on what the difference between the Dawn and Empress gas prices will be (the difference being termed the "spread" or "price differential").

This is evidenced in these proceedings by the deviance amongst the price differential forecasts used by the three LDCs. Union's experts forecast an average Empress-Dawn price differential of $0.98/MMBtu US ($0.917/GJ CDN) over the 2014-2023 period (see Sch. 11-4, col. C). Enbridge's experts forecast the Empress-Dawn price differential over the 2016-2025 period to be approximately $0.49/GJ CDN. (See A-3-9 Attachment 1, pg. 3). Gaz Métro provides an Empress-Dawn price differential of $0.73/GJ (Exhibit M.SCGM.TCPL 1).TransCanada is unable to determine how it was applied.

The following chart demonstrates the range of the price differentials between NIT and Dawn since 2004[3], and hence the fragility of savings forecasts that are premised on price differentials:



It can be seen that the price differential has varied from monthly averages of approximately $0.25/GJ to over $2.50/GJ, with the current price differential of approximately $1.50 being in the range of the historical norm. Accordingly, net savings are uncertain and there could in fact be a loss depending on the future price differentials between Empress and Dawn.

In other words, if the projects proceed, TransCanada's long-haul revenue loss will be a certainty and this represents a potential cost to Ontario consumers. The costs of the redundant facilities

[3] The NIT/Dawn price differential is used as a proxy for the Empress/Dawn price differential

will be a certainty and these represent direct costs to Ontario consumers. The predicted savings are anything but certain.

For example, Union calculates its savings at approximately $15 million per year premised on a price differential of $0.92/GJ. Price differentials are currently in the range of $1.50/GJ, which if sustained would erase Union's predicted savings and give rise to a substantial loss.

The following table indicates the LDCs' calculations of savings[4], with the resulting impacts on the revenue deficiency in the TSA[5] that tracks revenues during the multi-year fixed tolls period (all analysis assumes the Enbridge current Base Case in the July 22 Updated Evidence):

Table 4.3 Net Impact Based on LDC Stated Savings

($M / year)	Forecasted Savings	TSA Impact	Net Impact
Gaz Métro	88	(117)	(29)
Enbridge	173	(251)	(78)
Union	15	(33)	(18)
Total	**276**	**(401)**	**(125)**

The following table provides the results of the same calculations, but using Union's assumed $0.92/GJ price differential and TransCanada's calculation of LDC savings:

Table 4.4 Net Impact Based on $0.92/GJ Price Differential from Empress to Dawn

($M / year)	Forecasted Savings	TSA Impact	Net Impact
Gaz Métro	30[6]	(117)	(87)
Enbridge	98	(251)	(153)
Union	9[7]	(33)	(24)
Total	**137**	**(401)**	**(264)**

The following table provides the results of the same calculations, but using current price differentials of $1.50/GJ and TransCanada's calculation of LDC savings:

Table 4.5 Net Impact Based on $1.50/GJ Price Differential from Empress to Dawn

($M / year)	Forecasted Savings	TSA Impact	Net Impact
Gaz Métro	(26)	(117)	(143)
Enbridge	(6)	(251)	(257)
Union	(6)	(33)	(39)
Total	**(38)**	**(401)**	**(439)**

As shown in the Table above, the LDCs actually incur higher gas costs by shifting gas purchases to Dawn from Empress using current price differentials.

[4] TransCanada has been unable to confirm these calculations and provides its own calculation of LDC savings in subsequent tables.
[5] TSA and the NEB RH-3-2011 Decision are discussed in detail in TransCanada's original evidence.
[6] Exhibit M.TCPL.CME.1, Attachment 1A, page 3.
[7] Exhibit M.TCPL.CME.1, Attachment 1A, page 1.

And it must not be forgotten that, as previously noted, $310 million[8], in addition to $135 million (see table 4.2) to increase the size of Segment A from NPS 24 to NPS 42, will be spent to build facilities to take the gas from Enbridge's Segment A to the Maple area so that the $264 million (assuming a $0.92/GJ price differential) or $439 million (assuming a $1.50/GJ price differential) in losses can be achieved.

TransCanada notes that Enbridge's calculations assume two major contractual changes that may or may not occur prior to November 1, 2015. If these changes do not occur as assumed by Enbridge, the savings claimed by Enbridge will be over-stated.

First Enbridge has assumed that its Direct Purchase customers will contract for an additional 157,768 GJ/d of long-haul firm service from Empress. Enbridge then assumes that if the Applications are approved, these Direct Purchase customers will drop their long-haul firm service contracts and take an assignment of short-haul Dawn-Parkway capacity on the Union system from Enbridge. In Exhibit I.A1.Enbridge (Update).TCPL.6, Enbridge was asked to provide some evidence or rationale to support this assumption. Enbridge did not provide any such evidence. Consequently TransCanada assumes that this assumption has no supporting evidence. TransCanada notes that it has not received any requests for long-haul firm service to the Enbridge CDA from any Direct Purchase customer. If this Enbridge assumption turns out to be false, Enbridge's claimed savings would be reduced by approximately $60 million/year.

Second, Enbridge has assumed a large increase (191,500 GJ/d) in the amount of contracted long-haul STFT by 2016 relative to current levels. In Exhibit I.A1.EGD (Update).TCPL.13, TransCanada requested an explanation for this large increase. Enbridge declined to provide a response so this assumption is not supported by any evidence. Again, any assumed contractual long-haul volume that does not actually materialize (and thus does not exist for conversion to short-haul) serves to incorrectly increase the savings claimed by Enbridge. The unsubstantiated 191,500 GJ/d of incremental STFT volumes incorrectly increase the savings claimed by Enbridge by approximately $70 million/year.

6. Supposed supply diversity from the Applications

6.1 GTA Project exacerbates a narrow supply path diversity for Enbridge

TransCanada submits that, especially from an LDC perspective, transportation path diversity is as important as supply diversity, because the latter goes to economic opportunities whereas the former goes to both economic opportunities and security of supply. On the measure of transportation path diversity, the GTA project fails because it leaves the Enbridge franchise area increasingly dependent on one pipeline system, Union's Dawn-Parkway system. Based on information provided in the response to Exhibit I.A1.EGD (Update).TCPL.1, TransCanada calculates Enbridge reliance on the Union system as follows:

[8] Plus the $25 million that it will cost to expand service to Enbridge on TransCanada's Hamilton Line

Table 6.1 TransCanada and Union Contracts – 2015 with GTA Project Facilities

Enbridge Contract by Path	TJ/d	% of Total
TransCanada Long-haul (includes STFT)	501	12.3
TransCanada Short-haul (incudes STS)	954[9]	23.4
Union contracts	2,625	64.3
Total	4,080	100

What the numbers show is that of the contracts that Enbridge holds with TransCanada and Union to serve its customers, 83% of those contracts rely on the Dawn to Parkway system.[10] TransCanada also notes that Enbridge, as indicated in its response to Exhibit.I.A3.EGD (Update). APPrO.16, intends to contract for an additional 170 TJ/d of short haul service to the Enbridge EDA, which will further increase its reliance on Union's Dawn to Parkway system. TransCanada considers this to be an important metric that Enbridge has omitted from its analysis. A major incident on the Union system could result in major supply impact on the Enbridge franchise area.

TransCanada disputes the claim that the GTA project increases supply diversity. Although the project may increase access to additional US sourced supply at the Dawn Hub, such as via the proposed Nexus project, the majority of that supply must still come to the GTA on the Union system. As noted above, this makes the Enbridge franchise more dependent on only one transportation path, the Union system.

Enbridge has risked a further reduction in supply diversity by purporting to cancel the MOU. Under the MOU, Enbridge's supply to the GTA will flow directly into Enbridge's GTA reinforcement project from TransCanada's proposed Bram West interconnect. By connecting to the Mainline at Bram West, Enbridge would be able to access gas supplies delivered from the north through the Mainline in the event of an incident on Union's Dawn to Parkway system. Connecting the GTA project as now proposed by Enbridge in the Amended Application eliminates this supply option, and leaves Enbridge distribution customers with an increased level of exposure to an incident on Union's Dawn to Parkway system.

7. WCSB supply is understated

The supply analysis put forward by Enbridge and Union in their applications provides a misleading characterization of the WCSB as a potential source for Eastern LDC supply. TransCanada conducts detailed WCSB supply analysis and is providing its views on the future potential for WCSB gas supply as follows.

TransCanada uses a technical recoverable estimate of approximately 560 Tcf for WCSB ultimate potential resources in its Base Case supply analysis. This number has more than tripled since

[9] Contract volumes on the Hamilton line total 200 TJ/d, leaving 754 TJ/d of TransCanada short-haul dependent on the Union system.

[10] The TransCanada short haul contracts referenced in the table above include 200 TJ/d that Enbridge intends to contract from Niagara to the Parkway Enbridge CDA, which will not utilize the Dawn to Parkway system. As a result, this contract quantity is not reflected in the 83% number.

2005. This estimate has never been higher. Figure 7-1 shows the growth of forecast ultimate potential resources over time.

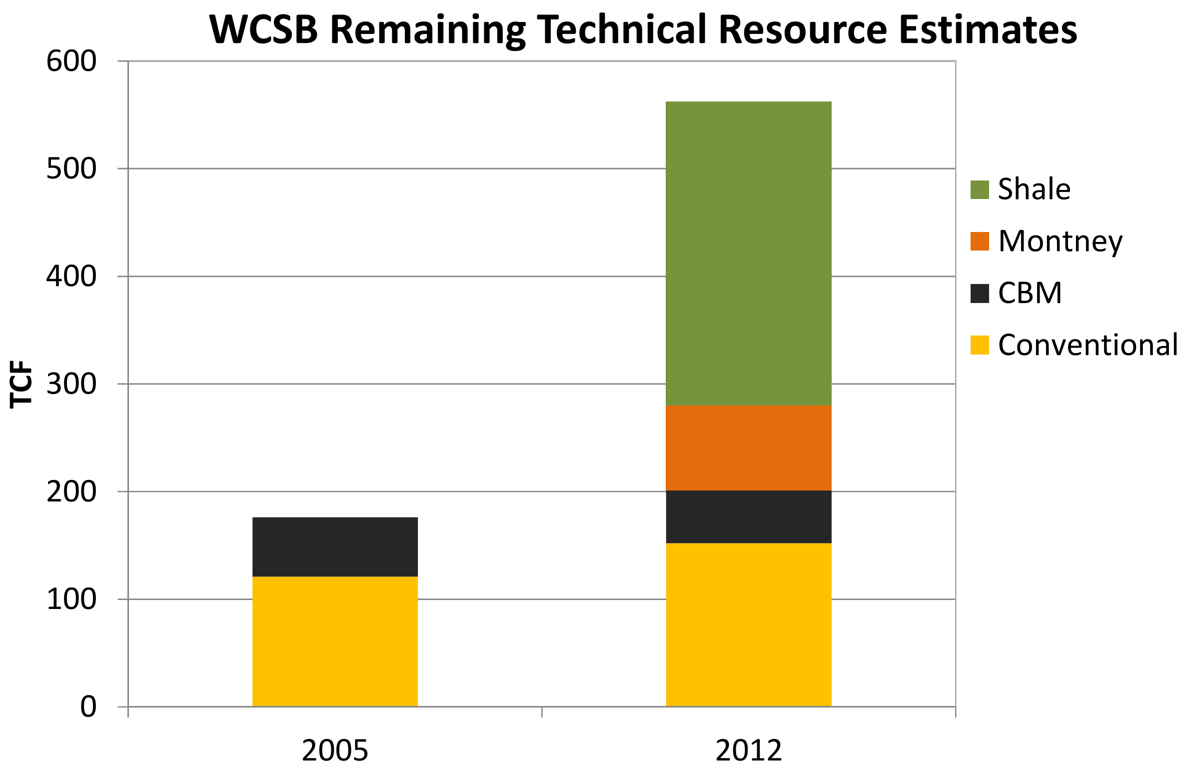


Figure 7-1 WCSB Remaining Technical Resource Estimates

TransCanada resource estimates based on compilation of data from National Energy Board (NEB), Energy Resources Conservation Board (ERCB), Alberta Geological Survey (AGS), British Columbia Ministry of Energy and Mines, (BCMEM), Canadian Society of Unconventional Gas (CSUG), Canadian Association of Petroleum Producers (CAPP)

By this measure there are ample supplies in the WCSB to satisfy eastern LDC markets for many decades to come.

With the advent of horizontal drilling and multi-stage fracturing, the North American gas supply/demand balance has been altered, with a supply glut dramatically reducing prices (Figure 7-2).

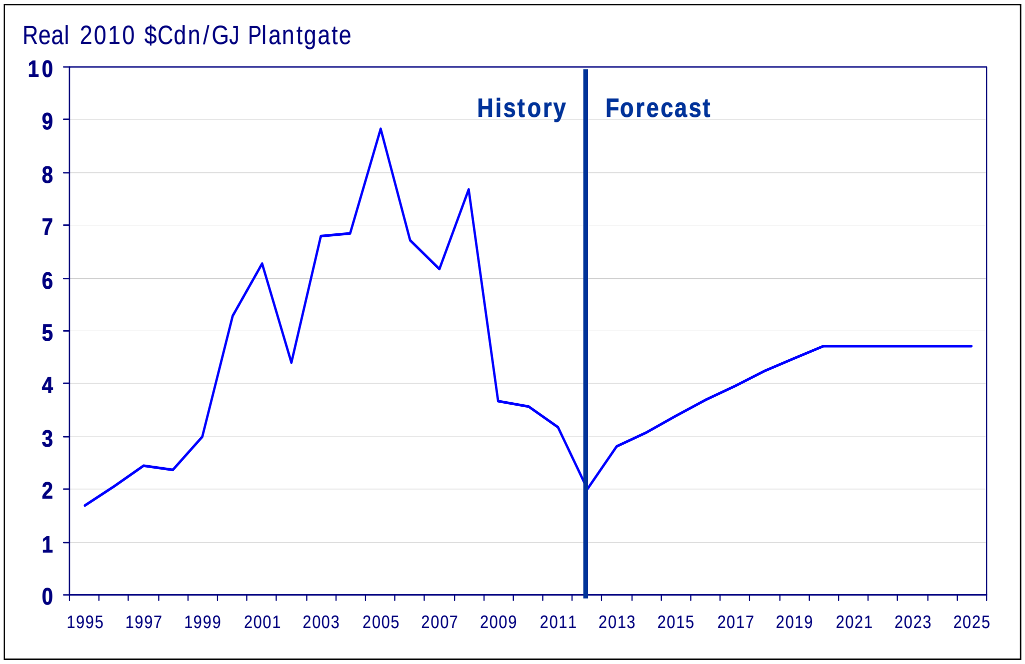


Figure 7-2 Canadian Plant Gate Gas Prices

The low prices had a major impact on WCSB conventional supply development as producers have avoided developing some of the more marginal gas plays that have higher development costs associated with them. As a result, WCSB conventional production has declined (Figure 7-3).

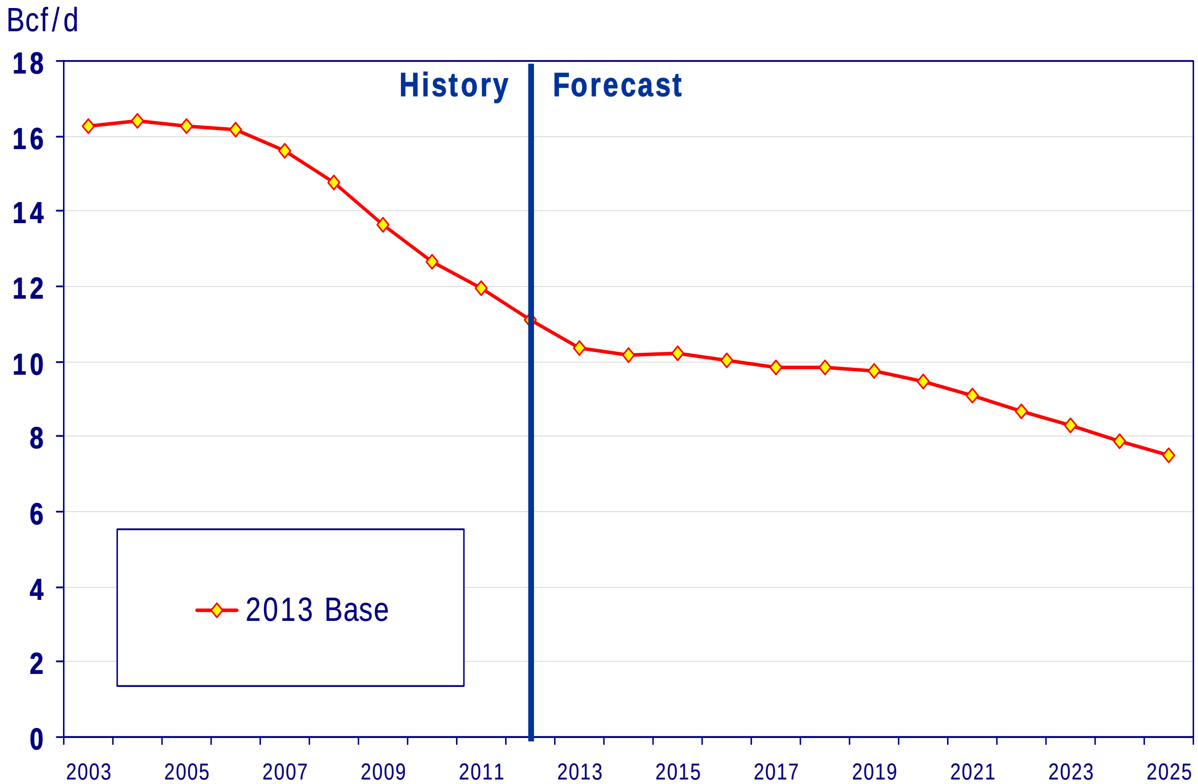


Figure 7-3 WCSB Conventional Supply

Due to improvements in technology, changes in regulation, royalty incentives, production efficiencies, and the expectation of higher prices, conventional production is now forecast to flatten out over the 2013-2018 period before it resumes its long term decline. By 2025, TransCanada's Base case declines to approximately 7.5 Bcf/d from the 2012 level of 11.0 Bcf/d.

Major advances in technology, particularly in the use and improvement of multi-stage fracturing and horizontal drilling technology, have allowed new unconventional resources such as the shales and other tighter formations to be tapped. Supply costs for these resources have declined over time as the technology continues to improve. As a result, technical recoverable resource estimates for the basin have increased substantially.

As a result of the generally positive developments related to the potential economic production of shale and other tight formation plays and in anticipation of LNG export capability, TransCanada has included approximately 11 Bcf/d of production in its Base Case by 2025 from new areas such as the Montney gas play, Duvernay, Horn River, Liard and Cordova shales (Figure 7-4).

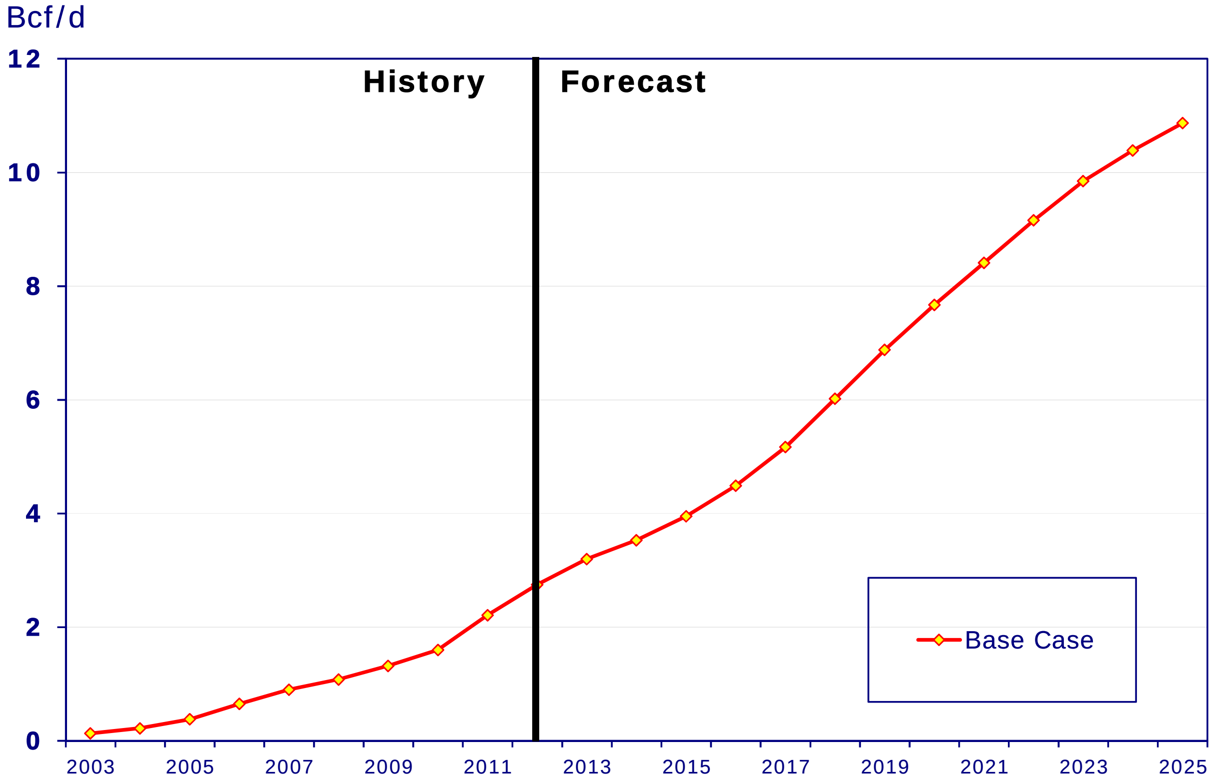


Figure 7-4 WCSB Unconventional Supply

The significant growth in unconventional supply results in TransCanada's Base Case forecast for total WCSB supply (conventional and unconventional combined) rising to about 18 Bcf/d by 2025 (Figure 7-5). Unconventional production in the WCSB is real, happening today, and is not just a potential future supply. At present, unconventional production is already approximately 3 Bcf/d and is growing. Producers are developing these supplies today and are asking TransCanada (and other companies) to connect these supplies to its existing pipeline grid with actual contracts. Currently over 70% of all supply development activity in the WCSB is now targeting unconventional plays.

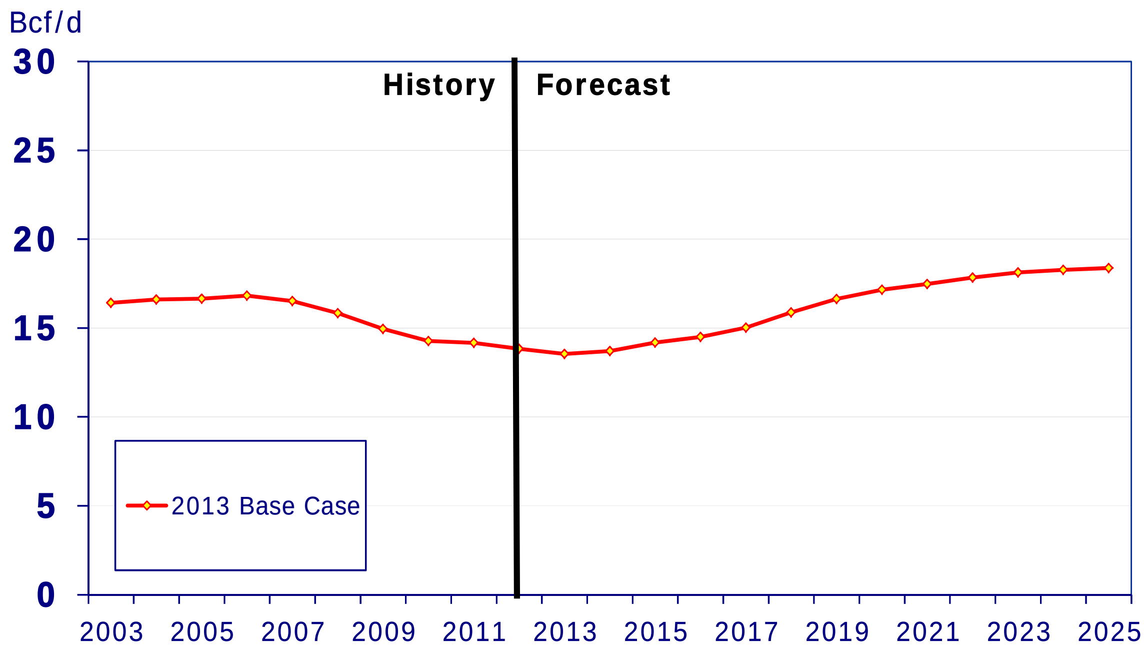
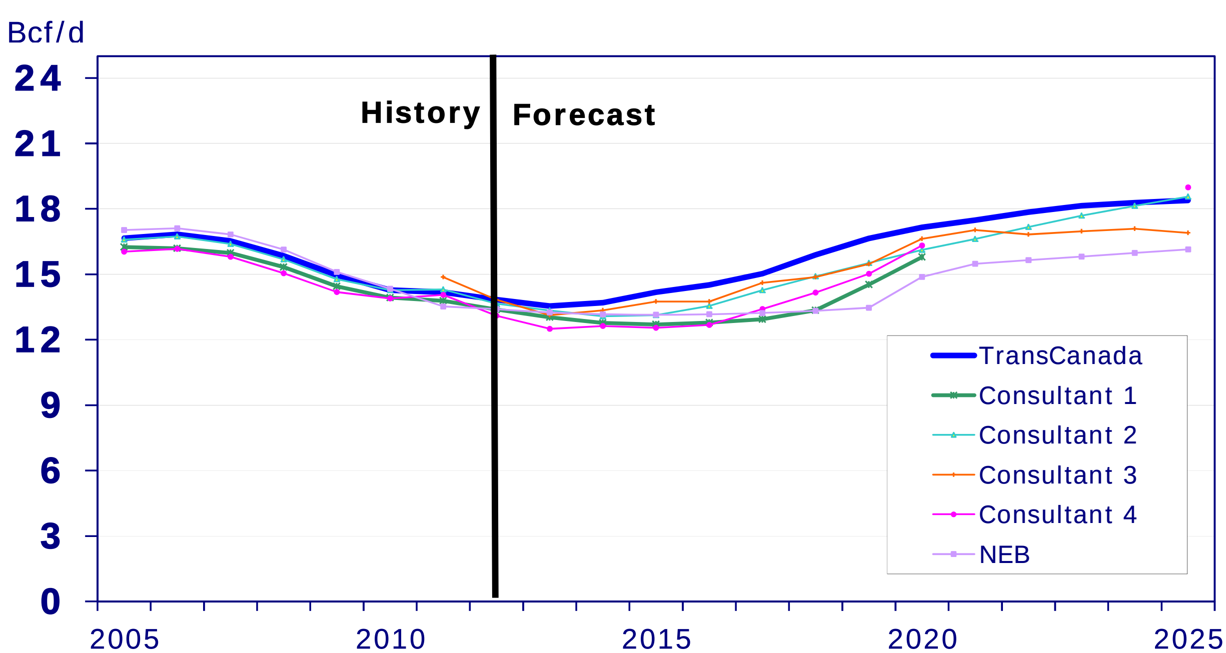


Figure 7-5 Total WCSB Supply

TransCanada has compared its forecast to third party forecasts (Figure 7-6). The forecasts range from a low of 16 Bcf/d to a high of 19 Bcf/d by 2025. If all forecasts were normalized to a common starting point for the year 2013, 5 of the 6 forecasts are within 0.8 Bcf/d by 2020.



Sources: Energy Supply and Demand Projection to 2035, NEB, 2011. Consultant forecasts are proprietary.

Figure 7-6: WCSB Supply Comparisons

Another clear indicator of ample WCSB supply is the amount of gas in western storage facilities at the end of both the injection and withdrawal seasons over the last 8 years (Figure 7-7). These growing storage volumes and capacity indicate that the WCSB is awash with supply and capable of meeting seasonal demands. The recent decline in transportation of gas to eastern markets from the WCSB is not due to a lack of supply available, rather a lack of contracting and demand.

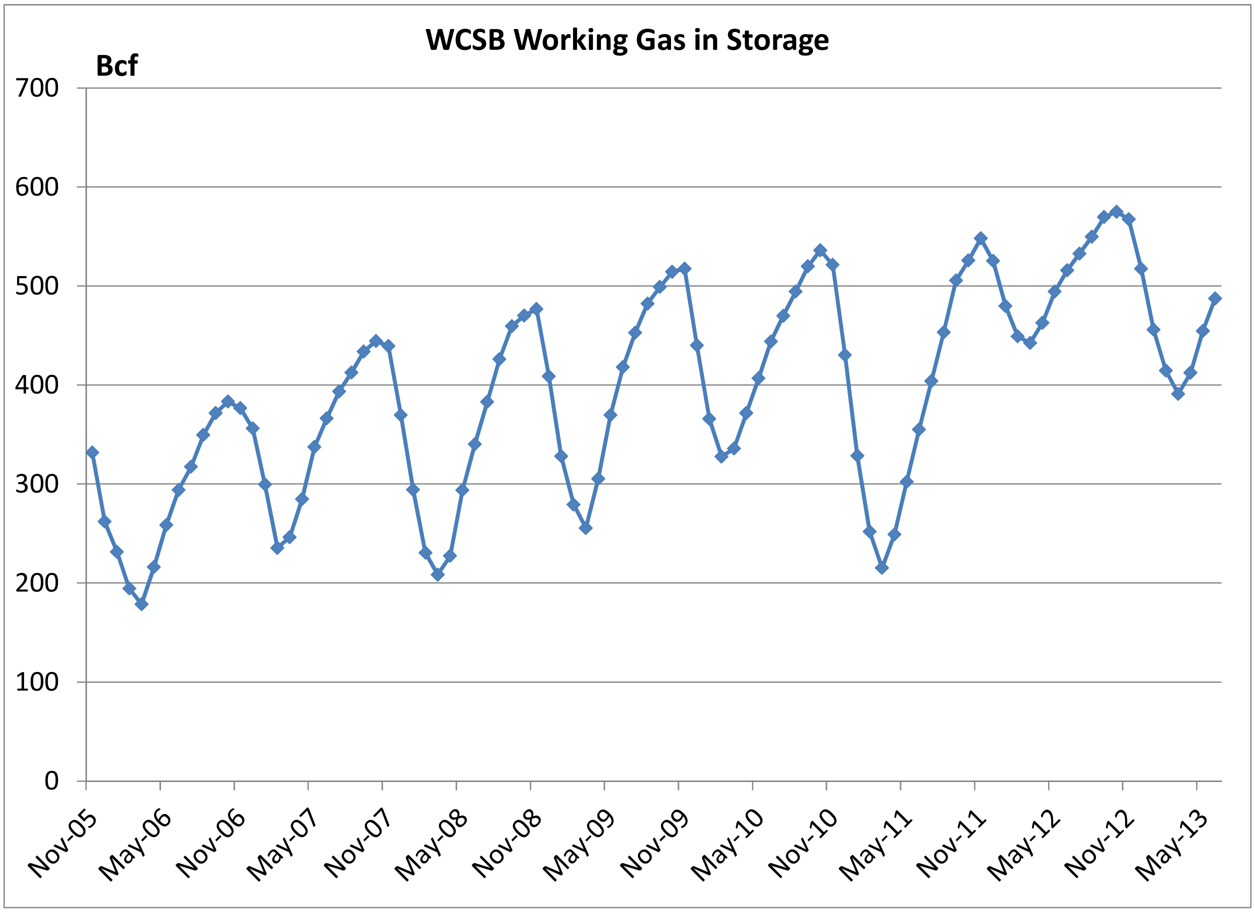


Figure 7-7 WCSB Working Gas in Storage

Source: NGTL system receipts and historical WCSB flow balance

Both Enbridge (EB-2012-0451, Exhibit A, Tab 3, Schedule 5, page 16, Figure 9) and Union (EB-2012-0433, Section 4, Figure 4-4) refer to a graph from an ERCB supply study which shows only conventional supply from only Alberta. They claim that production will decline to approximately 7 Bcf/d by 2021, which is a gross misrepresentation of the supply capability of the WCSB. The appropriate forecast is for both conventional and unconventional supply for the total WCSB, as presented in Figure 6-5. This figure shows total WCSB supply at approximately 17 Bcf/d in 2021, with this forecast validated by several other forecasts including the NEB.

Although west coast LNG export facilities will access some of this supply, there will be ample volumes remaining to securely supply eastern markets for decades to come as the ultimate potential resource base has tripled since 2005 when the eastern LDCs were largely accessing WCSB supply.

8. Conclusion

It is submitted that this supplemental evidence establishes that Segment A, as currently applied for in the absence of the MOU, is substantially over-sized and will represent a wholly unnecessary cost burden to distribution customers.

In addition to being over-sized, Segment A in combination with the other projects applied-for in these proceedings contributes to approximately $1.3 billion in capital expenditure: $1 billion for the Union and Enbridge projects and $310 million for the pipeline from Albion to Maple, whoever builds it. The evidence indicates that this capital cost will be incurred with the result that the LDCs will expose their customers to the risk of almost $1 billion in future tolls when TransCanada's TSA is disposed of. And all of this is being done so that the LDCs can pay between $260 million and $425 million /year more for their gas by buying it at Dawn[11]. Into the bargain, Enbridge reduces its supply path diversity to the point where it is highly reliant on a single path.

For these reasons, TransCanada opposes the Amended Application and submits that it is not in the best interest of the nation, Ontario, or Ontario's consumers.

[11] Based on Empress to Dawn price differentials of $0.92 and $1.50/GJ

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2012-0433** **EB-2012-0451** **EB-2013-0074**

VOLUME:	**8**	
DATE:	**October 9, 2013**	
BEFORE:	**Cynthia Chaplin**	**Presiding Member and Vice-Chair**
	Marika Hare	**Member**
	Peter Noonan	**Member**

I N D E X   O F   P R O C E E D I N G S

MR. ELSON: Thank you. My name is Kent Elson. I represent Environmental Defence, and today I'll have questions almost exclusively for the TCPL witnesses.

And just so that I can understand your respective expertise, my understanding, Mr. Schultz, is that your expertise is more in financial matters; is that correct?

MR. SCHULTZ: So previous to the role that I'm in currently, I did spend five years leading our system design group, so I probably would feel much more comfortable in technical engineering matters than I do in financial matters, but I also have acquired financial knowledge and expertise along the way as well, so I think I'm comfortable in both areas.

MR. ELSON: I guess my question is, if I were to divide the panel or both of you between technical network expertise and financial, who would be the financial person? Would that be yourself?

MR. CLARK: Mr. Elson, perhaps we'll -- thank you. Perhaps we'll help you by answering your questions -- we'll figure out who can best answer your questions, so why don't we leave it at that, and we'll do our best to accommodate you.

MR. ELSON: What role did each of you play in drafting, reviewing, or approving the supplementary evidence that TCPL provided on August 16th, 2013?

MR. SCHULTZ: So I would have the oversight of that activity.

MR. ELSON: Was that picked up on the record?

MR. SCHULTZ: Sorry. It's two buttons and --
MS. CHAPLIN: Two buttons, two mics, only one control.
MR. ELSON: You oversaw that evidence?
MR. SCHULTZ: Yes, so under my areas, accountability. I didn't do all of the drafting or everything else, but that was my group.
MR. ELSON: Thank you. I would ask if the Board Panel and the witness panel could refer to Environmental Defence's cross-examination document book number 3, which is dated October 8th, 2013.
Do each of you -- this is a new document book, and I believe copies were provided to Board Staff, and there should be a copy on the dais. I provided a copy to Board Staff --
MR. MILLAR: I have copies here. It's -- it'll be Exhibit K8.4.

EXHIBIT NO. K8.4: ENVIRONMENTAL DEFENCE'S CROSS-EXAMINATION DOCUMENT BOOK NUMBER 3

MR. ELSON: Thank you. And the first item in this document book is the supplemental evidence of TransCanada, and I'm going to be asking primarily about this evidence. First I'm going to ask you questions to get a better understanding of the evidence at the time it was submitted prior to the settlement agreement, and then I'm going to move on and discuss the settlement agreement and what has changed since this evidence was filed, but for the meantime I'll be asking that you restrict your answers to the circumstances existing prior to the settlement agreement in order to gain an understanding of this evidence.

And I would like to start by asking you to refer to page 2 of the document book, which is page 1 of the TransCanada supplemental evidence. And I've underlined a portion on this page, and I will read that to you. It says:

"This evidence will: Describe why the savings that Enbridge and Union claim for their respective projects in the new circumstances of the amended application will not be realized and why those predictions of savings are inaccurate and unreliable, and why the projects are likely to represent net costs rather than savings."

Now, of course, things have changed, but at the time that this evidence was submitted do you, Mr. Schultz, believe that this statement that I just read is true?

MR. SCHULTZ: Yes.

MR. ELSON: In other words, you believe that the savings predictions in Enbridge's and Union's evidence were inaccurate and unreliable?

MR. SCHULTZ: That's correct.

MR. ELSON: And that they would likely represent net costs?

MR. SCHULTZ: That was the analysis, yes.

MR. ELSON: If you could turn to page 3 of the TCPL evidence -- that's page 4 of the document book -- in the underlined portion, TCPL states that it has:

"...serious concerns with the savings calculated by Enbridge and Union."

And then provides two bullet points, 1 and 2, and I'll read the first one. TCPL says:

"They do not in any way take into consideration the impact that the approval of these applications will have on TransCanada's existing infrastructure and the consequential impact that they will have on Ontario consumers, i.e., savings arising from a project are only transitory if they become increased expenses in subsequent years."

Now, I'll get to this point in more detail shortly, but generally speaking, the point that is being made in this paragraph is that Enbridge's and Union's purported gas savings would likely be more than offset by TCPL tolls; is that roughly accurate?

MR. SCHULTZ: I think the way we were describing it was that the deferred amounts would accumulate in the TSA account, and that the disposition of that TSA account, depending on how that was treated, could result in increased tolls in the future, yes.

MR. ELSON: And in that sense, the savings would be transitory>

MR. SCHULTZ: That's correct.

MR. ELSON: I'm going to come back to item 2 later, but I'll focus on that first issue. And if you could turn over the page to page 4 of the evidence -- that's page 4 of TransCanada's supplementary evidence -- and I'll read the underlined portion here. The evidence says:

"Ontario consumers have historically paid increased TransCanada tolls, offsetting the short-term savings that the Ontario LDCs have realized by switching from long-haul to short-haul service on the Mainline."

And therefore, TCPL further states, further down, quote:

"The savings that Enbridge and Union and Gaz Métro hope to realize with lower transportation costs will evaporate, and Ontario consumers will have paid more expensive Dawn-sourced gas to no benefit, resulting in a net loss."

Then further down the page:

"If the projects proceed, the net revenue reduction experienced by TransCanada would be approximately $400 million per year."

So I understand from this that if the project had proceeded as planned, according to this evidence, back at the time prior to the settlement agreement, TCPL's revenue would have been reduced by approximately $400 million per year; is that right?

MR. SCHULTZ: That's correct.

MR. ELSON: And although it's impossible to say for sure, this would likely result in increased TCPL tolls?

MR. SCHULTZ: That's right. So the ultimate disposition of the TSA has some uncertainty associated with it. The belief we have is that at the end of 2017, that the board has given us an indication -- the NEB, that is --

that the effects of the TSA are likely to be borne by the shippers and result in some adjustment to our tolls going forward.

But there is also some uncertainty there as to whether or not all of that effect would be borne by shippers or not.

MR. ELSON: And that's why -- to use the words of the evidence -- it is stated that the savings would, quote, evaporate? Is that correct?

MR. SCHULTZ: Well, to the extent that those deferred costs were then included in the calculation of future tolls, that would be the -- it was just a deferral of collecting the revenues.

MR. ELSON: Thank you. If you could move back to page 3 of TransCanada's supplementary evidence, I'm going to move onto the second point here.

The second point that you were making in this evidence is -- and I'll read it:

> "The projected savings are premised on differences between gas commodity costs at Empress and at Dawn that are optimistic and inherently unreliable."

And I understand this paragraph to be making basically two points. One is that the price differential fluctuates a lot and is unpredictable, which means that the savings predictions are inherently unreliable. And a second but related point is that the price differential assumed by Enbridge is overly optimistic. Is that a fair summary?

MR. SCHULTZ: Yeah. I believe that was our opinion at that time.

MR. ELSON: And if you could turn to page 7 of TransCanada's supplementary evidence, this page goes further on that point.

And you'll see there's a table showing the Empress-Dawn price differential from 2004 to 2013. Do you have that table in front of you?

MR. SCHULTZ: Yes.

MR. ELSON: My understanding of reading this is that when the price differential is at one, the cost of Empress is twice the cost at Dawn; is that right?

MR. SCHULTZ: Actually, this is the absolute dollar difference in the two prices. So it doesn't necessarily correlate to a multiple.

MR. ELSON: So this is a dollar difference?

MR. SCHULTZ: A dollar difference, yes.

MR. ELSON: The dotted line is the Enbridge's assumed differential?

MR. SCHULTZ: That's correct.

MR. ELSON: The jagged line that is above the dotted line are the historic figures?

MR. SCHULTZ: That's correct.

MR. ELSON: It was once over $2.50 and it's now at roughly $1.50?

MR. SCHULTZ: Yeah. At the time this chart was produced, that was roughly what the levels were, is the $1.50. It has fluctuated constantly since then as well.

MR. ELSON: One of the purposes of this chart is to show that Enbridge's estimate for the price differential is too optimistic; is that correct?

MR. SCHULTZ: We were observing that it would be below what the historic norm had been.

MR. ELSON: Another purpose was to show that the differential is highly uncertain?

MR. SCHULTZ: That's correct.

MR. ELSON: In contrast, the TCPL evidence states below that, quote:

"TransCanada's long-haul revenue loss will be a certainty."

Is that correct?

MR. SCHULTZ: That's correct, at least to the extent based on the assumptions we used at the time. Again, the math was showing the differential on a marginal basis of switching from long-haul to short-haul, what the effects of that would be. To the extent that that was an absolute number, I think, is open for some question, but ultimately that was the assumptions that were used in the analysis.

MR. ELSON: If you could turn to the following page, which is page 8 of TransCanada's supplemental evidence, on this page there's a number of tables summarizing the two factors we just discussed. And table 4.3 provides the net impact based on the LDCs' stated savings.

So in the first column here, I'm just going to ask if you if I'm interpreting this table correctly. The first column is the forecasted savings, and that's from the LDCs' application.

The second column is the TSA impact, which is, roughly speaking, the revenue lost to TransCanada.

And the third column is the net impact, which accounts for both forecasted savings and the revenue loss.

Is that -- am I describing this correctly?

MR. SCHULTZ: Yes.

MR. ELSON: And overall, the net impact TCPL was predicting was $125 million in net losses?

MR. SCHULTZ: That's correct.

MR. ELSON: And further down on table 4.4, the columns represent the same figures, except it's calculated based on a 92-cent price differential from Empress to Dawn, and here the expected net impact is a $264 million loss?

MR. SCHULTZ: Yes, that's what the table shows.

MR. ELSON: And those are net losses per year?

MR. SCHULTZ: Yeah. It's an annual number, the net effect of the TSA deferred amounts and the forecasted savings.

MR. ELSON: And you oversaw the preparation of this evidence, which you believed at the time was correct; is that right?

MR. SCHULTZ: That's correct.

MR. ELSON: The next table is table 4.5, which shows the net impact based on $1.50 price differential from Empress to Dawn. And in that case, there's a $439 million net loss every year; is that correct?

MR. SCHULTZ: That's correct.

MR. ELSON: I'm going to move on and change gears a bit here. During earlier cross-examinations --

MR. CLARK: Mr. Elson, are you going to come back and ask us about --

MR. ELSON: That's what I'm doing right now.

MR. CLARK: Okay. Thank you.

MR. ELSON: But I assume you were about to ask me if I was going to ask you about the settlement agreement.

MR. CLARK: No, no, when you started your remarks you said we'll start with a pre-settlement discussion.

MR. ELSON: Yes, yes.

MR. CLARK: And --

MR. ELSON: Now I'm moving to the post-settlement --

MR. CLARK: -- (inaudible) make sure we go to the post-settlement discussion. Thank you.

MR. ELSON: During earlier cross-examinations Mr. Isherwood agreed that TCPL is more or less going to be kept whole as a result of the shift from long-haul to short-haul. That quote appears at page 24 of our document reference book. Would you agree with that statement?

MR. SCHULTZ: As a result of the settlement? Is that what we're talking about now?

MR. ELSON: Yes, that's correct.

MR. SCHULTZ: Yeah, I think to the extent that the implications of the revenue change from long-haul to short-haul are being factored into future rates. I think the settlement also addresses other cost inputs, though, things like a reduced ROE and such. So there is some implication to TransCanada, in terms of revenues pre- versus post-settlement. But in terms of the implications of customers shifting from long-haul to short-haul, that will be factored into the tolls that will be calculated.

MR. ELSON: And therefore TCPL, roughly speaking, would be kept whole?

MR. SCHULTZ: For the period of the 20 -- out to 2020, yes, between 2015 and 2020.

MR. ISHERWOOD: I should just add to that a bit, I guess. And the very next day I think I went into a bit more detail, in terms of the impacts to Union Gas customers. So there's testimony the next day that gets into both how it was covered under section 11 of our evidence, but also went through some new analysis that I share with the Board, and we formalized it and submitted it as part of J4.5, which showed it more from perspective of Union Gas customers.

MR. ELSON: Thank you. And I believe other intervenors will be addressing that in some detail.

So in other words, if TCPL is going to be kept whole, the settlement agreement, in a sense, eliminates the $400 million per year revenue short-haul -- shortfall discussed in the TCPL evidence. Is that roughly accurate, Mr. Schultz?

MR. SCHULTZ: Well, in that, yes, there won't be a deferral account building with that shortfall in it. It will be factored into the new set of rates that will be produced and then charged to all customers.

So the 400 would have been viewed as a marginal analysis of the effects of just those contracts being transferred from long-haul to short-haul and the revenue implication of that, versus the settlement deals with everything in a comprehensive manner, factoring all of the effects of the transition and the other implications into the new rates.

MR. CLARK: Mr. Elson, I think, if I may add, I think one of the things we have to do when assessing the settlement and the application that's -- the applications that are before you is to look at this thing in a broader sense and also for a longer-term.

One of the things that the settlement does is it reduces our costs. We've agreed to reduce our return on equity and make a contribution to the financial underpinnings of the Mainline.

Over the longer-term it also allows the marketplace to transition to a short-haul world where short-haul markets do -- have -- no longer have accountability for the Prairies and northern Ontario pipeline costs.

So to focus on a short time frame, you know, a moment in time, I think is -- doesn't actually give a fair and accurate characterization of the overall result that comes out of the settlement. I think that's an important thing for the Board to consider in its deliberations here.

MR. ELSON: And I would like to get back to my original questions, but I'll follow that line with you briefly, Mr. Clark.

One of the issues you referred to was the ROE. What's the yearly impact of the reduction in the ROE, roughly speaking? I don't need an exact number.

[Witness panel confers]

MR. CLARK: Just give us a moment, please.

[Witness panel confers]

MR. ISHERWOOD: That number actually shows up in J4.5. The reduction from 11.5 percent to 10.1 percent is about 35 million per year. Mr. Clark mentioned in addition to that the $20 million per year contribution.

MR. ELSON: And the ROE, my understanding from the settlement agreement is that that term would persist whether or not the Board approves this project; is that correct?

MR. CLARK: That's correct. However, I want to point out that the settlement was negotiated as a collection of initiatives, including the construction of these facilities and TransCanada's commitment to construct the Kings North connector.

So I don't think you can parse one from the other. The spirit and intent of the agreement is for the package to be considered as a whole.

MR. ELSON: I'm not sure if at the end your answer was yes or no. I believe -- I guess I'll have to repeat the question. It is correct to say that the reduction in the ROE would -- is part of the settlement agreement that will persist or will be adopted whether or not the Board approves this project? I believe that was the evidence that was provided.

MR. CLARK: So I think from a mechanical point of view the settlement isn't conditioned with OEB approval of these facilities, but I want to emphasize the spirit and intent of the agreement, and the alignment of all the outcomes and the positions of the parties is for the settlement to be considered as a whole.

MR. ELSON: Okay. I'm going to take a step back out of the details and focus in again on the number in the TCPL supplemental evidence. And Mr. Schultz, when I asked you about, you know, what happens to that $400 million revenue short-haul, part of your answer -- shortfall, part of your answer was that it is factored into new rates.

Would it be fair to say that overall the shortfall is made up by being factored into new rates, including the bridging payment? Is that about right, Mr. Schultz?

MR. SCHULTZ: So the calculation of the rates that result from the settlement will include a forecast of how much volumes are going to be sourced from short-haul or long-haul sources, and that will result in the tolls that we'll be applying for with the NEB. So it will include sort of the effects of all of those changes that are anticipated.

MS. GIRIDHAR: If I could just maybe add to the response, Mr. Elson. Mr. Schultz talked about the fact that the 400 million number was calculated on a marginal basis by taking into account simply the contracts related to Enbridge, Gaz Métro, and Union.

In any toll calculation you don't look just at revenue shortfalls, you look at what the revenue requirement is. So you look at, what does the aggregate of volumes and paths mean in terms of revenues and how does that relate to the revenue requirement.

And it's important to note that the settlement agreement allows for that kind of calculation in the derivation of the toll impacts, which again, as we note elsewhere, consist of two things. One is ensuring that the costs of the Eastern Ontario Triangle are borne through rates charged to the eastern Ontario volumes, and that accounts for over two-thirds of the rate impact, and the remainder is a bridging contribution associated with the transfer of volumes from long-haul to short-haul.

By way of context, I should just add that in terms of Enbridge Gas Distribution's own volumes, the -- what we have done recently for the next two winters is to take on long-haul firm transportation to essentially meet a seasonal need that prior to this arrangement actually was sourced through short-term arrangements and weren't necessarily viewed as long-haul FT contracts in the revenue requirement calculation. Thank you.

MR. ELSON: No, I wouldn't dispute that the tolls would be calculated based on aggregate numbers, and including all of the relevant factors, but my question pertains in particular to the number that you calculated, Mr. Schultz, which is a marginal number, which is the marginal impact on your revenue.

And I'm just wondering what happens with that $400 million, and I believe that it would be accurate to say that that gets factored into the new rates; is that correct, Mr. Schultz?

MR. SCHULTZ: Yeah. Like, ultimately it won't be 400 anymore in the new world with the settlement, because all of the inputs will have changed. So the absolute number will be different. However, the overall effect of people transitioning from long-haul to short-haul will be included in the calculation of the new rates, so I think it's not exactly 400 being used, but it's the overall effect of people sourcing gas from the locations they want to source them, and factoring in the cost of service of the TransCanada Mainline and establishing what the rates are to achieve recovery of those costs.

MR. ELSON: In other words, the overall effect of people transitioning from long-haul to short-haul, and in particular the potential lost revenue, that gets factored into the new rates; is that right?

MR. SCHULTZ: Right, in that it's used to create what the rates are.

MR. ELSON: The second issue raised in the TCPL evidence is the variability of the price differential between Dawn and Empress, and Enbridge's overly optimistic projections. And I'm going to go back to that briefly.

Now, Mr. Schultz, am I correct in saying that the settlement agreement does not address that issue, the price differential?

MR. SCHULTZ: That's correct. It's basically the price differential isn't specifically relevant input into TransCanada's determination of new rates and tolls. That's just a marketplace phenomenon that moves around and changes, and it's sort of the world we live in as opposed to an input into any of our calculations.

MR. ELSON: So if TCPL's point was correct about the price differential before the settlement agreement, there's nothing in the settlement agreement that would change that, and TCPL's point about the price differential would be correct after the settlement agreement?

MR. SCHULTZ: I think the marketplace is the marketplace, and I think all we observed through that chart that we were looking at earlier was that over history and time, the price does vary, and that ultimately being able to predict with any certainty what the future marketplace will derive as prices is a challenging activity and is an uncertain one.

MR. ISHERWOOD: Just to add to that, Mr. Henning did testify to that basis and some variability around it, and in his Undertaking 3.5 provided some more insight in that direction as well.

But to Mr. Schultz's answer, it is a market-driven number; nothing that we can actually do about it.

MS. GIRIDHAR: If I might add, Enbridge has provided several times a range of outcomes based on different basis assumptions, ranging from 50 cents up to a $1.50, including sort of a longer-term average assumption around 80 or 90 cents, but in addition, the different utilization ratios that should be considered within the analysis.

So irrespective of the point estimate that Enbridge originally used, there have been additional scenarios run on a range of different bases and utilization scenarios. Thank you.

MR. ELSON: I guess the basic issue that I'm asking that Mr. Schultz agree with me with -- and I believe you have actually -- is just that if the -- TCPL was right before the settlement agreement on that issue, it will be correct afterwards?

MR. SCHULTZ: I would agree.

MR. ELSON: Thank you. If you could please turn to page 28 of the --

MR. CLARK: Mr. Elson, I would just like to supplemental me Mr. Schultz's answer.

I think you have to look at these -- the implications of the settlement agreement take into account all of the effects. So if you -- I don't think you can just peel it apart and say the basis differential is the same before as it was after, with or without the settlement.

You also have to net into the -- because these calculations, these value calculations, all the other attributes that I listed to you before. So I just don't want that to be overlooked and lost in the conversation.

MR. ELSON: Thank you. The questions were only meant to pertain to the price differential issue.

If you could please turn to page 28 of Environmental

ONTARIO ENERGY BOARD

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	Marika Hare	**Member**
	Peter Noonan	**Member**

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calculation for the project. Do you recall that?

MR. FERNANDES: Yes, that was -- we stated that was the scenario in column 6.

MR. ELSON: So just as a bit of a housecleaning matter, I believe your counsel is going to provide an updated response to Exhibit -- sorry, to the undertaking response to J4.10. And that relates to the transportation savings and providing a PV of that based on a different price differential, is 92 cents and $1.50, so unless we're not on the same page as that I think we can move on from the total transportation savings.

Is that correct, Mr. Cass?

MR. CASS: I wasn't proposing that I would personally give the answer, but, yes, you are correct, the undertaking will be responded to.

MR. ELSON: Okay. Thank you.

So the next two items in the charts would be the total customer additions and the total volumes, which in a sense aren't relevant, but in our scenario there would be total customer additions, but those wouldn't have a bearing on this project, because the project wouldn't be needed to address those customer additions, so you can effectively ignore them. Is that a fair way to describe it?

MR. FERNANDES: That would be fair. They would not be included in the economic evaluation of the project, and that's what is shown in column 6, where the capital associated with attaching those customers and all of the revenues associated with those customers have been removed.

And in the case that we just described, we were taking out the revenue stream or the benefit of the incremental customer adds, but we're also taking out the capital costs to attach them to the system.

MR. ELSON: Yes. So under this scenario, roughly speaking, the net present value could be calculated by taking the present value of the capital costs which you provided us and subtracting from that the present value of the transportation savings and the present value of the service charges; is that right?

MR. FERNANDES: There are a few other items, but those are the major ones. The way the feasibility calculation goes is all of the net operational cash flows compared to the capital costs of the project.

MR. ELSON: So those are the major items that we've gone over, and some of the minor items would be, for example, taxes. So taxes would increase the cost a bit; is that right?

MR. FERNANDES: Operating maintenance and other types of costs that are shown in the table.

MR. ELSON: So OM and taxes would be the other two items, and both of those would, I guess, bring your profitability down; is that correct?

MR. FERNANDES: It would reduce the net operational cash flows from that distribution revenue. There are a few other items in there, but they're relatively small in their order of magnitude relative to the other cash flows.

MR. ELSON: Okay. Thank you.

So I guess if you want to do a sort of back-of-the-envelope calculation, you could do that with just the present value of the capital costs, the present value of the transportation savings, and the present value of the service charges. Would that be fair?

MR. FERNANDES: That would be fair. However, I should point out that the sensitivity analysis, the summary that we're actually looking at here, was intentionally put together in order for people to interpolate between what we hope are the bookends of the various major cost drivers and benefit drivers.

So for instance, I would like to point you to looking down near the bottom of the table. We did provide our base case that is shown in grey, and for all of the other scenarios where we're changing one single variable we did list an item that says "variance to current base case NPV", and if you want to look at those numbers, the major cost drivers are generally linear.

So you have the dollars to be able to do an addition, and the example I could give is, if you go to column 7, for instance, this sensitivity was a 10 per cent increase in capital costs, and I should note that that is all capital increased, including the cost of capital to attach the incremental customers and those other reinforcements that we're not asking for as part of this project.

But when we look down there, there is a $600 million NPV. So for example, if you look at column 4, which has half the transportation savings, it has a differential or variance of negative 427 million, and if you look at column 5, which has zero transportation services charge, or assuming there's nothing flowing downstream of Albion, it has an incremental of 158 million.

You can take the 427, the 158, add them together, and subtract them from the 600 million in the other case and see that the net present value would still be greater than zero under a scenario where we had a 10 per cent increase in all of our capital costs, no transportation services revenue, and half of the transportation savings.

So the structure of the table wasn't specifically intended to be helpful for people to be able to interpolate.

The one item that I would want to note is that, specifically with the capital cost increase, it is the only variable that is not really linear, because it feeds back into the transportation services revenue. But it's a fairly small component. But for the other ones, the transportation savings and the transportation services charge, they are directly linear, so they are additive.

MR. ELSON: That's very helpful, and actually, maybe we could do an example of that. If you were to take column 6, and you have the net present value of $449 million, if we were to take that example and then assume from column 4 50 per cent transportation savings and from column 5 zero per cent transportation service charges, we would end up with a negative -- or, sorry, a profitability index of less than one; is that right?

MR. FERNANDES: That would have a net present value that is negative, according to the numbers on here, but I should note that you've basically taken out all of the benefits.

MR. ELSON: Not surprising that the --

MR. FERNANDES: So that would --

MR. ELSON: -- NPV is negative. Yes. And it doesn't take out all the benefits, actually. It just reduces your transportation savings by 50 per cent; is that right?

MR. FERNANDES: And to remind everyone that we stated in Exhibit E, tab 1, schedule 1 that the primary purpose of the project is not based on the economics, it's based on the reliability of our supply chain.

MR. ELSON: Thank you. I'll be moving to another area now.

There seem to be a number of factors that we've gone over that could impact the overall profitability index of this project. One example that we talked about more or less Thursday was the price differential between Empress and Dawn; is that right?

MR. DENOMY: That's correct.

MR. ELSON: And another would be the magnitude of the TCPL tolls -- the, sorry, the TCPL toll increases that are required to compensate for dollars that aren't being spent on the TCPL Mainline?

MS. GIRIDHAR: So Mr. Elson, I just wanted to say that, in terms of basis differentials, you should not that, while it is true that the benefits are a function of basis differentials, they're also a function of utilization of pipe, and we have -- do you have the reference, Mr. Denomy?

MR. DENOMY: Yeah, I do. TCPL No. 2.

MS. GIRIDHAR: TCPL No. 2 provides a range of basis differentials and a range of utilization ratios, and you really need to consider both of them in conjunction because, for simplification purposes, our benefits calculation assumed full utilization associated with approximately a 50-cent basis differential.

The reality is we're talking about displacing discretionary volumes that are used for seasonal purposes. At best that transport would be used throughout the winter. More likely it will only be used partially through the winter, so it's appropriate when we talk about the gas supply benefits that we recognize not just basis differentials, but also utilization of pipe.

MR. ELSON: So I guess that would be another factor that could impact the PI; is that correct?

MS. GIRIDHAR: Correct. And any utilization under 100 percent will increase the PI.

MR. ELSON: Okay. And another was the magnitude of the TCPL toll increases that could result as a consequence of reducing the revenue that goes towards the TCPL Mainline as result of this project; is that another factor?

MS. GIRIDHAR: That is a more complex factor. For instance, that's -- the term sheet is about the terms and conditions of providing market access to the rest of Ontario and Quebec.

MR. ELSON: I can leave that to the joint panel, if you prefer.

MS. GIRIDHAR: Well, I just wanted to make one point. And we can take it up again with the joint panel.

But we should also note that the benefits of market access are that we are able to displace discretionary volumes in Ottawa as well, so there's 170,000 gigaJoules of long-haul that we would otherwise require in order to meet peak day in Ottawa. If we didn't do that, we'll be short 25 percent of peak day.

So while the term sheet does result in an increase in short-haul tolls, it also allows us to displace a significant amount of long-haul that we would otherwise use on very few days of the year to meet Ottawa demand.

So I would suggest that if you are talking about the term sheet, we do need to take a wider approach in terms of what does market access mean for the rest of Enbridge's franchise. And none of that is in these calculations at this point.

MR. ELSON: If it ultimately turns out that the project has a PI of less than one, would Enbridge still seek to have all of the $680 million cost of this project included in rate base?

MS. GIRIDHAR: The answer is yes. As Mr. Fernandes has mentioned several times, the primary purpose of this project is to provide reliability, flexibility and diversity for both our existing customers and our new customers over the next 10 years.

MR. ELSON: In response to Environmental Defence Interrogatory No. 2 -- sorry, 29. Actually, perhaps you could turn that up. I'm not going to ask any specific questions of it, but that's Exhibit I.A4.EGD.ED.29.

Enbridge calculated its net income from 2015 to 2025 resulting from this project. And according to the response to that interrogatory, the net income is roughly $17 million in 2016, declining to about $12.8 million in 2025; is that right?

MS. GIRIDHAR: That is what the numbers show.

MR. ELSON: I believe these numbers were based on the previous version of this project, which had a smaller segment A. And now the capital costs have been increased to 686 million. Could you provide an update to this chart based on the higher figures?

MS. GIRIDHAR: Yes.

MR. ELSON: Thank you.

MR. MILLAR: J6.1.

UNDERTAKING NO. J6.1: EGD TO UPDATE EXHIBIT I.EGD.ED GTA PROJECT ASSUMED EARNINGS IMPACTS TABLE.

MR. ELSON: Again, I think I know the answer to this, but <u>if it turns out that a significant portion of this pipe isn't ultimately used because demand does not grow as predicted and the profitability index turns out to be less than one, would you commit to a reduction in Enbridge's net income from the project?</u>

MS. GIRIDHAR: The answer is <u>no.</u> I'll let Mr. Fernandes continue, but first of all, this project is in the public interest. Our view -- and we obviously provide that in argument -- is that this project is required to meet the reliability, diversity and flexibility needs. The project has been demonstrated to be positive under a number of different scenarios that Mr. Fernandes has just walked us through. He's also going to be able to talk about the strategic manner in which this project has been routed in order to ensure it connects to the largest gate station on our system and the centre of our GTA distribution area.

And I'll just let him talk to that.

MR. ELSON: I think you've actually answered my question, but if you have more to add, subject to the Board's discretion we could hear it.

MS. CHAPLIN: That's fine, but we don't need to re-hear testimony we have already heard.

MR. FERNANDES: So the other important point I think you said about it being under-utilized, part of this is very strategic in the long one.

We've said we're dealing with ageing infrastructure. So we are providing the capability to lower the pressure in those lines, which is a part of our long-term planning.

In addition, our segment A, the path chosen to both distribution and transmission for short-haul is very strategic. We intentionally wanted to bring load -- bring in supply into the centre of the extra high-pressure grid. That has a long-term benefit to the entire system. It provides pressure and flow support, and we believe it's going to pay dividends for many, many, many years to our ratepayers.

The odds of that infrastructure being under-utilized when it's connected into the single largest integrated network in the entire country, the largest single demand centre, are extremely low.

MR. ELSON: That brings me to my next and final few questions, which relate to this SMYS pressure issue. I'm going to ask just a few questions on this on a high level. I believe Mr. Poch and perhaps some other intervenors are going to can ask some more detailed questions.

Could you turn to tab 18 of our document reference book, which is Exhibit A, 3-1, page 1? This is the summary of the purposes in your application.

My question relates to the pressure issue and whether, taken by itself, it's a sufficient justification for this project. So I'm going to briefly go through our position on these other purposes, just as background, and to understand it in the context of all the purposes of the project.

So under item A in the list, the first purpose is load growth. Our position that we addressed to a certain extent on Tuesday is that recent trends suggest that there isn't going to be the peak hours demand growth that has been predicted, and we will be putting forth some evidence on DSM.

So you get to the next purpose of the project, which is B, and B talks about operational risks and safety; that's on the following page. That's page 58 of our document reference book. That's the focus of my last set of questions.

But quickly with respect to C, which is entry point diversity, it seems to us that the Parkway West gate station provides sufficient entry point diversity and backup to Parkway without the need for segment A and B.

And with respect to D, which is the gas supply benefits, there seem to be some highly speculative assumptions or risks, including those set out in the TCPL evidence.

I don't want to get into those issues. I'm not asking you to agree with what I've just said. The point of that background is that if we are right, it's potential that the only benefit of this $686 million project would be the purported reliability benefits in part B of this summary table. So my questions relate to whether this project is worthwhile if those are the only benefits.

My first question is this: My understanding is that Enbridge, the Enbridge system in the GTA area, currently meets all minimum standards relating to operational risk, safety and reliability; is that correct?

MR. THALASSINOS: It meets the minimum standards in the CSA Z662 code that -- I just emphasize those are minimum standards.

MR. ELSON: Even if this project doesn't proceed, there are no minimum standards relating to operational risk, safety and reliability that will not be met? I believe that answer was provided in response to ED 14 –

ED 34; is that correct?
MR. THALASSINOS: That's correct.
MR. ELSON: However, of course part of the purpose of this project is to reduce the pressure on some of Enbridge's lines in the east of the city; is that right? That's the SMYS pressure issue?
MR. THALASSINOS: That's correct.
MR. ELSON: Again, currently those lines are above 30 percent SMYS. Enbridge wants to bring them down below that level. I believe on Tuesday Mr. Naczynski said that Enbridge has 208 kilometres of pipe that is operating at above 30 percent SMYS. Is that the right number?
MR. MOORE: Sorry, approximately we have somewhere around that number that's -- that has the ability to operate up to or above 30 percent SMYS. We don't always operate them at that level, and directionally we'd like to be lower.
MR. ELSON: So those would be the pipes that are sometimes operated at above 30 percent SMYS. They're not necessarily always operated at that level?
MR. MOORE: Correct.
MR. ELSON: And how many kilometres of pipe are being addressed in this project with regard to the SMYS issue? Just approximately.
MR. MOORE: Well, it's the 26-inch line that goes across the city and what we call the Don Valley line, the 30-inch line that comes from Victoria Square down, which --
MR. FERNANDES: It's about 45 kilometres, give or take

a few.

MR. MOORE: These are in the, you know, very congested parts of our franchise, and they are very critical, ageing lines.

MR. ELSON: And that -- the kilometres that we're talking about in this project, is that included or excluded from the 208 kilometres we were talking about before?

MR. MOORE: Included.

MR. ELSON: Included. Have you calculated the likelihood, the mathematical likelihood, of an accident occurring on these lines as a result of this pressure issue?

[Witness panel confers]

MR. MOORE: Sorry, I think you are asking about the likelihood?

MR. ELSON: "Probability" would be another word that I could use.

MR. MOORE: Well, we -- the consequences are very high. The probability -- the likelihood of an event we hope to be low, but the consequences are very high.

MR. ELSON: And I take it by that answer that you haven't actually calculated a number, such as the probability or the likelihood. Mr. Moore, I believe you would know the answer to this question.

MR. MOORE: I haven't. You know, I'm not sure it's necessary for us to do that, to be honest.

MR. ELSON: And have you --

MR. MOORE: The consequences are so great.

MR. ELSON: Has Enbridge calculated the probability or the likelihood of, not an accident, but simply service losses arising from this pressure issue?

MR. FERNANDES: One of the important points that we have on the record is that there has been a general societal decrease in the tolerance for risk that has been embodied by the actual code, as per FS-196-12, which places a responsibility on operators to take a look at these types of infrastructure that are operating in a higher-stress condition in highly populated areas, and it is incumbent on the operator to look at those risks and understand whether they need to take steps to avert those risks. And that's one of the things that the company is prudently planning its network.

We know the lines that we're speaking of are in highly populated areas, some of the most populated areas in the entire country, and they are also well over four decades old, so they have served our ratepayers well. We're not talking about taking them out of service. We're taking them to a lower level of service, and that's prudent planning on our part.

MR. ELSON: Perhaps I'll ask my question again. Has Enbridge calculated the likelihood or the probability of service losses arising from this pressure issue? I believe Mr. Moore and Mr. Thalassinos would have been the people who would have been in charge of this, and I imagine you know the answer off the top of your head.

MR. MOORE: If I understand your question correctly, we would lose significant customers in the winter if we had to currently drop the Don Valley, for example, and the 26-inch line below 30 percent SMYS.

And we -- this isn't a theoretical thing, it's something that has happened this summer. You know, we did have to reduce pressure on both of those lines. We directionally want to be operating lower, but we were -- we had to because of the unexpected flood at the -- in the Bayview area on the Don Valley line and other integrity matters we've been working through.

MR. ELSON: Now, when you dropped the pressure this summer that wasn't a problem. There was no service losses, because you weren't at a peak demand period; is that right?

MR. MOORE: That's right. But in the winter, fall-winter, we would lose --

MR. ELSON: So it depends whether it happens at a peak time or not. That's the issue.

MR. MOORE: If it's cold.

MR. ELSON: So I'm going to go back, actually, to my question, which is whether you have calculated the likelihood or the probability of service losses arising from the pressure issue. I believe you just discussed some of the consequences, and I'm asking whether you've calculated the likelihood or the probability of service losses arising from this pressure issue.

[Witness panel confers]

MR. THALASSINOS: So I'm not 100 percent clear about what you mean by "service losses", but we have done some analysis to look at what it would be, the overall corridor risk, if we were to lower our operating stresses to below 30 percent of SMYS, if that is what your question is.

MR. ELSON: No, that's not my question. I'm asking whether you have calculated the probability, the chance of something occurring, and that something occurring is some event that would result in service losses on this line because of this pressure issue.

And have you -- I think the answer is no, and I don't know why it's a difficult question to answer. But the probability of service losses arising from the pressure issue.

MR. THALASSINOS: So we've not probabilistically determined, based on any event, how many customers you would lose. We have in evidence specific examples of events that would lead to customer losses, but that's not done on a probabilistic load profile.

MR. ELSON: With respect to electricity, there are certain service-interruption criteria that can serve as the basis for deciding on capital upgrades. For example, a load loss of 250 megawatts must be restored within half an hour.

My understanding is that there isn't such similar risk criteria for natural gas; is that right? What I'm talking about again is service-interruption criteria.

MR. THALASSINOS: So we have emergency response criteria which is within -- to respond with emergency within one hour of notification.

MR. ELSON: But you don't have service-interruption criteria that would say what is an allowable service interruption and what isn't that is equivalent to the electricity sector.

MR. FERNANDES: So the natural gas industry doesn't have quite the same standards as the electrical system would. However, we should note that operationally the restoration is fundamentally different, and that is on the record.

For an electric system we stated in the evidence automatic restoration, but it's actually remote restoration, whereas for the natural gas system, once we have customer outages, it requires two site visits, one to shut off the meter at the customer's premise and ensure that it's safe, and then a second visit. Once we restored normal operating pressures within our system, it requires us to visit each and every premise in order to safely relate their equipment.

So the consequences of an outage are substantially different from the electrical system, and we have noted that there were a number of events that have occurred in the natural gas industry that took prolonged outages.

If you get to the point of somewhere on the order of 25,000 customer outages, it becomes a very significant issue for the community and for the company. And those types of event have happened in the industry and they have taken on the order of weeks to restore service.

MR. ELSON: I think the gist of that answer is that you don't have service interruption criteria. So in the interest of time, I'm going to move on. And I understand that there are differences between electricity and gas in that respect.

Have you done a comprehensive risk analysis comparing the risks associated with this 30 percent SMYS issue and other risks in the Enbridge system, including a comparison of the likelihood of service losses, the likelihood of accidents, the consequences of those events and the costs of addressing the various risks?

I'm talking about a risk analysis that has numbers and probabilities set out, such as those I just mentioned.

MR. THALASSINOS: Yes. So we do have an integrity management program that assesses the risks of all of our pipelines, including the lines operating over 30 percent of SMYS, which includes many risk factors.

Some of those risks factors are qualitative, that they are not done quantitatively, and I don't know that we would have all of those risk factors or things that you mentioned mathematically. Some of those are more qualitative.

MR. ELSON: So there's some qualitative analysis but no quantitative analysis; is that right? In your integrity management program?

MR. THALASSINOS: We have a combination of quantitative and qualitative analysis.

MR. ELSON: But you wouldn't have comparisons such as I discussed of the likelihood of service losses, the likelihood of accidents, the severity of the consequences and the costs of addressing those various risks? It wouldn't reach that level of detail; is that right?

MR. THALASSINOS: Not all that level of detail. Correct.

MR. ELSON: What does this document look like? Could you provide it by way of an undertaking?

MR. THALASSINOS: Yes, I think we could.

MR. ELSON: Thank you.

MS. GIRIDHAR: Mr. Elson, You did make a statement in passing, and forgive me for bringing it up here, but we weren't given the opportunity to address it. And the statement that you made in passing was that it was your view that the gas supplies -- our purported gas supply savings may or may not occur based on evidence that TransCanada has provided.

We believe very firmly that those gas supply savings are real, and we would like to have the opportunity to explain why we would not agree with that piece of evidence from TransCanada.

MR. ELSON: And that is something that I think all the parties are going to address at the joint panel. I don't intend to address it today, subject to the Board's discretion, of course.

MS. CHAPLIN: That's fine. Let's leave it for the joint panel.

MR. MILLAR: There was an undertaking given.

MS. CHAPLIN: Yeah.

MR. MILLAR: J6.2.

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2012-0433** **EB-2012-0451** **EB-2013-0074**	
VOLUME:	**3**	
DATE:	**September 17, 2013**	
BEFORE:	**Cynthia Chaplin**	**Presiding Member and Vice-Chair**
	Marika Hare	**Member**
	Peter Noonan	**Member**

INDEX OF PROCEEDINGS

MR. POCH: Do those two terms survive regardless of what happens in these proceedings?

MR. ISHERWOOD: They do.

MR. POCH: All right. So you're going to enjoy that benefit regardless?

MR. ISHERWOOD: Yes.

MR. POCH: Okay.

So I want to just look at that then, how the math works now. You've spoken of it that you're going to -- the intent is that the differential between short-haul and long-haul is going to be maintained, whatever happens to tolls, that the differential in dollars and cents, as opposed to percentage, you expect -- you expect -- and the intent is to try to maintain it.

MR. ISHERWOOD: That's correct.

MR. POCH: And what level is the expectation? I think I heard $1.45, roughly?

MR. ISHERWOOD: No, sorry, the expectation in this element is a surcharge -- or an increase in the short-haul tolls. We're going to do our best to try and keep that to below 50 percent.

MR. POCH: No, I didn't mean the increase. I meant what's the differential between short-haul and long-haul? What are you expecting to hold?

MR. ISHERWOOD: Today, short-haul from Parkway to the EDA is 25 cents, and I believe the long-haul path to the RDA is $1.65, I believe.

MR. POCH: Right. And that was -- so we're talking about $1.40 is the difference.

MR. ISHERWOOD: Today, correct.

MR. POCH: Today. Okay. And the intent is to try to keep it at that scale?

MR. ISHERWOOD: That's correct.

MR. POCH: All right. TCPL cites in their evidence -- it's cited that Union's long-term forecast for the price differential -- commodity price differential between Dawn and Empress as 92 cents?

MR. ISHERWOOD: That's correct.

MR. POCH: You hold by that?

MR. ISHERWOOD: Yes.

MR. POCH: All right. So when you calculate your gas savings, in simple terms you're saying -- you're looking at the volumes that you can -- that these projects will allow you to move from long-haul to short-haul. You're going to save a $1.40 on each cubic metre, and you're going to pay 92 cents more for the gas, and so the difference between those figures is your gas savings. Is that right?

MR. ISHERWOOD: Yes, I think so.

MR. POCH: Okay. And so for every $1.40 that you save on transportation costs, TCPL loses $1.40 in revenue, roughly?

MR. ISHERWOOD: That's true.

MR. POCH: All right. Now, the first six years of that you're going to be -- you and all shippers are going to be making a bridging payment.

MR. ISHERWOOD: That's correct.

MR. ISHERWOOD: So the 48 cent savings, if you want. And we're talking about here about a 12 cent increase in short-haul tolls. So there is still a savings within the bucket.

MS. CHAPLIN: But I guess what I'm trying to understand is: Is the reason that there are savings because the shortfall is going to be collected over a longer period of time than what it's being accrued in? In other words, it's six years of shortfall being collected over 16 years, and that's why you see some savings?

MR. ISHERWOOD: I think that would have a small impact. The bigger impact is the difference in price of gas between buying gas at Dawn versus buying gas in Alberta. So without even this agreement happening, to calculate the savings you need to look at the toll differential between long-haul and short-haul, which we've gone through in some depth.

The other thing we always look at is the difference in cost of buying gas at Empress versus buying gas at Dawn. And that's an important part of the calculation as well.

The impact of the bridging contribution being spread out 16 years versus six years would have an impact as well, but the bigger impact is the gas cost savings between Dawn and Empress.

MS. CHAPLIN: Thank you.

MR. POCH: Mr. Isherwood, just in that compare -- you compared the 48 cents that you're -- sort of your net savings, by saving $1.40, but having to pay an extra 92 cents. You save 48, but for every 48 cents you save, at the margin, all else being equal -- I hear you, Mr. Henning -- all else being equal, TCPL loses $1.40 that would add to their bridging needs.

MR. ISHERWOOD: We've already established that, yes.

MR. POCH: All right. I just wanted to make sure, because we don't want to compare apples and oranges. The 12 cents is a 16-year amortized number, as opposed to a six-year number.

MR. ISHERWOOD: But I think, you know, the important thing here is Ontario needs to get access and Quebec needs to get access to Dawn at Niagara. Other utilities, other market participants, have already gotten access. I think Ms. Giridhar described this at the Friday technical conference: The settlement agreement is about getting equal access to everybody. There's no first, there's no second. Everybody gets access, and we get the same benefits, and TCPL is protected. I think it's really a win-win amongst the market and the pipeline company, TCPL.

MR. POCH: Well, I certainly see how TCPL's shareholders are -- get some protection here, and I understand that the gas companies here get to put pipe in the ground. I guess what we're looking at is whether it helps the end-users.

MR. ISHERWOOD: I think the point that Mr. Henning made yesterday was, without this type of agreement Ontario would be stranded. We will have the highest cost gas in North America. So what we're trying to protect is to make

MR. SMITH: Thank you very much, members of the panel. Those are my questions.

QUESTIONS BY THE BOARD:

MS. CHAPLIN: Thank you. Following on from that, Mr. Isherwood, I have one question still on that general area. So you've given the explanation for the importance of these projects in terms of enhanced access. But one of the underpinnings of the application was this calculation of gas cost savings.

MR. ISHERWOOD: Yes.

MS. CHAPLIN: So I'm going to come back to that again, just to see if I can understand it better, because my understanding of the agreement with TCPL and sort of the general expectation is that TCPL more or less is going to be kept whole as a result of this shift from long-haul to short-haul?

MR. ISHERWOOD: That's correct.

MS. CHAPLIN: So maybe the monies reallocated are moved around, but there's not really -- not driving costs out of the TCPL system. They're still going to be recovered?

MR. ISHERWOOD: That's correct.

MS. CHAPLIN: And I believe you've also testified that the gas commodity is more expensive at Dawn than at Empress?

MR. ISHERWOOD: Yeah, so we have that 92-cent number.

MS. CHAPLIN: Right.

MR. ISHERWOOD: On the record. So the difference is

92 cents.

MS. CHAPLIN: So can you explain for me how are there any gas cost savings in that situation? In the broad sense?

MR. ISHERWOOD: So in the new framework, if the settlement agreement gets approved by the NEB, there's still the differential between long-haul and short-haul that still drives that $15.4 million savings.

So the way I look at it is we're going from a framework today to the new framework, and that has the costs increasing for long-haul and short-haul. But I think the part that I'd like to think about as well is the current framework, even though there's a lower toll, is not recovering all its costs today, and those costs are unfortunately accumulating in a deferral account that gets dealt with in 2017.

So I think people have a comfort level that today's tolls are cheaper. Why don't we just keep going on those tolls?

The reality is in four years, in 2017, those costs will become as high as the -- as high as the settlement tolls or potentially even higher. And in the meantime for those four years, if we left it alone and just kept on the compliance tolls, there's no access to Dawn for Ontario or for Quebec. So what the loss is is access to the new and growing supplies in Marcellus and Utica; that's the difference.

So to the extent that we can get TCPL comfortable and they can recover their costs, then it opens up the whole world of options and choice for customers to go back to the new supply.

MS. CHAPLIN: And have you quantified that broader analysis of access? Or is that something the joint panel may be able to do?

MR. ISHERWOOD: Yeah, I think -- and I think, just based on yesterday and today, I think it would be important for the joint panel to come forward with not the only expectations of the tolls in that new settlement, but to also describe why the existing framework is not economically advantageous for Ontario or Quebec, and what that means to us as well.

MS. CHAPLIN: Or some sort of quantitative comparison?

MR. ISHERWOOD: Yes.

MS. CHAPLIN: Thank you. That would be helpful.

The Panel has no further questions, so this witness panel is excused with the Board's thanks.

And let's press on and...

MR. SMITH: Radical changes ahead. I will call Ms. George to come forward, and ask, I believe, three of the six to leave us.

MR. ISHERWOOD: I'll be a lot more comfortable up here, then.

UNION GAS – PANEL 3

Jim Redford, Previously Sworn

Mark Isherwood, Previously Sworn

Paul Rietdyk, Previously Sworn

GTA Reference Material

Economic Sensitivity Results

Column #	1	2	3	4	5	6	7
Document Type:	**Undertaking**	**Evidence**	**Evidence**	**Evidence**	**Evidence**	**Evidence**	**Evidence**
Scenario Description:	Previous Base Case **36" Shared with TransCanada**	Current Base Case **42"**	Current Base Case with 75% Transportation Savings **42"**	Current Base Case with 50% Transportation Savings **42"**	Current Base Case with 0% Transportation Services Charges **42"**	Current Base Case with No Customer Additions **42"**	Current Base Case with 10% Increase in Capital Cost **42"**
Filed Date:	6/18/2013	7/22/2013	7/22/2013	7/22/2013	7/22/2013	7/22/2013	7/22/2013
Reference:	Ex. JT2.16, pg 2	Ex. E, Tab 1, Sch. 1	Update No. 6 Ex. A, Tab 3, Sch. 9	Update No. 6 Ex. A, Tab 3, Sch. 9	Update No. 6 Ex. A, Tab 3, Sch. 9	Update No. 6 Ex. A, Tab 3, Sch. 9	Update No. 6 Ex. A, Tab 3, Sch. 9
Capital Investment							
Total Upfront Capital	$554,575,341	$652,144,124	$652,144,124	$652,144,124	$652,144,124	$652,144,124	$717,358,537
Future Reinforcement Projects							
2017	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$0	$23,100,000
2018	$16,400,000	$16,400,000	$16,400,000	$16,400,000	$16,400,000	$0	$18,040,000
2019	$13,000,000	$13,000,000	$13,000,000	$13,000,000	$13,000,000	$0	$14,300,000
2020	$250,000	$250,000	$250,000	$250,000	$250,000	$0	$275,000
Capital Maintenance Costs[1]	$5,218,238	$5,230,240	$5,230,240	$5,230,240	$5,230,240	$5,230,240	$5,753,264
Services[2]	$379,533,696	$379,533,696	$379,533,696	$379,533,696	$379,533,696	$0	$417,487,066
Total Capital	$989,977,275	$1,087,558,060	$1,087,558,060	$1,087,558,060	$1,087,558,060	$657,374,364	$1,196,313,866
Total Transportation Savings[3]	$1,465,078,594	$1,732,650,739	$1,299,488,054	$866,325,369	$1,732,650,739	$1,732,650,739	$1,732,650,739
Total Transportation Services Charge[1,4]	$277,595,905	$471,256,624	$471,256,624	$471,256,624	$0	$471,256,624	$517,377,889
Total Distribution Revenues[1]	$4,546,724,222	$4,546,724,222	$4,546,724,222	$4,546,724,222	$4,546,724,222	$0	$4,546,724,222
Total Customer Additions (2015 - 2024)	146,337	146,337	146,337	146,337	146,337	-	146,337
Total Volumes (10^3m^3)	24,709,032	24,709,032	24,709,032	24,709,032	24,709,032	-	24,709,032
SUMMARY OF RESULTS							
Net Present Value (40 years)	$551,186,248	$667,432,377	$453,688,742	$239,945,108	$509,342,599	$449,816,391	$600,770,866
Variance to Current Base Case NPV (40 years)			($213,743,634)	($427,487,268)	($158,089,778)	($217,615,985)	($66,661,511)
Profitability Index (40 years)	1.67	1.73	1.50	1.26	1.56	1.75	1.60

NOTES:

[1]Total for the 40 year horizon of analysis.

[2]Services include the costs for distribution mains, services and meters based on the 2013 capital budget.

[3]Total transportation savings, considered from 2015 to 2025 only, are equal to expected gas supply benefits and incorporate the total cost of landing gas in the Enbridge franchise area including costs associated with tolls, fuel and commodity procurement (i.e. basis differentials) /u
Prepared with TransCanada tolls based on the NEB's Toll Order TG-006-2013 (issued June 11, 2013) which made TransCanada's Compliance Filing tolls final and effective July 1, 2013

[4]Transportation Services Charges to be received from contracted shippers for transportation from Parkway West to to Albion. (Current Base Case)

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #44

INTERROGATORY

Issue A.3 “Are the costs of the facilities and rate impacts to customers appropriate?”

Reference: Ex. A, Tab 3, Schedule 9, Attachment 3

Please reproduce this exhibit assuming the time horizon for calculating the “Total Transportation Savings” and “Total Transportation Services Charge” revenues is limited to the 2015 to 2024 time period.

RESPONSE

For clarity, the original exhibits included upstream “Total Transportation Savings” for the period of 2015 to 2025, with 2015 being a partial year due to the gas year start in November.

The “Total Transportation Services Charge” represents the toll revenue from the transportation service. The initial contracts will be for a 15 year duration as per I.A1.EGD (Update).BOMA.2. The Company therefore views a scenario with less than 15 years, as has been requested, to be unrealistic.

However, the results are presented below. In all scenarios the project is feasible.

Witness: S. Murray

Column #	1	2	3	4	5	6
Document Type:	**IR**	**IR**	**IR**	**IR**	**IR**	**IR**
Scenario Description:	ED-44 Resulting Base Case **42''**	ED44 Base Case with 75% Transportation Savings **42"**	ED44 Base Case with 50% Transportation Savings **42''**	ED44 Base Case with 0% Transportation Services Charges **42''**	ED44 Base Case with No Customer Additions **42"**	ED44 Base Case with 10% Increase in Capital Cost **42"**
Filed Date:	8/12/2013	8/12/2013	8/12/2013	8/12/2013	8/12/2013	8/12/2013
Reference:	ED-44	ED-44	ED-44	ED-44	ED-44	ED-44
Capital Investment						
Total Upfront Capital	$652,144,124	$652,144,124	$652,144,124	$652,144,124	$652,144,124	$717,358,537
Future Reinforcement Projects						
2017	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$0	$23,100,000
2018	$16,400,000	$16,400,000	$16,400,000	$16,400,000	$0	$18,040,000
2019	$13,000,000	$13,000,000	$13,000,000	$13,000,000	$0	$14,300,000
2020	$250,000	$250,000	$250,000	$250,000	$0	$275,000
Capital Maintenance Costs[1]	$5,230,240	$5,230,240	$5,230,240	$5,230,240	$5,230,240	$5,753,264
Services[2]	$379,533,696	$379,533,696	$379,533,696	$379,533,696	$0	$417,487,066
Total Capital	$1,087,558,060	$1,087,558,060	$1,087,558,060	$1,087,558,060	$657,374,364	$1,196,313,866
Total Transportation Savings[3] (2015-2024)	$1,561,635,909	$1,171,226,931	$780,817,954	$1,561,635,909	$1,561,635,909	$1,561,635,909
Total Transportation Services Charge[4] (2015 - 2024)	$175,104,348	$175,104,348	$175,104,348	$0	$175,104,348	$192,392,044
Total Distribution Revenues[1]	$4,546,724,222	$4,546,724,222	$4,546,724,222	$4,546,724,222	$0	$4,546,724,222
Total Customer Additions (2015 - 2024)	146,337	146,337	146,337	146,337	-	146,337
Total Volumes (10^3m^3)	24,709,032	24,709,032	24,709,032	24,709,032	-	24,709,032
SUMMARY OF RESULTS						
Net Present Value (40 years)	$534,351,214	$336,622,917	$138,894,620	$445,281,250	$316,735,228	$460,933,849
Variance to ED.44 Base Case NPV (40 years)		($197,728,297)	($395,456,594)	($89,069,964)	($217,615,985)	($73,417,365)
Profitability Index (40 years)	1.59	1.37	1.15	1.49	1.52	1.46

NOTES:

[1]Total for the 40 year horizon of analysis.
[2]Services include the costs for distribution mains, services and meters based on the 2013 capital budget.
[3]Total transportation savings are equal to expected gas supply benefits and incorporate the total cost of landing gas in the Enbridge franchise area including costs associated with tolls, fuel and commodity procurement (i.e. basis differentials) Prepared with TransCanada tolls based on the NEB's Toll Order TG-006-2013 (issued June 11, 2013) which made TransCanada's Compliance Filing tolls final and effective July 1, 2013
[4]Transportation Services Charges to be received from contracted shippers for transportation from Parkway West to Albion. (Current Base Case)

Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2012-0433
EB-2012-0451
EB-2013-0074

VOLUME: 9

DATE: October 10, 2013

BEFORE:	Cynthia Chaplin	Presiding Member and Vice-Chair
	Marika Hare	Member
	Peter Noonan	Member

I N D E X   O F   P R O C E E D I N G S

I N D E X O F P R O C E E D I N G S

MR. MONDROW: Thank you.

And I think Mr. Brett attempted and fairly did characterization the RH-003-2011 decision of the NEB and the extent to which your agreement effectively rewrites it. And I think you agreed with that.

And you would agree, I hope, that that decision was a major, perhaps unprecedented decision?

MR. CLARK: I would agree with that.

MR. MONDROW: Thanks. I want to follow up on another matter, Mr. Clark, that you spoke about yesterday with Mr. Elson. And as I listened to your discussion and read the transcript, Mr. Elson confirmed with you in reference to your earlier prefiled evidence that prior to the settlement agreement, the situation that we were in regarding these projects was that -- according to TransCanada and your prefiled evidence -- was that the shift from long-haul to short-haul sought by your eastern shippers would result in a revenue shortfall to TransCanada, and ultimately recovery of that revenue shortfall by TransCanada would increase tolls and render the projects uneconomic. And this was before the settlement agreement. And you agreed with that.

Would you accept that characterization of your evidence?

MR. SCHULTZ: I think, in principle, that's correct. Prior to the settlement, that was our position. I'm not sure I can agree with the precise words you used. I just --

MR. MONDROW: Well, that's fine. In principle is fine. Thank you.

And then you were anxious to move to the post-settlement world with Mr. Elson, and you did eventually do that. And I'm not sure I quite caught the nuance.

Mr. Elson did confirm with you that now, with the settlement, the revenues that TCPL would otherwise lose as a result of the same shift from long-haul to short-haul will be recovered. And I'm not sure I understand why the projects are now not uneconomic if they were uneconomic before.

MR. CLARK: Let's go step by step here.

I think the discussion I had yesterday noted that on the near term, the consequence of a shift from long-haul to short-haul would be addressed by virtue of the settlement.

Post-2020, that's not so clear, whether we would be able to recover the costs of a shift from long-haul to short-haul, particularly on the Prairies and the NOL, because now with the settlement or the certainty of recovery of those costs -- well, our ability to recover those costs from Eastern Triangle shippers is -- has been truncated.

I think without the settlement, we would still be making the arguments that our shippers overall have the responsibility for -- responsibility for provision of a reasonable opportunity to recover our prudently incurred costs. Just rolls off your tongue, doesn't it?

So what we've done with the settlement, we've given the markets certainty that they will no longer have accountability for those costs to the extent they do not use the Prairies and NOL.

So I think the point I'm trying to make is in the near term we have addressed our concerns about the shift from long-haul to short-haul. Over the longer term, though, those issues are still there. In fact, the -- part of the value that the settlement brings to the Eastern Triangle is that it's clear that markets there will no longer have accountability for those costs post-2020.

MS. GIRDHAR: Maybe I have to –

MR. CLARK: So –- sorry. We're at an impasse here.

[Laughter]

MS. GIRIDHAR: I wasn't sure if you had finished, but I was going to jump in with a really quick comment. Thank you.

Again, without repeating anything that was said in the past, I just want to direct you to a couple of things, Mr. Mondrow.

One is our undertaking response, J6.X, that factors in the implications of the settlement agreement in terms of the impact on our gas supply portfolio in the context of the savings that the project brings around, and access to the EDA. And you will see under a range of scenario the project is economic.

I just do want to also point out this undertaking response very comprehensively addresses clause number 14 of the amendment to the EBO-134, that we take into account explicitly the impact on transmission systems of facilities that are planned in Ontario.

So for all of those reasons, I would suggest that we have provided on the record evidence that the combination of the term sheet does preserve the economics of the GTA project.

MR. SCHULTZ: Mr. Mondrow, what I was going to just wrap with was when I talked to Mr. Elson yesterday, we were discussing whether the settlement reduces costs, and my position is that it does, because we've reduced our return on equity as well as made the contribution of $20 million a year for a period of six years.

So we had a little go-round this morning about a zero sum game, and I think Ms. Giridhar had described this as a gain because there is a reduction in the overall costs of the system that is delivered with the settlement.

We can go back and forth about, Gee, what does the analysis look like? To really do that, you have to some have certainty about what would have been the world in the absence of the settlement, and I think we've talked about we really don't know what that would -- where we would have been, say, post-2017 when things like the TSA and the long-term adjustment account was dealt with.

MR. MONDROW: Let me see if I understand this.

Prior to the settlement agreement, you acknowledged yesterday, the recovery of TransCanada's revenue loss from the shift from long-haul to short-haul would result in the projects being uneconomic.

Now there's a settlement agreement. Is it

TransCanada's position that the projects that -- that the settlement agreement provides for recovery of those lost revenues resulting from the shift long-haul to short-haul? Same revenue loss?

I understand your position as you've just stated it to be: Because we're contributing 20 million a year and dropping our ROE from 11 and a half to 10.1, the projects are no longer uneconomic as a result of our revenue loss recovery; is that your evidence?

MR. CLARK: I can't comment on the economics of the projects. I'll leave that to the LDCs to --

MR. MONDROW: Well, sorry, you commented on it before. You said they would be uneconomic.

MR. CLARK: I agree.

MR. MONDROW: And are they economic now in light of the settlement agreement?

[Witness panel confers]

MR. CLARK: Mr. Mondrow, I'm not sure we actually said the projects were uneconomic. The discussion yesterday took us through the analysis that we had filed in our supplemental evidence. And we said, given the circumstances prior to the settlement, we felt that was a reasonable --

MR. MONDROW: Mr. Clark, I don't have the time for going back and forth. Your evidence said, and I quote -- and you talked about this yesterday:

"The savings that Enbridge and Union and Gaz Métro hope to realize with lower transportation costs will evaporate, and Ontario consumers will have paid for more expensive Dawn-sourced gas to no benefit, resulting in a net loss."

Is that no longer the case?

[Witness panel confers]

MR. CLARK: Mr. Mondrow, the reason we were struggling here is I thought you attributed that as a quote to me.

MR. MONDROW: That was a quote in your evidence.

MR. CLARK: That's where we were getting crossed up, because I thought you had characterized those as my words.

MR. MONDROW: Sorry about that. That's what your evidence said. Was that true at the time? I think you acknowledged yesterday that you felt it was.

And I think you also said that it's no longer true because of the settlement agreement, and I'm trying to confirm what is it about the settlement agreement that makes that no longer true. Is it the $20 million and the ROE decrease? Are those the two factors we should pay heed to?

[Witness panel confers]

MR. SCHULTZ: So I think the issue is, is that we haven't -- and I think we did talk about this yesterday -- is that we have not rerun the analysis. TransCanada hasn't. Malini mentioned that Enbridge has looked at it from their own perspective, but ultimately the analysis that we did do, I think we commented that it was a marginal analysis looking specifically at those contracts and the revenues attributed to those contracts. It wasn't a comprehensive analysis that looked at the full implications of all of our revenues and costs, the changes to the costs being part of the equation, but I think there's redistribution, the allocation of revenues, who's paying for which of the increased toll charges, what percentage are being borne by which constituents, which customers of TransCanada.

So I think the perspective has changed, and I don't think it's -- the ability to sort of just do it quick, is this still true -- I think we commented yesterday that we felt things have changed and that the net result of doing the settlement is positive overall, compared to what it was previously.

MR. MONDROW: Mr. Schultz, you said three things. You said the costs being, I assume, the 20 million per year for six years, and the ROE decrease. That's what I pointed out to you a minute ago. And the third thing you said, although you said it in at least three ways, is a reallocation of the burden, and I'm using the word "burden". You didn't.

Are those the three things that make these projects now economic when they weren't before, or were you simply wrong before? It's okay. I just need to know. Has something changed or not? And if so, what is it?

MR. SCHULTZ: I think I was also saying that we haven't rerun the analysis to establish what we would call the economic threshold, and that that has been done by the LDCs.

MR. MONDROW: Okay. So you were right before and you're not sure now. Is that what you're telling me?

MR. SCHULTZ: Well, I think that's probably fair. We said that things have changed. We haven't rerun this analysis, so we don't know what the actual result would be.

MR. MONDROW: Okay. So you were right before, and you're not sure now?

MR. SCHULTZ: Yes. Yes.

MR. MONDROW: Thank you.

Now, Enbridge, Union, Ms. Giridhar, you're not seeking any approval or endorsements from this Board for the settlement agreement or for the delivery rate impacts resulting from the tolls that fall out of the settlement agreement; is that right, Mr. Isherwood? Ms. Giridhar?

MR. ISHERWOOD: That's correct.

MR. MONDROW: And you'll agree that on behalf of your customers you've each assumed -- you've each agreed to assume significant costs of under-utilized TransCanada capacity through this settlement agreement.

MR. ISHERWOOD: I disagree with that statement, actually. There's an increase in cost on the short-haul for sure, the 50 percent we've talked about. As I mentioned earlier this morning, two-thirds of that is just to recover the costs of service in Eastern Triangle, which I think is a cost we need to always assume that we have that cost anyways. The incremental costs we're really talking about today is the one-third part of that increase --

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November 7, 2013

VIA COURIER, EMAIL and RESS

Ms. Kirsten Walli
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Re: Enbridge Gas Distribution Inc. ("Enbridge")
EB-2012-0451 - Greater Toronto Area ("GTA") LTC Project
Updated Undertaking Responses

In accordance with the Ontario Energy Board's (the "Board") Procedural Order No. 13, enclosed please find the updated undertaking responses for J6.X and J9.1.

Information in relation to the LTAA will be filed by Union Gas Limited on behalf of the applicants.

The submission is being filed through the Ontario Energy Board's Regulatory Electronic Submission System and all of the GTA evidence can be found on Enbridge's website at www.enbridgegas.com/gtaproject.

Please contact me if you have any questions.

Yours truly,

[original signed]

Shari Lynn Spratt
Supervisor Regulatory Proceedings

Encl.

cc: EB-2012-0451, EB-2012-0433, and EB-2013-0074 Interested Parties

UNDERTAKING J6.X

UNDERTAKING

On Hearing Day 2 (September 13, 2013)[1] and Hearing Day 3 (September 16, 2013)[2], the Joint Panel committed to provide an indicative impact of the Settlement Term Sheet with TransCanada. On Hearing Day 4 (September 17, 2013)[3], Union committed to provide the impact through Undertaking J4.5 and Enbridge committed to respond to the same request on Hearing Day 6 (September 26, 2013)[4], however no separate undertaking number was assigned. The following response is provided on behalf of Enbridge.

This is an update to the October 10, 2013 undertaking and is based on information from the Settlement Agreement filed on October 31, 2013.

RESPONSE

This response provides the impact of the Settlement Agreement with TransCanada. Impacts of the Settlement Agreement include an increase in transportation costs as a result of higher TransCanada tolls and a decrease in transportation costs as a result of access to short haul transport to the Enbridge EDA, made possible as a result of the Settlement Agreement.

The toll impacts of the Settlement Agreement provided by TransCanada are a 55% increase in short haul tolls to the Enbridge Franchise and a 19% increase in long haul tolls to the Enbridge Franchise. The tolls contained in the Settlement Agreement are within the ranges Enbridge provided in its original response to J6.X.

The impact on tolls stemming from the Settlement Agreement relative to compliance tolls and the tolls provided in the original response to J6.X for transportation service utilized by Enbridge are as follows:

[1] Refer to Hearing Day 2 (September 13, 2013) transcript at page 120, line 28 to page 121, line 7.
[2] Refer to Hearing Day 3 (September 16, 2013) transcript at page 127, lines 4 to 16.
[3] Refer to Hearing Day 4 (September 17, 2013) transcript at page 54, line 22 to page 55, line 21.
[4] Refer to Hearing Day 6 (September 26, 2013) transcript at page 63, lines 10 to 17.

Witnesses: J. Denomy
M. Giridhar

$/GJ	Compliance Filing Toll	13% Increase in Long Haul & 45% Increase in Short Haul	20% Increase in Long Haul & 55% Increase in Short Haul	Settlement Agreement Toll
Empress to Enbridge CDA	1.57	1.77	1.88	1.86
Empress to Enbridge EDA	1.62	1.83	1.94	1.92
Dawn to Enbridge CDA	0.24	0.34	0.37	0.37
Dawn to Enbridge EDA	0.44	0.63	0.68	0.68
Dawn to Iroquois	0.42	0.61	0.65	0.65
Parkway to Enbridge CDA	0.12	0.18	0.19	0.20
STS to Enbridge CDA	0.12	0.18	0.19	0.20
STS to Enbridge EDA	0.32	0.47	0.50	0.50
Parkway to Enbridge CDA SN	0.13	0.19	0.20	0.20

The annual increase in gas costs resulting from the Settlement Agreement tolls provided above relative to the compliance tolls and using the October 2013 QRAM gas supply portfolio is approximately $66.4 million. This calculation is provided in the table below. The bridging contribution accounts for approximately 1/3rd of the impact on gas costs with the remaining impact accounting for cost recovery of the Eastern Ontario Triangle.

$ Millions	Total TCPL Transportation Costs October 2013 QRAM	Total TCPL Transportation Costs Settlement Agreement Tolls
	234.7	301.0
Difference Relative to October 2013 QRAM		66.4

The average annual decrease in gas supply costs resulting from the ability to displace 170,000 GJ/d of long haul transport to the Enbridge EDA with short haul transport in 2016 is estimated to be approximately $49 million per year. This expected benefit was calculated using TCPL Compliance Filing Tolls, an average Empress to Dawn basis differential of $0.51 /GJ and 100% utilization of long haul capacity.

The table below shows the annual average expected gas supply benefits for Enbridge's ratepayers arising from the GTA Project over the 2015 to 2025 timeframe for a range of basis and utilization scenarios.

Witnesses: J. Denomy
M. Giridhar

Annual Average GTA Project Benefits Calculations for Current Base Case - Basis and Utilization Scenarios @ Compliance Filing Tolls - 2015-2025

$ Millions		Average Empress-Dawn Basis = 0.51 $/GJ	Average Empress-Dawn Basis = 0.92 $/GJ	Average Empress-Dawn Basis = 1.50 $/GJ
Enbridge CDA				
Long Haul Load Factor = 100% (January to December)	System Gas	109	62	(2)
	Direct Purchase	64	39	5
	Total	173	101	3
Long Haul Load Factor = 42% (November to March)	System Gas	138	119	92
	Direct Purchase	64	39	5
	Total	202	158	96
Long Haul Load Factor = 25% (December to February)	System Gas	145	134	118
	Direct Purchase	64	39	5
	Total	210	173	122
Enbridge EDA				
Long Haul Load Factor = 100% (January to December)	System Gas	49	21	(15)
Long Haul Load Factor = 42% (November to March)	System Gas	65	53	38
Long Haul Load Factor = 25% (December to February)	System Gas	69	62	53
Grand Total				
Long Haul Load Factor = 100% (January to December)		222	122	(12)
Long Haul Load Factor = 42% (November to March)		267	211	134
Long Haul Load Factor = 25% (December to February)		279	235	175

Enbridge has not updated the benefits resulting from the GTA Project using the tolls provided in the Settlement Agreement. With other assumptions held constant, the expected gas supply benefits using the tolls in the Settlement Agreement would be higher. However, the reason why Enbridge has not updated the benefits using tolls in the Settlement Agreement is because, while the unit increase in long haul tolls is higher than the unit increase in short haul tolls, these increases are based on a six year surcharge recovery for long haul vs. a sixteen year surcharge recovery for short haul. Over the term of the Settlement Agreement the differential in tolls is expected to be approximately the same as the differential in compliance tolls.

The combined benefits of the GTA Project and the Settlement Agreement are substantial and far exceed the increase in short haul and long haul tolls resulting from the Settlement Agreement under all but the scenario where Enbridge uses all its contracts at a 100% load factor and the basis differential between Alberta and Dawn is $1.50 or more.

As noted in evidence, 100% utilization is an unrealistic assumption given that Enbridge operates its distribution system at approximately 30% utilization factor. In addition, Enbridge has not included upstream arrangements necessary to meet growth in peak demand. The absence of short haul supply will result in ever decreasing utilization of long haul transport increments resulting in a transfer of wealth from Enbridge rate payers to other shippers on the TransCanada system. Enbridge has or is in the process of firming up approximately 360 TJ/d of long haul transport in lieu of previously contracted STFT for 2014. Enbridge would note that while the determination of final

Witnesses: J. Denomy
M. Giridhar

Mainline tolls were based on an average throughput from Alberta they did not explicitly incorporate firming up of Enbridge's 2013 peak day demand or growth in Enbridge's peak day demand over time.

Finally, the basis differentials reflected in the table do not reflect changes in Marcellus basis relative to Alberta. Enbridge notes that at TGP Zone 4 Marcellus, a trading point in the Marcellus formation, gas is currently trading at approximately $2.60 /GJ, a discount of approximately $0.60 /GJ relative to AECO in Alberta. Enbridge's analysis has assumed that Marcellus basis would trade above Alberta basis. In addition, Enbridge would note that current basis differential between AECO and Dawn is approximately $0.45 /GJ.

Witnesses: J. Denomy
M. Giridhar

UNDERTAKING J9.1

UNDERTAKING

TR 9, page 43

EGD to provide the expected annual total bill impact for charges by rate class that flow from applications and the settlement agreement.

RESPONSE

The Company has determined that the impact on its gas costs stemming from the Settlement Agreement[1] will be $66.4 million relative to its October 1, 2013 gas costs[2]. The original undertaking response was based on the Settlement Agreement term sheet which estimated the impact on its gas costs to be approximately $60 million. The bill impacts are relative to the October 1, 2013 QRAM rates currently in effect.

Impact relative to October 1, 2013 QRAM

Rate Class	Total Bill Impact
1	2.3%
6	2.9%
9	2.0%
100	2.8%
110	2.9%
115	3.2%
135	3.2%
145	2.8%
170	3.4%
200	3.4%

The annual dollar impact for an average residential customer would be approximately $20. There is no impact on Unbundled rates 125 and 300.

[1] Settlement Agreement among TransCanada Pipelines Limited, Enbridge Gas Distribution Limited, Union Gas Limited and Gaz Métro Limited Partnership filed October 31 2013.
[2] Page 2 of Undertaking J6.X

Witness: A. Kacicnik

UNDERTAKING J4.10

UNDERTAKING

TR 4, page 140

To provide an update of the transportation savings based on the different price levels of 92 cents and $1.50.

RESPONSE

Please see the response to TCPL Interrogatory #2 at Exhibit I.A1.EGD(Update).TCPL.2 for the impact of both basis differential and the utilization of long haul capacity and lists assumptions. In the event that the GTA Project facilities are not approved and Enbridge must contract for increased amounts of firm long haul transportation, including firming up the entire gas supply portfolio to eliminate all use of peaking and discretionary supply in the CDA and EDA, Enbridge will have to flow these contracts at a load factor significantly below 100% in order to match annual demand.

The discounting shown below is consistent with the discounting used in Exhibit E, Tab 1, Schedule 1, Attachment, Pages 2-5.

			Forecast Total Transportation Savings up to 2025 ($ millions, or $MM)
1)	Average Empress-Dawn Basis	$0.51	$1,733
	Present Value		$1,163
2)	Average Empress-Dawn Basis	$0.92	$1,010
	Present Value		$682
3)	Average Empress-Dawn Basis	$1.50	$31
	Present Value		$24

Notes
Assumes Long Haul Load Factor = 100% (January to December)

Witness: J. Denomy

Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2012-0433**
EB 2012-0451
EB-2013-0074

VOLUME: **Technical Conference**

DATE: **June 12, 2013**

I N D E X   O F   P R O C E E D I N G S

increment. As a matter of fact, it is an order of magnitude lower. Our estimation of efficiency gains in those types of activities would be smaller than that.

So once that there is that large of a decrement in terms of looking at it, we chose to go no further.

MR. POCH: So you didn't actually conduct an analysis of possible load reductions beyond even offsetting load growth? You concluded that it was simply -- the scale of it suggested to you it was not feasible?

MR. FERNANDES: The question referred to the pressure reduction, and given that it's well beyond an order of magnitude away from what we thought was reasonable, we conducted no further study on that.

MR. POCH: I took it from your answer a minute ago that what you thought was reasonable was, at most, offsetting load growth; correct?

MR. FERNANDES: No, what I stated was that our load growth was almost an order of magnitude lower and we felt efficiency gains would account for some fraction of that.

MR. POCH: Did you study that specifically? Is there a study specifically looking at intensive load reduction DSM and related efforts in the particular target area?

MR. FERNANDES: I think I'll have to defer that to my counterpart on the DSM panel.

MR. POCH: Okay. Just on that, I am correct that these pipes have been running at the higher pressure -- I think it's 37 percent as opposed to 30 percent -- that you are now proposing?

MR. FERNANDES: Correct. The pipes were constructed in 1967 and 1971, and they have operated over 30 percent since that time.

MR. POCH: Right. That, I believe, is in the record. Do we know at what -- in fact, what percent pressure they have been running? Has it been consistent throughout at the 37, or has it fluctuated?

MR. THALASSINOS: So I'll refer to Interrogatory Response -– and just give me a sec here to find that.

So BOMA Interrogatory No. 8. Okay. So, sorry, which line were you specifically referring to?

MR. POCH: Well, in this case, we were talking about the Don Valley pipelines, NPS 26 and 30.

I was referring to the fact that you've indicated that, while you're targeting the 30 percent SMYS, they're currently at 37 percent and they have been over 30 percent throughout their life. I was just asking if they have been at 37 percent throughout their life, or has it changed over time.

MR. THALASSINOS: The percent of SMYS on that line has changed over time. I actually have to refer to a different interrogatory; I think I've referenced the wrong one. Just give me a moment, please.

Yes, so the Don Valley pipeline has been operating at different pressures over the years. The operating pressures can change over time, which is different than the maximum operating pressure. Those operating pressures can change due to things such as movement of gas, moving of gas supplies from one part of the network to another. And we also periodically change our operating pressures when we're running internal inspection pigs, when we're doing major work, and also sometimes when we have temporary restrictions when we find integrity issues on our pipelines.

MR. POCH: Obviously at times, you lower the pressure because you are doing work or you have concerns. Have they ever run at higher than 37 percent?

MR. THALASSINOS: For this particular line, my understanding, it's been operating only up to 37 percent.

MR. POCH: And the other lines that you're trying to lower the pressure on in this application?

MR. THALASSINOS: Just in --

MR. POCH: Perhaps there's an interrogatory that spells this out I've missed. Please direct me it to if there is.

MR. THALASSINOS: Hold on. So I'll refer to GEC Interrogatory 8(e).

MR. POCH: Yes, I have that in front of me.

MR. THALASSINOS: So the pressures on the –– as you see here, the pressure on the NPS 26 was lowered in 2005 due to the class location, and -- from a class 3 to a class 4. That, of course –– and you can see the percent of SMYS reduction that was caused by that.

MR. POCH: That's the 49.6 going to 39.8?

MR. THALASSINOS: That's correct, yes.

So when we did a class location study in 2005, we

ENVIRONMENTAL DEFENSE INTERROGATORY #6

INTERROGATORY

Issue 1: "Is the 2014 DSM Budget ($32.2M) reasonable and appropriate? Should the Board determine that the DSM budget for 2014 should be increased, what are the implications and required next steps."

Interrogatory No. 1-ED-6 DSM Benefits: Protection from Energy Price Fluctuations, etc.

Reference: Ex. B, Tab 1, Schedule 2, page 3

A report by the Canadian Council of Chief Executives concluded as follows:

> Fundamentally, however, Canada needs to begin with a renewed commitment to energy conservation. We must use existing and future energy supplies as efficiently as possible, embracing the maxim that the cheapest form of energy is the unit that is not used. Better conservation practices will help to insulate Canadians from volatile energy prices, reduce costs for public institutions such as hospitals, and improve the international competitiveness of Canadian companies.

...

> The bottom line is that governments must resist the temptation to shield Canadians from higher energy prices. By any reasonable measure, energy remains a comparative bargain for Canadians.[1]

The relevant excerpts are attached for your reference.

a) Does Enbridge agree with the Council of Chief Executives that "[b]etter conservation practices will help to insulate Canadians from volatile energy prices, reduce costs for public institutions such as hospitals, and improve the international competitiveness of Canadian companies"? If no, why not?

b) Please explain how better conservation practices will help to insulate Canadians from volatile energy prices.

---

[1] Canadian Council of Chief Executives, *Energy- Wise Canada, Building a Culture of Energy Conservation*, December 2011, http://www.ceocouncil.ca/wp-content/uploads/2011/12/Energy-Conservation-Paper-FINAL-December-20111.pdf, pp. 2 & 4.

c) Please explain how better conservation practices will improve the international competitiveness of Canadian companies.

d) Is the protection from volatile energy prices resulting from conservation given a dollar value and factored into the TRC analysis for DSM programs?

RESPONSE

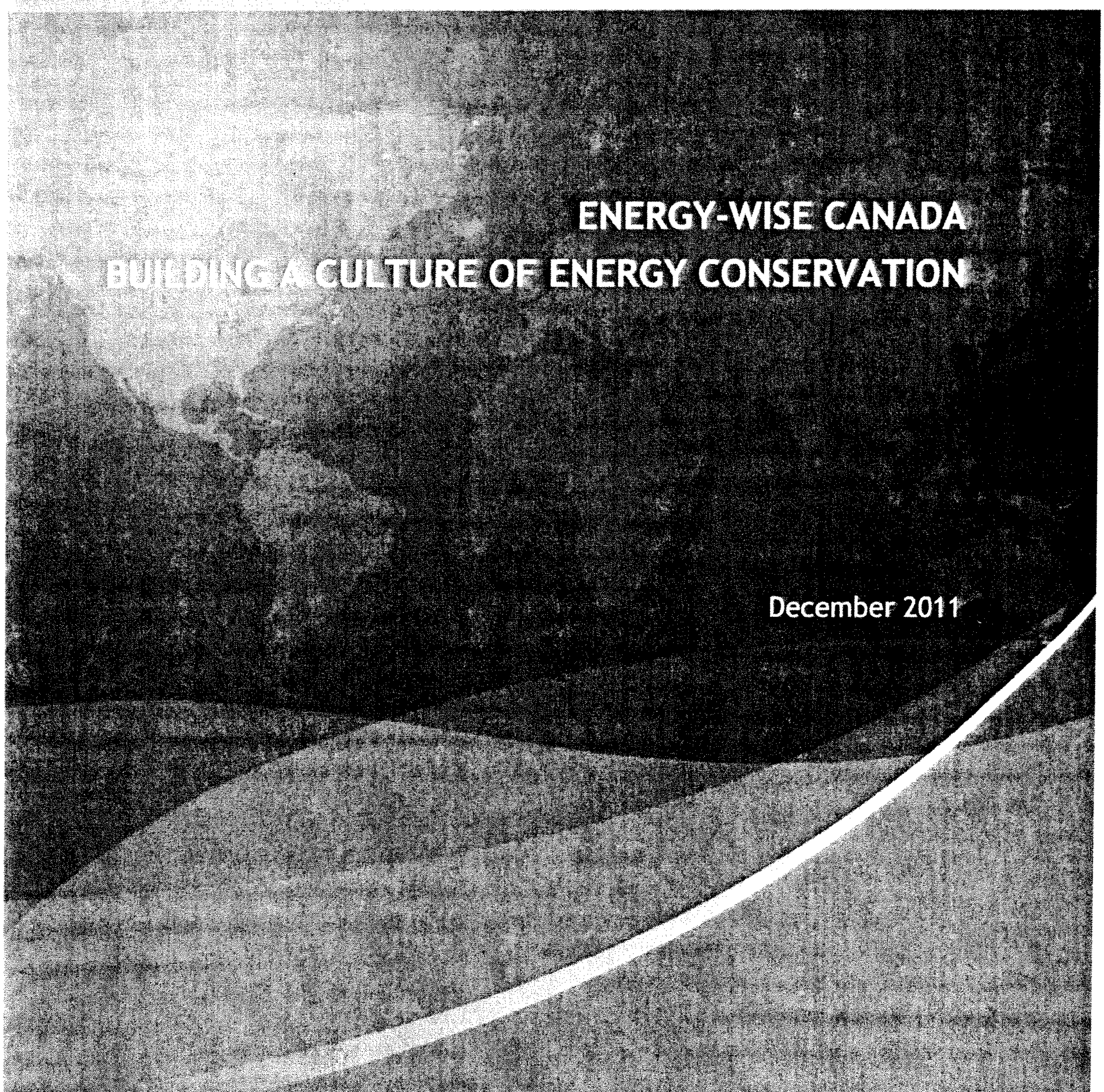
a), b), c) & d)

Enbridge generally accepts that a sustained focus on energy efficiency assists with the long-term environmental sustainability and economic competitiveness of the Province. While energy efficiency helps customers lower their overall energy usage which in turn reduces one input cost for businesses, it does not directly address energy price volatility. Price volatility is outside the scope of conservation programming. Customers wishing to insulate themselves from price volatility could do so through fixed price commodity contracts.

Schedule A to Interrogatory No. 1-ED-6

CANADIAN COUNCIL of **CHIEF EXECUTIVES**

CONSEIL CANADIEN des **CHEFS D'ENTREPRIS**



ENERGY-WISE CANADA
BUILDING A CULTURE OF ENERGY CONSERVATION
Canadian Council of Chief Executives
December, 2011

Executive Summary

A key driver of Canada's future prosperity, and a source of comparative advantage for the country, is our diverse array of energy resources. By combining smart government policy with private sector commitment and innovation, Canada can demonstrate to the world that it can be a reliable and environmentally responsible energy supplier and partner.

In previous papers, the Canadian Council of Chief Executives has advocated a multi-pronged strategy, aimed at bringing on a larger and varied supply of energy to meet growing domestic and international demand. This includes investing in advanced energy technologies that can create new business and employment opportunities and position Canada to compete successfully in a world of rising energy prices.

Fundamentally, however, Canada needs to begin with a renewed commitment to energy conservation. We must use existing and future energy supplies as efficiently as possible, embracing the maxim that the cheapest form of energy is the unit that is not used. Better conservation practices will help to insulate Canadians from volatile energy prices, reduce costs for public institutions such as schools and hospitals, and improve the international competitiveness of Canadian companies.

Cutting our energy use would bring other benefits to society as well. Reduced use of carbon-based fuels would make urban air more breathable. Smart transportation choices would diminish traffic congestion and improve workplace productivity. And better urban design would make cities more livable and help Canadians achieve a better work-life balance.

Few of us deliberately waste energy. Yet the choices we make cause energy waste that cascades through the system. For instance, because of inefficiencies and losses at nearly every stage in production, transmission and end use, the amount of energy actually delivered to a light bulb in our home or to a fuel tank in our car is usually at least 50 percent, and sometimes as much as 90 percent, less than the energy content at source.

There are some signs of progress in our quest for energy efficiency. The overall energy intensity of our economy – the amount of energy consumed per unit of GDP – improved 22 percent between 1990 and 2008. The manufacturing sector overall used 8 percent less energy and produced 25 percent more output in 2008 compared to 1995. In the agriculture sector, energy intensity has declined steadily over the past 20 years. Some municipal governments are ahead of the curve and are embracing sustainability in urban design and transportation planning. And programs such as LEED (Leadership in Energy and Environmental Design) are re-defining how new commercial and public buildings are designed for overall energy and environmental coherence.

In too many instances, however, such gains are outweighed by trends toward greater energy consumption. New building codes and better construction materials are helping to make Canadian homes more energy-efficient, yet the number of houses continues to grow with immigration and shifting demographics. Moreover, the average size of a house is larger and the percentage of homes with air conditioning has doubled since 1990, to 45 percent. Today's televisions and computers are more efficient than those manufactured as recently as five years ago, but many homes now have more than one of each, operating for many more hours. Vehicle fuel efficiency is set to increase significantly with the new North American standards recently announced, but overall passenger-kilometres travelled continues to increase. As well, there has been a significant shift to trucks as the mode of choice for freight transportation and to airlines for passenger travel.

This paper analyzes energy consumption trends and conservation initiatives in each of the major segments of Canadian society: industry, residential, commercial and institutional, transportation, municipalities and agriculture. Needless to say, there is scope for significant improvement in all of these areas.

A review of these trends leads us to two main conclusions. First, governments, industry and public-spirited groups should work together to improve Canadians' energy literacy. We do not underestimate the challenge of changing consumers' behaviour. After all, governments have been preaching the merits of energy conservation and efficiency since the first oil-price shocks of the mid-1970s, with limited success. Nevertheless, Canadians need to understand the energy choices that the country faces so that they can make informed decisions based on realistic assessments of their respective costs and benefits.

A second, closely related, conclusion is that the most effective means of promoting energy conservation is to allow energy prices to rise. It seems clear that higher prices will influence Canadians' behaviour in a way that public exhortation and appeals to the greater good have not. That is why the CCCE has previously stated its support for a broad-based carbon pricing scheme in Canada. Canadians – as business owners, farmers, building managers and individual consumers – need to see the everyday cost of inefficient use of energy and be motivated to change their energy consumption patterns and investment decisions. To be sure, carbon pricing would have to be introduced gradually, both to allow businesses and consumers time to adjust and to avoid any disproportionate impact on Canada's competitive position. (For Canadians on fixed incomes, the impact could be offset through other social or fiscal policies.)

The bottom line is that governments must resist the temptation to shield Canadians from higher energy prices. By any reasonable measure, energy remains a comparative bargain for Canadians. Electricity in particular is cheaper today on an inflation-adjusted basis than it was 20 years ago. In most provinces the regulated electricity rates paid by households and some industries do not even cover the cost of producing and delivering it, but ultimately these costs will have to be recouped through the broader tax base.

Canada's vast array of natural resources, our growing population, our climate and geography push us towards above-average energy consumption. But the present trend is unsustainable. It is time for Canadians to get serious about energy conservation, for the health of our economy as well as the environment.

ENVIRONMENTAL DEFENSE INTERROGATORY #7

INTERROGATORY

Issue 1: "Is the 2014 DSM Budget ($32.2M) reasonable and appropriate? Should the Board determine that the DSM budget for 2014 should be increased, what are the implications and required next steps."

Interrogatory No. 1-ED-7 DSM Benefits: Increased Productivity, GDP, etc.

Reference: Ex. B, Tab 1, Schedule 2, page 3

In 2011, the former Governor of the Bank of Canada, Mark Carney, gave a speech to the Empire and Canadian Clubs and stated that:

> In a world where deleveraging holds back demand in our traditional foreign markets, the imperative is for Canadian companies to invest in improving their productivity and to access fast-growing emerging markets.
>
> This would be good for Canadian companies and good for Canada. Indeed, it is the only sustainable option available. A virtuous circle of increased investment and increased productivity would increase the debt-carrying capacity of all, through higher wages, greater profits and higher government revenues. This should be our common focus.[1]

The relevant excerpts are attached for your reference.

A report by Dr. Ernie Stokes of the Centre for Spatial Economics, which quantifies the economic benefits of energy efficiency investments which reduce Ontario's natural gas consumption, found that a 16.1% reduction in Ontario's natural gas consumption in 2021 would increase Ontario's GDP by $5.5 billion, increase employment by 33,800 jobs, raise corporate profits by $446 million and reduce the provincial deficit by $479 million.[2] The relevant excerpts are attached for your reference.

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[1] Mark Carney, *Growth in the Age of Deleveraging, speech to Empire Club of Canada & Canadian Club of Toronto*, December 12, 2011, http://www.bankofcanada.ca/wp-content/uploads/2011/12/speech-121211.pdf, p. 11.

[2] Centre for Spatial Economics, *The Economic Impacts of Reducing Natural Gas Use in Ontario*, April 2011, http://www.cleanairalliance.org/files/cse.pdf, p. 7.

a) Does Enbridge agree with Mark Carney that Ontario would benefit if its industries increased their investment and productivity? Does Enbridge agree that this could lead to higher wages, profits, and government revenues?

b) When a business participates in one of Enbridge's resource acquisition DSM programs, is that an investment that increases productivity? Please explain.

c) Generally speaking, will Enbridge's DSM programs increase productivity and GDP? If not, why not?

d) Are the economy-wide benefits of conservation spending, such those resulting from increased productivity, given a dollar value and factored into the TRC analysis for DSM programs?

RESPONSE

a), b), c) & d)

Mark Carney's remarks that increased investment results in increased productivity appear reasonable. It is the understanding of the Company that pervasive economic theory does suggest that higher productivity may lead to higher wages, profits and government revenues. Enbridge believes that when a business participates in DSM programs and invests in energy efficiency upgrades, all other things being equal, it may see increases in productivity. While Enbridge cannot specifically predict the future impacts of DSM on overall productivity and GDP, it believes that DSM initiatives can be a factor in elevated productivity and thus, GDP. These productivity gains – which may be difficult if not impossible to predict with any certainty – are not factored into the TRC analysis for DSM programs.

Schedule A to Interrogatory No. 1-ED-7

BANK OF CANADA
BANQUE DU CANADA

Remarks by Mark Carney
Governor of the Bank of Canada
Empire Club of Canada / Canadian Club of Toronto
12 December 2011
Toronto, Ontario

Growth in the Age of Deleveraging

Introduction

These are trying times.

In our largest trading partner, households are undergoing a long process of balance-sheet repair. Partly as a consequence, American demand for Canadian exports is $30 billion lower than normal.

In Europe, a renewed crisis is underway. An increasing number of countries are being forced to pay unsustainable rates on their borrowings. With a vicious deleveraging process taking hold in its banking sector, the euro area is sinking into recession. Given ties of trade, finance and confidence, the rest of the world is beginning to feel the effects.

Most fundamentally, current events mark a rupture. Advanced economies have steadily increased leverage for decades. That era is now decisively over. The direction may be clear, but the magnitude and abruptness of the process are not. It could be long and orderly or it could be sharp and chaotic. How we manage it will do much to determine our relative prosperity.

This is my subject today: how Canada can grow in this environment of global deleveraging.

How We Got Here: The Debt Super Cycle

First, it is important to get a sense of the scale of the challenge.

Accumulating the mountain of debt now weighing on advanced economies has been the work of a generation. Across G-7 countries, total non-financial debt has doubled since 1980 to 300 per cent of GDP. Global public debt to global GDP is almost at 80 per cent, equivalent to levels that have historically been associated with widespread sovereign defaults.[1]

The debt super cycle has manifested itself in different ways in different countries. In Japan and Italy, for example, increases in government borrowing have led the way. In the United States and United Kingdom, increases in household debt have been more significant, at least until recently. For the most part, increases in non-financial corporate debt have been modest to negative over the past thirty years.

In general, the more that households and governments drive leverage, the less the productive capacity of the economy expands, and, the less sustainable the overall debt burden ultimately is.

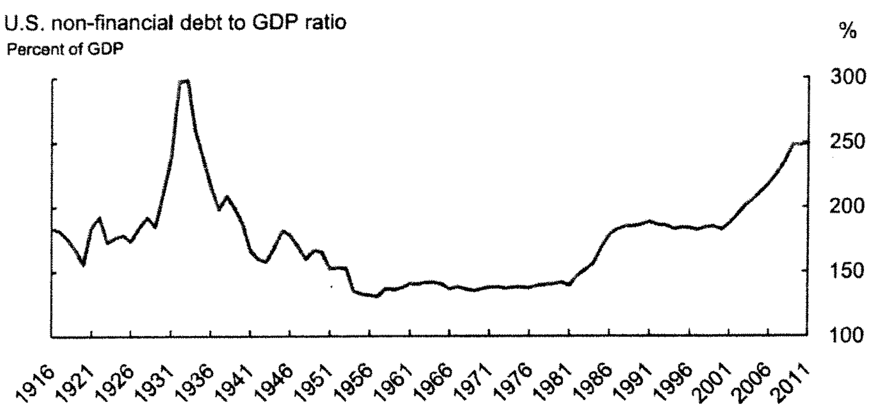
Not for publication before 12 December 2011
12:55 Eastern Time

Another general lesson is that excessive private debts usually end up in the public sector one way or another. Private defaults often mean public rescues of banking sectors; recessions fed by deleveraging usually prompt expansionary fiscal policies. This means that the public debt of most advanced economies can be expected to rise above the 90 per cent threshold historically associated with slower economic growth.[2]

The cases of Europe and the United States are instructive.

Today, American aggregate non-financial debt is at levels similar to those last seen in the midst of the Great Depression. At 250 per cent of GDP, that debt burden is equivalent to almost US$120,000 for every American (**Chart 1**).[3]

Chart 1: U.S. non-financial debt near levels of the Great Depression



Sources: U.S. Census Bureau data from 1916 to 1953, U.S. Flow of Funds data from 1954 to 2011, Bureau of Economic Analysis

Last observation: 2011Q3

Several factors drove a massive increase in American household leverage. Demographics have played a role, with the shape of the debt cycle tracking the progression of baby boomers through the workforce.

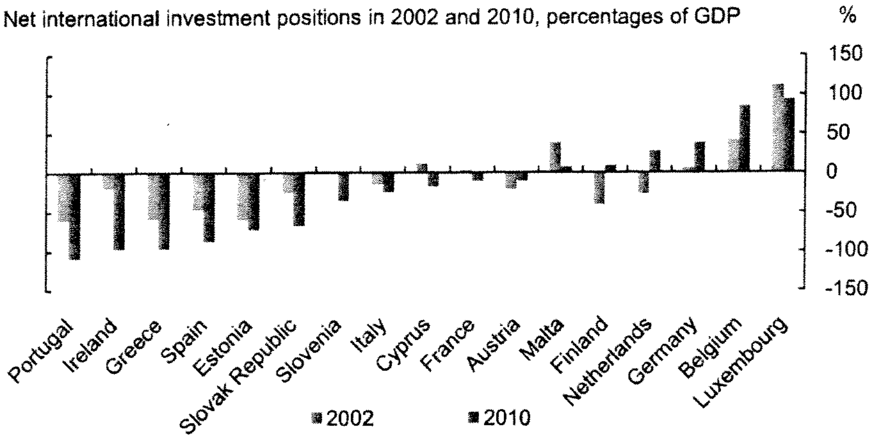
The stagnation of middle-class real wages (itself the product of technology and globalisation) meant households had to borrow if they wanted to maintain consumption growth.[4]

Financial innovation made it easier to do so. And the ready supply of foreign capital from the global savings glut made it cheaper.

Most importantly, complacency among individuals and institutions, fed by a long period of macroeconomic stability and rising asset prices, made this remorseless borrowing seem sensible.

From an aggregate perspective, the euro area's debt metrics do not look as daunting. Its aggregate public debt burden is lower than that of the United States and Japan. The euro area's current account with the rest of the world is roughly balanced, as it has been for some time. But these aggregate measures mask large internal imbalances. As so often with debt, distribution matters (**Chart 2**).

Chart 2: Euro-area imbalances have widened



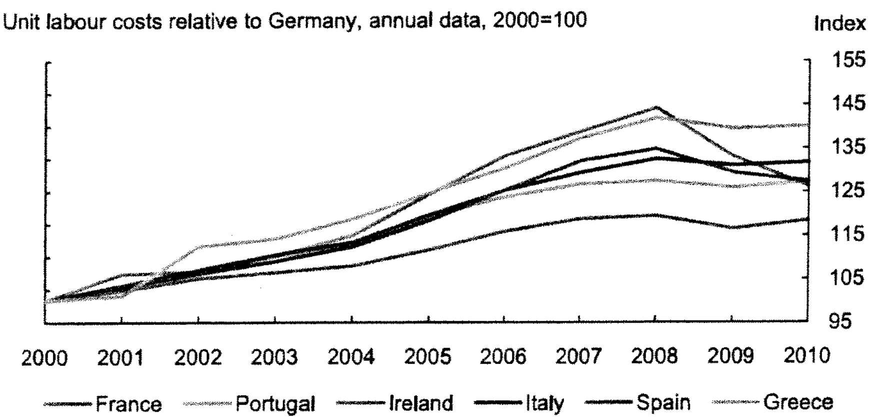
Sources: International Monetary Fund International Financial Statistics, International Monetary Fund World Economic Outlook

Last observation: 2010

Europe's problems are partly a product of the initial success of the single currency. After its launch, cross-border lending exploded. Easy money fed booms, which flattered government fiscal positions and supported bank balance sheets.

Over time, competitiveness eroded. Euro-wide price stability masked large differences in national inflation rates. Unit labour costs in peripheral countries shot up relative to the core economies, particularly Germany. The resulting deterioration in competitiveness has made the continuation of past trends unsustainable (**Chart 3**). Growth models across Europe must radically change.

Chart 3: Unit labour costs in peripheral countries up, relative to core



Sources: Deutsche Bundesbank, national statistics agencies

Last observation: 2010

It's the Balance of Payments, Stupid!

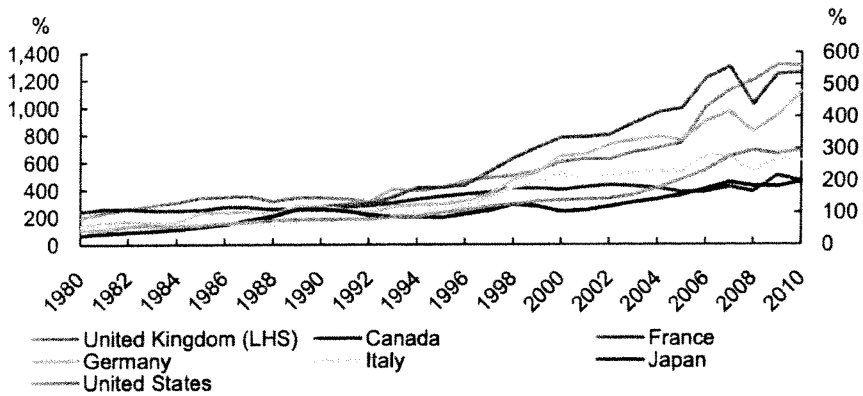
For years, central bankers have talked of surplus and deficit countries, of creditors and debtors. We were usually ignored. Indeed, during a boom, the debtor economy usually feels more vibrant and robust than its creditors. In an era of freely flowing capital, some even thought current account deficits did not matter, particularly if they were the product of private choices rather than public profligacy.

When the leverage cycle turns, the meaning and implications of these labels become tangible. Creditors examine more closely how their loans were spent. Foreign financing constraints suddenly bind. And to repay, debtors must quickly restore competitiveness.[5]

Financial globalisation has provided even greater scope for external imbalances to build (**Chart 4**). And its continuation could permit larger debt burdens to persist for longer than historically was the case. However, experience teaches that sustained large cross-border flows usually presage liquidity crunches.[6]

Chart 4: Capital flows have expanded rapidly

Gross foreign assets and liabilities as percentages of GDP, annual data



Source: International Monetary Fund International Financial Statistics, International Monetary Fund World Economic Outlook

Last observation: 2010

The Global Minsky Moment Has Arrived

Debt tolerance has decisively turned. The initially well-founded optimism that launched the decades-long credit boom has given way to a belated pessimism that seeks to reverse it.

Excesses of leverage are dangerous, in part because debt is a particularly inflexible form of financing. Unlike equity, it is unforgiving of miscalculations or shocks. It must be repaid on time and in full.

While debt can fuel asset bubbles, it endures long after they have popped. It has to be rolled over, although markets are not always there. It can be spun into webs within the financial sector, to be unravelled during panics by their thinnest threads. In short, the central relationship between debt and financial stability means that too much of the former can result abruptly in too little of the latter.

Hard experience has made it clear that financial markets are inherently subject to cycles of boom and bust and cannot always be relied upon to get debt levels right.[7] This is part of the rationale for micro- and macroprudential regulation.

It follows that backsliding on financial reform is not a solution to current problems. The challenge for the crisis economies is the paucity of credit demand rather than the scarcity of its supply. Relaxing prudential regulations would run the risk of maintaining dangerously high leverage—the situation that got us into this mess in the first place.

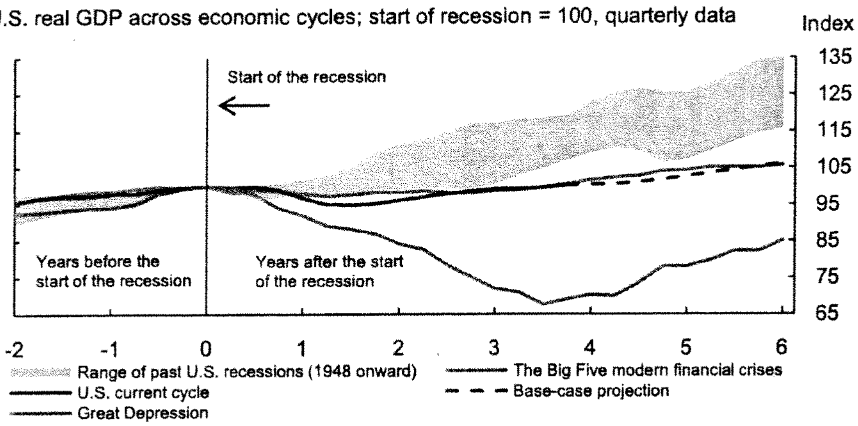
The Implications of Deleveraging

As a result of deleveraging, the global economy risks entering a prolonged period of deficient demand. If mishandled, it could lead to debt deflation and disorderly defaults, potentially triggering large transfers of wealth and social unrest.

History suggests that recessions involving financial crises tend to be deeper and have recoveries that take twice as long.[8] The current U.S. recovery is proving no exception (**Chart 5**). Indeed, it is only with justified comparisons to the Great Depression that the success of the U.S. policy response is apparent.

Chart 5: Weakest U.S. recovery since Great Depression

U.S. real GDP across economic cycles; start of recession = 100, quarterly data



Note: The Big Five modern financial crises include Spain (1977), Norway (1987), Finland (1991), Sweden (1991) and Japan (1992).
Sources: U.S. Bureau of Economic Analysis and Organisation for Economic Co-Operation and Development

Such counterfactuals—it could have been worse—are of cold comfort to American households. Their net worth has fallen from 6 ½ times income pre-crisis to about 5 at present (**Chart 6**). These losses can only be recovered through a combination of increased savings and, eventually, rising prices for houses and financial assets. Each will clearly take time.

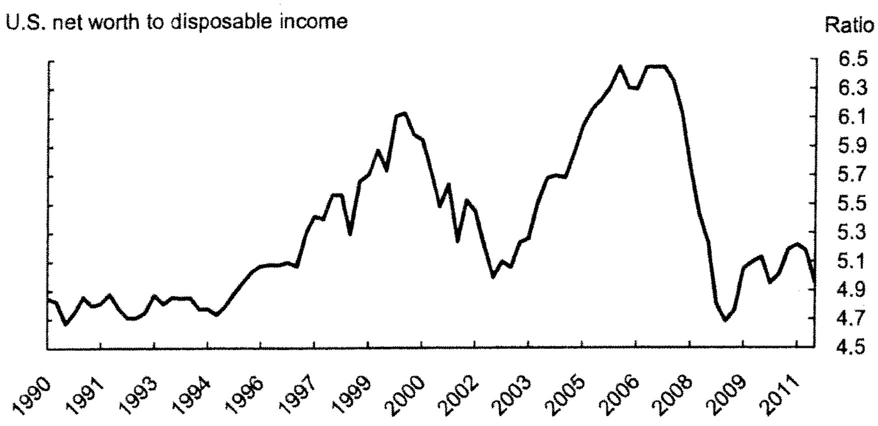
In Europe, a tough combination of necessary fiscal austerity and structural adjustment will mean falling wages, high unemployment and tight credit conditions for firms. Europe is unlikely to return to its pre-crisis level of GDP until a full five years after the start of its *last* recession (**Chart 7**).

Managing the Deleveraging Process

Austerity is a necessary condition for rebalancing, but it is seldom sufficient. There are really only three options to reduce debt: restructuring, inflation and growth.

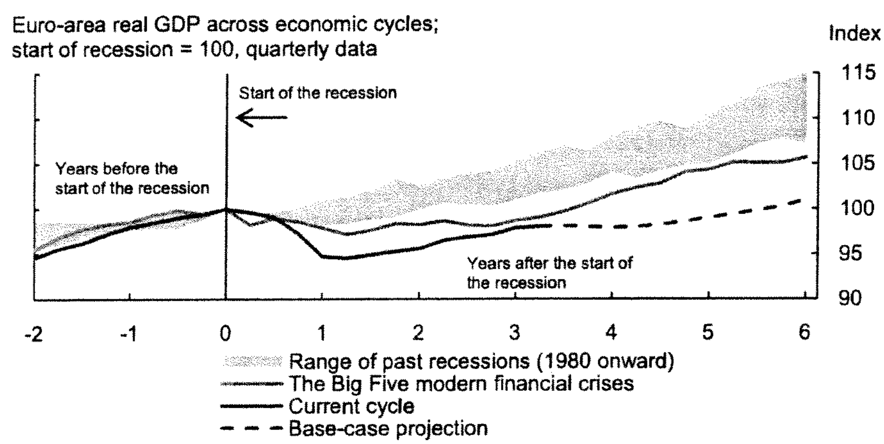
Whether we like it or not, debt restructuring may happen. If it is to be done, it is best done quickly. Policy-makers need to be careful about delaying the inevitable and merely funding the private exit. Historically, as an alternative to restructuring,

Chart 6: Large drop in U.S. household wealth



Sources: U.S. Federal Reserve, Bureau of Economic Analysis, and Bank of Canada calculations   Last observation: 2011Q3

Chart 7: Euro-area recovery was weak, is over



Note: The Big Five modern financial crises include Spain (1977), Norway (1987), Finland (1991), Sweden (1991) and Japan (1992)
Sources: Eurostat and Organisation for Economic Co-Operation and Development

financial repression has been used to achieve negative real interest rates and gradual sovereign deleveraging.

Some have suggested that higher inflation may be a way out from the burden of excessive debt.[9]

This is a siren call. Moving opportunistically to a higher inflation target would risk unmooring inflation expectations and destroying the hard-won gains of price stability. Similarly, strategies such as nominal GDP level targeting would fail unless they are well understood by the public and the central bank is highly credible.[10, 11]

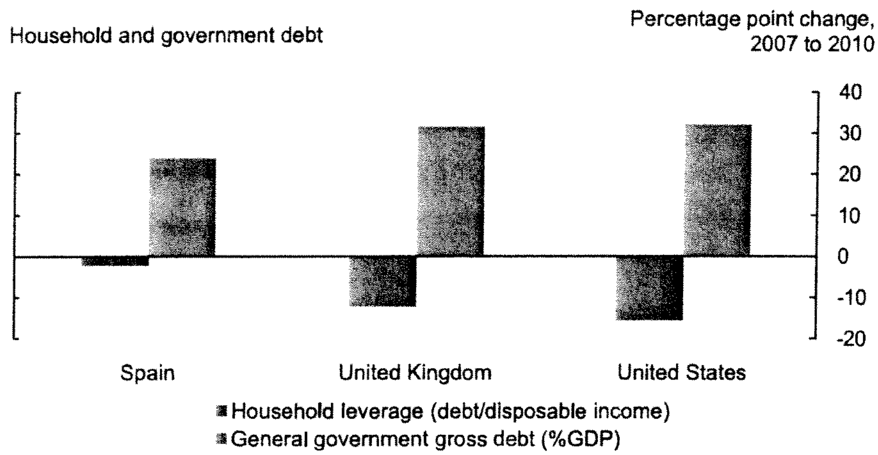
With no easy way out, the basic challenge for central banks is to maintain price stability in order to help sustain nominal aggregate demand during the period of real adjustment. In the Bank's view, that is best accomplished through a flexible inflation-targeting framework, applied symmetrically, to guard against both higher inflation and the possibility of deflation.

The most palatable strategy to reduce debt is to increase growth. In today's reality, the hurdles are significant.

Once leverage is high in one sector or region, it is very hard to reduce it without at least temporarily increasing it elsewhere.

In recent years, large fiscal expansions in the crisis economies have helped to sustain aggregate demand in the face of private deleveraging (**Chart 8**). However, the window for such Augustinian policy is rapidly closing. Few except the United States, by dint of its reserve currency status, can maintain it for much longer.

Chart 8: Private deleveraging, public leveraging



Sources: Bank for International Settlements, IMF World Economic Outlook September 2011

In most of Europe today, further stimulus is no longer an option, with the bond markets demanding the contrary.

There are no effective mechanisms that can produce the needed adjustment in the short term. Devaluation is impossible within the single-currency area; fiscal transfers and labour mobility are currently insufficient; and structural reforms will take time.

Actions by central banks, the International Monetary Fund and the European Financial Stability Facility can only create time for adjustment. They are not substitutes for it.

To repay the creditors in the core, the debtors of the periphery must regain competitiveness. This will not be easy. Most members of the euro area cannot depreciate against their major trading partners since they are also part of the euro.

Large shifts in relative inflation rates between debtor and creditor countries could result in real exchange rate depreciations between euro-area countries. However, it is not clear that ongoing deflation in the periphery and higher inflation in the core would prove any more tolerable than it did between the United

Kingdom and the United States under the postwar gold standard of the 1920s and 1930s.

The route to restoring competitiveness is through fiscal and structural reforms. These real adjustments are the responsibility of citizens, firms and governments within the affected countries, not central banks. A sustained process of relative wage adjustment will be necessary, implying large declines in living standards for a period in up to one-third of the euro area.

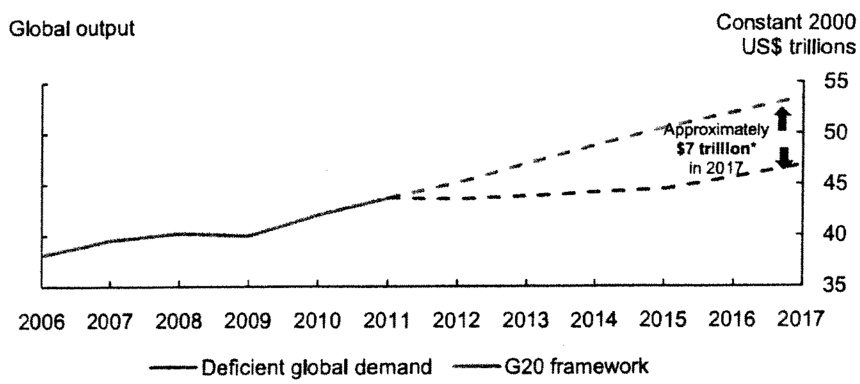
We welcome the measures announced last week by European authorities, which go some way to addressing these issues.

With deleveraging economies under pressure, global growth will require global rebalancing. Creditor nations, mainly emerging markets that have benefited from the debt-fuelled demand boom in advanced economies, must now pick up the baton.

This will be hard to accomplish without co-operation. Major advanced economies with deficient demand cannot consolidate their fiscal positions and boost household savings without support from increased foreign demand. Meanwhile, emerging markets, seeing their growth decelerate because of sagging demand in advanced countries, are reluctant to abandon a strategy that has served them so well in the past, and are refusing to let their exchange rates materially adjust.

Both sides are doubling down on losing strategies. As the Bank has outlined before, relative to a co-operative solution embodied in the G-20's Action Plan, the foregone output could be enormous: lower world GDP by more than US$7 trillion within five years (**Chart 9**). Canada has a big stake in avoiding this outcome.

Chart 9: The $7-trillion question



*This estimate is a rough approximation. Depending on the assumptions, it could range from $6 trillion to $9 trillion.
Sources: Bank of Canada, World Bank

To Summarize Thus Far

The market cannot be solely relied upon to discipline leverage.

It is not just the stock of debt that matters, but rather, who holds it. Heavy reliance on cross-border flows, particularly when they fund consumption, usually proves unsustainable.

As a consequence of these errors, advanced economies are entering a prolonged period of deleveraging.

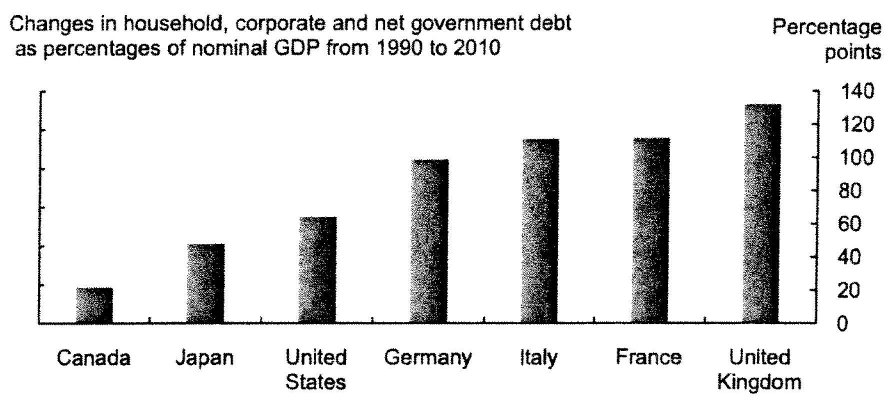
Central bank policy should be guided by a symmetric commitment to the inflation target. Central banks can only bridge real adjustments; they can't make the adjustments themselves.

Rebalancing global growth is the best option to smooth deleveraging, but its prospects seem distant.

What It Means for Canada

Canada has distinguished itself through the debt super cycle (**Chart 10**), though there are some recent trends that bear watching. Over the past twenty years, our non-financial debt increased less than any other G-7 country. In particular, government indebtedness fell sharply, and corporate leverage is currently at a record low (**Chart 11**).

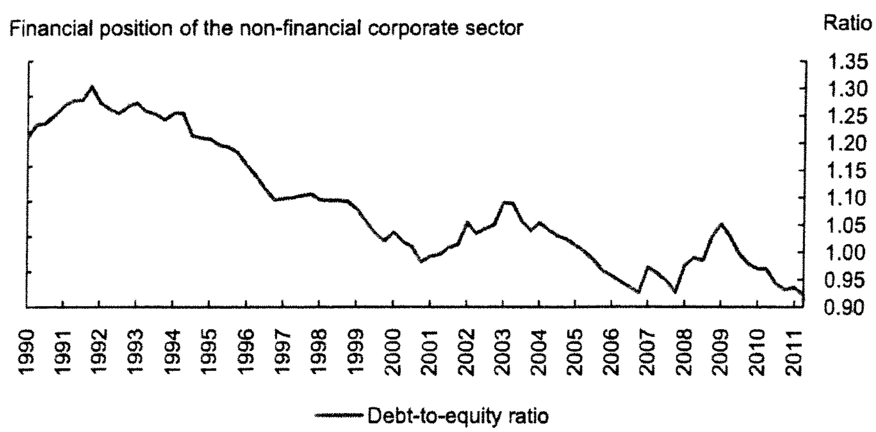
Chart 10: Canadian debt has risen less than its G-7 peers



Note: German data prior to 1991 reflects West Germany.
Sources: Cecchetti, Mohanty and Zampolli 2011, Organisation for Economic Co-operation and Development, and Bank of Canada calculations

Last observation: 2010

Chart 11: Corporate leverage at a record low



Source: Statistics Canada, Quarterly Financial Statistics for Enterprises

Last observation: 2011Q3

In the run-up to the crisis, Canada's historically large reliance on foreign financing was also reduced to such an extent that our net external indebtedness was virtually eliminated.

Over the same period, Canadian households increased their borrowing significantly. Canadians have now collectively run a net financial deficit for more than a decade, in effect, demanding funds from the rest of the economy, rather than providing them, as had been the case since the Leafs last won the Cup.

Developments since 2008 have reduced our margin of manoeuvre. In an environment of low interest rates and a well functioning financial system, household debt has risen by another 13 percentage points, relative to income. Canadians are now more indebted than the Americans or the British. Our current account has also returned to deficit, meaning that foreign debt has begun to creep back up.

The funding for these current account deficits has been coming largely from foreign purchases of Canadian portfolio securities, particularly bonds. Moreover, much of the proceeds of these capital inflows seem to be largely, on net, going to fund Canadian household expenditures, rather than to build productive capacity in the real economy. If we can take one lesson from the crisis, it is the reminder that channelling cheap and easy capital into unsustainable increases in consumption is at best unwise.

Canada's relative virtue throughout the debt super cycle affords us a privileged position now that the cycle has turned. Unlike many others, we still have a risk-free rate and a well-functioning financial system to support our economy. It is imperative that we maintain these advantages. Fortunately, this means largely doing what we have been doing—individuals and institutions acting responsibly and policy-makers executing against sound fiscal, monetary and regulatory frameworks.

It cannot entirely be business as usual. Our strong position gives us a window of opportunity to make the adjustments needed to continue to prosper in a deleveraging world. But opportunities are only valuable if seized.

First and foremost, that means reducing our economy's reliance on debt-fuelled household expenditures. To this end, since 2008, the federal government has taken a series of prudent and timely measures to tighten mortgage insurance requirements in order to support the long-term stability of the Canadian housing market. Banks are also raising capital to comply with new regulations. Canadian authorities are co-operating closely and will continue to monitor the financial situation of the household sector.

To eliminate the household sector's net financial deficit would leave a noticeable gap in the economy. Canadian households would need to reduce their net financing needs by about $37 billion per year, in aggregate. To compensate for such a reduction over two years could require an additional 3 percentage points of export growth, 4 percentage points of government spending growth or 7 percentage points of business investment growth.

Any of these, in isolation, would be a tall order. Export markets will remain challenging. Government cannot be expected to fill the gap on a sustained basis.

But Canadian companies, with their balance sheets in historically rude health, have the means to act—and the incentives. Canadian firms should recognize four realities: they are not as productive as they could be; they are under-exposed to fast-growing emerging markets; those in the commodity sector can expect relatively elevated prices for some time; and they can all benefit from one of the most resilient financial systems in the world. In a world where deleveraging holds back demand in our traditional foreign markets, the imperative is for Canadian companies to invest in improving their productivity and to access fast-growing emerging markets.

This would be good for Canadian companies and good for Canada. Indeed, it is the only sustainable option available. A virtuous circle of increased investment and increased productivity would increase the debt-carrying capacity of all, through higher wages, greater profits and higher government revenues. This should be our common focus.

The Bank of Canada is doing its part by fulfilling its mandate to keep inflation low, stable and predictable so that Canadian households and firms can invest and plan for the future with confidence. It is also assisting the federal government in ensuring that Canada's world-leading financial system will be there for Canadians in bad times as well as good and in pushing the G-20 Action Plan because it is in Canada's interests.

Conclusion

It makes sense to step back and consider current challenges through the longer arc of financial history. Today's venue is an appropriate place to do so. A century ago, when the Empire Club and the Canadian Club of Toronto would meet, the first great leveraging of the Canadian economy was well under way. During the three decades before the First World War, Canada ran current account deficits averaging 7 per cent of GDP. These deficits were largely for investment and were principally financed by long-term debt and foreign direct investment.

On the eve of the Great War, our net foreign liabilities reached 140 per cent of GDP, but our productive capacity built over the decades helped to pay them off over time. Our obligations would again swell in the Great Depression. But in the ensuing boom, we were again able to shrink our net liabilities.

When we found ourselves in fiscal trouble in the 1990s, Canadians made tough decisions, so that on the eve of Lehman's demise, Canada was in the best fiscal shape in the G-7.

We must be careful, however, not to take too much comfort from these experiences. Past is not always prologue. In the past, demographics and productivity trends were more favourable than they are today. In the past, we deleveraged during times of strong global growth. In the past, our exchange rate acted as a valuable shock absorber, helping to smooth the rebuilding of competitiveness that can only sustainably be attained through productivity growth.

Today, our demographics have turned, our productivity growth has slowed and the world is undergoing a competitive deleveraging.

We might appear to prosper for a while by consuming beyond our means. Markets may let us do so for longer than we should. But if we yield to this temptation, eventually we, too, will face painful adjustments.

It is better to rebalance now from a position of strength; to build the competitiveness and prosperity worthy of our nation.

Endnotes

[1] C. M. Reinhart and K. S. Rogoff, "A Decade of Debt," National Bureau of Economic Research Working Paper No. 16827, Cambridge, 2011.

[2] C. M. Reinhart and K. S. Rogoff, "Growth in a Time of Debt," *American Economic Review* 100, no. 2 (May 2010): 573–78.

[3] These figures, daunting as they are, actually understate the extent of the problem. They do not include the liabilities stemming from the pension and health care promises made by governments but not yet funded, which some estimate to be even larger than the current explicit stock of debt.

[4] R. G. Rajan, *Fault Lines: How Hidden Fractures Still Threaten the World Economy* (Princeton: Princeton University Press, 2010).

[5] Japan illustrates the importance of whether one's creditors are domestic or foreign. The public and total non-financial debt burdens in Japan have risen well beyond levels that have proved unsustainable in other countries, owing largely to the fact that the preponderance of that debt is owed domestically. From an external perspective, Japan is the largest net creditor in the world.

[6] See M. Carney, "Global Liquidity," a speech delivered to the Canada-United Kingdom Chamber of Commerce in London, United Kingdom, 8 November 2011.

[7] See A. Turner, "Debt and Deleveraging: Long Term and Short Term Challenges," a speech delivered to the Centre for Financial Studies, Frankfurt, Germany, 21 November 2011. Turner argues, in fact, that the current situation is the result of "decades of cumulative, massive policy errors," particularly the over reliance on free markets, (p.6).

[8] See C. M. Reinhart and V. R. Reinhart, "After the Fall," *Macroeconomic Challenges: The Decade Ahead*, Federal Reserve Bank of Kansas City 2010 Economic Policy Symposium. Available at: <http://www.kansascityfed.org/publicat/sympos/2010/reinhart-paper.pdf>.

[9] K. Rogoff, "Inflation Is Now the Lesser Evil," *Project Syndicate*, December 2008.

[10] See J. Hatzius, Z. Pandl, A. Phillips, and S. J. Stehn, A. Tilton, S. Wu, and M. Acosta-Cruz, "The Case for a Nominal GDP Level Target," *US Economics Analyst*, No: 11/41; Goldman Sachs Global ECS Research, 2011; and C. Romer, "Dear Ben: It's Time for Your Volcker Moment," *New York Times*, 29 October 2011.

[11] Indeed, if inflation is both higher and more uncertain, a higher inflation risk premium might result, prompting an increase in real interest rates that would exacerbate unfavourable debt dynamics.

Schedule B to Interrogatory No. 1-ED-7

THE CENTRE FOR SPATIAL ECONOMICS

The Economic Impacts of Reducing Natural Gas Use in Ontario

Prepared for
Ontario Clean Air Alliance
and
Ontario Clean Air Alliance Research Inc.

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The EJLB Foundation, The Toronto Atmospheric Fund and
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TORONTO Atmospheric Fund   TORONTO COMMUNITY FOUNDATION

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INTRODUCTION

The Ontario Clean Air Alliance and the Ontario Clean Air Alliance Research Inc. requested the Centre for Spatial Economics (C_4SE) to undertake a study that looks at the economic impacts of reducing the use of natural gas in Ontario. The possibility of achieving a significant reduction in the use of natural gas has been shown in a study undertaken for Enbridge Gas Distribution that estimated possible reductions in natural gas use on the part of its customers. The current study examines the economic impacts of reducing natural gas in the province by creating a projection for the future economic performance of the Ontario economy that contains a reduction in the use of natural gas that is similar in nature to that shown in the Enbridge Gas Distribution analysis and compares the results of this scenario against a projection that does not contain this reduction.

The next section provides a description of the approach adopted to estimate the impacts of reducing the use of natural gas and the assumptions behind the approach. The third section discusses the expected impacts of reducing the use of natural gas on the economy from a qualitative point of view. The fourth section then presents the quantitative estimates of the impacts found using the assumptions for the reduction in natural gas considered.

STUDY APPROACH AND ASSUMPTIONS

Enbridge Gas Distribution commissioned a study regarding the possibility of reducing the use of natural gas by its customers in Ontario using a Demand Side Management (DSM) approach (Marbek Resource Consultants Ltd. "Natural Gas Energy Efficiency Potential: Update 2008, Residential, Commercial and Industrial Sectors Synthesis Report," September 2009). The results of the study suggest estimates of possible reductions in natural gas use for industrial, commercial, and residential customers under different assumptions regarding DSM costs. Under its Economic Potential Forecast, for example, reductions in residential, commercial, and industrial, natural gas usage over a 10-year period are estimated at 18, 29, and 34 percent, respectively. These reductions are to be realized (Marbek, op. cit. page 4):

> ".. if all equipment and building envelopes were upgraded to the level that is cost-effective from Enbridge's perspective. All the energy efficiency technologies and measures that have a positive measure TRC.. (net benefits that result from an investment in an efficiency technology or measure).. are incorporated into the Economic Potential Forecast. These technologies and measures are applied at either natural stock turnover rates or at designated years for immediate application."

The Ontario Clean Air Alliance is interested in estimating the impact on the Ontario economy if a reduction in natural gas use could be achieved in the province as a whole. The assumptions adopted for the reduction in natural gas use found in the Enbridge study serve as a starting point for those used in this study. The reduction is assumed to take place over the 10-year time period 2012 to 2021.

The approach adopted to estimate the economic impacts on Ontario of reducing the use of natural gas employs the C_4SE macroeconomic model of the Ontario economy. This model is used to prepare two economic projections for the future performance of the economy. The first projection shows the performance of the economy without the reduction in the use of natural gas. The second one shows the performance when the usage of natural gas is reduced. The impacts on the economy are then estimated by comparing the results of the two projections for key economic and fiscal variables such real Gross Domestic Product (GDP), the Consumer Price Index (CPI), employment, population, and government budget balances.

The C_4SE macroeconomic model is a multi-sector (industry) model that assumes the existence of a gross output (total value of production) KLEM production technology for the different sectors – KLEM stands for the production inputs of capital, labour, energy, and materials. It incorporates variable input-output coefficients that respond to changes in relative prices for production inputs. For example, increases in the price of natural gas will lead to a reduction in natural gas's share of total inputs to gross output and an increase in the share for the other inputs. The model also incorporates a Green House Gas emissions component that estimates CO_2 equivalent emissions by industry.

The projection that does not contain the reductions in natural gas is called the base case projection. It is created by making assumptions about the key drivers for the Ontario economy such as economic growth and inflation in Ontario's major trading partners, oil prices, natural gas prices, fiscal policy, and so on. The projection with the reductions in natural gas is created using the base case assumptions and then reducing the input shares of natural gas for the various industries along with the consumer expenditure share of natural gas for households. The input shares are variables in the macroeconomic model.

The Enbridge study does not cover all of Ontario's economy. The current study wishes to expand the coverage to the province as whole. The reductions in natural gas use employed are 25 percent for the industrial sector, 20 percent for the commercial sector, and 15 percent for the residential sector. These reductions are lower and, therefore, more conservative than those found in the Enbridge Economic Potential Forecast.

It is assumed that an increase in the share of capital in gross output will occur with the reduction in natural gas use in gross output as firms purchase new energy efficient technologies. As a result, there will be an increase in the share of value-added (net output or GDP) in gross output in the economy. In the case of households, the reduction in the share of natural gas in consumer expenditures is replaced by an increase in the share of the other consumer expenditure categories.

While the Enbridge study provides estimates of reductions in natural gas use, it does not contain estimates of the amount of capital expenditures that would be required to achieve these reductions. The C_4SE model suggests that the "incremental" increase in the stock of capital over the projection period required to achieve the non-residential natural gas reductions measured in $2010 would be about $4 billion. For the residential sector it is assumed that a $3 billion increase in the value of residential structures would be required – which is about $500 per household (occupied housing unit). This assumption is a "rough" estimate, but is similar to the ratio of the increases in non-residential capital stock to natural gas reductions produced by the model. Lower amounts of residential expenditures would reduce the economic impact on the economy and higher ones would increase the impact.

It is also assumed that the prices for capital goods purchased to reduce natural gas usage will not rise from those found in the base case projection other than through possible increases in wholesale and retail trade margins for local firms as demand pressures rise. The prices for imported capital goods remain unchanged from base case values.

While the reductions in natural gas use are assumed to take place over the 10-year period 2012 to 2021, the projection period is extended for another 5 years to 2026. The longer time period is adopted to allow the economy to fully adjust to both the direct and indirect impacts of the reductions in the use of natural gas on the economy.

A final set of assumptions includes the absence of a response of fiscal and monetary policy on the part of governments. The Bank of Canada will not respond to changes in inflation associated with the reduction in natural gas use. Governments will not change policies in the face of changes in their budget balances. Any improvements or deterioration in budget balances will lead to changes in government debt.

EXPECTED IMPACTS

Before presenting the quantitative estimates of the impact of the reduction in natural gas use it is worthwhile to review the nature of impacts expected from a qualitative point of view – that is, directions of change rather than the estimated size of change.

The reduction in the use of natural gas is to be accomplished by replacing natural gas with more energy efficient capital equipment. This replacement is expected to allow firms to produce the same amount of goods and services they did when using natural gas because the more productive capital replaces the contribution of natural gas use in gross output. It should be noted that the reductions in natural gas use implemented through the model's input shares will not likely reduce natural gas use in the same proportion. This difference is a result of changes in economic performance caused by the changes in technology. While the share of natural gas in the economy is reduced, the actual size of the economy will increase, which in turn, will lead to additional use of natural gas. Nevertheless, the latter increase will be small in relation to the decline that results from introducing more efficient capital equipment.

Significant increases in investment expenditures in the economy are expected to be observed over the period relative to the base case projection when firms substitute capital for natural gas. Over the long run when the more efficient capital begins to wear out, additional replacement expenditures are expected with the higher valued capital in contrast to the relatively lower replacement values for the old capital.

The purchase of new equipment and the construction of structures needed to achieve lower gas use will increase production and employment in industries throughout the economy. The increased employment and disposable income will lead to increases in consumer and housing expenditures. These increases, in turn, will lead to additional production and employment, and so on.

Because Ontario does not produce natural gas the reduction in its use will not have a major negative impact on the economy. Nevertheless, firms in the natural gas distribution system are likely to see a reduction in their sales, which will offset somewhat the increases in GDP resulting from the more productive capital.

The fall in natural gas use will be observed through a reduction in provincial imports, which will lead to an improvement in the trade balance (exports minus imports) over the long run. During the period in which the capital is being replaced, nevertheless, the reduction in natural gas imports will be offset by imports of machinery and equipment. The import share of the machinery that will be purchased to reduce natural gas use is high for the province.

The higher GDP associated with the increase in capital to replace natural gas will lead to increases in labour productivity, which, in turn, will result in increases in wages and personal income. The latter will cause an increase in consumer expenditures, in addition to that observed as a result of the increased investment activity mentioned above.

The increased economic activity resulting from the reduction in gas use will also result in an improvement in the budget balances of the federal and provincial governments. This improvement comes from increases in revenues from both income taxes – personal and corporate – and indirect taxes such as the HST. Expenditures also rise as the increase in employment results in additional persons moving into the province, but this increase will be lower than the increase in revenues.

The reduction in the use of natural gas will lead to a reduction in CO_2 emissions. This reduction will be somewhat offset by increases in emissions resulting from a higher level of economic activity associated with replacing the natural gas with more energy efficient capital.

ESTIMATED IMPACTS

Estimates of the impacts of reducing natural gas use in the province for key economic indicators are shown in **Table 1**. The impacts for many indicators refer to the percentage differences and level differences from the base case projection values. The level differences for expenditure or income variables are measured in millions of 2010 dollars.

The results for real GDP show a 0.6 percentage point increase from the base case in 2026. This increase represents $5.1 billion measured in 2010 dollars. It should be noted that part of the

TABLE 1: IMPACT ON KEY ECONOMIC INDICATORS
(Level or Percentage Difference from Base Case)

	2016	2021	2026
Real GDP $2010 Millions			
% Difference	0.2	0.7	0.6
Difference	1706	5497	5144
GDP Deflator % Difference	0	0.1	0
Consumer Expenditures $2010 Millions			
% Difference	0.2	0.6	0.5
Difference	787	2694	2630
Residential Investment $2010 Millions			
% Difference	1.4	3	0.6
Difference	686	1651	394
Non-Residential Investment $2010 Millions			
% Difference	0.5	1.3	0.7
Difference	346	891	559
Exports $2010 Millions			
% Difference	0	-0.1	0
Difference	-49	-284	142
Imports $2010 Millions			
% Difference	0.1	0	-0.1
Difference	204	126	-628
CPI % Difference	0	0.1	0
Hourly Wage Rate $ % Difference	0.2	0.5	0.2
Employment 000s			
% Difference	0.2	0.4	0.4
Difference	12.2	33.8	28.5
Productivity (GDP/Hour) % Difference	0	0.2	0.2
Personal Income $2010 Millions			
% Difference	0.3	0.7	0.5
Difference	1215	3738	2612
Corporate Profits Before Tax $2010 Millions			
% Difference	0.1	0.7	0.6
Difference	73	446	451
Federal Net Lending $2010 Millions Difference	231	496	148
Provincial Net Lending $2010 Millions Difference	159	479	443
Natural Gas Final Demand (BCF)			
Difference	-69	-196	-192
% Difference	-6.9	-16.1	-15.4
Total Provincial CO2 Equivalent Emissions (KT)			
Difference	-4107	-13742	-13061
% Difference	-2.1	-6.1	-5.5

increase in GDP and some of its components is a result of an increase in population caused by higher employment leading to additional migration to the province.

Consumer expenditures account for the largest amount of the increase in GDP in 2026 where the percentage difference in expenditures is 0.5. The increase in consumer expenditures is the result of an increase in personal income, which rises 0.5 percent.

The increase in personal income results from increases in employment and wages. The wage rate rises 0.2 percent above base case values while there is a 0.4 percent increase in employment. The increase in employment in level terms is 29 thousand in 2026. Part of the increase in wages is due to the higher productivity that results from the increase in capital with the reduction in the use of natural gas. The fact that the Consumer Price Index (CPI) does not change over the period adds to the purchasing power of the wage increase.

As expected non-residential investment expenditures show a noticeable increase reaching 0.7 percent above base case values in 2026. The latter increase is less than the 1.3 percent observed for 2021 when the use of natural gas is being reduced through investments in energy saving capital.

There is also a 3.0 increase in residential investment to 2021, which falls to 0.6 percent in 2026 as the additional residential capital needed to reduce natural gas consumption is put in place. Some of the higher residential investment is accounted for by an increase in population associated with the higher employment attracting more people to the province.

Imports rise to 2021 in the projection where natural gas use is reduced, which is a result of both higher investment and consumer expenditures. Nevertheless, they fall later as the higher level of investment and associated activity is reduced. The increase in productivity that is caused by the reduction in the use of natural gas reduces business costs enough to cause exports to rise slightly by 2026. This latter increase leads to an improvement in the trade balance of almost $800 million that year. The reduced costs are also responsible for the increase in corporate profits before taxes over the projection period.

The federal and provincial governments see an improvement in their budget balances with the increased economic activity. The federal budget balance by 2026 is nearly $150 million higher while that for the provincial government is about $445 million higher. The sum of these differences over the period suggests about a $3.8 and $4.4 billion decline in federal and provincial government debt, respectively.

The percentage reduction in natural gas use for total final demand – which excludes natural gas used to produce electricity – is 15.4 percent in 2026. The reduction in physical units is 192 billion cubic feet of natural gas (BCF). This reduction divided into the increase in GDP in 2026 shows a $26 million dollar increase in GDP for each 1 BCF of natural gas reduction.

The reduction in the use of natural gas has a noticeable impact on total provincial CO_2 emissions over the projection period. By 2026 the level of CO_2 equivalent emissions is reduced 5.5 percent or 13.1 megatonnes with the replacement of natural gas by the more energy efficient capital.

The estimated percentage impacts on the industries in the economy that are covered in the C_4SE model are shown in **Table 2**. The impacts on the various industries reflect their relative intensities of natural gas use as well as their involvement in producing and installing capital goods. The construction industry, for example, will see a larger increase in activity as it builds and installs new capital. Industries with high shares of their production represented by natural gas such as primary metals will tend to have larger responses to the reduction in gas use.

The mining and manufacturing industries see relatively large increases in GDP because they use relatively large amounts of natural gas. Within the manufacturing industry the two automobile related industries show the smallest increase while primary metals and other manufacturing, which includes the pulp and paper industry, show relatively large increases in GDP.

As expected the construction industry registers a large increase to 2021 with a 2.0 percent difference between the base case projection and the reduced natural gas projection. This impact declines to 0.7 percent once the conversion to more efficient capital is completed.

The impacts on the service industries reflect in part the higher population associated with the employment increase as well as a reduction in natural gas use. The retail and wholesale trade, finance, insurance, and real estate, and accommodation and food services show the largest increases among private services.

TABLE 2: IMPACT ON INDUSTRY GDP (%)
(Percentage Difference from Base Case)

	2016	2021	2026
Total	0.2	0.7	0.6
Agriculture	0.1	0.2	0.2
Forestry	0.2	0.4	0.4
Mining	0.4	1.3	1.3
Manufacturing	0.4	1.3	1.1
Plastics	0.2	0.6	0.5
Motor Vehicle Assembly	0.1	0.4	0.3
Motor Vehicle Parts	0.1	0.4	0.4
Machinery	0.3	0.7	0.7
Fabricated Metals	0.3	0.8	0.6
Primary Metals	0.7	2.1	1.9
Other Manufacturing	0.6	1.8	1.6
Construction	0.8	2	0.7
Utilities	0.1	0.5	0.4
Transportation & Warehousing	0.1	0.3	0.3
Trade	0.2	0.6	0.5
Finance, Insurance & Real Estate	0.2	0.7	0.6
Professional, Scientific & Management Services	0.1	0.3	0.2
Accommodation & Food	0.2	0.6	0.5
Health Services	0.1	0.4	0.4
Other Services	0.2	0.6	0.5
Education Services	0.2	0.7	0.6
Government Services	0.1	0.4	0.5

APPENDIX: THE CENTRE FOR SPATIAL ECONOMICS

The Centre for Spatial Economics (C_4SE) monitors and forecasts economic and demographic change throughout Canada at virtually all levels of geography. The C_4SE also prepares customized studies on the economic, industrial and community impacts of various fiscal and other policy changes, and develops customized impact and projection models for in-house client use. Our clients include government departments, crown corporations, manufacturers, retailers and real estate developers.

The C_4SE was formed in July 2000 through an initiative of two consulting firms: Strategic Projections Inc. and Stokes Economic Consulting Incorporated. These two firms specialize in demographic and economic research. A key part of this research has been the geographical distribution of demographic and economic activity. The C_4SE was established as a partnership of SPI and SEC to improve the quality of information and research conducted in Canada and to make the information and research available to organizations requiring such information, and to the public as the opportunity arises. The C_4SE draws from a list of academics and research consultants on an as needed basis to minimize overhead costs and to obtain the best researchers for the topic at hand.

The staff of the C_4SE is currently as follows:
Ernie Stokes - Managing Partner
Tom McCormack - Partner
Robert Fairholm - Partner
Robin Somerville - Partner
Aaron Stokes - Staff Economist
Tara Schill - Staff Economist
Adam Papp – Staff Economist
Robert Daniells - Consultant
Sam Patayanikorn – Consultant

Ernie Stokes, the author of this report, is the Managing Partner of the C_4SE, as well as the President of Stokes Economic Consulting. He has more than 30 years experience as an economic advisor in both the private and public sectors. Ernie has worked both in North America and developing countries. He has a Ph. D. in economics from Queen's University (1979). Prior to establishing Stokes Economic Consulting in 1995 he served as Managing Director, the WEFA Group, Canada (1989 to 1994), as senior economist with the Alberta Energy Company (1987 to 1989), as a senior official with the Canada Department of Finance (1985 to 1987) and as Director of the National Forecasting Group with the Conference Board (1978 to 1984).

Stokes is currently a member of the B.C. Minister of Finance Forecast Council and the Ontario Minister of Finance Forecast Council as well as an expert on the Ontario Minister of Infrastructure Strategy Panel.

For more information on the C_4SE see our website: www.c4se.com

Filed: 2013-10-02
EB-2012-0451
Exhibit J6.1
Page 1 of 1
Plus Attachment

UNDERTAKING J6.1

UNDERTAKING

TR 6, page 13

EGD to update Exhibit I.A4.EGD.ED.29, GTA project assumed earnings impacts table.

RESPONSE

Please see the attached table.

Witnesses: K. Culbert
S. Murray

Enbridge Gas Distribution GTA Project assumed earnings impacts

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Rate Base (A)	135,515,487	639,261,010	619,936,080	600,611,042	581,285,897	561,960,646	543,137,348	524,296,267	504,935,340	485,574,317	466,213,210
Common Equity (B)	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%	36.00%
Allowed Return on Equity (C)	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%	8.93%
Earnings (A x B x C)	4,356,552	20,550,963	19,929,705	19,308,444	18,687,179	18,065,911	17,460,779	16,855,076	16,232,661	15,610,243	14,987,822

Notes: 1) Using data which assumes Segment A's Parkway West to Albion is a 42" pipeline.
2) Using the 2013 OEB approved ROE% for approximating purposes.