David I. Poch Barrister tel. (613) 264-0055 fax (613) 264-2878

November 15, 2013

Ontario Energy Board
2300 Yonge St., 27th Floor
Toronto, ON
M4P 1E4

Attn: Ms Kirsten Walli
Board Secretary

By electronic filing and e-mail

Dear Ms Walli:

Re: EB-2012-0451, EB-2012-0433, EB-2013-0074, GEC Final Argument

Attached please find GEC's submissions in this matter.

Sincerely,

David Poch

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

BEFORE THE ONTARIO ENERGY BOARD

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.

GREEN ENERGY COALITION (GEC)

FINAL ARGUMENT

Filed: November 15, 2013

David Poch, Barrister
Counsel for GEC

Contents

INTRODUCTION

The Green Energy Coalition (GEC) represents over 125,000 Ontario residents who are members or supporters of its member organizations: the David Suzuki Foundation, Greenpeace Canada, Sierra Club of Canada and WWF-Canada. All of the GEC's member groups are charitable or non-profit organizations active on environmental and energy policy matters.

GEC's submissions address the need for the facilities proposed by both Enbridge Gas Distribution Inc. and Union Gas Limited, and we address the treatment of alternatives.

Union Gas has indicated that it would not build its Brantford to Kirkwall loop or Parkway West (load growth compressor D) if Enbridge does not obtain approval for its Segment A[1]. Accordingly, while our submissions largely focus on the need for and the alternatives to the Enbridge proposals, we submit that the need for the Union facilities (with the possible exception of the Parkway West Loss of Critical Unit (LCU) proposal) is subject to the same considerations.

As set out below, GEC respectfully submits that Enbridge and Union have failed to demonstrate need or economic value for the proposed facilities (again, with the possible exception of the LCU proposal) and have failed to adequately consider more cost-effective and societally preferable alternatives to those facilities.

ISSUE A1- Are the proposed facilities needed?

The Public Interest Context – the failure of planning

Section 96.(1) of the *Act* requires the Board must find that the proposals before it are in the public interest if it is to grant leave to construct. The Board interprets that section in light of its statutory objectives.

[1] 1.A1.UGL.Staff.8

Enbridge's witnesses pointed to the objective: "to facilitate rational expansion of transmission and distribution systems" which prompts us to ask: in a province where carbon emissions are to come down by 80% in the decades ahead, do we not need to consider the meaning of "rational expansion" in a new light? In light of this policy context and environmental reality, can the LDCs meet their burden of proving that their proposed facility expansions are rational without demonstrating that there is no alternative more consistent with the Provincial goal? Is the public interest to be construed so narrowly that the utilities are free to ignore this major public policy context?

Natural gas consumption accounts for roughly 35% of Ontario's greenhouse gas (GHG) emissions[2]. Ontario government policy is to achieve an 80% reduction in GHG emissions from 1990 levels by 2050[3]. This would require a reduction from 176 to 36 MT/a. By 2010 Ontario had only slightly reduced emissions to 171 MT/a[4]. Even in the unrealistic future where all other emissions were eliminated and where there were no gas fired electricity emissions, the numbers dictate that the end-use gas sector would need to reduce GHG emissions by 23%[5]. In a more realistic assessment, emissions associated with end-use natural gas consumption would need to decline closer to 80% along with all other sectors.

The commitment of roughly a billion dollars to long-lived gas supply infrastructure, with highly speculative economic justification, and where conservation initiatives could address any pressing need, cannot be reconciled with these policy and environmental imperatives. In our submission, the fact that the applicants have offered no evidence of how their proposals conform to government policy should in itself be fatal to the applications. The added financial costs of facilities that will do little or nothing to avoid the zero sum game of TCPL's revenue shortfall simply compounds this failure.

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[2] K4.5, p. 37-42 (Ex. I.I Sched. 1-ED-5 from EB-2012-0394)
[3] L.EGD.GEC.1, p. 12
[4] V.7, p.50
[5] V.7, p.50

When Enbridge's project team were asked about the consideration given to the government's GHG reduction policy they acknowledged that they were unaware of the details of the policy. [6]

The Board's statutory objective to promote conservation must also inform the public interest test to be applied in this case. We have witnessed a utility attitude toward conservation that compliments their wilful blindness to government policy on GHG reduction. Reading the one and a half page description of DSM as an alternative included in Enbridge's pre-filed evidence, one might assume that DSM can be of no assistance in reducing peak load and is more likely to exacerbate peak load problems. When pressed, Enbridge could identify only one DSM program that would exacerbate peak load and 54 that would reduce it[7].

This cavalier approach to least-cost planning is nowhere more evident than in Enbridge's scandalous failure to include distribution capital costs in its DSM avoided costs, despite a decade's prior knowledge of an emerging pressure problem at Station B and clear Board guidance to include such costs[8]. The explanation offered by the witness panel, that Enbridge wanted to avoid some sort of double counting, as the company would be both rewarded for DSM that defers additions and earn a fair return on its rate base additions, is completely illogical. Enbridge would receive an incentive based on the benefits of deferring capital construction on which it would otherwise have earned a return. Enbridge's explanation appears to be a post hoc justification for a decision to reduce DSM activity, by a utility bent on building rate base rather than lowering customer costs.

Enbridge acknowledges that they have foreseen the potential for a load-related low-pressure problem at Station B since at least 2002 but made no effort to address the issue with either

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[6] Vol.5, p.25 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. *(continues over)*

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.

[7] L.EGD.GEC.2, pp. 4-5

[8] V.5, p.115 (Board DSM Guidelines at section 6.2 specifically require "... long-term estimates, and include avoided supply-side costs such as capital, operating and commodity costs.")

DSM or various interruptible rate incentives[9]. DSM staff were not even invited to the meeting where DSM was screened out as an alternative to pipe[10]. Thus, the company has ignored least-cost planning. As a result, it now seeks to visit higher-than-necessary system costs on customers[11]. As we suggest in our conclusions, if any approvals are granted, the Board should reserve its right to adjust rate base inclusion to recognize this failure. If the Board accepts Enbridge's view that it is too risky at this date to pursue the least-cost approach, then shareholders, not customers should pay the added costs due to sub-optimal planning. However, as discussed below, GEC submits that there is no need to foreclose demand-side alternatives at this time.

The LDCs have identified a number of drivers for their proposals and in the following sections we will address each in turn. The economic merit of the proposals (which largely turns on purported gas transportation savings) is discussed subsequently under Issues A2 & 3. The economic savings and the achievability of GEC's proposed alternative, a demand side approach, is discussed under Issue A4.

Purported Drivers

Enbridge and Union identify five drivers for their proposed projects: gas supply savings, load growth (Station B low pressure), reliability (including LCU and multiple entry points for gas to the GTA influence area, lowering pressures to achieve 30% SMYS, and supply reliability), supply diversity and operational flexibility. We address each of these below.

Gas Supply Savings

The LDCs have proposed most of their investments to allow them to switch from buying lower-cost Western Canada gas and shipping it over TCPL's long-haul mainline to buying more expensive US gas and shipping it over various short-haul services. Their claim is that the

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[9] Transcript, June 13th, page 116, lines 16 to 24:

> *"First of all, in 2006 was this capacity shortfall at station B foreseen?"*
> *Mr. Naczynski:*
> *"In 2006 the capacity shortfall was foreseen. It was foreseen in 2002 as well, prior to the Portlands Energy Centre…"*

[10] Vol.7, p.8

[11] This will be the case whether or not the portion of the facilities needed to access purported 'gas savings' occurs.

increased investment, plus the increased price of gas, plus the short-haul tariffs, will be less than the reduction in payments to TCPL. Please refer to our submissions below under "Issues A2 & A3 – A Zero Sum Game" for a discussion of this claim from the perspective of the LDC customers and all Ontario gas shippers, including direct-purchase customers and power generators.

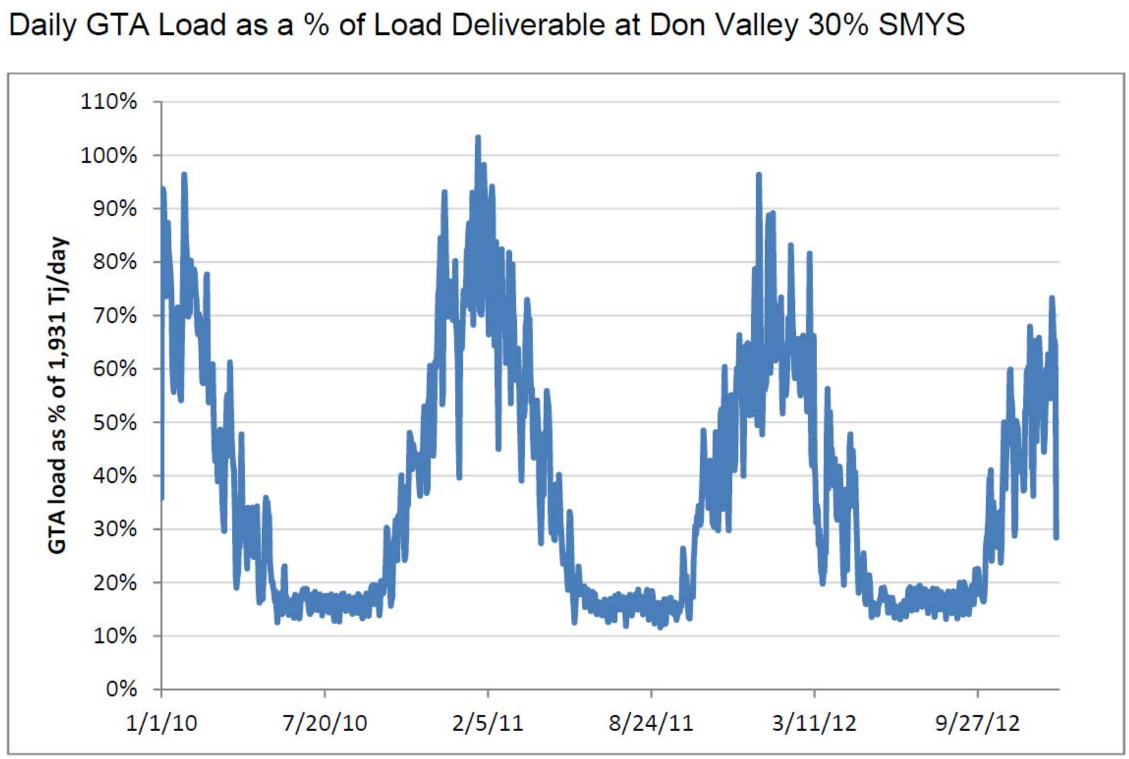
Load Growth - Providing Adequate Gas Pressure at Station B

The only truly time-sensitive driver for the GTA projects is the anticipated low pressure problem at Station B, on those infrequent occasions when temperatures drive an extreme peak load.

This issue requires a consideration of several factors including the load forecast, the opportunity for DSM to offset load growth, and the ability to address infrequent and short-lived system peaks with an enhanced approach to interruptible contracts. We review these matters briefly here and we will address the achievability of DSM and interruptible support further under issue A4 – Alternatives.

In Ex. L.EGD.GEC.1, Mr. Chernick charts the data that EGD provided for GTA winter peak loads in recent years against the level that requires pipeline pressures above 30% SMYS (expressed as 100% in the graphic reproduced below). Using EGD's preferred conversion factor for daily to peak hourly flows, the 30% level would be at the 95% level on the graphic.[12] In either case, it is apparent that the loads exceed the 30% SMYS threshold on only a very few days (4 days over 95%) in the three years of data available.

[12] See M.GEC.EGD.1. In J6.6 EGD has indicated that the 165TJ/day reduction in the Don Valley line capacity to achieve 30% SMYS it would convert to 219 10^3m^3 (a 23% reduction) rather than the 181 10^3m^3 (a 19% reduction) Mr. Chernick utilized.



Since Enbridge models system pressures with interruptible loads 'on' (i.e. not interrupted), it is clear that adequate pressure can be maintained at 37% SMYS (which EGD has utilized for the entire life of these pipes) at current load levels, and that adequate pressure can be maintained at the 30% level on all but rare occasions. (We discuss Enbridge's modelling with interruptible loads 'on' and its ability to meet 30% SMYS in emergencies at all times below, under the heading: *Reliability – 30% SMYS*.)

Further evidence can be found in JT2.25 Table 3, which shows 2015/16 peak day transient modelling results for Station B pressures at 240 psi (well above the required 225 psi) with no added infrastructure and no interruption of interruptible loads, and without added DSM, if 37% is maintained[13].

[13] For a discussion of transient modelling see Vol. 7, p.33

In short, there is no low-pressure problem at Station B in the near term. In the long term, if DSM can largely offset load growth in the GTA, or (in a more targeted way) in those parts of the GTA that affect the Don Valley corridor, there will never be a low-pressure problem at Station B.

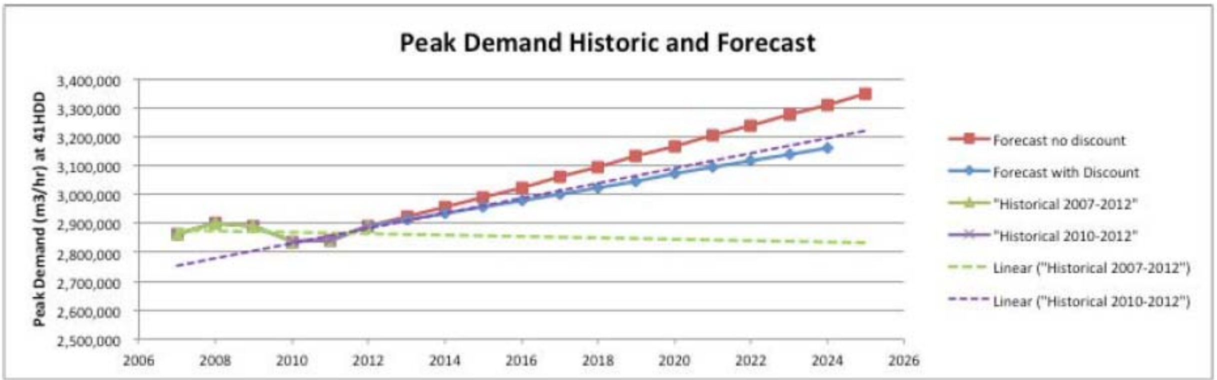
With DSM offsetting growth, it is only in the circumstance where Enbridge insists on maintaining 30% SMYS on the coldest day and refuses to utilize other measures (such as enhanced interruptible or curtailment rates) to attain 30% SMYS in the rare event of an emergency at system peak times that a 'problem' occurs. As discussed below, this refusal to address the infrequently exceeded 30% SMYS target creatively is not justified.

Load Growth is Overstated

Enbridge's projected pressures at Station B are premised on its peak load growth projection.

Environmental Defence addressed the load forecast issue in its cross-examinations and we rely upon their detailed submissions, in the interest of efficiency. In short, as is apparent from the Enerlife graphics reproduced below (weather normalized to 41DD), Enbridge appears to have utilized a very short trend analysis which extrapolates the rebound from the economic slump of 2008 and results in an inflated peak load forecast for GTA demand. Enbridge's forecast includes a subjective downward adjustment (since its initial trend line just seemed too high), but Enbridge was unable to break out what is included in that adjustment and it appears (at most) to roughly approximate the anticipated DSM at current levels of activity[14].

[14] V.5, p.24



Enbridge's annual load forecast seems to simply ignore the trend of both the meter billing level (green line) and station level data (red line)[15].

Since Enbridge's forecast appears to be significantly inflated, addressing Station B issues with likely base load growth, enhanced DSM and possible an enhanced approach to interruptible loads should not be problematic.

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[15] See Enerlife Report, L.EGD.ED.1, pp. 17- 18

Reliability, Flexibility, Diversity

Reliability benefits have been asserted for several features of the GTA infrastructure. These include the LCU, multiple entry points for gas to the GTA influence area, the reduction of pressures on certain lines to 30% SMYS, and improved upstream supply reliability. We address each of these in turn.

Reliability – Redundancy, LCU and multiple entry points

GEC takes no position on the need for and benefits of the LCU and the reconfiguration of the Parkway facilities that the LDCs indicate will provide redundancy and multiple entry points. Other parties, more familiar with the gas flow dynamics, the forecast for turn back, etc., will be addressing this matter.

We do note that Enbridge does not propose to loop its NPS 30 line south of Jonesville Station, despite the recent washout on that section of the line and Enbridge's position that the Don Valley line is vital for serving the downtown core. Accordingly, Enbridge does not appear to be proposing redundant gas supply routes to the downtown core.

Reliability – 30% SMYS

Enbridge repeatedly cited its desire to reduce operating pressures from 37% to 30% SMYS on Segment B (the NPS 26 line from Keele to the Don Valley and the NPS 30 Don Valley line) as a justification for the GTA projects.

Enbridge's policy on reducing line pressures to 30% SMYS is that it will consider doing so when it is driven to alter a line for other purposes.[16] However, when Enbridge was challenged on

[16] V.5, p. 106: 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 these other purposes (such as the need for the segment to meet load or to supply US gas), it would engage in a circular argument and claim that the facilities were driven by the need to address the 37% 'problem'. As Mr. Chernick elaborated, since access to US gas does not require Segment B and achieving required pressures at Station B is possible with lower-cost demand side options, no triggering event has in fact occurred for Segment B. Enbridge is in effect trying to get the project to pull itself up by its bootstraps.

This is not to deny the fact that lowering pressures to 30% is advantageous. The question is whether 30% must be achieved 100% of the time, and even if that is the conclusion, would a plan to lower pressures over several years as DSM builds be a reasonable alternative?

One might also ask, if 30% SMYS is so urgent, why does Enbridge maintain these lines at 37% throughout the winter season rather than only when needed based on weather forecasts and ramping constraints? Why has Enbridge not pursued DSM to reduce peak demands and lower the pressure on the lines, or even asked the DSM collaborative for assistance in accelerating weather-related load reductions along these pipelines? Why does Enbridge operate 262 kms of line at greater than 30%[17], and why does Union operate 133 different lines (a list 3 pages long) at pressures above 30%[18]?

In Exhibit I.A1.EGD.ED.34 Enbridge specifically noted:

> 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.
>
> The project is not justified based on meeting minimum safety standards….

Enbridge did note that the TSSA recently released the Oil and Gas Pipeline Systems Code Adoption Document Amendment FS-196-12 which directs companies such as Enbridge to

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meet our load growth or other challenges on the system, but also incorporate what would be required to be able to reduce pressures on those lines to below 30 percent.

[17] V.5,p.106, V.6, p.76

[18] J4.3

implement risk reduction activities for higher risk assets. While Enbridge implied that the lower pressures were required by TSSA standards, it eventually acknowledged that operating those lines at 37% SMYS complies with TSSA standards, so long as Enbridge maintains an appropriate integrity management program, which it does.

Enbridge's witness spoke of the problem of third parties damaging pipes, but those incidents appear to be much more common on lower-pressure distribution lines along streets, rather than these well marked high-pressure lines that follow utility rights of way and the Don Valley and are buried under meters of soil. Enbridge did offer a more compelling rationale for lowering pressures—when welding or maintenance is unexpectedly required, as Enbridge pointed out has been the case on occasion, it is safer to operate at or below 30% until the repair is completed. The evidence discussed below suggests that 30% SMYS can be attained at all times with either the east-west portion of Segment B or the north-south portion, by utilizing existing interruptible load and offsetting load growth with DSM. With no new facilities, 30% SMYS can be attained in emergencies under almost all circumstances, while supplying all firm load. Most of the year, the lines can operate at 30% and routine inspections and maintenance can occur. With neither Segment B1 or B2, an emergency that required a reduction to 30% SMYS arising during extreme design day peak winter conditions would require curtailment of some large firm customers. Since design day weather occurs only a day or less a decade, and since Enbridge has identified only one physical problem requiring reduction of pressure on either of these lines (this spring's flooding on the Don), the combination of those contingencies would be unlikely in the lifetime of the proposed project. In that rare case, if it should ever arise, Enbridge's contracts with its large customers would allow for emergency curtailment of their usage to maintain burner-tip pressure.

In analysing this issue, it important to note the fact that Enbridge models system design with interruptible loads on[19]. This overstates the reduction in (firm) volumes required to meet load and to achieve 30% SMYS in an emergency. Enbridge's planning approach also requires firm ratepayers to pay twice for the same reliability. First, ratepayers compensate interruptible customers for the right to interrupt, and then ratepayers pay for capital additions that obviate any potential need to interrupt. Surely, the point of having interruptible loads is to reduce

[19] Vol 7, p. 17

costs by relying on interruptions in infrequent peak and emergency situations – why else have other ratepayers pay for it?

The impact of ignoring the interruptible resource in planning is apparent from Exhibit J2.25, where Enbridge uses its "unsteady" state model to predict pressures at Station B under differing configurations. Table 3 of the exhibit also offers a rough indication of the impact of DSM load growth reduction; it indicates that Enbridge expects design-condition pressures at station B to fall 4 psi between 2014/15 and 2015/16 (load growth being the only change). This would amount to 8 psi over the two year period from now until the start of the 2015 winter, attributable to load growth. Since Enbridge should be able to offset load growth with additional DSM, we expect that DSM could increase pressure by a like amount. These two effects (interruptible loads and DSM) are displayed in the table below, which takes data from J2.25 assuming 30% SMYS is maintained at 41DD (with transient modelling) [20].

The various combinations are considered in the table below.

Station B Pressures (with 30% SMYS on NPS 26 and 30 lines)				
Unsteady State Model (unless noted otherwise)				
	2015/16 No new facilities	2015/16 Seg B only	2015/16 N-S Segment B only	2015 Seg. A & E-W Seg. B
Interruptible loads on	148	231	193	
Interruptible loads off	156	245	219	
Interruptible loads off and two years of load growth removed[21]	164	253	227	
2015 Steady State Result with 4 large industrial loads curtailed[22]	(225 psi at 33DD)	(225 psi at 33DD)		262

[20] Also reproduced as part of J7.1

[21] From J2.25. Load Growth removed based on difference in JT2.25 table 3, Station B, Change from 2014//15 to 2015/16 multiplied by 2.

[22] J6.7

The transient modelling (which was conducted by Enbridge at the request of Mr. Quinn) gives a more accurate result than steady state modelling because transient modelling takes account of load profiles and dynamics such as line pack. Enbridge prefers to use the more conservative steady state model for system planning, which ignores the realities of line pack and other dynamics. There is no compelling rationale for ignoring these realities. It is notable that Enbridge is content to ignore line pack when it's inclusion suggests less need for facilities, but when asked whether more active pressure regulation would allow Enbridge to achieve 30% SMYS more often (potentially avoiding new facilities), Enbridge's witnesses said that the need to build line pack would limit the potential of the approach. The importance of line pack to Enbridge's analysts seems to vary with its effect on the project justification.

Enbridge requires 225 psi at Station B (with PEC running). It is apparent that without the east-west portion of Segment B (and thus with no help from segment A), with DSM offsetting load growth, 30% can be attained in an emergency, simply by calling upon interruptible loads, without invoking emergency interruptions to firm customers. In J6.7 Enbridge provided the more conservative steady state run result for 2015 loads with PEC and its 4 large industrial loads removed and Station B pressure at 41 DDC was 262 psi with no North-South portion of Segment B. For that configuration, given that PEC and interruptible loads account for 59% of station B load,[23] it is reasonable to presume that 225 psi and 30% SMYS at 41DD could be attained just by interrupting existing interruptible loads and PEC (although precise results for that particular combination were not provided).

As discussed above under the heading 'Providing adequate pressure at station B', in a scenario with no Segment B or no Segments A and B, with DSM offsetting growth, Enbridge could operate at or below 30% nearly all the time. It is also important to recognize that on those occasions that more than 30% SMYS is required, only part of the lines would be at the highest pressure[24]. Without the North-South portion of Segment B, on those extremely rare occasions

[23] Ex. 1.A1.EGD.GEC.3 indicates that "95 TJ/day of firm load, or 37% of the downtown core total is expected to be supplied from Station B in 2014-2015". At J6.7 Updated, page 2, it is noted that "The interruptible customers and PEC account for approximately 136 TJ/day". PEC flows of 116 103m3 converted at 1.327 (as per J6.6) = 87.4 TJ/day.

[24] V.5, p. 111:

that an emergency arises during a period of extreme cold weather, 30% SMYS can be attained with the curtailment of limited amounts of firm customers (PEC and possibly some of the four large industrials' loads).

GEC requested model runs to assess this scenario and the scenario with no new facilities and to evaluate how often this could arise.[25] Enbridge refused to do runs with emergency interruption of firm customers (beyond the 4 large customers) and claimed it had no hourly data to evaluate how often an emergency would require such a response. Given that Enbridge earlier provided hourly data in I.A4.EGD.ED.10, this response appears to be inaccurate. When pressed, Enbridge revised its responses and indicated that (with the more conservative steady state model) with *no new facilities,* it could stay at or below 30% SMYS at temperatures down to 33 DD by curtailing the four large customers. (As noted above, with Segment A and the East-West part of Segment B 262 psi is attained at 41DD.) Enbridge also indicated that 33 DD is exceeded approximately 4 times per year[26]. With transient modelling, the temperature that can be served at 30% SMYS would be lower, and the frequency of it being that cold would also be lower. With more realistic load forecasts (see above) the results would also improve.

All of these scenario results could be improved over time if a concerted effort to deliver DSM in the area were embarked upon. Certainly, in a matter of a few years, 30% SMYS could be attained at design day temperatures *with no new facilities* by a combination of DSM, interruptibles and a curtailment arrangement with PEC.

Mr. Wolnick in his cross suggested that the need to lower pressures to 30% in emergencies is foreseeable and therefore to plan in a manner that doesn't allow for emergency pressure reduction at peak times without interrupting firm customers like PEC would breach contractual commitments. First, even unlikely tornadoes are foreseeable but surely 'foreseeable but

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> MR. POCH: So not only is the line below 30 percent some portion of the year, and above it, as you've indicated, in the winter, but physically a bunch of the line would be below that 30 percent simply because of the physics, that as you go south the pressures drop; correct?
> MR. NACZYNSKI: That's correct.

[25] J6.5 and J 6.7
[26] J6.7 Updated 2013-10-08

unlikely' is not the test of *force majeure*. Second, Enbridge claims that currently it cannot achieve 30% today in 41 DD design conditions[27]. Given the relative youth of the agreement with PEC, this circumstance (that an emergency at 41 DD would require interruption of major loads) would have been readily foreseeable. Accordingly, Mr. Wolnick's interpretation cannot have been the interpretation of either Enbridge or PEC when that contract was made.

More to the point, why would EGD not have investigated whether PEC and OPA (PEC's electricity client) could live with a contractual winter peak curtailment option, given that Toronto and Ontario are summer peaking for electricity[28]? This option and the alternative of broader curtailment rates are discussed further under Issue A4.

IESO filed a comment supporting a robust gas system to accommodate gas-fired electricity generation, but despite the extensive materials attached to their comment they do not specifically address the need for PEC at winter peak. In its July 10th letter to the Board IESO stated:

> IESO's letter was not intended to be filed as evidence, but rather as a submission in support of Union's Parkway West Project and Enbridge's GTA Expansion Project to the extent that these projects enhance electric reliability.

IESO offered to provide witnesses but as is apparent from M.IESO.GEC.1 they would not have been in a position to attest to much of the content of the materials. Mr. Chernick analysed the specifics of the issue of the need for PEC at winter peak in great detail in his pre-filed evidence. He noted that there is no conflict between Ontario or GTA winter electricity needs and curtailment of PEC[29]. GEC also sought further information from the IESO by way of interrogatories. As a review of the M.IESO.GEC series of responses makes clear, IESO offers no information that would demonstrate a lack of GTA regional electricity capacity or reserve at winter peak if PEC were unavailable. The fact noted repeatedly by Enbridge that PEC has operated at winter peak times is simply indicative of economic dispatch, not of need.

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[27] J7.1
[28] V.6, p.86
[29] L.EGD.GEC.1 pp. 23-30

Supply Diversity

TCPL in its August 16th supplemental evidence addresses the Enbridge claim that the GTA project improves diversity of supply. TCPL points out that transportation path diversity can be more critical than commodity source diversity noting that "the latter goes to economic opportunities whereas the former goes to both economic opportunities and security of supply". The GTA projects will increase the growing and dominant reliance that EGD is placing on the Union Dawn to Parkway system[30]. Enbridge agreed that in addition to supply diversity, firm transportation path diversity is also important to ensuring reliability to the GTA[31].

As to the commodity source element of supply diversity, TCPL provides a review of numerous forecasts for total WCSB supply and for technical resource estimates which suggest that there is certainly no near term issue[32]. As we suggest below, a deferral of any decision on these matters may be appropriate given the many uncertainties at play. The availability of western Canadian supply is certainly not a constraint in the near term and may not be in the long term. The picture will continue to evolve as the Western basins are developed, decisions are made about pipelines to the west coast and LNG exports from BC, the Gulf Coast and the MidAtlantic, and tar sands development evolves.

In comparing TCPL's view of western gas supply to Enbridge's it is vital to note that EGD, inexplicably, does not include shale gas in western gas projections[33].

Notably, the NEB found no decline in economically available gas supply to the mainline in its RH-003 Decision[34].

Of course, displacing elements of the GTA project by DSM would reduce reliance on supply and improve reliability and it is this approach we urge upon the Board, an approach entirely consistent with Ontario government policy. The supply and environmental risks of new gas

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[30] See TCPL Supp. Evid. pp. 9-10 where TCPL calculates an 83% reliance proposed for this path.
[31] I.A1.EGD(Update).TCPL.7
[32] TCPL, i*bid*, pp.11-17
[33] See 1.A1.EGD(Update).TCPL.20
[34] K1.5, NEB decision, Discussed at Transcript V.2, p. 87-89

supply projects addressed by CoC's experts simply amplify the wisdom of emphasizing DSM. We were particularly struck by the facts outlined by Mr. Hughes, who noted that actual data shows declines already occurring in shale plays only a few years old, despite optimistic forecasts to the contrary. Dr. Ingraffea highlighted how shale gas production dramatically increases GHG emissions. His evidence was not seriously contested. Thus, whether gas is to be obtained from the U.S. or Canada, DSM that reduces reliance on it must be an increasingly important approach.

Operational Flexibility

Enbridge offers a further rationale for its proposals, improved operational flexibility due to the east-west link provided by Segment A and the east-west portion of Segment B (i.e. B1)[35]. However, Enbridge offered no example of any significant difficulty operating their system to date or going forward without this added link. While adding options certainly increases flexibility, there is simply no basis to conclude that there is any significant value in this enhanced flexibility.

ISSUES A2 & A3- Do the facilities meet the Board's economic tests – are the costs and rate impacts appropriate?

TCPL's Revenue Shortfall -- A Zero Sum Game

Enbridge provides the profitability index for its projects in the absence of gas savings as 0.79[36]. The project fails and it will raise rates unless gas savings are significant. Do the gas cost savings offer salvation? Hardly. Despite every effort by Enbridge to avoid the obvious conclusion, whether or not the NEB accepts the Term Sheet and October 31st Settlement Agreement deal, either the TSA and LTAA balances or the bridging adjustment plus tolls at full COS will visit on end users the TCPL lost revenues due to shippers switching from long haul western Canadian gas to short haul U.S. gas facilitated by these projects.

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[35] The option of eliminating Segment B2 maintains the added flexibility that Enbridge suggests.
[36] At 1.A1.EGD (Update).TCPL 5

The math is simple. U.S. gas commodity is forecast by the LDCs themselves to cost $0.51 to $0.91 or $0.92/Gj *more* than western gas (and TCPL provides even higher projections at $1.50). Since TCPL will be made whole, much of its lost revenue in the 2015-2020 period will have to be recaptured over time by way of the bridging charge and on an ongoing basis by way of tolls at COS (or by way of the NEB's TSA and LTAA variance accounts if the term sheet and October 31 Settlement is not accepted). The LDCs will pay a higher price for US fracking gas, will not avoid the costs of TCPL's mainline, will shift some costs of the mainline to other Ontario shippers, and will spend roughly a billion dollars building and operating infrastructure.

GEC understands why the LDCs and TCPL have entered into the term sheet and October 31st Settlement Agreement. Our dispute is not with the wisdom of that proposal. Our dispute is with the wisdom of the GTA projects. The deal simply takes the speculation out of the question of whether TCPL will be made whole and makes clear there are no gas savings.

The benefit of the deal's lower RoE and $20M/year contribution from TCPL will occur regardless of the approval or denial of these applications[37]. Switching to short haul will not avoid significant upstream NOL costs post 2020 because that is when the TCPL lines will be fully depreciated anyway. (TCPL's witnesses acknowledged that it is no coincidence it agreed to the zoning only after 2020[38].) What the term sheet and Settlement Agreement do is simply recognize the reality that TCPL has sunk costs and it is the shippers that must pay for them. That intent is clear from the language of the Term Sheet:

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[37] V.3, p.44, l.13 and at page 46, l. 22:

> MR. POCH: Okay. Part of the deal has TCPL making this contribution, $20 million a year for, I think, six years?
> MR. ISHERWOOD: That's correct.
> MR. POCH: And there's an earnings-sharing mechanism with a lower pivot point for the return on equity?
> MR. ISHERWOOD: Yes.
> 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.

[38] V.9, p.5

> ***"The LDCs commit to remain consistent with the principles of this Term Sheet, in which the LDCs support TransCanada having a fair opportunity to recover its costs, including lost revenue associated with shifts from long haul to short haul service, over an appropriate period of time."***[39]

The October 31st agreement preserves the arrangement (see Purpose section 2.2(d)).

It is certainly likely that shippers who can escape the TCPL tolls and bridging fees will flee. The US Northeast shippers may be able to do so as pipelines south of the border materialize. The fact that they are already on short haul service will not shield them from rising tolls forecast for both long haul and short haul to compensate for TCPL's lost throughput.

Similarly, the zonal segmentation (post 2020) in the term sheet and October 31st Settlement Agreement offers little mitigation because the risk sharing RoE mechanism is on a total system basis, not a segmented basis, and because the LDCs will still be significant shippers on the Prairie and NOL lines as well as the EOT.

To the extent that toll increases during or after the initial 6 year period are required to maintain TCPL's COS return due to added switching facilitated by the GTA projects, that will raise both short and long haul tolls. As the Chair succinctly noted, there is no escaping TCPL's sunk costs. (Except for the US shippers, whose departure will further reduce TCPL revenues and increase TCPL rates.)

As noted above, Enbridge's P.I. is below 1 without gas savings. For its P.I. to be otherwise the cost of western Canadian gas would have to rise to offset both the $0.91/Gj differential plus the facilities costs. We do not credit the project with revenue from customer additions because with adequate DSM (which is cost-effective based upon gas savings alone) the existing system can accommodate new loads. In other words, the revenue from customer additions can be obtained in a no-new-facilities scenario.

[39] K1.1, p.9

The numbers for Union appear no better. Union estimated moving 70,000 GJ/day to short haul produces $15.4M per year in savings, $92.4 over 6 years. However, as discussed at Vol. 3 p. 69 *et seq.*, the tolls differential of approximately $140/GJ will drive a revenue shortfall for TCPL that will be picked up by the bridging charge of $214M. The difference is a loss of $121.6M and then the capital and operating costs of the project are on top of that. Mr. Wolnick summarized that in his cross at V. 3, page 75:

MR. WOLNIK: Okay. So incrementally there's a net additional cost overall to the system of about $100 million.

MR. ISHERWOOD: That's correct.

MR. WOLNIK: Okay. And in addition to that, in order to make this shift, there's a number of additional facilities that are required, Dawn to Parkway, Parkway to Albion, Albion to Vaughan; is that right?

MR. ISHERWOOD: I'm just a little conscious of the Enbridge pipe is also distribution, but you need the whole path completed.

Gaz Metro corroborates our analysis with its estimate of a $2 billion shortfall in TCPL revenue due to switching to short haul that will largely be transferred to the shippers as a result of the term sheet and Settlement Agreement deal[40] . They recoup this revenue by way of the amortized bridging payment and the COS tolls. TCPL's initial estimate of the shortfall for the 2015-20 period that it will have to carry for up to 16 years in the deferred portion of the bridging charge is $1.2 billion[41].

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[40] Transcript Sept. 13, p.37
[41] Transcript Sept. 13 p.36

TCPL's witnesses subsequently made clear that the $1.2 billion is not the full bridging cost – it is just the part that will be collected post 2020[42]. On a simple basis, $1.2 billion being 10/16ths of the shortfall implies that the total shortfall to be collected will approach 2 billion dollars, just as GMi's Mr. Cabana suggested. Two billion dollars swamps the net benefits for these projects claimed in the pre-filed evidence. Of course the shortfall will be shared by all shippers, but the volumes that other shippers shift to short haul (facilitated by the GTA projects) will also add to the shortfall shared by the LDCs. Any shipper that is not party to the term sheet will likely flee the TCPL system if it has an alternative, further increasing the shortfall.

TCPL in its supplementary evidence indicated:

> "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."

Under cross-examination TCPL's witnesses were asked how the situation had changed with the term sheet settlement. They agreed that their analysis was correct at the time but that they were "not sure now" as they had not rerun the analysis[43]. Given TCPL's pledge to the LDCs to support the GTA project applications, it is not surprising that they declined to offer a definitive appraisal, but we would submit that the conclusion to be drawn is obvious.

Union in Exhibit J4.5 and Enbridge in Exhibit J6.X sought to demonstrate that their projects have positive economics (i.e. a profitability index > 1). However, their analyses are based on the assumption that the indicative tolls that TCPL provided tell the whole story and treat the 50% toll increase as a hard cap – an assumption that is not supported by the term sheet[44].

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[42] V. 9 pages 6-8

[43]

[44] MR. POCH: First of all, given the commitment to full cost of service, to the extent that the bridging at that level proves inadequate, is it fair to say that you, then –- the sort of cost of service resets will be the mechanism by which TCPL will attempt to regain or attain full cost of service return?

MR. SCHULTZ: I think we indicated that after the first three years we would revisit the assumptions that were made currently to set those rates, and adjust for any differences between what we assumed and what was actually occurring.

Indeed, the goal in the term sheet is for a 50% toll increase on short haul with 30-35 basis points of the 50 attributable to TCPL regaining full COS revenue, i.e. 15-20 attributable to bridging. Mr. Isherwood acknowledged that using Union's J4.5 part b methodology at 20 basis points attributable to bridging, rather than the 15 basis points that Union used, reduces their p.i. to well below 1[45].

Enbridge's J6.x injects the complication of added demand charges due to lower long haul utilization factors. But any further 'saving' of demand charges due to shifting to short haul would exacerbate TCPL's revenue shortfall and be clawed back in a larger required bridging charge or in triennial COS adjustments. Any premium paid for seasonal commodity (as opposed to transportation) would presumably be paid on the commodity whether from out west or from the south. Enbridge also bases its savings analysis on the "illustrative" 6 year tolls that TCPL has provided. If the bridging leaves TCPL with a shortfall the result will be higher COS tolls on each segment of TCPL's mainline and the LDCs will have to pay their share (based on use after 2021). As we heard, the LDCs both anticipate remaining significant users of the TCPL mainline (i.e., the Prairie and NOL sections as well as the EOT) in the post 2020 period[46].

Simply put, the only saving ensured by the term sheet and October 31st Settlement is due to the 6 years of $20 million annual contribution from TCPL and the lower RoE target, but these benefits are shared with all other shippers and are obtained whether or not the GTA projects proceed. On the negative side of the ledger are the project costs and the $.91/GJ premium for US commodity. The only possible way for Enbridge to show a positive P.I. is by claiming net revenues from customer additions, but those revenues can be obtained more economically with a DSM strategy that offsets load growth, allowing new loads to be met by existing supply-side resources.

[45] V.9, p.20
[46] V.9, pp. 9-10

It should also be noted that the benefits from adding customers that Enbridge counts in its feasibility analysis assumes current annual loads per customer despite the trend in declining average use[47].

We note that the Parkway West costs have already increased from $203 to $219 million, and Union hasn't even broken ground yet, and the last three compressor projects have all had significant cost overruns[48]. The Portlands project, which was budgeted at $41 million, actually cost $61 million. Accordingly, the net loss from these projects is only likely to increase as cost overruns inevitably accrue.

ISSUE A4 - Alternatives:

Failure to consider DSM and Interruptible Rate Options as an alternative to some or all of the supply-side proposals

As discussed at the outset of this submission, Enbridge has simply failed to adequately consider demand side alternatives that could offer lower costs and lower adverse impacts. Enbridge has not studied how annual demand reductions relate to peak demand reductions despite, as Mr. Neme testified, off the shelf models for measures and building profiles being readily available for this purpose. Enbridge's failure to seriously consider DSM is also evident in the inaccurate portrayal of the peak reduction impacts of Demand Side Management in its pre-file, in the company's failure to capture T&D costs in avoided costs, in the lack of a least cost planning or IRP approach to system design, and in the failure to include DSM personnel in project planning.

The *OEB Act* provides the following Board objective:

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[47] V4, p.129 and at page 130 the following summary appears:

> MR. ELSON: Thank you. So to recap what we've gone over today, from 2004 to 2012 Enbridge's customers increased by approximately 128,000, but its annual demand declined by about 25,000 tJs, whereas in this summary of inputs, over the next ten years, the inputs state that there will be an approximately 23,000 tJ increase in annual consumption, which is based on customer additions of 131,000. Is that an accurate summary, subject to check?
>
> MR. FERNANDES: So I think you're doing the math correctly, Mr. Elson, but the economic feasibility holds everything constant in 2013 parameters. It's not a forecast, it's only intended to show the net incremental for comparative purposes.

[48] Exhibit I.A3.UGL.Staff.13

> *2. The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:*
>
> > *5. To promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.*

There can be little doubt that DSM with its history of a 4:1 benefit to cost ratio is societally preferable even on a narrow economic basis (i.e. without counting avoided externalities). At K4.5, page 4 Environmental Defense has utilized Enbridge data to show net TRC incremental benefits that DSM offsetting GTA load growth would bring. The net benefit amounts to $1.688 billion over the 2014-2025 period[49]. As Mr. Chernick summarized:

> "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."[50]

There can be no doubt that greenhouse gas avoidance by way of DSM is required by the GHG reduction goals of Ontario Government policy and in accord with its conservation-first approach recently articulated for electricity planning.

[49] Constant dollars not discounted. Confirmed in JT2.20 where Enbridge shows $140,654,152 per annum 2014-25
[50] V.7, p.49

Any concern about the impact on rates of non-DSM participants from a targeted DSM program is mitigated by the fact that the costs of building, financing and operating the proposed facilities and the premium to be paid for US gas would otherwise be borne by *all* ratepayers.

It is apparent that Enbridge's ignoring of externalities and of the capital-cost avoidance benefits of DSM has systematically undervalued this alternative[51]. This in turn has led to decisions about DSM budgets and rate impacts that fail to account for the full benefits and that fail to recognize that DSM displacing or deferring capital investments in T&D has less rate impact than DSM that avoids only upstream supply. The Board's decision to impose a three-year moratorium on real increases in DSM budgets (apart from an increase for low income programs) was arrived at in light of a concern for rate impacts on non-DSM participants, a concern that was based on this incomplete picture offered by the utilities.

The Environmental Commissioner has noted how the freeze on DSM budgets is at odds with the government's climate change objectives:

[51] An Enbridge witness suggested the Board had never approved the use of environmental externalities in cost-effectiveness testing for DSM, presumably suggesting they should not be considered today. In fact the EBO-169 Decision specifically identified the Societal Cost Test as the test to use - it differs from the TRC test only by the inclusion of monetized environmental externalities (see EBO-169-III Decision July 23, 1993, para 4.2.7 and 4.2.8). Not only did the Board come to this conclusion, but Consumers Gas supported fully valuing conservation through inclusion of externality and 'future avoided system costs' in avoided costs:

> 4.1.15 Consumers Gas agreed with Board Staff that it is appropriate to extend some portion of DSM costs to the system, as all ratepayers will benefit from the avoided costs of future supply, including externality costs. Consumers Gas also agreed that a balanced portfolio of DSM programs is warranted given the existence of significant market barriers to conservation.
>
> 4.1.16 Consumers Gas submitted that the analysis of future avoided system costs could reveal significant benefits for gas customers….

> *A QUESTION OF COMMITMENT*
>
> *Review of the Ontario Government's Climate Change Action Plan Results*
>
> *Annual Greenhouse Gas Progress Report 2012 Environmental Commissioner of Ontario December 2012*
>
> *Furthermore, reductions in indirect emissions associated with electricity use in the building sector have not been matched by similar reductions in direct emissions associated with the use of natural gas. As such, recent decisions by the Ontario Energy Board (OEB) to freeze natural gas utility demand-side management budgets and deny pricing support for renewable natural gas (i.e., biogas) are regrettable and may impede progress in this area."*

The failure to consider innovative rate structures to obtain curtailable load is a parallel example of Enbridge's inadequate treatment of alternatives.

Achieving DSM

Assuming that Enbridge's load forecast does not overestimate growth (which, as noted above is an assumption GEC does not accept), and using Enbridge's (inappropriate) assumption that peak should be assessed without resort to contracted interruptible capability (i.e. modelling is done with interruptible loads on) Enbridge's estimates of the peak effective DSM required in the GTA to address its forecast of shortfall at Station B by winter peak 2015/16 amounts to 26 10^3m^3/hr.[52] Mr. Chernick notes that less would be required if DSM effort is concentrated in the areas that most influence the flows on the Don Valley line.

Mr. Neme estimates a 2015 *achievable* peak hour DSM savings in the GTA area as approximately 30 10^3m^3/hr and the 2016 value is close to 37 10^3m^3/hr.[53] The achievable

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[52] See derivation at L.EGD.GEC.1, pp. 21-22
[53] L.EGD.GEC.2, p. 12

incremental DSM would thus be 23 $10^3 m^3$/hr in 2016. Give that there is over 100 $10^3 m^3$/hr of interruptible load in the GTA (see below) this added DSM is more than adequate to address the station B shortfall in 2016 and continued DSM efforts would outstrip growth beyond that timeframe.

Mr. Neme's values are based on real world experience in other jurisdictions as well as an understanding of Enbridge's current programs. Notably, in the very heat sensitive (i.e. peak contributing) residential sector, Mr. Neme observes that Enbridge has a particularly modest program in place with lots of room for growth. He suggested that improving and ramping up existing programs would expedite and ensure timely savings. Mr. Neme identified that just a single program (the residential retrofit program) could accomplish the required reductions in the residential sector.

Mr. Jarvis of Enerlife offered highly representative data gathered from actual buildings (the majority of which are in the GTA) to show the DSM potential of that one program approach for commercial buildings that has proven to be particularly effective.

Enbridge, in its cross examination of the GEC and Enerlife DSM witnesses attempted to suggest that a strategy to address the Station B issue utilizing DSM was risky. Of course, if it really was so risky there is even more reason to criticize Enbridge for failing to plan on a timely basis. (EGD had known of the Station B issue from at least 2002.)

In fact, there is no evidence that the risk of achieving the needed DSM is a significant concern apart from Enbridge's witnesses' doubts, witnesses who acknowledge that they have not even tried to assess the role of DSM in peak reduction. Mr. Neme and Mr. Jarvis, both experts in program delivery, expressed confidence in the approach.

In an attempt to make the point about risk, Mr. Stoll cited two references in the RAP study that Mr. Neme authored on integrated resource planning in the electricity sector[54]. First Mr. Stoll

[54] Exh.M.GEC.EGD.6, Att. A (also at K7.1, tab 1)

cited page iii of the report and read into the record the statement that peak demand savings were 30% below targets. He stopped short of reading the following words:

> "they were still three to five times greater than those achieved statewide (notable since the statewide savings were already the highest in the nation)."

The DSM strategy proposed by the GEC and Enerlife witnesses would require a threefold increase in GTA DSM, less if targeted in the 'peach area'.

Mr. Stoll also read into the record an extract from page 15 of that same report pointing out that for geo-targeted programs in Vermont, not all results were as good as hoped or projected. Again he failed to read the related references on that same page, including:

- Efficiency program participation was considerably higher in geo-targeted areas of the state... commercial and industrial customers participated at a rate nearly four times as great as their counterparts in the rest of the state.

- Savings per participant were also higher than in statewide programs – 20% to 25% higher for commercial and industrial customers and 30% higher for residential customers.

These two effects of higher participation and higher savings per participant can be multiplied together and illustrate that significant increases have and can be achieved – again far more than the threefold increase in the 'peach area' of the GTA needed to address the station B issue.

The programs that Mr. Neme and Mr. Jarvis proposed are cost-effective with Enbridge's existing avoided costs. Mr. Chernick noted that avoided costs for targeted DSM would be 49 to

130% higher than Enbridge's standard avoided costs for heat sensitive load[55]. Accordingly, there is every reason to expect these program results are achievable and affordable.

Enhanced Interruptible and Curtailable Rate Mechanisms for PEC and Other Customers

As discussed in detail at L.EGD.GEC.1 pp. 23-30, one customer, the Portlands Energy Centre (PEC) contracts for up to 116 10^3m^3 which is approximately 30% of the peak load Enbridge plans for at Station B. This is at least 4 times more than the 26 10^3m^3 load reduction that Enbridge indicates it requires at Station B in 1016 assuming that no targeted DSM is utilized. Mr. Chernick's evidence illustrates in great detail how the 25% curtailment that might be sought from PEC (if no DSM were to materialize) on the few days when weather approaches 41 DD would not conflict with Ontario or GTA electricity needs. The cost to compensate PEC and customer, the OPA, for the ability to obtain such a minimal and infrequent curtailment would surely be trifling and there is no reason to expect that PEC's customer, OPA, being a public agency, could not be persuaded to act in the best interest of Ontarians.

Of course, PEC is just one of 4 or 5 large industrial customers in the area and other large users such as large apartments and commercial buildings could be offered an enhanced interruptible or curtailment rate (curtailment affecting less critical parts of their load) to avoid more expensive infrastructure. Enbridge's witness acknowledged that they had not considered this option and seemed unable to grasp the concept that an enhanced version of their current interruptible rate offerings might reduce rates for all customers[56]. Surely, in Ontario where we have the example of the electricity sector adding several versions of demand response programs to address peak, this option should be an obvious consideration if reducing system costs, rather than building rate base is the goal.

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[55] Exh. M.GEC.ED.1 Revised

[56] Vol. 5., p.86: You say interruptible load is waning, if I've got the waxing and the waning right there. Did you look at what would happen if you raised the incentive to customers to take interruptible service based on the avoided costs of infrastructure, this infrastructure, that you might be able to thereby avoid?

[Witness panel confers]

MR. FERNANDES: The short answer is no, but I do need to add that that would require significant policy change in terms of being able to offer additional incentives, because we would need to understand where that would come from.

According to Ex. A-3-4 p.9, GTA forecast demand is 3093 10^3m^3/hr in 2015, and 3117 in 2016 growing 24 10^3m^3/hr. From Ex. A-3-7 p.4 we see that curtailable load in the GTA is over 2000 10^3m^3/day or 100 10^3m^3/hr on a 20 hour/day basis. Thus, interruptible load is clearly a major factor to be considered in addressing both the Station B 'problem' and the 30% SMYS target in the near term, yet Enbridge models without utilizing this resource.

Here we see yet another example of an alternative that Enbridge simply failed to consider. Asked about the loads that are currently interruptible and the availability of fuel switching capacity, the company could offer no information[57]. Analogous to its inadequate approach to valuing and investing in DSM, EGD prices its interruptible rate offering to reflect its gas supply savings, not avoidable T&D[58]. Nor does the company offer curtailment rates rather than full interruption[59].

Utilizing US gas with no Segment B or no Segment B2

As discussed above, GEC submits that there is no net gas savings and thus no need to ensure that US gas can be utilized in a scenario where demand-side options eliminate the need for some or all of the pipeline proposals. However, should the Board conclude that there is merit to accessing US shale gas, we offer the following observation.

During the June 12 Technical Conference (transcript pp. 39-40) we discussed with Mr. Fernandes the shipment of gas via Segment A, then along the Albion to Maple link and on to Victoria Square. He thought it would be possible and we asked if that had been costed – the answer was no. (Consistent with the fact that Enbridge has ignored alternatives with fewer pipeline facilities.)

Nevertheless, Mr. Stoll, in his cross-examination of Mr. Chernick, suggested that Mr. Chernick had failed to count the cost of transporting gas from Albion to Maple in his ‘economic analysis’. In fact, Mr. Chernick’s ‘economic analysis’ did not purport to evaluate the savings or losses attributable to a switch from western to U.S. gas, so Mr. Stoll’s criticism was misdirected.

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[57] L.EGD.GEC.1, p. 31 referencing 1.A1.EGD.GEC.23b.
[58] L.EGD.GEC.1, p. 31 referencing 1.A1.EGD.GEC.23c(ii).
[59] L.EGD.GEC.1, p. 31.

However, as Mr. Chernick noted, all the gas that flows into the Don Valley line already flows from Maple to the Victoria Square station. If US gas is advantageous (which we doubt) and the facilities other than Segment B were built, that US gas could be brought along Segment A, up the link to Maple and along its current path to Victoria Square; in the 'no Segment B2' scenario, an additional portion of the US gas could simply flow to the interconnect with the Don Valley NPS 30 line. In any case, Mr. Chernick has shown that Enbridge could utilize all the proposed purchase of US gas on the west side of its GTA system without the need to transport it to Victoria Square[60]. It is not clear that Enbridge would actually have any additional US gas to send to the Don Valley.

Further, TCPL's witnesses confirmed that TCPL could assure supply at Victoria Square so long as Enbridge was prepared to commit to a suitable contract term.[61]

ISSUE A5- Is the timing of facilities appropriate?

Given the uncertainties about TCPL tolls, Energy East, Western Gas diversions to LNG, NEB approvals for King North, and Empress/Dawn price differentials, delaying a decision could be a valuable option. To do so it would be appropriate to address forecast Station B low pressures by ensuring that GTA focussed DSM proceeds in the interim and enhanced rates for curtailable loads are considered. The deferral of the capital outlays would have considerable net present value even if later it was determined that they should be pursued, and the DSM would all have high societal value based solely on interim supply cost avoidance[62] .

ISSUES C6 & D6 – Conditions

Please see the conditions proposed in our recommendations, below.

CONCLUSIONS & RECOMMENDATIONS

EGD's approach to this application is a stunning testament to the disconnect between gas industry planning and government policy and societal value. Enbridge's admission that it did

[60] L.EGD.GEC.1, pp. 15-16
[61] V.9, p.15
[62] See M.GEC.ED.1 Revised

not address the 80% GHG reduction target and that its planners did not even understand the target in detail is simply disheartening. EGD made no inquiry of OPA and PEC to examine curtailment options. It did not evaluate enhanced interruptible or curtailable rate options for a broader array of customers. No tools have been developed to utilize DSM for peak reduction, despite the station B supply objective being on EGD's radar since at least 2002. The failure to include capital cost avoidance in DSM avoided cost analyses has undervalued DSM, overstated the rate impact on non-participants and led to proposals for more expensive supply side alternatives.

Elaborate explanations of the toll increase target and demand charges notwithstanding, ultimately, if TCPL is to be made whole, it is a matter of simple logic that there is no escaping the sunk costs that TCPL will need to recover to receive its full COS return (as the term sheet and October 31st Settlement Agreement guarantee) because the EOT shippers are obliged to, and plan to, remain the primary users of the EOT TCPL facilities and will remain significant shippers on the NOL and Prairie portions of the mainline[63].

GEC respectfully suggests that the Board:

1. Deny approval of the Enbridge and Union proposals (with the possible exception of the LCU and related station reconfiguration, which we leave to others to evaluate).

2. In the alternative deny approval of Segment B1 and/or B2 and require alternative approaches to addressing Station B pressure issues (DSM and interruptible rates).

3. In the further alternative defer consideration of approval and require alternative approaches to addressing Station B pressure issues.

4. Direct the LDCs to utilize a 10 year planning horizon to enable least cost planning.

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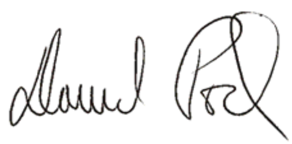
[63]Even if we were wrong about the extent of the claw back of gas savings by way of the term sheet mechanisms, the construction of the Union facilities and Segment A alone would obtain any possible gas supply benefits and Segments B1 and/or B2 would still be unjustified.

5. Direct the LDCs to include transmission and distribution reinforcement and capital project costs and avoidable transmission tolls in its avoided costs utilized for DSM planning and interruptible rates and to do so at a system and local level.

6. Condition any approval or deferral of a decision on leave to construct with a requirement to pursue all cost-effective DSM and curtailment and interruptible rate options to achieve least cost outcomes and to propose budgets compatible with that goal in the forthcoming multi-year DSM proceeding.

7. If the Board accepts Enbridge's view that it is too late to place reliance upon a lower cost approach relying on DSM and interruptible rate enhancement, then shareholders, not customers should pay the added costs due to sub-optimal planning, and the Board should indicate to the utility that any leave to construct should not be construed to suggest that those added costs will be considered prudent.

ALL OF WHICH IS RESPECTFULLY SUBMITTED



David Poch
Counsel to the GEC