500 Consumers Road
North York, Ontario
M2J 1P8
PO Box 650
Scarborough ON M1K 5E3

Shari Lynn Spratt
Supervisor Regulatory Proceedings
Telephone: (416) 495-5499
Fax: (416) 495-6072
Email: EGDRegulatoryProceedings@enbridge.com

October 8, 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
Undertaking Response

Enclosed please find Enbridge's updated response to Undertakings J6.5 and J6.7 from the hearing held on September 26, 2013.

This update is in response to an enquiry from an Intervenor and is provided in order to clarify certain fundamental aspects of the operation of the natural gas system.

This evidence 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 J6.5

UNDERTAKING

TR 6, page 83

EGD to provide model simulation related to the pressures at Station B in response to GEC scenarios.

October 8, 2013 Updated Response:

This update is in response to an enquiry from an Intervenor and is provided in order to clarify certain fundamental aspects of the operation of the natural gas system.

The pressure ramping or elevating of natural gas systems have to take into account the physical movement of gas, the mass flow rates based on pressure differentials, the facilities design, contractual obligations and the physical properties of natural gas itself.

First, the ability to bring gas into the distribution system is subject to the contractual obligations with upstream suppliers in terms of nominations and hourly flow rates. The distribution system also has various control systems that operate many variables to maintain a steady system operation. Elevating the pressure in a longer, larger piping system takes additional time. The combination of these factors places constraints on how the system, and in particular, the large diameter critical feeds into the system, can be operated in prudent practice. The Company does typically vary the pressure in the lines described in the pre-filed evidence, specifically the Don Valley NPS 30, including operation below 30% SMYS where practical. However, the increase in pressure from a shoulder season operation to winter conditions, where the pressure is increased above 30% SMYS, is typically performed over several days in order to manage the many variables involved while maintaining orderly system operation. Pressure increases as contemplated in the undertaking cannot prudently occur over a few minutes or even hours.

The initial response below included performing a system analysis with interruptible customers shed from the system, and also forcing off a large firm customer. As stated, this does not comply with the Company's system design criteria. This particular analysis already includes the shedding of the largest loads on the system that would have a direct impact on the point of minimum system pressure at Station B. To further change the results of the modeling in a material fashion would require the additional shedding thousands of firm customers from the system. This is not practical and

represents the invoking of “force majeure”. Invoking “force majeure” as a planned, normal response to cold temperatures would be inconsistent with prudent planning.

To clarify, the 33 DDC condition, which below was stated as typically occurring multiple times every winter, occurs more than 4 times per winter on average based on historical data.

The pressure reduction proposed for the NPS 30 Don Valley line reduces the system capacity by approximately 165 TJ/d as measured at Station B. As described in the first two scenarios below with no reinforcements installed, or only Segment A, in addition to the interruptible customers and PEC removed from the system as requested, there is still a supply shortfall of 29 TJ/d as measured at Station B. The interruptible customers and PEC account for approximately 136 TJ/day. The 29 TJ/d shortfall represents additional firm load that must be removed from the system. This would entail removing hundreds of firm commercial and industrial loads or a systematic isolation of the system through load shed.

RESPONSE

It should be noted that Enbridge does not agree with the assumptions in this analysis.

Portlands Energy Centre (“PEC”) has a 20 year Gas Delivery Agreement for firm service with Enbridge, and further paid a contribution in aid of construction to receive such service. As mentioned on Hearing Day 6 at transcript page 88, lines 17 to 20, “Portlands is systemically important to the electric system, and they also stated that they have run every single peak winter day since being in operation”. Enbridge considers peak weather conditions as foreseeable and would therefore not consider interrupting PEC or using terms within its contract (i.e., force majeure) to shed its firm load under cold weather conditions. It does not view failing to meet firm commitments as a reasonable alternative to prudent system planning and would not consider potentially jeopardizing the reliability of the electric system to increase the reliability of the natural gas system when the proposed facilities increase the reliability of both systems.

Simulations were completed as requested for 2015 using steady state modeling with PEC and all large interruptible loads removed in downtown core of Toronto. The NPS 26 and the Don Valley line are running at 30% of SMYS.

- With No reinforcements: model out of pressure at Station B
- With Segment A only: model out of pressure at Station B
- Segment A and East-West portion of Segment B: 262 psi at Station B

Witness: E. Naczynski

UNDERTAKING J6.7

UNDERTAKING

TR 6, page 94

EGD to provide model simulation to show if it can reduce SMYS to 30 percent or below today if it interrupted PEC and/or its 4 industrial customers; to include scenarios Segment A, east-west, portion of Segment B.

October 8, 2013 Updated Response:

This update is in response to an enquiry from an Intervenor and is provided in order to clarify certain fundamental aspects of the operation of the natural gas system.

The pressure ramping or elevating of natural gas systems have to take into account the physical movement of gas, the mass flow rates based on pressure differentials, the facilities design, contractual obligations and the physical properties of natural gas itself.

First, the ability to bring gas into the distribution system is subject to the contractual obligations with upstream suppliers in terms of nominations and hourly flow rates. The distribution system also has various control systems that operate many variables to maintain a steady system operation. Elevating the pressure in a longer, larger piping system takes additional time. The combination of these factors places constraints on how the system, and in particular, the large diameter critical feeds into the system, can be operated in prudent practice. The Company does typically vary the pressure in the lines described in the pre-filed evidence, specifically the Don Valley NPS 30, including operation below 30% SMYS where practical. However, the increase in pressure from a shoulder season operation to winter conditions, where the pressure is increased above 30% SMYS, is typically performed over several days in order to manage the many variables involved while maintaining orderly system operation. Pressure increases as contemplated in the undertaking cannot prudently occur over a few minutes or even hours.

The initial response below included performing a system analysis with interruptible customers shed from the system, and also forcing off a large firm customer. As stated, this does not comply with the Company's system design criteria. This particular analysis already includes the shedding of the largest loads on the system that would have a direct impact on the point of minimum system pressure at Station B. To further change the results of the modeling in a material fashion would require the additional shedding thousands of firm customers from the system. This is not practical and

represents the invoking of “force majeure”. Invoking “force majeure” as a planned, normal response to cold temperatures would be inconsistent with prudent planning.

To clarify, the 33 DDC condition, which below was stated as typically occurring multiple times every winter, occurs more than 4 times per winter on average based on historical data.

The pressure reduction proposed for the NPS 30 Don Valley line reduces the system capacity by approximately 165 TJ/d as measured at Station B. As described in the first two scenarios below with no reinforcements installed, or only Segment A, in addition to the interruptible customers and PEC removed from the system as requested, there is still a supply shortfall of 29 TJ/d as measured at Station B. The interruptible customers and PEC account for approximately 136 TJ/day. The 29 TJ/d shortfall represents additional firm load that must be removed from the system. This would entail removing hundreds of firm commercial and industrial loads or a systematic isolation of the system through load shed.

RESPONSE

It should be noted that Enbridge does not agree with the assumptions in this analysis.

PEC has a 20 year Gas Delivery Agreement for firm service with Enbridge, and further paid a contribution in aid of construction to receive such service. As mentioned on Hearing Day 6 at transcript page 88, lines 17 to 20, “Portlands is systemically important to the electric system, and they also stated that they have run every single peak winter day since being in operation”. Enbridge considers peak weather conditions as foreseeable and would therefore not consider interrupting PEC or using terms within its contract (i.e. force majeure) to shed its firm load under cold weather conditions. It does not view failing to meet firm commitments as a reasonable alternative to prudent system planning and would not consider potentially jeopardizing the reliability of the electric system to increase the reliability of the natural gas system when the proposed facilities increase the reliability of both systems.

Simulations were completed as requested for 2015 using steady state modeling with Portlands Energy Centre (PEC) and all large interruptible loads removed in downtown core of Toronto. The NPS 26 and the Don Valley line are running at 30% of SMYS.

- No reinforcements: Station B pressure is at approximately 225 psi at 33 DDC
- Segment A only: Station B pressure is at approximately 225 psi at a 33 DDC
- Segment A and East-West Segment B: Station B pressure is at approximately 262 psi at 41 DDC

Witness: E. Naczynski

Enbridge cannot predict the number of hours in a given year of when pressure above 375 psi would be required as it is dependent upon the prevailing weather. In the first and second scenarios, Station B will have inadequate pressure at anything more than 33 DDC (-15 C) which typically happens multiple times every winter.