John A.D. Vellone
T (416) 367-6730
F 416.367.6749
jvellone@blg.com

Borden Ladner Gervais LLP
Bay Adelaide Centre, East Tower
22 Adelaide Street West
Toronto, ON, Canada M5H 4E3
T 416.367.6000
F 416.367.6749
blg.com

June 15, 2018

Delivered by Email, RESS & Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2701
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Enbridge Gas Distribution Inc. & Union Gas Limited
MAADs Application (EB-2017-0306)
Rate Application (EB-2017-0307)
Submissions of The Association of Power Producers of Ontario

Pursuant to Procedural Order No. 9, please find enclosed Submissions of the Association of Power Producers of Ontario.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Per:

Original signed by John A. D. Vellone

John A. D. Vellone

cc: Applicant and Intervenors of record in EB-2017-0306 & EB-2017-0307
Dave Butters, APPrO
John Wolnik, Elenchus

EB-2017-0306 / EB-2017-0307

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. and Union Gas Limited, pursuant to Section 43(1) of the *Ontario Energy Board Act, 1998* for an order or orders granting leave to amalgamate as of January 1, 2019;

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. and Union Gas Limited, pursuant to Section 36 of the *Ontario Energy Board Act, 1998*, for an order or orders approving a rate setting mechanism and associated parameters during the deferred rebasing period, effective January 1, 2019.

SUBMISSIONS OF THE ASSOCIATION OF POWER PRODUCERS OF ONTARIO ("APPrO")

June 15, 2018

Borden Ladner Gervais LLP
Bay Adelaide Centre, East Tower
22 Adelaide St W.
Toronto ON M5H 4E3

John A.D. Vellone
Tel: (416) 367-6730
Facsimile: (416) 361-2758
Email: jvellone@blg.com

INTRODUCTION:

1. The Association of Power Producers of Ontario ("**APPrO**") makes these written submissions on the Application filed by Union Gas Limited ("**Union**") and Enbridge Gas Distribution Inc. ("**Enbridge**", and together with Union the "**Applicants**") with the Ontario Energy Board (the "**Board**" or "**OEB**") on November 2, 2017 seeking approval to amalgamate pursuant to section 43(1) of the *Ontario Energy Board Act, 1998* (the "**OEB Act**") and to defer rate rebasing until 2029 (the "**Section 43 Application**") and the Application filed by Union and Enbridge with the OEB on November 23, 2017 seeking approval of a rate-setting mechanism and associated parameters during the deferred rebasing period pursuant to subsection 36(1) of the OEB Act (the "**Rate Mechanism Application**").

2. The Board assigned file numbers EB-2017-0306 and EB-2017-0307 to these applications.

3. On March 1, 2018 the OEB issued its Decision and Procedural Order No. 3 ("**PO3**") within which the OEB determined that it would combine the Section 43 Application and the Rate Mechanism Application (hereinafter referred to as the "**Applications**") and approving an issues list for the combined proceeding (the "**Issues List**").

4. These submissions are prefaced by a general statement of APPrO's position on the Applications followed by a more detailed set of submissions that follow the general ordering of the Issues List.

EXECUTIVE SUMMARY

5. On September 6, 2016, Enbridge Inc. ("**EI**"), Enbridge's parent company, announced a planned merger with Spectra Energy Corp ("**Spectra**"), Union's parent company.[1] On December 8, 2016, the Board confirmed its view that this merger transaction did not require OEB approval under section 43 of the OEB Act. The merger closed on February 27, 2017.[2]

6. In light of this fact, APPrO has no objections to the merger of Enbridge and Union

[1] https://www.enbridge.com/~/media/Enb/Documents/Investor%20Relations/2016/ENBS_Sept62016_Presentation.pdf
[2] http://www.enbridge.com/media-center/news/details?id=2126823&lang=en&year=2017

provided:

a. the associated rate making framework is appropriate; and
b. natural gas fired generators are protected from potential anti-competitive availability and pricing of natural gas storage and associated transportation services.

7. As more fully detailed in the submissions below, APPrO is of the view that the rate making framework proposed by the Applicants does not meet the "no-harm" test in a number of material respects. Specifically, APPrO is concerned about the harm to ratepayers caused by:

a. The proposed 10 year rebasing deferral;
b. The proposed ESM;
c. The proposed stretch factor; and
d. The proposed ICM.

8. In APPrO's submission, the Board can approve the requested merger on the condition that the Applicants adopt a different prescribed rate-making framework, and such other conditions of approval as the Board may deem appropriate. APPrO's views on the appropriate ratemaking framework are set out below.

THE "NO HARM" TEST

1. Have the applicants appropriately applied the 'No Harm" test in this case, including in consideration of the OEB's statutory objectives in relation to natural gas?

9. APPrO agrees with the Applicants[3] that the appropriate test for the Applications is the "no harm" test, and that it is to be applied by reference to the OEB's statutory objectives and that the application of the test involves consideration of whether a proposed transaction will have an adverse effect on OEB's statutory objectives for natural gas regulation as set out in Section 2 of the OEB Act.

10. Section 2 of the OEB Act provides:

[33] Applicants' Argument-in-Chief dated June 1, 2018 (the "**AIC**") at pg. 4, para. 9.

> The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:
>
> 1. To facilitate competition in the sale of gas to users.
> 2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.
> 3. To facilitate rational expansion of transmission and distribution systems.
> 4. To facilitate rational development and safe operation of gas storage.
> 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.
>   5.1 To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.
> 6. To promote communication within the gas industry and the education of consumers.

11. APPrO also agrees with the Applicants that in addition to price, reliability and quality of gas service and financial viability (from the Decision and Order in EB-2016-0351), that the section 2 objectives with regards to gas storage and the rationale expansion of transmission and distribution are also of direct relevance to the Applications.[4]

12. However, as explained in response to issue 12 below, APPrO does not agree with the Applicants' suggestion that the policies established in the *Handbook to Electricity Distributor and Transmitter Consolidations* dated January 16, 2017 (the "**Handbook**") apply to the Applications.

2. Have the applicants met the test?

13. APPrO has carefully reviewed the evidence and is of the view that the merger of Enbridge and Union does not violate the "no harm" test <u>provided</u>:

   c. the associated rate making framework is appropriate; and

   d. natural gas fired generators are protected from potential anti-competitive effects of the merger with regards to the availability and pricing of natural gas storage and associated transportation services.

14. In APPrO's submission, the Applicants' proposed "standalone scenario" does not provide

[4] AIC at para. 11-12.

an adequate factual basis upon which to assess the “no harm” test. The standalone scenario assumes “no sharing of staff or rationalization of activities”[5] and indeed assumes no cost savings arising from the merger of EI and Spectra despite evidence that those cost savings are already occurring and will occur into the future. These assumptions are not realistic, and are not consistent with the obligation on gas utilities to demonstrate ongoing continuous improvement in their productivity and cost performance.

15. The merger of EI and Spectra has and will cause a material change in underlying cost structures of Enbridge and Union as the utilities moved to rationalize operations and achieve efficiencies following the merger. This is what a normal company would do in the presence of competitive forces. Regulation should, to the greatest extent possible, incent utilities to do what they would otherwise do if they faced competitive forces.

16. A realistic “standalone scenario” is one that would account for productivity improvements arising following the merger of EI and Spectra. In this regard, APPrO has had an opportunity to consider the revised standalone strawman prepared by SEC. In general terms, APPrO is of the view that the changes proposed by SEC represent more realistic assumptions than what has been posed by the Applicants.

17. As more fully detailed below in the submissions below, APPrO is of the view that the rate making framework proposed by the Applicants does not meet the “no-harm” test in a number of material respects. Specifically

e. The proposed 10 year deferral of rebasing;
f. The proposed ESM;
g. The lack of a stretch factor; and
h. The proposed ICM.

18. However, the Board can still approve the requested merger provided the Board clearly indicates in its decision that approval is conditional upon the adoption of a different rate-making framework and meeting certain conditions of approval.

[5] Transcript Volume 1 at page 146.

REBASING DEFERRAL

3. Is deferral of rebasing appropriate in the context of this application?

19. APPrO submits that the deferral of rebasing is not appropriate for four reasons.

20. First (and as described above), the Handbook does not, and should not, apply to the merger. It does not apply to natural gas utilities on the face of the clear language of the Handbook. And it should not apply since the policy drivers (to incent electricity utility mergers) are not relevant in the natural gas context, particularly when the EI and Spectra have already merged.

21. Second, the February 2017 merger of EI and Spectra can reasonably be expected to have caused a material change in underlying cost structures of Enbridge and Union as the utilities moved to rationalize operations and achieve efficiencies following the merger.

22. This is what a normal company would do in the presence of competitive forces.

23. There is evidence that this is exactly what EI and Spectra have done in their non-regulated businesses:

> "**Anticipated Cost Savings**
>
> Enbridge's merchant storage line of business is not large, as already noted. Enbridge runs this business using part of the time of three employees for a total of two full-time equivalents ("FTEs"). Given Union's larger operations, it is Enbridge's expectation that Union can readily absorb managing the terms of the Enbridge contracts without any need for the two FTEs within Enbridge. As a result, all salary, benefit, travel, supply and miscellaneous expenses associated with these individuals would be saved. Below we provide a breakdown of these costs for Enbridge in 2016 and Enbridge's 2017 budget without the transaction.[35] The 2016 costs are based on six months of actual costs and six months of forecast costs, as this is how Enbridge reports the figures."[6]

24. The table that follows quantifies these anticipated savings, which were (correctly) filed in confidence. In addition, the report goes on to identify two other categories of expenditures with potential savings relating to consulting services and costs allocated to the merchant

[6] Enbridge/Spectra: Section 96 Trade-off Analysis, dated February 8, 2017 by Charles River Associates at pg. 11.

storage business for managing injection and withdrawal.

25. APPrO believes that regulation should, to the greatest extent possible, incent regulated utilities to do what they would otherwise do if they faced competitive forces.

26. The OEB does this through its *Handbook for Utility Rate Applications* dated October 13, 2016 (the "**Rate Handbook**"). The Rate Handbook adopts an outcomes based approach for natural gas utilities that includes the following outcomes:

- Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and by providing services in a manner which is responsive to customer preferences.
- Utilities are expected to demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives.
- Utilities are expected to demonstrate sustainable improvements in their efficiency and in doing so will have the opportunity to earn a fair return.

27. Third, it would be inconsistent with commitments made by Union to APPrO and other parties in a prior OEB approved settlement agreement. Specifically, in a Decision and Order dated October 7, 2013 in EB-2013-0202, the OEB approved a Settlement Agreement pursuant to which the parties agreed that:

> "Union would (subject to any subsequent agreement of all parties to extend the IRM term) prepare a full cost-of-service filing at the time of rebasing, regardless of whether Union applies to set rates for 2019 on a cost-of-service basis or not.
>
> At the time of rebasing, Union would provide 2013-2017 actual, 2018 bridge and 2019 forecast information. In addition, Union would provide historical plant continuity information for 2012, 2013, 2014, 2015 and 2016 similar to the information provided in the EB-2011-0210 proceeding at Exhibits B6/T1 & T2/S 1 – 5."[7]

28. APPrO was party to this approved settlement. APPrO has not been asked to, and does not agree to, waive this obligation. The settlement of this issue was completed in the context

[7] EB-2013-0202 Settlement Agreement at Exhibit A, Tab 2, page 34, Section 14.

of a broader settlement on a number of different issues. In this regard, "[t]he parties to the Agreement acknowledge and agree that none of the completely settled provisions of this Agreement are severable"[8] and "[i]t is further acknowledged and agreed that parties will not withdraw from this Agreement under any circumstances except […]."[9] The exception was limited to circumstances where evidence arises at the hearing that may affect the settlement proposal. No such evidence arose in the course of the EB-2013-0202 hearing.

29. Enbridge made an equivalent commitment during sworn testimony during the first day of the oral hearing in the EB-2012-0459 rate application. This is shown in the following exchange, where Mr. Shepherd was taking the Enbridge witnesses through the commitments made by Union in the above noted settlement. The exchange is noteworthy:

> "MR. SHEPHERD: Exactly.
>
> Finally, on page 34, this deals with rebasing in 2019. And if I understand what you are proposing, it is essentially the same as Union. You are agreeing that you will file -- regardless of whether you are rebasing, you will file a full cost of service application in 2019?
>
> MR. CULBERT: That's correct.
>
> MR. SHEPHERD: To the best of your knowledge, have I missed any of the other factors in this comparison between the two? Have we caught everything, or does something jump out at you, put it that way? I can't think of anything.
>
> MR. CULBERT: Not at this time. If I do, I will certainly bring it to your attention.*"*[10]

30. The parties to EB-2012-0459, including APPrO, relied on this commitment made by Enbridge's witnesses in their sworn testimony. If Enbridge had refused to make such a commitment, the parties would have been put on notice that this was a live issue in the application and would have made submissions on this point.

31. Fourth, APPrO is concerned that the underlying methodologies for cost allocation and rate design are in need of changes since the time of last rebasing for each of Enbridge (July 17,

---

[8] Ibid. at pg. 2.
[9] Ibid. at pg. 3.
[10] EB-2012-0459, Transcript Vol. 1 dated Feb. 20, 2014 at page 126, line 27 – page 127, line 11.

2014 in EB-2012-0459) and Union (October 7, 2013 in EB-2013-0202).

32. For example, Union proposed two changes to its cost allocation methodology as part of the Panhandle reinforcement proceeding (EB-2016-0186):

> "First, Union proposed to base the allocation on the Panhandle System's design day demand plus incremental design day demands of the Project. In 2013, the OEB had approved a cost allocation methodology based on design day demands from the combined Panhandle and St. Clair Systems.
>
> Second, Union proposed to exclude ex-franchise Rate C1 and M16 firm contracted demands from the cost allocation. In 2013, the OEB had approved a cost allocation methodology that included in-franchise and ex-franchise rate classes.
>
> Union's position is that using the combined Panhandle and St. Clair Systems to allocate costs no longer reflects the costs to serve customers on their respective parts of these Systems. In addition, Union submitted that C1 and M16 ex-franchise customers are not driving the need for the Project because their gas flows counter to the flow of design day volumes."[11]

33. Although APPrO supported Union's proposed changes to the cost allocation methodology, the OEB did not approve the changes on the assumption that the next rebasing application would occur within **"14 months"**:

> "The OEB finds that both proposals should be deferred to Union's next cost of service or custom IR application. It would be inconsistent to change the depreciation term and cost recovery for one project, while Union's other assets are depreciated and recovered on different bases. A comprehensive review is required for parties to test, and the OEB to assess, the merits and implications of these two proposals and this should be at Union's next cost of service or custom IR application.
>
> While these proposals may have merit, they cannot be adequately considered during the IRM term, for one project in isolation. A leave-to-construct application requesting a capital pass-through mechanism for cost recovery over 14 months is not the appropriate forum to consider deviations from principles embedded in current OEB-approved rates."[12]

34. By failing to address this cost allocation issue as part of a 2019 rate application, as was expected by the OEB and the parties following the February 23, 2017 decision - natural gas power generators and other large volume customers are directly harmed by the proposed

[11] OEB Decision and Order in EB-2016-0186 dated February 23, 2017 at pg. 9.
[12] Ibid. at pgs. 10-11.

rate plan.

35. In light of this known inequity and harm to ratepayers, APPrO submits that the Applicants should be ordered to undertake a full cost allocation study to rectify this issue as soon as practical. The Applicants' commitment to "at some point during the deferred rebasing period, perhaps at the five year point" is not sufficient. The study should be done as soon as possible.

4. If so:

(a) What is the appropriate deferral period?

36. APPrO is generally not supportive of a deferred rebasing for the reasons noted above. If rebasing is deferred for practical reasons (i.e. to allow Union and Enbridge to prepare applications) it should be for no more than the period reasonably required to prepare the applications. APPrO expects that, realistically, this may be for rates effective in 2021.

37. If, in the alternative, the Board determines that deferred rebasing period is appropriate, it should not exceed 5 years and should include a more robust ESM that protects ratepayers during this period as more fully detailed below.

(b) Is an earnings sharing mechanism (ESM) appropriate and if so, what should that mechanism be and when should it apply?

38. Yes, APPrO believes an ESM is appropriate.

39. Enbridge's current ESM provides that all over-earnings are to be shared 50:50 between ratepayers and shareholders (EB-2012-0459):

> "The Board finds that the dead band should be eliminated and that all over-earnings will be shared 50:50 between ratepayers and shareholders. The Board agrees that the central issue is that the sharing with ratepayers needs to be balanced with an incentive to find and retain efficiencies. The Board also agrees with CCC that a key consideration is the overall IR framework and the other parameters. The Board is approving a Custom IR for Enbridge, but must address the shortcomings of the plan. The lack of total cost benchmarking and the lack of independent budget assessments result in a greater risk that costs have been over-forecast. Therefore, the Board

> concludes that additional ratepayer protection is warranted. A 100 basis point dead band provides insufficient protection for ratepayers, and therefore the Board finds that the dead band should be eliminated for this Custom IR plan."[13]

40. Union's current ESM provides that all over-earnings more than 200 basis points would be shared 90:10 between ratepayers and shareholders (EB-2013-0202):

> "If, in any calendar year, Union's actual utility ROE is more than 200 basis points over the 2013 Board approved ROE of 8.93%, then such earnings in excess of 200 basis points would be shared 90/10 between customers and Union (i.e., customers would be credited 90% and Union would be credited 10%)."[14]

41. To ensure "no harm" to ratepayers, the new ESM must apply immediately and must continue to apply for the duration of any new rate plan for the merged utility. Waiting 5 years before applying the ESM would mean that ratepayers would lose the benefit of the existing ESMs. This would result in a direct harm to ratepayers, particularly given the evidence of the pattern of over-earnings by both Enbridge and Union in the 2013-2017 period.[15]

42. To ensure "no harm" to ratepayers, the new ESM must be at least as favorable to ratepayers as the existing Enbridge and Union ESMs. The new ESM could, for instance, combine the best elements of the Enbridge and Union ESMs such that:

- Any over-earnings up to 200 basis points are to be shared 50:50 between ratepayers and shareholders; and
- Any over-earnings more than 200 basis points are to be shared 90:10 between ratepayers and shareholders.

43. This approach would ensure "no harm" to ratepayers while still creating a strong financial incentive on the merged utility to achieve efficiencies. The benefits of those efficiencies would shared in an appropriate manner between ratepayers and shareholders.

(c) What additional considerations and requirements are appropriate to protect the

[13] OEB Decision and Order dated July 17, 2014 in EB-2012-0459.
[14] EB-2013-0202 Settlement at Exhibit A, Tab 1, page 37.
[15] LPMA.18

interests of customers pending rebasing?

44. Assuming that the Applicants would not be able to file a rebasing application until 2021, the Applicants should be directed to complete a new and more comprehensive cost allocation study as soon as possible to rectify known issues with the existing cost allocation methodology (including the over-allocation of costs to power generator and other large customers arising in the context of the Panhandle reinforcement).

5. What commitments to future action have the utilities made during their respective 2013-2018 rate plan terms, what other rate setting issues merit attention now (including cost allocation issues), and when and how are these commitments and issues to be addressed?

45. Yes. As is previously discussed, Union's cost allocation methodology includes known issues that are of fundamental concern to APPrO members. Union should be directed to undertake a new cost allocation study immediately to resolve known issues. In addition, both Union and Enbridge committed to filing a cost of service information for 2019, regardless of whether they rebase or not. They should be directed to fulfill this commitment at the earliest practical time.

IMPACTS OF THE MERGER

6. Would the proposed merger impact any other OEB policies, rules or orders (e.g. regulation of new storage, Storage and Transmission Access Rule (STAR)? If so, what are those impacts and how should the OEB address them?

46. On April 19, 2018, in response to a motion to compel further and better interrogatory responses brought by the School Energy Coalition, the Applicant's filed[16] redacted versions of three reports that were previously filed with the federal Competition Bureau prior to the merger of EI and Spectra (the "**EI/Spectra Merger**"):

a. Analysis of Merchant Natural Gas Storage Competition in Ontario, dated January 30, 2017 by ICF;
b. Statistical Analysis of Dawn Hub Gas Prices dated January 31, 2017, by Charles River

[16] http://www.rds.oeb.ca/HPECMWebDrawer/Record/605802/File/document

Associates; and

c. Enbridge/Spectra: Section 96 Trade-off Analysis, dated February 8, 2017 by Charles River Associates.

47. Each of these three reports relate the Board's November 7, 2006 Decision with Reasons in the Natural Gas Electricity Interface Review (EB-2005-0551) (the "**NGEIR Decision**").[17]

48. The NGEIR Decision is frequently cited for the Board's determination that "Ontario storage operates compete in geographic market that includes Michigan and parts of Illinois, Indiana, New York and Pennsylvania" and on that basis "[t]he Board finds that the market is competitive and that neither Union nor Enbridge have market power."[18]

49. In general terms, the reports titled *Analysis of Merchant Natural Gas Storage Competition in Ontario* and *Statistical Analysis of Dawn Hub Gas Prices* both provide compelling evidence that neither the passage of time from 2006 to 2017 nor the EI/Spectra Merger adversely impacts the Board's determination that the market for gas storage remains a competitive activity.

50. In the NGEIR Decision, the Board also approved a settlement between the power generators and the gas utilities to create (a) new high deliverability gas storage and transportation services; and (b) more frequent nomination windows for the distribution, storage and transportation of natural gas.[19]

51. These high deliverability, short notice gas storage and transportation services were then, and are today, essential services required by dispatchable gas-fired power generation plants so they can meet their five-minute dispatch instruction obligations under the Independent Electricity System Operator (IESO) market rules.[20]

52. The unique requirements of the IESO market rules results in natural gas profiles that are more volatile and difficult to forecast than the relatively stable profiles for residential,

[17] Exhibit K2.5 at Tab 3.
[18] NGEIR Decision at pg. 3.
[19] NGEIR Decision at pg. 2.
[20] Transcript Vol. 2 at pg. 146, lines 6-14.

commercial and industrial gas users. Storage on its own is not enough. The gas that is in storage must also be transported. As a result, gas generators also require short notice transportation services to make use of high deliverability, short notice storage services.

53. In this context, the report titled *Enbridge/Spectra: Section 96 Trade-off Analysis* dated February 8, 2017 by Charles River Associates (the "**Section 96 Trade-off Analysis**") raises an area of concern for APPrO members. Specifically:

> "There are a limited number of merchant storage customers that may not have adequate access to alternatives to physical storage at Dawn. We understand that the Bureau's concerns are focused on Ontario power generators because they may have sufficiently high deliverability requirements that commit them to use merchant storage at Dawn."[21]

54. After discussing with its members, APPrO is in agreement that the Bureau's concerns were and are valid. Ontario gas fired generators are, for all practical purposes, only able to access storage at Dawn. The high deliverability, short notice transportation and storage services that were approved in the NGEIR Decision are, by and large, unique to Ontario. This has had the practical effect of limiting gas generators ability to access other geographic markets for storage services. For example, short notice service on the Vector pipeline on its own is insufficient. It would need to be accompanied by a short notice, high deliverability storage service.

55. APPrO explored its concerns with the Applicants during the second day of the oral hearing on May 4, 2018.[22] The focus of this additional questioning is best reflected by a single exchange with Mr. Redford:

> "MR. VELLONE: And so generators' concerns around this merger is the potential for an increase, an anti-competitive increase, to the prices paid for gas storage. That's a -- you understand the nature of that concern?
>
> MR. REDFORD: I can understand a concern. I will say that our interests are well-aligned with the gas-fired power generators in Ontario. After NGEIR, we put in the ground about half a billion dollars' worth of assets to serve the power generation market, many of those under long-term contracts, and we have an interest in making sure that they remain utilized, same as the power generators have an interest in

[21] Section 96 Trade-off Analysis at page 2
[22] Transcript Vol. 2, pgs. 144-165 and Exhibit K2.5.

making sure that their facilities remain utilized.

So to the extent -- and while there may not be other physical options for storage in Ontario, there are other options available to generators, specifically around high-deliverability storage services. As contracts roll off and expire, power generators have the ability to look at term, deliverability, space in -- either on a stand-alone basis or in combination with other market participants, including marketers, to recontract.

So I don't actually believe that gas-fired power generators have few options. It's a storage service. It has different parameters or different attributes than, say, what an LDC might take to serve residential customers, but there are market participants that gas-fired generators could appeal to get bids for, for storage services.

MR. VELLONE: So just continuing on that point and basically where I started from as well, which was the NGEIR decision really did result in a negotiated settlement between gas-fired generators and the utilities, are the utilities willing to formally commit to work together with gas-fired generators to address their concerns about potential anti-competitive effects of the merger on their access to gas storage in Ontario?

[Witness panel confers]

MR. REDFORD: So generally, yes, we're willing to work with gas-fired generators. We're willing -- we are willing to work with all of our customers and potential customers, and -- but we would expect commitments that were made at the time of NGEIR and any contracts would continue forward.

About two-thirds of our transportation that gas-fired generators have on our system and about two-thirds of the deliverability, the terms of those contracts extend past 2028, so they're -- they are long-term contracts. We do have contracts that are renewing in the near future and absolutely, we would work with gas-fired generators to see what their needs are and what we can do to make it work for them.

MR. VELLONE: That's good to hear. […]"[23]

56. APPrO acknowledges Mr. Redford's comments: Gas generators and the gas utilities do have a long history of working together to develop solutions to meet gas generators needs. In addition, the interests of gas generators and gas utilities are often aligned.

57. For this reason, APPrO is willing to accept a firm commitment from the Applicants that:

(i) they will not increase the pricing of high deliverability, short notice gas

[23] Transcript Vol. 2 at pg. 157, line 5 to pg. 158, line 26.

storage and transportation services on an anti-competitive basis; and

(ii) that they are willing to work with gas-fired generators to address their needs in the future.

58. APPrO asks that the Applicants clearly make both of these commitments in reply submissions. If this is not possible, please explain in detail why not.

7. If leave is granted, what conditions should be attached?

59. APPrO takes no position on this issue.

8. What is the status of the Undertakings to the Lieutenant Governor in Council of Ontario?

60. APPrO takes no position on this issue.

9. To the extent that the Undertakings are impacted by this application, should any of the provisions of the Undertakings be replaced by a condition of any OEB approval?

61. APPrO takes no position on this issue.

10. If so, what should the content of the condition be?

62. APPrO takes no position on this issue.

RATE-SETTING MECHANISM ISSUES LIST

RATE FRAMEWORK:

1. ***If the OEB grants the Applicants' request for approval of the amalgamation and deferral of rebasing, what should be the features of a Price Cap IR mechanism during the deferral period, including?***

a. What is the appropriate inflation factor [I]?

63. APPrO takes no position on this issue.

b. What is the appropriate productivity factor [X]?

64. APPrO has reviewed the expert report prepared by the Pacific Economics Group Research LLC ("**PEG**") as it relates to the relevant productivity factor.

65. APPrO is in agreement with PEG's recommendation that 0% productivity factor makes sense based on the econometric analysis and data available. However, to support the 0% productivity factor, the OEB must not approve the requested rebasing deferral.

66. The Applicant expressly ignores this important limitation on the 0% productivity factor recommended by PEG. However, if one references PEG's research the limitation is noted by PEG at page 7 and again at page 50 of their report:

> "Since the Board is free to deviate from MAADs rules, it can require a rebasing of each Applicant's revenue to their recent and normalized historical costs followed by their formulaic escalation to 2019 values. **This would sidestep problems of performance incentives and merger related costs**."[24]

67. If the Board does approve a rebasing deferral, then the productivity factor should be adjusted to incorporate a performance incentive to capture merger related savings. PEG has adjusted their analysis to exclude mergers,[25] and has made an assumption that allowed them to "sidestep problems of performance incentives and merger related costs". Since the Applicants have forecasted that they will over-earn over the ten year deferral period by an average of 0.2% above the Board approved ROE – this provides a reasonable starting point for such a productivity factor that would properly include merger savings.

c. Should a stretch factor apply and if so, what is the appropriate stretch factor?

68. APPrO has reviewed the expert report prepared by PEG and is in agreement with the rationale provided by Dr. Lowry that a 0.30% stretch factor is appropriate.

69. This approach ensures that the merged utility demonstrates ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives, and sustainable improvements in their efficiency.

70. The Applicants argue in response that the imposition of a stretch factor of 0.3% would create

[24] Exhibit M1 at page 7 and at page 50.
[25] Exhibit M1 at page 33.

a significant disincentive to amalgamation because of the magnitude of the financial hurdle it would create in relation to the total expected achievable integration savings.

71. APPrO does not agree. Implicit in the Applicants' argument is an assumption that no stretch factor would (or should) apply if there is no merger, and therefore applying a 0.3% stretch factor in the merger scenario creates a disincentive to merge. This is assumption is without merit.

72. An equivalent stretch factor should, and would, apply in the absence of a merger as well.

73. The OEB has previously rejected the concept of a zero stretch factor. See the Report of the Board in EB-2010-0379 titled *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* issued November 21, 2013, as corrected December 4, 2013, the OEB states at pages 18-20:

> *"The Board believes that stretch factors continue to be required and is not persuaded by arguments that stretch factors are only warranted immediately after distributors switch from years of cost of service regulation to IR. Stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend. Consequently, stretch factors continue to have an important role in IR plans after distributors move from cost of service regulation.*
>
> [...]
>
> *It is important to note that stretch factors are consumer benefits. They are somewhat analogous to earnings sharing mechanisms, although stretch factors take effect immediately with the application of the formula and are not dependent on the realization of any productivity gains or excess earnings, as would be the case with an earnings sharing mechanism. Stretch factors are an integral part of the IR formula, and are not dependent on future performance by the distributor.*
>
> [...]
>
> *The Board has determined that the appropriate stretch factor values range from 0.0% to 0.6%. The Board is setting the lower-bound stretch factor value to zero to strengthen the efficiency incentives inherent in the rate-adjustment mechanism and in doing so reward the top performers."*

74. It is worth noting that the stretch factor proposed by PEG falls in the middle of the OEB's range of stretch factors under the Renewed Regulatory Framework.

75. In addition, both Enbridge and Union's existing rate plans have productivity expectations embedded within them (although they are framed differently than a stretch factor).

76. Finally, the OEB's determination in the PowerStream Custom IR application is relevant. PowerStream proposed a custom IR framework that did not embed any productivity improvements – an argument that is akin to the Applicants' proposed 0% stretch factor. The OEB's response was as follows:

> "***Productivity Improvement***
>
> *Continuous productivity improvement is a key element for longer-term rate setting under the principles of the RRFE.*
>
> *PowerStream has submitted that it continuously seeks improvements in productivity, as demonstrated by its participation in Excellence Canada and the management efforts of its Organizational Effectiveness department. PowerStream also submits that productivity gains are embedded in its cost forecasts.*
>
> *The concept of productivity improvement means a continuous increase in productivity expectations. However, PowerStream has not produced its productivity improvement estimates on this basis. This is illustrated by the fact that a significant portion of the estimated savings are attributed to its cable injection program. Given the evidence that PowerStream has been implementing this cable injection approach since 2011, these savings are now embedded in the expectations for normal operations and are not appropriate for inclusion in the estimates of savings due to productivity improvements for 2016-2020.*
>
> *As pointed out by several parties, in its decision on Hydro One's Custom IR application the OEB did not accept the approach of embedding productivity gains in forecasts:*
>
>> *The OEB expects Custom IR rate setting to include expectations for benchmark productivity and efficiency gains that are external to the company. The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency incentives. Incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses.*
>>
>> *The OEB does not believe that Hydro One's plan contains adequate efficiency incentives to drive year-over-year continuous improvement in the company. Furthermore, the plan lacks measurement of increased efficiency year-over-year, that is in a form indicating trending and that is transparent.*[8]
>
> *Accordingly, PowerStream needs to rethink the approach in its application to*

> *assessing productivity improvement. It would not be appropriate for the OEB to direct a solution to remedy this basic deficiency. PowerStream should consider how best to achieve this in its next rebasing rate setting application.*"[26]

77. In light of the OEB's policy on this question, APPrO submits that the Applicants' should reasonably expect that a stretch factor will apply regardless of whether they merge or not. Therefore, the application of a 0.3% stretch factor would not create a disincentives to merge. Rather it would create an incentive to demonstrate continuous improvements in productivity in a manner consistent with the OEB's rate setting policies under the RRFE.

d. Should there be pass through (Y factor) treatment for costs such as:

i. Gas commodity and upstream transportation costs?

78. APPrO does not object to gas commodity and upstream transportation costs being treated as a pass through to those classes of customers that rely on Enbridge/Union to provide gas commodity and transportation services, provided those costs were prudently incurred.

ii. Demand side management (DSM) costs?

79. Power generators are sophisticated gas users and generally will not benefit from utility DSM programs. Power generators will make needed investments when appropriate, and do not need ratepayer funded DSM programs. Consequently, APPrO does not agree with the flow through of DSM costs to power generators, which realistically will not benefit from these programs.

iii. A lost revenue adjustment mechanism (LRAM)?

80. APPrO takes no position on this issue.

iv. Cap-and-trade costs?

81. APPrO does not object to cap and trade costs being treated as a pass through, provided that those costs are prudently incurred and they are disposed of on a prospective basis (akin to gas commodity and upstream transportation costs). A retroactive (or one-time) recovery

[26] EB-2015-0003 Decision and Order dated August 4, 2016 at pages 10-11.

mechanism creates significant hardship for gas fired generators and has the potential to cause distortions to the power market.

82. APPrO made detailed submissions on the need for a prospective disposal of cap-and-trade costs in the 2017 Cap and Trade compliance plan proceeding.[27] APPrO's concerns were reinforced by the IESO.[28] APPrO will not repeat these submissions again here.

v. Changes to normalized average consumption/average use?

83. APPrO takes no position on this issue.

e. Should there be a Z factor, and if so what are the appropriate parameters and materiality threshold?

84. APPrO does not object to inclusion of a Z factor mechanism that meets the causation, prudence and management control criteria as set out in the Applications. However, the proposed materiality threshold for Amalco of $1 million is much too low.

85. By way of comparison, the existing Z factor threshold for Union is $4 million and for EGD it is $1.5 million. It makes no sense that the materiality threshold for Amalco would be less than the sum of its parts.

86. In this context, APPrO submits that the $10 million Z factor threshold that was approved for Ontario Power Generation (EB-2016-0152) is a more appropriate threshold for a utility the size of Amalco (which is larger than OPG).

f. Should there be an earnings sharing mechanism and if so what are the appropriate parameters?

87. APPrO has addressed this question under issue 4(b) above.

g. Is the proposal for calculating the cost recovery treatment of qualifying capital investments consistent with the OEB's policy for Incremental Capital Modules, and if not are any deviations

[27] http://www.rds.oeb.ca/HPECMWebDrawer/Record/571908/File/document
[28] http://www.rds.oeb.ca/HPECMWebDrawer/Record/571858/File/document

appropriate?

88. The Applicant's proposal for Incremental Capital Modules is inconsistent with the Board's policy on ICM as most recently articulated in the Board's April 6, 2018 Decision and Order in EB-2017-0024.

89. First, the OEB has established criteria and tests so that the ICM does not become just a top-up to the ICM materiality threshold. Minor expenditures in comparison to the overall capital budget should be considered ineligible for ICM treatment. A certain degree of project expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget.

90. Despite this known requirement, the Applicants' have failed to include a project specific materiality factor in their proposed ICM. APPrO submits that this should be added to the proposed ICM.

91. It is noteworthy that the OEB elected not to quantify a project specific materiality factor in their EB-2017-0024 Decision and Order. Rather it applied the test on a qualitative basis, guided by the words "significant influence on the operation of the distributor" and "minor expenditure in comparison to the overall capital budget" in assessing the project-specific materiality of each project. A qualitative approach has the benefit of flexibility for the OEB when adjudicating a particular case, and a similar approach should be applied to the Amalco ICM.

92. Second, ICM projects do need to be different in kind from those that are carried out through typical base capital programs. Otherwise, the OEB would need to scrutinize all capital projects for optimization, not just the ICM projects.

93. Despite this requirement, the Applicants' have failed to specify this criteria as part of their proposed ICM. APPrO submits that this should be added to the proposed ICM.

2. How should the framework address the four objectives in the Renewed Regulatory Framework of customer focus, operational effectiveness, public policy responsiveness and financial performance?

94. The framework should be consistent with the Board's Renewed Regulatory Framework, and should include features that directly address each of the four objectives. APPrO has made recommendations throughout these submissions on how to best address each of these objectives. This includes rebasing and updating cost allocation as promised to customers (customer focus), incorporating a stretch factor of 0.3% (operational effectiveness), ensuring cap and trade costs are disposed of on a prospective basis (public policy responsiveness), and ensuring a fair ESM that does not harm customers and shares overearnings with ratepayers (financial performance).

3. What changes to rates, regulated services, cost allocation or rate design should be permitted or required during the deferred rebasing period and what process should be required for such changes to be made?

95. This question assumes approval of the deferred rebasing period, which as previously stated APPrO opposes.

96. If, by chance, the OEB does approve a deferred rebasing period, then at a minimum Amalco should be required to file a complete cost allocation study and the cost allocation methodology should be updated as soon as possible during the deferred rebasing period.

4. What should the annual rate adjustment process be?

97. This question assumes approval of the deferred rebasing period, which as previously stated APPrO opposes.

5. What deferral and variance accounts should continue?

98. APPrO takes no position on this issue.

6. What deferral and variance accounts should not continue?

99. APPrO takes no position on this issue.

7. What additional deferral and variance accounts are appropriate?

100. APPrO takes no position on this issue.

8. Is the proposed adjustment to reflect the full amortization of Union Gas' accumulated deferred tax balance at the end of 2018 appropriate?

101. APPrO takes no position on this issue.

9. Is the proposed adjustment to unwind smoothing of costs related to Enbridge Gas' Customer Information System and customer care forecast costs appropriate?

102. APPrO takes no position on this issue.

10. Is the proposed adjustment to Enbridge Gas' Pension and OPEB costs appropriate?

103. APPrO takes no position on this issue.

11. Is the proposed adjustment to reflect the removal of Enbridge Gas' tax deduction associated with the discontinued SRC refund appropriate?

104. APPrO takes no position on this issue.

OTHER:

12. Are the provisions of the MAADs Handbook related to harmonization applicable?

105. APPrO does not agree with the Applicants' suggestion that the policies established in the *Handbook to Electricity Distributor and Transmitter Consolidations* dated January 16, 2017 (the "**Handbook**") apply to the Applications.

106. The OEB has previously observed:

> "*Consolidation of the electricity distribution sector has been the subject of much discussion since the late 1990s when the sector was first restructured under the Energy Competition Act, 1998.*"[29]

107. The same cannot be said to be true for natural gas distributors.

108. The Handbook includes a lengthy pre-amble which frames the context in which the

[29] Decision and Order dated July 3, 2014 at pg. 2 in EB-2013-0196/EB-2013-0187/EB-2013-0198

Handbook was released:

> "*The Commission on the Reform of Ontario's Public Services, the Distribution Sector Review Panel and the Premiers Advisory Council on Government Assets have all recommended a reduction in the number of local distribution companies in Ontario and have endorsed consolidation. According to these reports, consolidation can increase efficiency in the electricity distribution sector through the creation of economies of scale and/or contiguity. Consolidation permits a larger scale of operation with the result that customers can be served at a lower per customer cost. Consolidations that eliminate geographical boundaries between distribution areas result in a more efficient distribution system.*
>
> *Consolidation also enables distributors to address challenges in an evolving electricity industry. This includes new technology requirements to meet customer expectations, changing dynamics in the electricity sector with the growth of distributed energy resources and to undertake asset renewal. Distributors will need considerable additional investment to meet these challenges and consolidation generally offers larger utilities better access to capital markets, with lower financing costs.*
>
> *Distributors are also expected to meet public policy goals relating to electricity conservation and demand management, implementation of a smart grid, and promotion of the use and generation of electricity from renewable energy sources. Delivering on these public policy goals will require innovation and internal capabilities that may be more cost effective for larger distributors to develop or retain.* " [30]

109. There is a similar, and even more detailed, pre-amble framing the context of the Board's consultation process and policy at pages 3-4 of the Report of the Board on Rate Making Associated with Distributor Consolidation dated March 26, 2015 (EB-2014-0138) (the "**2015 Report**").

110. The policies set out in the Handbook applies to Section 86 consolidation transactions for electricity distributors and transmitters. This is clear from the title and content of the Handbook, which focuses exclusively on Section 86 of the OEB Act and the objectives under Section 1 of the OEB Act.

111. The purpose of the policies in the Handbook are to incent consolidation among a large number of local distribution utilities. A similar incentive is not needed to encourage

[30] Handbook at pg. 1.

consolidation of two natural gas utilities – particularly given that their respective parent companies have already merged.

112. APPrO does not agree that the Handbook should be applied to consolidating natural gas distributors under Section 43 of the OEB Act and the objectives under Section 2 of the OEB Act. Rather, APPrO submits that the Applicants' proposals should be assessed as a whole, on the basis of the evidence filed, to determine whether or not the "no harm" test is met.

113. Finally, it is worth noting that the Handbook also includes a disclaimer:

> "*While the Handbook is applicable to both electricity distributors and transmitters, most of the OEB's policies and prior OEB decisions have related to distributors. Transmitters should consider the intent of the Handbook and make appropriate modifications as needed to reflect differences in transmitter consolidations.*" [31]

114. In this context, the Applicants' are obligated to consider the intent of the Handbook and make appropriate modifications as needed to reflect differences in the proposed consolidation of two natural gas utilities whose parent companies have already merged.

13. How should past OEB directives and utility commitments be addressed?

115. APPrO has provided its submissions on this issue as part of its response to issue 4 above.

14. Is the proposed scorecard appropriate?

116. APPrO takes no position on this issue.

15. What reporting should be required during the deferred rebasing period?

117. APPrO has no submissions on this issue.

16. What stakeholder engagement should be required during the deferred rebasing period?

118. APPrO is generally support of the level of customer engagement proposed by the Applicants, inclusive of efforts to inform stakeholders of its business plans, ICM requests

[31] Ibid. at pg. 2.

and its proposals for cost allocation.

119. In addition, the Applicants' have proposed that Amalco would host a funded stakeholder meeting every other year. This proposal assumes that the requested 10 year deferral is approved. If the requested 10 year deferral is denied, APPrO recommends that an annual stakeholder meeting be held.

COSTS:

120. APPrO has participated in this proceeding in a responsible and efficient manner, including coordinating interrogatories and cross-examination with other intervenors to minimize duplication and maximize efficiency of the hearing process. APPrO requests that it be awarded 100% of its reasonably incurred costs in connection with this matter.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 15TH DAY OF JUNE, 2018

BORDEN LADNER GERVAIS LLP

Per:

Original signed by John A. D. Vellone

____

John A.D. Vellone

TOR01: 7436681: v4