EB-2018-0264

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by EPCOR Natural Gas Limited Partnership for natural gas distribution rates and other charges for the period January 1, 2019 to December 31, 2028.

EPCOR NATURAL GAS LIMITED PARTNERSHIP (SOUTH BRUCE)

REPLY ARGUMENT

Filed: October 29, 2019

TABLE OF CONTENTS

I. SUMMARY OF PROCEEDING

1. In proceeding EB-2016-0137/0138/0139 (the "Southern Bruce Expansion proceeding"), the Ontario Energy Board (OEB) selected EPCOR Southern Bruce Gas Inc. as the successful proponent to develop a greenfield gas distribution system in the Southern Bruce region. In its decision, the Board approved EPCOR Southern Bruce Gas Inc.'s competitively offered Common Infrastructure Plan ten-year revenue requirement as filed in that process (the "CIP" or "CIP Proposal"). In EB-2018-0247, the OEB approved the transfer of the Certificates of Public Convenience and Necessity ("CPCNs") for the South Bruce municipalities from EPCOR Southern Bruce Gas Inc. to EPCOR Natural Gas Limited Partnership (these companies are collectively referred to as "EPCOR" in this submission).

2. In the South Bruce Expansion proceeding, the OEB approved a set of common assumptions, including a 10-year rate stability period, upon which each proponent was to base its CIP. The OEB also established the selection criteria it would use to determine the successful proponent. EPCOR's CIP Proposal included a commitment to values for those selection criteria as set out below. The cumulative gross revenue requirement for the 10-year rate stability period was $75.583 million.

Metric	Value
Cumulative 10-year revenue requirement per unit of volume	$\$0.2209/m^3$
Customer Years	42,569
Cumulative 10-Year Throughput Volume	$342,186,741\ m^3$

3. On October 2, 2018 EPCOR filed a custom incentive rate-making application with the OEB pursuant to section 36 of the *Ontario Energy Board Act, 1998* (as amended)(the "Act") seeking approval for: (i) rates that EPCOR may charge for gas distribution services from January 1, 2019 to December 31, 2028, adjusted annually by a proposed custom incentive rate-setting plan; (ii) EPCOR's forecast of upstream charges to be incurred by EPCOR; and (iii) the establishment of a number of deferral and variance accounts. This rate application will establish rates for first-time natural gas service customers within certain communities in the South Bruce region.

4. Enbridge Gas Inc. ("Enbridge Gas"), Industrial Gas Users Association ("IGUA"), School Energy Coalition ("SEC"), Vulnerable Energy Consumers Coalition ("VECC"), Anwaatin Inc. ("Anwaatin") and the municipality of Kincardine, the Municipality of Arran-Elderslie and the Township of Huron-Kinloss applied for and were granted intervenor status.

5. EPCOR participated in a robust written interrogatory process and answered numerous questions from OEB Staff as well as Enbridge Gas, IGUA, SEC, VECC and Anwaatin ("Intervenors").

6. The parties were not able to reach an agreement on the wording of all issues in the proposed issues list. EPCOR took the position that a number of the Board's typical issues (as set out in the draft issues list) had largely been predetermined through the CIP process, and as a result, this rate application should not be subject to the same level of regulatory scrutiny applied to conventional rate applications. The OEB issued its Issues List Decision on August 20, 2019. The OEB agreed with EPCOR that a number of issues should not be subject to the test of appropriateness but rather should be assessed on the basis of whether EPCOR's proposal for that issue was consistent with EPCOR's CIP Proposal. The OEB further noted that "*…a number of cost parameters and rate components had been determined in the South Bruce Expansion proceeding and [the OEB] would not be revisiting the overall commitments (with the exception of any proposed adjustments) that were made in the CIP process*." [1]

7. On August 21 and 22, 2019, EPCOR participated in a settlement conference, along with OEB Staff and certain of the Intervenors. EPCOR filed a revised settlement proposal on September 16, 2019, which indicated that the parties had reached an agreement on some of the issues and requested that the unsettled issues proceed to a hearing. This partial settlement had no impact on the cumulative ten-year revenue requirement.

8. The OEB reviewed the settlement proposal and accepted it as filed in the Decision on Settlement Proposal and Procedural Order No. 6, dated October 3, 2019. The OEB also determined that no further written discovery was required, and that there was sufficient information on the record to proceed to written argument.

9. The following is the list of unsettled issues in this proceeding:

Issue 1: Administration

b) Are EPCOR's proposed rates consistent with its CIP, and where there are departures are such departures appropriate?

Issue 3: Operating Revenue

3c) Are EPCOR's proposed Other Revenues during the rate stability period consistent with EPCOR's Southern Bruce's CIP proposal?

Issue 5: Revenue Deficiency/Sufficiency

a) Is EPCOR's proposal to recover an additional $1.764 million due to changes in construction schedule, and the associated rate rider calculation, consistent with EPCOR's Southern Bruce's CIP proposal and appropriate?

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1 EB-2016-0137/0138/0139 Decision and Order, April 12, 2018.

Issue 6: Cost Allocation and Rate Design

a) Are the proposed rate classes appropriate?
b) Are EPCOR's proposed cost allocation, rate design and revenue to cost ratios appropriate and consistent with EPCOR's CIP proposal?
c) Are EPCOR's proposed rates appropriate?

Issue 7: Proposed Deferral and Variance Accounts

a) Are the following EPCOR's proposed deferral and variance accounts appropriate?

ix. Regulatory Expense Deferral Account (REDA)

b) Are the following EPCOR's proposed deferral and variance accounts consistent with EPCOR's CIP proposal and appropriate?

i. Municipal Tax Variance Account (MTVA)
ii. Energy Content Variance Account (ECVA)

Issue 8: Incentive Rate Setting Proposal

e) Is EPCOR's request for availability of an Incremental Capital Module (ICM) consistent with EPCOR's CIP proposal?

Issue 10: Implementation

a) Is EPCOR's proposal for a January 1, 2019 effective date consistent with EPCOR's CIP proposal?

b) Is EPCOR's proposal for rate riders for recovery from and after the effective date consistent with EPCOR's CIP proposal and appropriate?

Issue 11: Stakeholder Engagement

a) Has EPCOR effectively engaged with and sought input from key stakeholders and First Nations and Metis communities?

10. Pursuant to Procedural Order No. 7, dated October 8, 2019, OEB Staff and the Intervenors filed their final arguments by October 18, 2019, which set out their respective positions on the unsettled issues.

11. EPCOR is herein filing its reply argument on the unsettled issues. This submission highlights that the unsettled issues have been fully addressed in the rate application and responses to interrogatories, and that EPCOR's proposals in respect of the unsettled issues are either consistent with the CIP or appropriate, as required. EPCOR submits

that in so far as the unsettled issues are concerned, the proposals set out in its application should be accepted as filed subject to any proposed adjustments detailed in this submission.

II. OVERVIEW OF EPCOR'S POSITION ON UNSETTLED ISSUES

12. The basis of this rate application is unique in that is it supported by EPCOR's successful CIP Proposal, which detailed EPCOR's proposal to provide gas distribution service to identified communities in the South Bruce region. The CIP Proposal was the product of a rigorous competitive process developed by the OEB, which formed the basis upon which the Board approved the CPCNs necessary to provide service to the South Bruce communities.

13. In this submission, EPCOR argues that the competitive process, anchored by the common assumptions and parameters[2] that were agreed to by the proponents and OEB in the South Bruce Expansion proceeding, established a strong framework upon which the economics of EPCOR's CIP was based. The economics of the CIP are also heavily dependent on the risk sharing principles that flow from these common assumptions and parameters.

14. As discussed in the specific issues in this submission, while EPCOR accepted a risk profile somewhat different than that of a standard utility, the intent of the CIP/competitive process was not for EPCOR to assume unlimited risk. Rather, as is always the case before the OEB, there was and should continue to be a proper balancing of the interest of (prospective) ratepayers and the utility. The effect of accepting many of the suggestions made by Board Staff and intervenors on several issues would ignore the risk-sharing balance struck in the South Bruce Expansion proceeding, and transfer risk to EPCOR after-the-fact. The effect would be a material loss of revenue for EPCOR, impacting the future viability of the utility. It would also, in EPCOR's submission, discourage future system expansions.

15. The main issues in dispute in this proceeding relate to: (a) a significant revenue deficiency that is due to externally caused delays in receiving regulatory approval; and (b) EPCOR's proposed cost allocation and rate design.

16. In terms of EPCOR's forecasted revenue deficiency, this issue arises as a result of external events that have caused a material change between: (a) the common assumptions agreed to in the CIP process regarding the construction schedule; and (b) the current construction schedule. The events that led to the delay in EPCOR receiving leave-to-construct approval for the South Bruce project were not within the scope of risk accepted by EPCOR as part of the CIP process. Therefore, it would be both consistent with the CIP process, and appropriate, for the impact of this delay to be accounted for in this rate application. The proposed revenue deficiency amount and proposed method

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2 EB-2019-0264, Southern Bruce Rate Application, Updated: April 11, 2019, Exhibit 1, Tab 2, Schedule 1, Table 1-1, page 11 of 64.

for recovery is reasonable. The OEB's final determination of the revenue deficiency issue is covered in Issue 5(a) and 10(a).

17. As for cost allocation and rate design, these issues depend upon EPCOR having limited discretion to set market-based rates to attract sufficient customers in a timely in order to achieve its cumulative 10-year throughput volume (which supports the revenue requirement). Regulated rates are a proxy for market-based rates in cases where insufficient competition is shown to exist. Once customers are captive to a utility, they understandably require the protection of regulation to ensure that the utility does not exercise monopoly power. In Southern Bruce, there are no customers served by EPCOR that require the protection of regulation for this initial setting of rates. Each potential customer has an existing energy supplier and will make their own decision to switch to natural gas if (and only if) the total value of the natural gas option exceeds the cost of their current energy choice (plus any cost of conversion). In other words, each South Bruce resident or business will have an individual competitive choice to make and will only switch to natural gas if the rate is competitive with their current energy choice.

18. In order for EPCOR to effectively compete with existing fuel choices and develop a utility that is viable in the long term, EPCOR needs the ability to design rates that reflect the competitive reality in the marketplace. This unique situation is not faced by mature utilities within an existing base of customers.

19. Moreover, EPCOR will be subject to standard cost-of-service rate regulation when it rebases at the end of the rate stability term, and it has considered and sought to set market-based rates in a manner which will mitigate the potential for rate shock for any particular class, or other undesirable effects, which could negatively impact its operations or relationship with customers in the long term.

20. In EPCOR's view, its proposed cost allocation and rate design proposals are appropriate and consistent with the CIP Proposal, as they reflect an appropriate balance of competing interests in the context of a greenfield expansion that has undergone a competitive process based on common assumptions.

21. The OEB's final determination of the cost allocation and rate design issues is covered by Issues 6 (a), (b), (c) and Issue 1(b).

22. The remaining unsettled issues relate to EPCOR's proposed Other Revenues (Issue 3(c)), proposed deferral and variance accounts (Issues 7(a) and (b)), an incentive rate setting proposal (Issue 8(e)), the proposed January 1, 2019 implementation date (Issue 10(a) and (b)), and stakeholder engagement (Issue 11(a)).

23. EPCOR submits that the record in this proceeding provides sufficient evidence for approval of the utility's proposals as they relate to each of these remaining unsettled issues.

III. SUBMISSIONS ON UNSETTLED ISSUES

Issue 1: Administration

b) Are EPCOR's proposed rates consistent with its CIP, and where there are departures are such departures appropriate?

24. Settlement of this overarching issue depends upon the complete settlement or adjudication of all issues in this proceeding. As noted above, this issue is heavily tied to Issues 5 and 10 (revenue deficiency) and Issue 6 (cost allocation and rate design), which the parties were not able to settle. These issues will be addressed in detail below.

25. EPCOR understands that the setting of rates was not directly determined as part of the competitive process; however, the rates proposed by EPCOR in this application are the direct outcome of the competitive framework under which it developed its CIP Proposal and are therefore consistent with it. EPCOR has not proposed any departures from the competitive framework on which its CIP was based.

Issue 3: Operating Revenue

c) Are EPCOR's proposed Other Revenues during the rate stability period consistent with EPCOR's Southern Bruce's CIP proposal?

26. In its decision on the final issues list in this proceeding, the Board recognized that the cumulative 10-year revenue requirement had already been established in the South Bruce Expansion proceeding, and stated that: "The OEB will not be re-adjudicating whether the revenue requirement or commitments made as part of the CIP are appropriate."[3]

27. EPCOR's CIP Proposal did not include any Other Revenue in its cumulative 10-year revenue forecast. Consequently, EPCOR has proposed Other Revenue of $0 in this rate application. EPCOR did not include any Other Revenue it its CIP proposal because it assumed Other Revenue would be offset by the incremental costs associated with providing services that might generate Other Revenue. EPCOR is proposing to include a forecast of Other Revenue and related incremental costs in its 2022 IRM filing once EPCOR has a developed a track record for the revenue and costs associated with these activities.

[3] EB-2018-0264, Decision on Issues List, August 20, 2019, Findings, page 3.

28. OEB Staff argues that EPCOR has forecasted Other Revenues of $31,851 for the first three years (cumulative) but has proposed Other Revenues of $0. While EPCOR developed a hypothetical[4] forecast using the experience of its Aylmer operations as a basis, EPCOR did not do so with the intent of accepting that as a proxy for its Southern Bruce operations. In fact, EPCOR specifically stated that "the relevance of using forecasts based on experience of other utilities versus a greenfield utility is unclear, and the [Other Revenues] dollars are expected to be minimal initially[5]". EPCOR presented this hypothetical forecast to demonstrate that if Other Revenue were to approximate the Aylmer experience, it would not be material during the first three years.

29. Further, EPCOR notes that many of the elements associated with Other Revenue, such as Utilities Fees (which are collected as a result of fixing line strikes) may be materially different for a greenfield utility (i.e., Southern Bruce) versus a mature utility (i.e., Aylmer). Moreover, as EPCOR expects to have a construction contractor in the area for several years, it would expect that a combination of third-party resources and employee overtime will be used to facilitate the work associated with Utility Fees; neither of which has been reflected in the O&M costs.

30. EPCOR notes that Utilities Fees associated with the Board Staff proposal[6] to use the Aylmer operations' Other Revenue amount is nearly 50% ($67,809 of the $147,777) of the total forecast annual Other Revenue for Aylmer.

31. Board Staff's proposal to use $432,915 as the 10-year Other Revenue should not be accepted by the Board for two reasons. First, as discussed above, there is no evidence to back-up the assumptions underpinning OEB Staff's calculations. The Aylmer operations cannot be compared to the greenfield operations in the South Bruce region. Second, this Issue 3(c) must be determined by the Board based on whether EPCOR's proposed revenues are consistent with its CIP Proposal. EPCOR can unequivocally state that Board Staff's proposal is not consistent with EPCOR's CIP.

32. Board Staff's alternative proposal to establish a deferral account to record actual Other Revenues should also not be accepted by the Board. This alternative is not consistent with EPCOR's CIP as it would record Other Revenue during the first several years of operation. EPCOR would not oppose establishment of such a deferral account starting in 2022, provided such deferral account also records the incremental costs associated with providing those services. However, EPCOR proposes that the specific mechanics of how Other Revenue would be dealt with be addressed in the IRM for 2022.

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4 EB-2019-0264, Southern Bruce Rate Application, Updated: April 11, 2019, Exhibit 3, Tab 1, Schedule 1, para. 3, page 15 of 16.

5 Ibid, page 3-4.

33. Overall, EPCOR's basis for setting the value of Other Revenue at $0 is both logical and reasonable, and is consistent with EPCOR's CIP. EPCOR's proposal to address the potential for a negative rate rider that would be effective starting in 2022 and applied for the remainder of the 10-year rate stability period is also reasonable as it will allow for an evidence-based forecast that would include the impact of any incremental costs associated with generation of Other Revenue.

34. As a number of parties have co-mingled and linked their response to Issues 5(a) and 10(a), EPCOR has structured its reply to address both of those issues together.

Issue 5: Revenue Deficiency / Sufficiency

a) *Is EPCOR's proposal to recover an additional $1.764 million due to changes in construction schedule, and the associate rate rider calculation, consistent with EPCOR's CIP proposal and appropriate?*

Issue 10(a): Implementation

a) *Is EPCOR's proposal for a January 1, 2019 effective date consistent with EPCOR's CIP proposal?*

35. EPCOR will address Issue 10(a) first because Board Staff and several Intervenors have suggested shifting the effective date (Issue 10(a)) as the basis for their argument to deny EPCOR recovery of its revenue deficiency (addressed in Issue 5(a)).

36. Each of Board Staff, IGUA, VECC and SEC have argued that the "solution" to the $1.764 million revenue deficiency is to change the start date of the tariff from January 1, 2019 to December 2019, or when EPCOR's first customer is connected. Board Staff also argue that because the January 1, 2019 start date for the proposed tariff has not been agreed to by Staff and intervenors, it is therefore open to further discussion, and a decision by the Board.

37. In fact, the Board has previously determined that the effective date for the EPCOR tariff must be January 1, 2019. This was confirmed when the Board determined the final language for Issue 10. In its decision on the issues list, the Board stated that: "The effective date was established as part of the CIP."[7] and finalized the language of that issue as whether the January 1, 2019 start date "is consistent with EPCOR's CIP".

38. The issue, then, is a simple one – whether EPCOR's proposal for a January 1, 2019 effective date for its tariff and revenue requirement is consistent with the January 1, 2019 date established in EPCOR's CIP Proposal. On the face of it, it seems clear that

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7 EB-2018-0264, Decision on Issues List, August 20, 2019, OEB Amendments on Issue 10, page 15.

the two dates are consistent, and no party has put forward an argument that they are not. Therefore, EPCOR asserts that the proposal for a January 1, 2019 effective date is consistent with the CIP. Any proposal by Board Staff or an Intervenor to change that date would result in the change of a material common assumption on which EPCOR submitted its CIP. As discussed below, such an after-the-fact change in the rules utilized in the competitive CIP process should be rejected as it would be unfair, and have material, negative consequences for EPCOR.

39. The January 1, 2019 effective date established in the South Bruce Expansion proceeding was premised on receipt of a Board decision in the leave-to-construct ("LTC") for the Southern Bruce gas distribution system by August 2018. There does not appear to be any disagreement on this point – i.e., that a common assumption agreed to by the OEB as part of the competitive CIP process was that the LTC would be approved by August 2018[8]. The actual date of approval was July 11, 2019, which means a delay of over 10 months. The following details the timeline that highlights the delay:

October 16, 2017 – CIP proposals were filed (in accordance with common assumptions).

December 2017 – Common assumption for date of Board decision on competitive process.

March 2018 – Common assumption for date that selected developer would file an LTC application.

April 12, 2018 – Board determined that EPCOR was successful proponent and awarded the necessary CPCNs. Board directed EPCOR to file its LTC application by October 12, 2018.

August 2018 – Common assumption for date that Board would issue LTC decision.

September 20, 2018 – EPCOR filed its LTC application (EB-2018-0263). This was well in advance of the Board's deadline of October 12, 2018[9].

October 3, 2018 – EPCOR notified the OEB that it had been informed that the Project would not be receiving previously approved funding under the Natural Gas Grant Program ("NGGP"). EPCOR also stated that "we are prepared to continue supporting the project on its current schedule if we receive confirmation from the Province that such funding will be available at some time in the future. …we are actively working with the municipalities to obtain such confirmation."[10] The NGGP was central to not

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8 EB-2016-0137/0138 /0139, OEB Staff Progress Update, July 20, 2017, Construction Schedule, page 6.
9 Ibid, Decision and Order, April 12, 2018, section 5 Order, para 4, page 14.
10 EB-2018-0263, EPCOR letter to OEB, October 3, 2018

just the CIP process but any significant gas expansion in Ontario. Its importance cannot be dismissed. EPCOR is of the view that without the NGGP, there would be no material gas distribution expansion in Ontario.

November 29, 2018 – The OEB informed EPCOR that the LTC had been placed in abeyance. As noted by Board Staff, in response to Staff IR#20, EPCOR confirmed its understanding that the OEB placed the LTC into abeyance as the project was not economically feasible without external funding. In its submission, SEC indulges in unsubstantiated speculation that if Union had been selected "It may have very well decided it did not need the funding, or more likely, it was a risk it was willing to take to move the project forward.[11]" Raised for the first time in its final argument, this statement by SEC must be completely disregarded by the Board. On this point, EPCOR notes that Enbridge filed an LTC application (EB-2018-0142) on May 7, 2018 for three projects that had been awarded funding under the NGGP (Chippewas of the Thames First Nation, North Bay Northshore and Peninsula Roads, and Saugeen First Nation). On November 29, 2018 the OEB placed that LTC in abeyance due to the loss of NGGP funding. On April 24, 2019 (over a month after EPCOR refiled its Southern Bruce LTC) Enbridge refiled an LTC application (EB-2019-0139) for the Chippewas of the Thames First Nation project only. On July 31, 2019 Enbridge requested that EB-2018-0142 be withdrawn, indicating it was updating the LTC for the other two projects. It is clear that delays due to the NGGP cancellation was not a risk that any proponent of a gas expansion would take.

February 27, 2019 – In order to maximize the efficiency of the OEB adjudication process, EPCOR filed an updated LTC that incorporated progress made since September 2018. This filing was in advance of legislation being passed that confirmed the project was eligible for funding.

March 8, 2019 – Ontario Regulation 24/19 was filed confirming that Southern Bruce was eligible for funding.

March 21, 2019 – OEB took EPCOR's LTC for Southern Bruce out of abeyance and commenced processing the application.

March 22, 2019 – OEB issued its Notice of Hearing and Letter of Direction.

July 11, 2019 – OEB approved the Southern Bruce LTC.

July 12, 2019 – EPCOR filed notice with the OEB informing it that construction of the project had commenced.

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[11] EB-2018-0264 SEC Submissions, October 18, 2019, page 2.

40. EPCOR is not suggesting that the delay in approval of the LTC was driven by any particular inaction by the OEB, and in fact, Board Staff point out that the LTC was approved in 112 days, under the 130 day metric.[12] Rather, EPCOR is stating that there was an over 10-month delay in approval of the LTC versus the common assumption approved by the OEB in the competitive process, and that the delay was the result of external factors beyond EPCOR's control. As a result of that delay, EPCOR is facing a revenue deficiency of $1.764 million and is requesting it be recovered through a rate rider to be implemented during the 10-year rate stability period.

41. The financial impact of the delay is detailed in Table 6-2[13] which has been reproduced below.

Table 6-2 Summary of Revenue Deficiency

		Col. 1
	Description	**NPV of Revenue Deficiency**
Row 1	Change in Customer Connection Profile - Forgone Revenue	2,324
Row 2	Delay in Property Taxes - Forgone Cost	(224)
Row 3	Change in Capital Expenditure Profile - Forgone Cost	(460)
Row 4	Deferred Recovery of Upstream Charges	124
Row 5	Sum	**1,764**

42. The NPV of $2.324 million in foregone revenue (Row 1) is the result of a delay in the construction of the system, which drives a delay in connecting each population centre to be serviced by the new gas distribution system. This includes the largest population centre, Kincardine, which will be delayed by 12 months.[14] As EPCOR detailed in Table 6-4 Customer Connections CIP vs New Construction Schedule[15], in order to mitigate the impact of this delay in construction, EPCOR is committing to a customer connection forecast that is more aggressive than that included in its CIP Proposal. However, even with this more aggressive connection schedule, there is a revenue shortfall.

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12 EB-2018-0264OEB Board Staff Submission on Unsettled Issues, October 18, 2019, Issue 5: Revenue Deficiency/Sufficiency, page 6.
13 EB-2019-0264, Southern Bruce Rate Application, Updated: April 11, 2019, Exhibit 6, Tab 1, Schedule 1, Table 6.2, page 3 of 12.
14 Ibid, Table 6-3, page 4 of 12.
15 Ibid, Table 6-4, page 5 of 12.

43. The "solution" proposed by OEB Staff, SEC, IGUA and VECC is to simply shift the start date of the 10-year rate stability period from the Board-approved effective date of January 1, 2019 to the date of the first customer connection (approximately December 2019). The suggestion is that any revenue forgone as a result of the delay due to approval of the LTC would be made up "at the back end" by extending the 10-year period to approximately November 2029. In other words, the argument is that shifting the rate stability period into year 11 would result in incremental revenue for EPCOR sufficient to be "kept whole". While attractive in its simplicity, this is simply not the case.

44. When competing for the right to own and operate the Southern Bruce system, EPCOR had to consider two phases of operation: Phase I, the initial 10-year period during which EPCOR would operate under the framework agreed to in the CIP; and Phase II, the post-CIP period of years 11 and beyond.

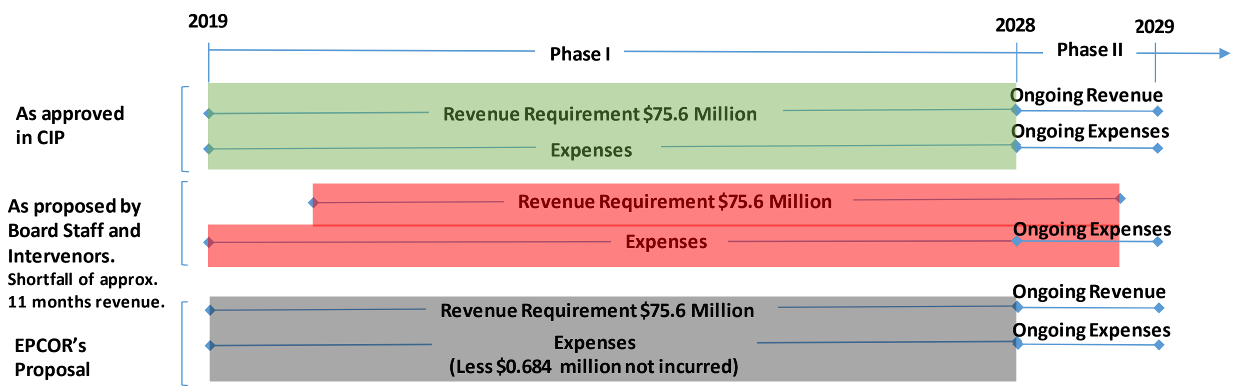
45. For Phase I, the OEB awarded EPCOR the Southern Bruce CPCNs based on a 2019 – 2028 revenue requirement of $75,586,261 ($58,534,551 after adjustments). However, as the utility will be a going concern there will clearly be ongoing revenues during Phase II. These ongoing revenues and expenses for years 11 and beyond (commencing January 1, 2029) were taken into account by EPCOR in the preparation of its CIP Proposal. The proposal by Board Staff and intervenors to simply shift the 10-year rate stability period into year 11 treats the revenue EPCOR would earn in year 11 as Phase I revenues. However, that was not the basis of the competitive CIP process.

46. As a result of the delay caused by the NGGP cancellation (and consequent regulatory delays), EPCOR's ability to earn Phase I revenues is compromised. The Year 11 revenues cannot address the $2.324 million foregone revenue from 2019 - 2028. What the suggestion by Board Staff and some intervenors does is extend the $75,586,261 revenue requirement into year 11, materially reducing the revenue EPCOR can earn over the 11-year period of 2019 - 2029. As a result, it will not address the $2.324 million foregone revenue on which the economics of the CIP were based.

47. EPCOR's proposal is to collect the foregone revenue of $2.324 million over the approved 10-year rate stability period through a rate rider. EPCOR is proposing to partially offset this revenue shortfall by crediting customers with the $0.684 million in reduced expenses incurred during the 10-year period ($0.224 + $0.460 as per Table 6-2 above.) EPCOR notes that since being selected as the successful proponent in April 2018, it has been incurring material expenses in good faith in order to meet the commitments it made in its CIP Proposal that would allow it to earn the approved $75.6 million revenue requirement. Its proposal therefore most accurately incorporates the competitive framework established by the OEB in the South Bruce Expansion proceeding.

48. The difference between: (a) the original CIP Proposal; (b) the proposal by OEB Staff and Intervenors to shift the effective date *contra* the CIP proposal; and (c) EPCOR's proposal in this rate application to address the revenue deficiency caused by the delay is illustrated in the diagram below.

Proposals for Addressing Revenue Deficiency



49. In their submissions on Issues 5(a) and 10(a), Board Staff and intervenors have made a variety of other statements or observations that EPCOR will address below.

50. In support of its proposal, Board Staff suggests that "the evidence does not indicate any increase in actual construction costs. … If there are actual increased construction costs related to the delay, EPCOR in reply is requested to provide the appropriate reference in the evidence.[16]" EPCOR notes that Table 6-7 Change in Capital Expenditure Profile[17] does indicate that capital expenditure costs have increased by $1.739 million from 2019 - 2021. In addition, in response to OEB 1.Staff.4, EPCOR reproduced that table and directly stated that construction costs had increased by this amount.

51. Board Staff also requested that if a start date is other than November 1, 2019, EPCOR would be expected to provide an update in its reply. EPCOR assumes the start date referred to is the connection of the first customer, and notes that in Table 6-3 Impact of Revised Construction Schedule on Connecting Population Centers,[18] the revised

16 EB-2018-0264, OEB Board Staff Submission on Unsettled Issues, Issue 10: Implementation, page 14.
17 EB-2018-0264, Southern Bruce Rate Case, Updated April 11, 2019, Exhibit 6, Tab 1, Schedule 1, page 7 of 12.
18 EB-2016-0137 / 0138 / 0139, Southern Bruce Rate Application, Exhibit 6, Tab 1, Schedule 1, page 4 of 12.

schedule for connecting the first customers is December 2019. This is re-stated in the response to OEB 6.Staff.20(b).

52. In its submission, VECC states "There is no evidence as to how the $1.739 million in additional capital costs arises. … No evidence exists to clarify.[19]" EPCOR notes that Table 6-7 Change in Capital Expenditure Profile[20] in the pre-filed evidence (filed in April 2019) indicated that there was an increase in capital costs of $1.739 million from 2019 to 2021. No party, including VECC, chose to dispute this amount in the pre-filed evidence.

53. Further, relating to the increase of $1.739 million in capital costs VECC states "Nor is there an explanation as to how this increase in costs leads to a decrease in revenue requirement."[21] Table 6-7 in the pre-filed evidence does in fact include details as to how the time value of the delay in capital expenditures offsets the increase in capital costs to result in a net decrease in revenue deficiency of $0.460 million as included in Table 6-2 reproduced above.

54. In its submission, IGUA asserts that the CIP proceeding did not assume a start date for the construction schedule, but [only] the construction schedule duration,[22] and therefore EPCOR should accept the risk of a delayed construction start. However, the South Bruce Expansion proceeding clearly did have a common assumption regarding a start date for construction. This date was March 2019.[23] As this was a common assumption, EPCOR should not be taking the risk resulting from external factors that delayed the construction start date.

55. In paragraph 36 of its submission, IGUA requested that the Board direct EPCOR to recalculate the $124,000 deficiency related to delayed upstream charges which is detailed in Table 6-8 of the pre-filed evidence and summarized in Table 6-2 above. EPCOR notes that each of the costs that sum to the $1.764 million revenue deficiency may have changed over time. While EPCOR proposes that the Board reject IGUA's request, if the Board accepts it, then EPCOR proposes that the Board should direct that all the cost elements of the revenue deficiency also be updated.

56. Each of IGUA and VECC suggests that by participating in the competitive process, EPCOR accepted any and all risks, including forecast risk of every element of the CIP

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19 EB-2018-0264, Submission of the VECC, October 21, 2019 para 18, page 5.
20 EB-2018-0264, Southern Bruce Rate Application, Exhibit 6, Tab 1, Schedule 1, page 7 of 12.
21 EB-2018-0264, Submission of the VECC, October 21, 2019 para 18, page 5.
22 EB-2018-0264, IGUA Final Argument, Issue: 5 Revenue Deficiency / Sufficiency, para 38 and 40, page 9.
23 EB-2016-0137 / 0138 / 0139, OEB Staff Progress Update, July 20, 2017, Construction Schedule, page 6.

and start of construction risk. EPCOR agrees that as the successful proponent it has accepted certain defined risks that are not typically assumed by a utility. However, the risks that were accepted by the proponents in the competitive CIP process were not unlimited and undefined. As detailed in Table 1-1 of the pre-filed evidence,[24] there were at least twenty parameters and common assumptions agreed to by the OEB that EPCOR relied on when developing its CIP Proposal. These were the basis upon which EPCOR committed to a schedule of customer attachments, a start of construction and a 10-year revenue requirement from January 1, 2019 to December 31, 2028. Proposing to cherry pick any single or group of items to set aside is not only changing the rules of the competitive process after the fact but ignores that many of these parameters and assumptions are interdependent. Such changes 18 months after the OEB determined that EPCOR was the successful proponent will have a direct impact on EPCOR and will negatively impact the economics of the project.

57. Therefore, EPCOR asserts that its proposal to collect the revenue deficiency of $1.764 million due to changes in construction schedule is consistent with EPCOR's CIP Proposal, and is appropriate. The difference between the common assumptions agreed to by the OEB and relied on by EPCOR in submitting its CIP Proposal, and what has occurred as EPCOR implemented the project is the basis for the additional $1.764 million in revenue deficiency. As EPCOR has detailed above, the drivers for these deltas were outside its control.

58. EPCOR asserts that its proposal related to the rate rider calculation to recover the $1.764 million revenue deficiency is appropriate as it allocates the revenue shortfall into each rate class in proportion to the revenue deficiency associated with that rate class. The rate that is to be applied to each rate class was determined by first calculating the NPV of the revenue deficiency in each rate class caused by the delay in a decision on the LTC. The proportion of the total $1.764 million revenue deficiency that each rate class represented was then allocated to that rate class. EPCOR has proposed that the rate rider be applied on a volumetric basis as the largest single factor creating the revenue deficiency is foregone revenue due to a reduction in volume as a result of the delay in connecting customers. EPCOR notes that there were no alternative proposals for calculation of the rate rider.

Issue 6: Cost Allocation and Rate Design

a) Are the proposed rate classes appropriate?

59. EPCOR has proposed four rate classes for its Southern Bruce operations, including Rate 1 (General Firm Service), Rate 6 (Large Volume General Firm Service), Rate 11 (Large

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24 EB-2018-0264, Southern Bruce Rate Application, Exhibit 2, Tab 2, Schedule 1, page 11 of 64.

Volume Seasonal Service) and Rate 16 (Contracted Firm Service) as set out in the application and pre-filed evidence.[25]

60. EPCOR notes that, other than Board Staff who indicated they had no concerns regarding the proposed rate classes, there were no submissions on this issue, including any alternative proposals. As a result, based on the evidence in this proceeding, EPCOR asserts that the proposed rate classes are appropriate.

b) Are EPCOR's proposed cost allocation, rate design and revenue to cost ratios appropriate and consistent with EPCOR's CIP proposal?

61. EPCOR reiterates that its proposed rates are based on its understanding (supported by the research included in its CIP and this proceeding) of the savings that a potential customer requires in order to consider it economic to switch from their existing fuel source to natural gas. As potential customers in each rate class will be undertaking this economic analysis in advance of connecting to EPCOR's distribution system, it is important for EPCOR to be responsive to this consideration, and offer economic rates to all customers, as no single rate class can support the utility in the long run.

62. Affordable long-term rates to consumers and the long-term financial viability of the gas utility serving Southern Bruce are both furthered by robust conversion rates.

63. The interests of EPCOR and its customers are completely aligned on this point, and consistent with the Board's statutory objectives with respect to natural gas.

64. Once a customer has connected, they will have the security of the 10-year rate stability period, ensuring that they will continue to benefit from the economics that convinced them to connect. After the 10-year rate stability period, EPCOR will file a rate application based on cost-of-service principles. The rate application filed by EPCOR for Year 11 rates will incorporate a cost allocation study that is supported by historical data from a then-mature utility.

65. Board Staff, IGUA and SEC have argued that EPCOR should have rates based on revenue-to-cost ratios ("RTC") that are strictly within the OEB established range of 0.8 to 1.20. Board Staff acknowledges that for a variety of reasons RTCs may vary from 1.0, which is why the Board has established a range. IGUA is arguing for a RTC of 1.0 for all rate classes and has requested that EPCOR file draft rates calculated on the basis of RTC for all rate classes set to 1.0.

66. The difference in approaches suggested by Board Staff, SEC and IGUA are indicative of the fact that while a RTC of 1.0 for a rate class is assumed desirable because it

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[25] EB-2018-0264, Exhibit 8, Tab 1, Schedule 1, p. 3-4 of 14.

suggests rates are precisely recovering the costs allocated to a class, in practice a RTC of 1.0 is rarely achieved and may in fact not be preferable. There may be other rate design objectives (e.g., customer attraction and retention) that warrant a deviation (potentially material) from a RTC of 1.0. As a result, different North American jurisdictions have varying policies on RTC ratios.

67. In its submission, Board Staff suggests that moving to a RTC as proposed in OEB 7.Staff.22, in which the RTCs are within the 0.8 to 1.20 range except for Rate 16 (RTC of 1.22) would be acceptable. EPCOR notes that in making this adjustment, Rate 6 customers would be subject to rate increases of 8.5% to 9.2% over that being proposed by EPCOR.[26] This increase could materially impact the conversion rate of Rate 6 customers, which represent 8.8% of total forecasted volume in 2028.[27] It is unlikely that any reduction in Rate 6 volumes (due to a reduced connection rate) would be offset by additional volumes and revenues from Rate 16 customers (which would benefit from an 8.3%[28] reduction in this scenario). Board Staff states they are of the view that this proposal is not likely to materially impact forecasted attachments; however, there is no basis for Board Staff's assertion – and it must clearly be incorrect, as it is unlikely that Rate 16 customers would require additional volumes as a result of a reduction in their tariff.

68. IGUA has stated that the rates proposed by EPCOR represent an after-the-fact effort to off-load customer connection risk onto certain rate classes. IGUA states that EPCOR was aware of the OEB policy regarding use of cost-of-service principles when submitting its CIP Proposal and it should have made some form of a statement in its CIP Proposal if the plan was to offer customers rates driven by a goal of maximizing conversion rates.

69. EPCOR notes that its CIP Proposal did discuss that its customer connection forecast was based on market research undertaken for the South Bruce project:

> "*…EPCOR has estimated the total available market to be 8,739 customers. EPCOR forecasts a total of 5,278 customers over the 10-year rate stability period based on a conversion rate of 60% for residential customers and 65% commercial customers. This is supported by formal survey results for*

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26 OEB 7.Staff.22b) and Exhibit 8, Tab 1, Schedule 10, page 1 of 1 includes customer bill information for Rate 6. EPCOR proposed customer bill is $13,290 (Medium Commercial) and $34,444 (Large Commercial). Staff proposed bill would be $14,414 (Medium Commercial) for an increase of 8.5% and $37,601 (Large Commercial) for an increase of 9.2%.

27 EB-2018-0264, Southern Bruce Rate Application, October 2, 2018, Exhibit 3, Tab 1, Schedule 2, Table 3-9, page 2 of 3. Total volume in 2028 is 40,283,419 m^3 versus volume for Rate 6 is 3,560,460 m^3.

28 OEB 7.Staff.22b) and Exhibit 8, Tab 1, Schedule 12, page 1 of 1, for Rate 16 EPCOR proposed bill is $839,569. Staff proposed bill is $770,157 for a decrease of 8.3%.

> *residences and extensive face to face meetings with commercial customers and augmented with results of a commercial survey.*"[29]

70. The results of the market research on which EPCOR based its customer connection forecast clearly indicated that price was the number one reason for converting (77%)[30] and there was a direct relationship between the likelihood of conversion **and expected savings** (varying between 44% and 58% depending on the savings scenario tested)[31].

71. EPCOR notes that there is precedent for the Board to allow flexibility for rates to be set in a competitive environment. In EPCOR Aylmer's recent rate case (EB-2018-0336), the Board approved an existing Rate 3 (Special Large Volume Contract Rate). This rate includes a Monthly Interruptible Delivery Charge for all interruptible volumes. That charge is to be negotiated between EPCOR and a prospective customer, provided the rate does not exceed 10.5118 cents per m^3 and not be less than 7.6156 per m^3.

72. The Board has also approved competitive rates[32] in order to address potential customer bypass. The principle associated with avoiding competitive bypass is similar to the case of Southern Bruce where it is to the advantage of all customers to promote the viability of the utility by offering a competitive rate that will convince customers to switch to natural gas in order for the distribution utility to be economically viable.

73. IGUA states in paragraphs 15 and 16 of its submission that EPCOR is proposing to use different methodologies in setting rates for Rate 16 and Rate 11 customers versus Rate 6 customers. That is not the case. EPCOR is using the same methodology in proposing rates for all rate classes, by targeting an energy savings of greater than 20% for each rate class in order to attract sufficient customers to sustain the new distribution utility in South Bruce.[33] Thus, there is an expectation that all rate classes will enjoy similar savings if they connect to EPCOR's system. Moving away from the proposed rates would, EPCOR submits, result in some customer classes achieving even higher savings, to the detriment of other customer classes. EPCOR notes that no party has submitted that EPCOR's proposed rates are not economically attractive enough to convince their clients to connect.

74. In completing its cost allocation study for this application, EPCOR applied accepted cost allocation principles and used a three-step methodology of functionalization, classification and allocation of the costs to provide service. The study categorizes all

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29 EB-2016-0137 / 0138 / 0139, EPCOR CIP, October 16, 2017, Tab 2, para 13, page 5 of 41
30 EB-2018-0264, Southern Bruce Rate Application, October 2, 2018, Exhibit 1, Tab 3, Schedule 1, page 41 of 53.
31 Ibid, Tab 5, para. 2 page 18 of 41
32 OEB, E.B.R.O. 457 CIL Application for Bypass Competitive Rate
33 EB-2018-0264, October 2, 2018, Exhibit 7, Tab 1, Schedule 1, Para 3, page 1 of 15.

costs into functional areas (gas supply, distribution related, customer and administrative), which are then classified as being commodity, demand, or customer related. These three major cost components are then allocated to the proposed customer rate classes based on allocation factors derived from basic customer data.

75. As an expansion project with no operating history, accounting data or actual customer usage information, EPCOR has used proxy data and factors from the 2020 Fully Allocated Costing Study completed for EPCOR's Aylmer operation[34]. With no system constructed, no customers and no operating history, the cost allocation study results have to be interpreted with significant caution (in contrast to cost allocation studies undertaken for a mature utility which would be based on a substantial operational history). EPCOR submits that if the Board believes that the results of this necessarily limited cost allocation study should form the basis for initial rates in South Bruce, the Board's typical range should be broadened to not only take into account the inaccuracies of the cost allocation study, but also take into account the uniqueness of the circumstances and in particular the objective of designing rates to maximize customer attachments.

76. In paragraph 34 of its submission, IGUA requests that the Board direct EPCOR to remove from allocation to Rate 16 customers, the costs for distribution facilities located downstream of the Bruce Energy Center pressure regulation and metering station. In making that request IGUA appears to have been relying on several incorrect assertions regarding the high-pressure system.

77. At paragraph 26 IGUA indicates: "This asset group is actually comprised of two distinct pipelines: a) 60 km of NPS 8 pipeline from the Dornoch connection with Enbridge Gas to the Bruce Energy Centre; and b) A smaller lower pressure NPS 6 pipeline running from Bruce Energy Centre to Kincardine."

78. While IGUA is correct in that the line does reduce to 6" close to the Bruce Energy Centre, the 8" and the 6" are an integral part of a single high-pressure system. The 6" has the same operating pressure as the 8" pipeline.

79. At paragraph 30 IGUA suggests:

> *"…the cost allocation analysis which indicates the 37% over-collection is premised on allocation to these customers of costs of facilities which will be downstream of them and will <u>not</u> be engaged in the provision to them of service."*

34 EB-2018-0336, Exhibit 7

80. EPCOR is constructing two types of mains for the Southern Bruce system: a high-pressure main system that will move gas long distances in rural environments, and lower pressure mains that will be used to service customers in more urban areas. The high-pressure main system commences at the interconnection with Enbridge at Dornoch and an 8" pipeline extends westerly on West Grey Road 25, Bentinck Sullivan Townline Road, Bruce Road 19 and Concession 18. It then extends southerly a short distance on Bruce Road 1 and continues westerly on Bruce Road 20 to the intersection of Bruce Road 20 and Bruce Road 23. The 8" high-pressure line 'tees' at this location with the 8" high-pressure line continuing westerly on Bruce Road 20 and then extends on Farrell Drive to service two Rate 16 customers in the Bruce Energy Centre. From the tee at the Bruce Road 20 and 23 intersection, a 6" high-pressure line continues southerly to its terminus at a point just north of Kincardine.

81. EPCOR makes it clear in its response to IGUA 9(b) that the 6" and 8" high-pressure lines operate as a single fully integrated high-pressure system and the design of each element of the high-pressure system is a function of all of the aggregate demands. This includes demands upstream of the section of pipe in question, e.g. the design of the 6" pipe takes into account the demand of industrial customers at the Bruce Energy Centre.

82. Rate 16 was designed to address a customer meeting the minimum volume and term requirements, provided the customer is served off any location of the high-pressure system. The IGUA proposal to only include assets upstream of a customer's location would require EPCOR to create multiple rate zones based on the location of each Rate 16 customer and the assets that happen to be upstream of their location. Moreover, this proposal could result in all rate classes advancing the same argument whereby each population center served demands a rate that only includes the combination of assets upstream of their location. This outcome would create multiple rate zones for each customer class based on location, would be administratively complex, and contrary to accepted rate making principles. Practically, this outcome would also result in population centers that are more distant from the supply source not being served because of the relative economics of serving them, negating the prime objective of providing gas to the Southern Bruce region. This would then require higher costs to be allocated to those customers that attached to the system at an upstream point.

83. The Board has a long-accepted practice of rate class rate making which results in pooling assets used to serve customers and all customers in the same class paying the same rate. IGUA's proposal would upend this practice even though the Southern Bruce system has no unique characteristics that EPCOR is aware of which would suggest the practice should be modified.

84. If the Board agrees with the IGUA proposal that the costs of assets downstream of a customer location should not be reflected in their rates, then as outlined above, the cost

of the assets between the tee, at the intersection of Bruce Roads 20 and 23, and the terminus of the 8" high pressure line in the Bruce Energy Centre should only be allocated to Rate 16 as these assets are not used to serve any other rate classes.

85. Given the above, IGUA's proposal to direct EPCOR to draft rates calculated on the basis of RTC for all rate classes set at 1.0, and to remove from allocation to Rate 16 customers the costs for distribution facilities located downstream of the Bruce Energy Centre pressure regulation and metering station should be rejected.

86. In its submission, IGUA also highlights concerns regarding the process used to allocate the costs of certain assets, including pressure regulating and metering stations and the plastic distribution mains. The allocation study was included in Exhibit 7 of the pre-filed evidence and IGUA has had ample opportunity to request additional evidence regarding these items but chose not to. EPCOR asserts that IGUA should not now be able to use its lack of understanding regarding the allocation of these assets, to propose that the allocation process be modified.

87. EPCOR notes that, other than Board Staff who indicated they had no concerns regarding the proposed rate design in terms of the fixed and variable charges, there were no submissions on this issue, including any alternative proposals. As a result, based on the evidence in this proceeding, EPCOR asserts that the proposed rate design is appropriate.

c) *Are EPCOR's proposed rates appropriate?*

88. EPCOR asserts, for the reasons highlighted above, and in the application, that EPCOR's rates are appropriate.

Issue 7: Proposed Deferral and Variance Accounts

a) *Are the following EPCOR's proposed deferral and variance accounts appropriate? …*

ix. Regulatory Expense Deferral Account (REDA)

89. The REDA is intended to record costs associated with EPCOR's participation in generic and Enbridge Gas proceedings that will impact the utility.[35] EPCOR included regulatory expenses in its OM&A forecast, but only related to its expected routine applications, annual IRM applications and expected Reporting and Recordkeeping Requirements ("RRR") reporting.

90. In its submission, OEB Staff has argued that the REDA should not be granted on the basis that there is no evidence that costs to participate in generic proceedings is expected

[35] EB-2018-0264, Exhibit 9, Tab 1, Schedule 1, p.5 of 9.

to exceed the materiality threshold and that these costs can be absorbed within the OM&A budget.[36] In response to OEB Staff 35, EPCOR has sufficiently outlined how the REDA meets the OEB's eligibility criteria of causation, materiality and prudence.[37]

91. Board Staff also argued that EPCOR could request a deferral or variance account if it participates in a generic proceeding that triggers significant costs. Meanwhile, both VECC and SEC have argued that EPCOR was in the position to appropriately estimate regulatory costs in its proposal and accordingly there is no need for this deferral account.[38]

92. The OEB has consistently approved a REDA account for EPCOR's Aylmer operation, on the grounds that: (a) the cost of participating in generic proceedings is material for EPCOR's Aylmer operations (relative to the size of the utility); (b) the timing of generic proceedings is difficult to forecast and beyond any one utility's control; and (c) in the absence of a REDA, a small utility such as EPCOR (Aylmer) would refrain from participating in generic proceedings and the Board would be denied the perspective of a smaller utility. EPCOR has no intent to utilize the REDA other than for such situations and would accept any clarifications along such lines in its REDA accounting order.

93. For these reasons, EPCOR submits that the proposed REDA is appropriate and should be approved.

b) Are the following EPCOR's proposed deferral and variance accounts consistent with EPCOR's CIP proposal and appropriate?

i. Municipal Tax Variance Account (MTVA)

94. The MTVA will record impacts to EPCOR resulting from changes in municipal tax rates or levies, or the introduction of new municipal tax or levies.

95. Submissions that oppose the MTVA assert that EPCOR assumed the risk as part of its OM&A costs underpinning the revenue requirement that was approved in its CIP Proposal,[39] the materiality threshold will not be met,[40] and the utility has not made a case there is a material risk to be considered.[41]

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36 EB-2018-0264, OEB Staff Submission p. 9-10.
37 Response to IR OEB Staff 35.
38 EB-2018-0264, VECC Submission, para 9 and SEC Submission, p.5.
39 EB-2018-0264, OEB Staff Submission, p. 10 and SEC Submission, p. 5.
40 Ibid, SEC Submission, p. 5.
41 Ibid, VECC Submissions, para. 8.

96. EPCOR has explained the need for the MTVA and why related amounts cannot be absorbed as part of routine OM&A expenditures.[42]

97. EPCOR based its forecasted cost of municipal taxes in 2017 for the CIP Proposal on two pieces of government regulation. The first is Ontario Regulation 397/16, which sets out the methodology for calculating the assessment base on which a municipality levies its mill rate. The second is the local municipality's bylaws, which determine the mill rate for that particular municipality. The tax bill is then determined by multiplying: (a) the assessment base (generally some portion of the cost of the pipe in the ground in a specific municipality); by (b) the municipality's mill rate. The province updates its methodology for calculating the assessment base every four years, with the next update scheduled to take effect in 2021. It is expected to be updated at least once more during the 10-year rate stability period. Municipalities can update their mill rates every year and it is not uncommon for them to do so.

98. In addition, while for a mature utility the Province would have already completed a calculation of the assessment base, they have not completed one for EPCOR as the utility does not have assets in the ground. Therefore, the assessment base[43] as estimated for EPCOR is subject to confirmation by the Province. Such a confirmation could result in a higher or lower assessment base and therefore a greater or lesser tax bill.

99. EPCOR also notes that this cost differs from a standard O&M cost in that it was required to subtract the value of any municipal tax holidays[44] from the 10-year revenue requirement approved by the OEB. As a result, EPCOR subtracted a value of $2.208 million[45] from its approved revenue requirement. However, this value is based on EPCOR's estimate of municipal taxes, and the actual value could be greater (which would benefit EPCOR) or lesser (which would benefit the ratepayer) than that forecast. Note that EPCOR did not receive a tax holiday from the provincially levied portion of municipal taxes e.g. the portion associated with school taxes. The utility will also pay the full municipal tax in municipalities through which EPCOR's pipeline assets transit, but do not provide service.

100. The establishment of the MTVA protects both the ratepayer and EPCOR if municipal taxes differ from what was forecast in the CIP. The drivers for these variances relate wholly to government actions over which a utility has no control over and were not expected to accept the risk for during the competitive process. Therefore, the

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42 EB-2018-0264, OEB 9.Staff.36 and 9.Staff.39 Attachment 1 (revised Accounting Order for the MTVA).
43 Ibid, Southern Bruce Rate Application, Updated April 11, 2019, Exhibit 3, Tab 1, Schedule 3, Table 3-14, page 2 of 3.
44 The Municipality of Kincardine, Arran-Elderslie and Huron-Kinloss.
45 Ibid, Exhibit 3, Tab 1, Schedule 1, Table 3-5, page 11 of 16.

establishment of the MTVA is both consistent with EPCOR's CIP Proposal and appropriate.

ii. Energy Content Variance Account (ECVA)

101. The ECVA will record any variations in revenues and costs resulting from the differences in the energy content of the gas delivered and the assumed energy content (38.89 MJ/m^3).

102. Notably, none of the Intervenors oppose this variance account. In fact, VECC supports approval of the ECVA on the basis that Enbridge has a similar account to address the variation in gas heat content and their effect on the distribution portion of rates.[46] Only OEB Staff is opposed to this variance account on the basis that the utility has assumed this risk as part of the CIP. This is not the case. As discussed below, an assumed energy content was used to develop the common assumption related to gas usage for the utility's customers.

103. During the CIP process, the proponents were required to develop common average use assumptions for each market other than industrial customers. EPCOR worked with Union Gas (now Enbridge) to develop these projections.[47] These projections were based directly on Union Gas's then current average use per customer for its adjacent markets, adjusted for the local weather conditions and building stock. Union Gas' average use per customer was also based on the recent energy content of the gas and made no adjustments for future changes to energy content.

104. As noted in the response to OEB 9.Staff.37, the energy content for gas in the delivery area (southern Ontario) has been changing overtime. This change has occurred both in gas sourced from Western Canada as well as supplies from the new Marcellus and Utica supply basins. Energy content is a function of economic decisions by the producer to leave natural gas liquids in the gas stream or extract and sell them separate from the natural gas stream. The energy content of the supply of gas depends on the relative mix of gas coming from the various supply sources and that mix will change over time.

105. Since EPCOR is proposing to sell gas volumetrically to its customers, the energy content of the gas inversely affects the volume of gas sold. The higher the energy content, the more energy is contained in a m^3 of gas, resulting in less volume required by the customer to meet its total energy requirements. Similarly, the lower the energy content of the gas the less energy is contained within a m^3 of gas, and the more volume is required to provide the same total energy needs. Energy content of the gas therefore

46 EB-2018-0264, VECC Submission, para. 11.
47 EB-2016-0137/EB-2016-0138/EB-2016-0139 Joint EPCOR/Union Letter dated October 2, 2017.

directly affects the throughput on the system and the resulting distribution revenue. As the energy content was an element of the common assumption of volume by customer type, it is not a risk that EPCOR accepted in developing its CIP Proposal.

106. The ECVA is required to allow for recovery/refund of any under/over collection of revenue as a result of differences in the volume delivered arising from differences in the energy content of the natural gas. Doing so will ensure equal protection to the ratepayer and the utility from future changes in the heat content of gas over the rate stability period. This variance account is proposed to keep both the utility and customers whole.

107. Therefore, EPCOR submits that the establishment of the ECVA is both consistent with its CIP Proposal and appropriate.

Issue 8: Incentive Rate Setting Proposal

e) Is EPCOR's request for availability of an Incremental Capital Module (ICM) consistent with EPCOR's CIP proposal?

108. EPCOR has proposed to make available an ICM in EPCOR's Custom IR Plan. The ICM would only be used in circumstances in which the system would be expanded in a manner incremental to that detailed in the CIP Proposal.

109. In its submission, SEC opposes access to an ICM as it is concerned that EPCOR would use it to address capital cost overruns associated with construction of the system that was detailed in the CIP. EPCOR agrees that it is responsible for capital cost overruns related to the system that was detailed in the CIP and has specifically identified that the ICM would be used for capital expenditures associated with expanding the system incremental that which was detailed in the CIP.

110. In its submission, Board Staff is concerned that an ICM would not be a good fit if EPCOR were to use it to expand the system into additional communities. EPCOR had used expansion of the system into additional communities as an example in its application. However, EPCOR agrees that if it had the opportunity to expand the system into additional communities the ICM would not be the most appropriate approach to do so, and as a result would not use an ICM in such an instance. EPCOR does submit that there are circumstances in which an ICM approach would be a good fit. An example would be if volume per customer (a common assumption) increased to such an extent that total volume requirements for the customers that were forecast to be connected in the CIP was such that EPCOR would have to strengthen the system. This could include the potential reinforcements of the high-pressure steel line feeding the system.

111. Board Staff also detailed that in its submission on the issues list it had submitted that the ICM was not available for utilities setting rates under a Custom IR plan. EPCOR notes that utilities requesting that rates be set under a Custom IR are historically mature utilities that have a long history of operation which has allowed them to develop detailed capital expenditure plans. As a result, they should have no need to file an ICM. As EPCOR is a greenfield utility, it does not have the operational history necessary to develop a detailed capital expenditure plan and access to an ICM may be necessary if certain events take place, including the example described above. Even if EPCOR filed an ICM application, the Board has full discretion in terms of whether to grant any relief brought pursuant to such ICM application.

112. For that reason, EPCOR submits that there are good reasons for an ICM to at least be made an option for EPCOR.

Issue 10(b): Implementation

a) Is EPCOR's proposal for a January 1, 2019 effective date consistent with EPCOR's CIP proposal?

See EPCOR's response to 10(a) included in its response to Issue 5(a).

b) Is EPCOR's proposal for rate riders for recovery from and after the effective date consistent with EPCOR's CIP proposal and appropriate?

113. EPCOR's CIP Proposal did not directly address the use of rate riders; however, EPCOR is of the view that its proposal for rate riders for recovery from and after the effective date is appropriate.

114. EPCOR is proposing the establishment of a rate rider that would be applied on a volumetric basis over the 10-year rate stability period. EPCOR has proposed the 10-year term for the rate rider as the revenue deficiency that the rate rider is intended to address is a direct result of a delay incurred in connecting customers during that 10-year forecast period. EPCOR's proposal would therefore closely align the recovery of costs from those initial customers, thereby avoiding intergenerational inequality that may be created by collecting the amounts over a longer period. Collecting the revenue deficiency over a shorter timeframe would result in a greater bill impact particularly if that timeframe only covered the initial period when customer totals are low. This would result in a greater impact as the revenue deficiency would be collected over a smaller volume. Such an impact could reduce the new customer connection rate, driving down the total revenue collected by the utility.

115. EPCOR notes that, with the exception detailed below, there were no alternative proposals made for recovery of the revenue deficiency.

116. OEB Staff have proposed that the $0.124 million (see Table 6-2 above) related to deferred recovery of upstream charges be collected through the Storage and Transportation Variance Accounts rather than through a rate rider (as proposed by EPCOR). The rationale for EPCOR proposing that this value be collected through a ride rider over the initial 10-year rate stability period is that such costs are the result of a delay incurred in connecting customers in the initial phase of the 10-year rate stability period. EPCOR's proposal would therefore closely align the recovery of costs from customers connecting during the initial 10 years. This would avoid intergenerational inequality that may be created by collecting the amounts over a longer period as would be the result if the dollars were collected through these variance accounts.

Issue 11: Stakeholder Engagement

a) Has EPCOR effectively engaged with and sought input from key stakeholders and First Nations and Metis communities?

117. EPCOR submits that it has responded to Anwaatin's general concerns in its submissions on the proposed issues list.

118. This rate application does not have the potential to adversely impact any existing Aboriginal or treaty rights. In the ten-year rate stability period outlined in the CIP and this application, EPCOR's distribution system will not serve any specific indigenous community and connection to the distribution system is voluntary for any individual.

119. In its submissions, Anwaatin proposes that the OEB impose three conditions on any approval of this rate application.[48] EPCOR submits that the two proposed conditions relating to archaeological work and construction are matters more appropriately within the scope of an LTC application.

120. With respect to Anwaaatin's proposed one-window, enhanced access to applications for low-income rates for Indigenous customers, EPCOR submits that if the Board is inclined to consider any such relief, it should be assessed on a generic province-wide basis and not at the utility-specific level. EPCOR notes that this type of a service is not one that other utilities are currently required to perform, and as a result, the costs associated with such a service were not included in EPCOR's CIP Proposal. EPCOR would expect to

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48 EB-2018-0264, Anwaatin Submissions, paras. 10, 14, and 15.

be able to collect the cost of providing any such new requirement through an increase in rates.

121. For these reasons, EPCOR submits that the Board should not impose any of Anwaatin's proposed conditions as they are either outside of scope of this rate application or relate to issues that should be addressed in an alternative hearing in which a wide range of industry stakeholders are invited to participate.

ALL OF WHICH IS RESPECTFULLY SUBMITTED,
this 29th day of October, 2019

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EPCOR NATURAL GAS LIMITED PARTNERSHIP
By its counsel, Osler, Hoskin & Harcourt LLP
Per: Richard J. King