ONTARIO ENERGY BOARD

ONTARIO ENERGY BOARD STAFF SUBMISSION ON UNSETTLED ISSUES

EPCOR Natural Gas Limited Partnership (Southern Bruce) 2019-2028 Rates Application

EB-2018-0264

October 18, 2019

1. Background

EPCOR Natural Gas Limited Partnership (EPCOR Natural Gas LP) filed a custom incentive rate-setting application with the Ontario Energy Board (OEB) on April 11, 2019 under section 36 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for gas distribution rates to be effective January 1, 2019 and for each following year through to December 31, 2028.

In 2018, the OEB selected EPCOR Natural Gas LP (EPCOR Southern Bruce)[1] as the successful proponent for the South Bruce gas distribution project.[2] The process was competitive and the selection was made on the basis of a cumulative revenue requirement, forecasted attachments and total throughput volume for the 10-year rate stability period. EPCOR Southern Bruce made these commitments as part of the Common Infrastructure Plan (CIP) process and the OEB in its decision noted that it expected that EPCOR Southern Bruce's rate application would be consistent with its CIP proposal.[3]

In the South Bruce expansion proceeding, EPCOR Southern Bruce committed to three specific criteria as part of its CIP for the 10-year rate stability period. These metrics are reflected in the current rates application. Based on the metrics, the resulting cumulative gross revenue requirement for the 10-year rate stability period is $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

EPCOR Southern Bruce and the intervenors reached a settlement on some issues. A settlement proposal was filed on September 13, 2019. The OEB issued a decision on October 3, 2019 accepting the settlement proposal and scheduled a written process to address the unsettled issues.

OEB staff has provided a summary of its position on the unsettled issues below. A detailed discussion, organized according to the Issues List, follows.

[1] EPCOR Natural Gas LP in this application has been referred to as EPCOR Southern Bruce in order to identify it separately from the Aylmer gas distribution utility.
[2] EB-2016-0137/0138/0139, Decision and Order, April 12, 2018.
[3] *ibid*

Summary of OEB Staff Positions on Key Unsettled Issues

- Other Revenues should be $432,915 for the 10-year rate stability period or $43,292 annually.
- The revised revenue-to-cost ratios should be 1.01 for Rate 1, 0.90 for Rate 2, 1.20 for Rate 11 and 1.22 for Rate 16.
- EPCOR Southern Bruce's request for the Regulatory Expense Deferral Account, Municipal Tax Variance Account and Energy Content Variance Account should be denied.
- The appropriate effective date should be November 1, 2019 or when the first customer is connected. The 10-year rate stability period should begin from this date.
- If the effective date of rates is moved to when the first customer is connected, the proposed recovery of a revenue deficiency of $1.764 million to address the delay in connecting customers would not be required.
- The Custom Incentive Rate-setting framework of EPCOR Southern Bruce is not eligible for an Incremental Capital Module (ICM) and the OEB should not approve a capital funding mechanism at this time.

Staff Submission

Issue 1: Administration

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

This issue was not settled. The rates issue is fairly broad and related to items that were not settled including cost allocation, other revenues and the revenue deficiency related to delays. These issues are discussed individually in the submission.

Issue 3: Operating Revenue

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

EPCOR Southern Bruce has proposed Other Revenues of $0 in its application. Other Revenues relate to non-recurring items and refer to revenues from other activities or work performed such as account information requests, bill reprint and returned cheque/payments. EPCOR Southern Bruce has forecasted Other Revenues of $31,851 for the first three years (cumulative), but has still proposed Other Revenues of $0 for the determination of rates.[4] OEB staff expects that Other Revenues in subsequent years will be higher than the first three years as EPCOR Southern Bruce connects more customers. In year three, EPCOR Southern Bruce expects to connect 3,676 of the total 5,278 customers. OEB staff submits that Other Revenues of $0 is not appropriate as EPCOR Southern Bruce is expected to earn additional revenues through service charges.

For the Aylmer distribution system, a second natural gas distribution utility owned by EPCOR Natural Gas LP, the OEB recently approved Other Revenues of $147,777 for 2020 in the cost of service application.[5] A proxy number for Other Revenues could be developed based on the assumptions underpinning the Aylmer forecast that could be applied to EPCOR Southern Bruce. In its application, EPCOR Southern Bruce has noted that in determining the charges for providing non-recurring services, EPCOR Southern Bruce has relied on the charges incorporated in EPCOR Aylmer's rates as applied for in the recent rates proceeding.[6] A proxy number based on the Aylmer numbers is therefore a reasonable approach. OEB staff has calculated a proxy number based on Other Revenues approved in the Aylmer rates proceeding. The calculation excludes revenues from customer connection charges as EPCOR Southern Bruce has proposed to not charge customers for connection. Other Revenues for EPCOR Southern Bruce using the methodology described above should be $43,292 annually or $432,915 for the ten-year period.

EPCOR Aylmer number of customers – 9,538, Other Revenues (approved) - $147,777

EPCOR Southern Bruce number of customers – 5,278

Other Revenues - $147,777 - $36,015 (connection charges) = $111,762 (EPCOR Southern Bruce does not propose to charge connection charges)

$111,762/9,538 X 5,278 = $61,845

EPCOR Southern Bruce will reach critical mass in 2022 (by 2022 EPCOR Southern Bruce will connect over 80% of the forecasted customers, therefore it is reasonable to apply the full revenues for only seven years)

$61,845 X 7 = $432,915, then divide by 10 = $43,292

Other Revenues should be **$43,292**

[4] Exhibit 3, Tab 1, Schedule 1, p.15.
[5] EB-2018-0336
[6] EB-2018-0336

In its application, EPCOR Southern Bruce indicated that it will present data in the 2022 rates application related to its 2019 to 2021 Other Revenues and provide a forecast for 2022. However, EPCOR Southern Bruce is expected to reach critical mass in year four and data for preceding years may not be an appropriate indicator for future costs in this case. OEB staff prefers an amount in rates now ($432,915 for 10 years) or if the OEB believes that there is not enough certainty to determine Other Revenues at this time, then a deferral account to record actual Other Revenues could be an appropriate alternate approach.

Issue 5: Revenue Deficiency/Sufficiency

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

In its application, EPCOR Southern Bruce has proposed to true up the $75.6 million revenue requirement to address the delay in the review of its leave to construct application.[7] The change in timeline on the construction schedule has triggered a revenue deficiency of $1.764 million on a net present value basis compared to that included in EPCOR Southern Bruce's CIP proposal. In other words, the utility is seeking to recover revenues that it will not be able to recover due to the delay in connecting the forecasted number of customers and additional costs incurred to speed up the construction process. Rates as proposed would be effective January 1, 2019 but since customers will be connected much later than what was assumed in the CIP, the entire approved revenue requirement will not be recovered through rates. This is because the start and end date of the ten-year rate stability period remains unchanged but the duration of revenue recovery through rates is shorter than what was estimated in the original CIP. One of the main issues is the partial loss of the 2019 construction season which will cause a 13-month delay in providing service to Kincardine.

EPCOR Southern Bruce noted in its evidence that there was a ten month delay in receipt of the leave to construction decision. EPCOR Southern Bruce has attributed the delay to late approvals from the OEB. EPCOR Southern Bruce filed its leave to construct application on September 20, 2018.[8] The funding to EPCOR Southern Bruce for expansion of natural gas in South Bruce under the Natural Gas

[7] Exhibit 6, Tab 1, Schedule 1, p.2.
[8] EB-2018-0263

Grant Program (NGGP) was cancelled by the provincial government.[9] On November 29, 2018, the OEB informed EPCOR Southern Bruce that it was placing the application in abeyance as the project was not feasible without external funding.

The funding was later restored through *Bill 32, Access to Natural Gas Act, 2018* which received Royal Assent on December 6, 2018, and Ontario Regulation 24/19, Expansion of Natural Gas Distribution Systems. In response to an interrogatory, EPCOR Southern Bruce confirmed that the cancellation of the NGGP impacted the construction schedule as the project was not economically feasible without external funding and as a result the leave-to-construct (LTC) application for the project was placed in abeyance.[10] On February 27, 2019, EPCOR Southern Bruce filed an updated application. Ontario Regulation 24/19 was filed on March 8, 2019. The OEB confirmed that EPCOR Southern Bruce's application was complete and that it would commence processing the application on March 21, 2019. The OEB issued its Notice of Hearing and Letter of Direction to EPCOR Southern Bruce on March 22, 2019. The OEB approved the LTC application on July 11, 2019. The total time that the OEB took to process the application was 112 days. The metric for processing LTC applications that are processed through a written hearing is 130 days.[11] Nevertheless, OEB staff has proposed an alternate approach in the discussion on the effective date that could provide an effective solution to recover the entire revenue requirement as determined in the CIP.

Issue 6: Cost Allocation and Rate Design

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

There was no agreement with respect to EPCOR Southern Bruce's proposal regarding rate classes, cost allocation, rate design, revenue-to-cost ratios and resulting rates for each of the classes. OEB staff has no concerns with the proposed rate classes or the rate design in terms of the fixed and variable charges. The issue is with respect to cost allocation and the proposed revenue-to-cost (RTC) ratios.

[9] The Natural Gas Grant Program was discontinued and EPCOR Natural Gas LP was informed that there would be no transfer payments in a letter dated September 26, 2018.
[10] Response to OEB Staff IR#20
[11] The EPCOR Southern Bruce leave-to-construct application was processed by way of a written hearing.

EPCOR Southern Bruce has proposed four rate classes. The RTC ratios as proposed in the application are:

Table 1

Rate Classes	RTC
Rate 1 – General Service	1.01
Rate 6 – Large Volume Gen. Service	0.78
Rate 11 – Large Volume Seasonal Service	1.35
Rate 16 – Contracted Firm Service	1.37
Overall	1.02

Ideally, the RTC for all rate classes should be 1.0. This would imply that the revenues from the particular rate classes are sufficient to recover the costs and there is no subsidy from one rate class to the other. However, the OEB recognizes that for a variety of reasons RTCs may vary from 1.0 and has established a target range for RTCs that is between 0.8 and 1.20.[12] EPCOR Southern Bruce acknowledged this target range in an interrogatory response where it notes that for a mature utility with existing customers, "a RTC ratio between 0.80 and 1.20 is generally considered acceptable, with a value closer to 1.0 being more desirable".[13]

As can be seen from Table 1, three of the four rate classes are outside the target range. In support of its cost allocation proposal, the utility noted that it has proposed rates that are attractive enough that potential customers in all classes will attach to the system. The applicant has further indicated that the long-term viability of the system requires that customer conversions reach levels as committed in the CIP. In the absence of these conversions, the system may be unable to generate sufficient revenues to support safe and reliable operations, potentially leading to material rate increases at the end of the rate stability period.[14]

The applicant has further noted that in case of a greenfield system expansion such as Southern Bruce, there are no existing customers that would be negatively impacted as a result of the proposed rates. Each potential customer will make an economic decision whether to connect to the system or remain with their existing energy source.[15] In its submission on the Issues List, EPCOR Southern Bruce argued that in order to create the incentive for customers to convert to natural gas, it must have the flexibility to charge a tariff that is based on its understanding as to what the delta from existing

[12] The target range applies to electricity distributors as per the Report of the Board, Review of Electricity Distribution Cost Allocation Policy, EB-2010-0219, March 31, 2011, p.36. The revenue-to-cost ratio for residential customers is required to be between 0.85 to 1.15 and for other rate classes from 0.80 to 1.20.
[13] Response to OEB staff IR#22.
[14] Exhibit 7, Tab 1, Schedule 1, p.5.
[15] Response to OEB staff IR#22.

energy sources must be. This has resulted in a more “market-based” tariff rather than the one that is primarily based on cost allocation and revenue to cost ratios.

OEB staff understands the rationale for developing tariffs that would enable EPCOR Southern Bruce to attach as many customers as possible. However, this does not justify that a certain class of customers provide significant subsidies to another rate class. A majority of the customers belong to the residential rate class (Rate 1) for which the proposed RTC is appropriate. The RTC for Rate 6 customers is 0.78 and there are 92 expected customers in this rate class in year 10. Rate 11 will have five customers and Rate 16 is expected to have two customers.

OEB staff requested EPCOR Southern Bruce to provide alternate RTC ratios increasing the Rate 6 RTC to 0.90 and distributing the revenues among rate classes 11 and 16. The resulting RTC ratio drops from 1.35 to 1.20 for Rate 11 and for Rate 16, the RTC ratio drops from 1.37 to 1.22.[16] OEB staff submits that the RTC ratios should be within the OEB’s target range of 0.80 to 1.20. A higher ratio than 1.20 results in an unreasonable subsidy from one rate class to the other. At the same time, moving the RTC ratio for all rate classes to 1.0 may result in significantly different rates as compared to that proposed by the utility. In such a case, the utility may not be able to achieve the required connections to function as a viable utility. Accordingly, OEB staff submits that the RTC ratios should be between 0.80 and 1.20 or alternatively, the RTC ratios could be as provided in staff IR#22 (ratios discussed above). OEB staff is of the opinion that the proposed RTC ratios (as noted in IRR#22) is not likely to materially impact forecasted attachments.

Issue 7: Unsettled Deferral and Variance Accounts

Regulatory Expense Deferral Account (REDA)

The Regulatory Expense Deferral Account (REDA) is meant to record costs associated with participating in generic and other OEB hearings that impact the utility. The deferral account is not meant to capture costs associated with hearings triggered by EPCOR Southern Bruce. A similar account exists for the EPCOR Aylmer franchise area.

For most utilities, the OEB has not granted a deferral account to record costs associated with participating in generic proceedings. This is a cost that should be absorbed by the utility within its operating, maintenance and administrative (OM&A) costs. In case a generic proceeding triggers significant costs for the utility, EPCOR

[16] OEB staff IRR#22

Southern Bruce can request a deferral or variance account at that time. OEB staff submits that EPCOR Southern Bruce's request for the REDA should be denied. The fact that a similar deferral account exists for the Aylmer franchise area is not a sufficient reason to grant a similar deferral account for Southern Bruce. The Aylmer REDA account was originally approved over 15 years ago and the recent continuation of the account was approved as part of a settlement.[17]

In response to an interrogatory, EPCOR Southern Bruce has described how the account meets the OEB's eligibility criteria of causation, materiality and prudence. With respect to materiality, EPCOR Southern Bruce has indicated that it expects these costs to exceed the materiality threshold of $50,000.[18] However, it has provided no information on what kind of proceedings could exceed the materiality threshold of $50,000, specifically proceedings where EPCOR Southern Bruce is likely to be a secondary participant or a participant in a generic proceeding wherein the OEB allocates cost to all utilities (section 30). In response to an interrogatory, EPCOR Southern Bruce confirmed that it intends to use the REDA account in the same manner as EPCOR Aylmer currently does for its own REDA account.[19] If the reference point is the REDA for the Aylmer franchise area, there is no evidence that the REDA account for Aylmer has exceeded $50,000 in a given year. Natural Resource Gas Limited (NRG), the predecessor utility to EPCOR Natural Gas (Aylmer), in its 2016 rates application provided the following balances related to the REDA account.[20]

Table 2

2010	2011	2012	2013	2014	2015
$ 4,728	$ 11,812	$ 14,639	$ 39,874	$ 63,360	$ 132,117

As can be seen from Table 2, costs for participating in generic proceedings is not significant. The costs in 2014 and 2015 mainly reflect costs to complete the system integrity study; it is not related to participating in generic proceedings. Generally, the significant costs recorded in the REDA by NRG were either related to the system integrity study or to participate in proceedings triggered by Integrated Grain Processors Co-operative, its largest customer with which it had a long standing dispute on several issues. In the 2016 to 2018 IRM rates proceeding, EPCOR Natural Gas (Aylmer) provided context for costs related to participating in generic proceedings. In response to an interrogatory, EPCOR Natural Gas noted that it did not provide a further breakdown of the REDA balance as it consisted of several small costs. The total cost for participating in some of the OEB generic proceedings related to corporate governance

[17] EB-2018-0336 Settlement Proposal dated June 10, 2019.
[18] Response to OEB Staff IR#35.
[19] *ibid*
[20] EB-2016-0236, Exh 5, T1, Sch. 1, p. 8.

and cyber security was $3,802.[21] Furthermore, neither EPCOR Aylmer nor EPCOR Southern Bruce intend at this time to implement demand side management programs for which there could be additional regulatory costs. Therefore there is no evidence that costs to participate in generic proceedings is expected to exceed the materiality threshold. These costs can be absorbed within the OM&A budget and there is no basis for granting the REDA.

Municipal Tax Variance Account (MTVA)

The MTVA is meant to capture the difference between the forecasted municipal taxes in EPCOR Southern Bruce's OM&A and actual municipal taxes that are levied by the municipalities in a given year. EPCOR Southern Bruce has requested this account to protect both the utility and the ratepayer in the event that municipal taxes differ from what was included in rates. It is not clear why EPCOR Southern Bruce is requesting this account considering that the three main municipalities[22] have agreed to provide contributions equivalent to the municipal taxes. The only taxes that EPCOR Southern Bruce is liable for are school taxes or county taxes.

Municipal taxes are part of OM&A costs and like any other costs, are approved on a forecast basis in all cost of service proceedings. EPCOR Southern Bruce has included the cost of the municipal taxes on a forecast basis in its OM&A. OEB staff agrees that municipal taxes are external costs but there are other external costs that are also not in control of management. Such costs include insurance, rent, utilities and fuel. EPCOR Southern Bruce has rationalized the need for the account on the basis of protecting the utility and the ratepayer. Cost of service ratemaking is on a forecast basis and for absolute protection, the regulator could set up deferral accounts for all OM&A costs. This is not the purpose of ratemaking under cost of service principles. Costs are approved based on the reasonableness of the forecast and there is an element of risk for both the ratepayer and the utility. The utility in this case bears certain risks in relation to the forecast but it can also benefit from incurring lower costs from that which it forecast. EPCOR Southern Bruce has assumed the risk of its OM&A costs underpinning the revenue requirement that was approved in the CIP. Approval of the MTVA reduces a portion of the risk that EPCOR Southern Bruce has already assumed as part of the CIP. Accordingly, OEB staff submits that the request for the MTVA should be denied.

Energy Content Variance Account (ECVA)

The purpose of the ECVA is to record any variations in revenues and costs resulting from differences in the energy content of the gas actually delivered and the assumed

[21] EB-2018-0235, Response to OEB staff IR#13
[22] Municipalities of Kincardine, Arran-Elderslie and Huron-Kinloss.

energy content. The assumed energy content is 38.89MJ/M.[3]

Differences in energy content would be captured in volumes delivered. Lower energy content would result in higher volumes delivered and vice-versa. In response to an interrogatory, EPCOR Southern Bruce agrees that the actual energy content would impact actual volumes delivered. However, it notes that since the Purchased Gas Commodity Variance Account (PGCVA) only deals with commodity costs and rates, the impact of the variations in the energy content on distribution revenue would not be captured in the PGCVA.[23] In other words, EPCOR Southern Bruce agrees that the commodity costs related to variations in heat content will be captured in the PGCVA. It is the impact on distribution revenue that will not be captured. OEB staff submits that EPCOR Southern Bruce has assumed this risk as part of the CIP. In the CIP, EPCOR Southern Bruce committed to a total volume throughput for the 10-year rate stability period. It also committed to a total revenue requirement and therefore should have considered all elements that could impact the revenue requirement. The heat content should have been considered in the initial development of the CIP. By requesting an ECVA, EPCOR Southern Bruce is attempting to reduce a portion of the risk that it should have assumed as part of the CIP. OEB staff submits that the request for the ECVA is not appropriate and consistent with the CIP. The request for the ECVA should therefore be denied.

Issue 8: Incentive Rate Setting Proposal

a) Is EPCOR Southern Bruce's request for availability of an Incremental Capital Module consistent with EPCOR Southern Bruce's CIP proposal?

EPCOR Southern Bruce has requested availability of an ICM as part of its Custom IR plan. This is to facilitate expansion beyond what was outlined in the CIP.

In its submission on the issues list, OEB staff submitted that the ICM and Advanced Capital Module mechanisms were not available for utilities setting rates under Custom IR.[24]

The OEB in its decision on the Issues List (p.13) noted:

> The OEB agrees that it is in scope of the proceeding to consider

[23] Response to OEB staff IR#37.
[24] Handbook for Utility Rate Applications, October 13, 2016, p.27

> whether the request for an ICM is consistent with the CIP. This consideration can take into account the OEB's policies with respect to ICMs.

In response to an interrogatory, EPCOR Southern Bruce noted that at this time it did not foresee any capital expenditures during the next 10 years that could result in the request for an ICM.[25] OEB staff submits that based on the evidence and the OEB's policies, the OEB should deny the request for an ICM. Should EPCOR Southern Bruce decide to expand beyond the communities identified in the CIP, EPCOR Southern Bruce can make the appropriate request to the OEB at that time.

OEB staff submits that a number of factors would have to be considered in case EPCOR Southern Bruce decides to connect additional communities. The existing rate was developed as part of the CIP and the external funding is for the specific communities identified in the CIP. If EPCOR Southern Bruce decides to connect additional communities, a number of issues would need to be addressed such as whether any portion of the approved external funding or the benefits of the funding could be applied or allocated to connect the new communities, whether the communities would be eligible for new external funding, if a surcharge should apply to the new connections under the OEB's generic community expansion policy[26] and whether there should be any capital funding mechanism if the project's Profitability Index as per EBO 188 is 1.0 or higher. Considering that EPCOR Southern Bruce does not expect to connect additional communities during the 10-year rate period, OEB staff submits that considering all these factors for an ICM that may not materialize is premature. EPCOR Southern Bruce can file the appropriate request when and if it decides to provide service to additional communities.

OEB staff does not want to stand in the way of any potential expansions, but submits that the traditional ICM approach would not be a good fit for these expansions. They would best be dealt with through a stand alone expansion application to the OEB and if approved, the cost and rate aspects can be dealt with in a subsequent rate case.

In response to an interrogatory, EPCOR Southern Bruce has indicated that it proposes to use a growth value of 0 to determine the ICM materiality threshold. EPCOR Southern Bruce noted that the 10-year revenue requirement incorporated into the application explicitly included both annual price adjustments and forecast customer growth for that period. Therefore to include a second adjustment for growth in the threshold value

[25] Response to SEC IR#19.
[26] EB-2016-0004

calculation would result in “double counting” for growth and inflation and unfairly penalize the utility.[27]

The requested exclusion for a growth factor further supports OEB staff’s view that the ICM should not apply to EPCOR Southern Bruce. The ICM is a mechanism that has been developed in conjunction with a specific IRM framework. When a utility requests a Custom IR that proposes an alternate framework, a standardised policy such as an ICM may not be appropriate or suitable for the custom framework. The OEB’s policy of not permitting ICM or Advanced Capital Modules for Custom IR frameworks is therefore logical and appropriate. The OEB could consider an alternate approach to consider EPCOR Southern Bruce’s request to fund system expansion beyond what it included in the CIP. However, since EPCOR Southern Bruce does not expect such an expansion during the rate stability period, OEB staff is of the view that a determination of an appropriate capital funding mechanism is not required at this time.

Issue 10: Implementation

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

Parties did not agree whether a January 1, 2019 effective date was consistent with the CIP. In the South Bruce competition proceeding, the OEB directed the proponents to develop a proposal using common attributes so that the competing proposals could be compared on an equal footing. The OEB determined that the term of the rate stability period would be 10 years; it did not determine a specific start and end date.[28] The proponents selected 2019 to 2028 to develop their proposals and this is what the OEB considered and approved. The OEB did not establish a January 1, 2019 effective date in the South Bruce expansion proceeding.[29] EPCOR Southern Bruce has requested an effective date of January 1, 2019. This is despite the fact that the first customer is expected to be connected in November 2019.[30]

EPCOR Southern Bruce submitted its revised LTC application in February 2019 and its rate application for Southern Bruce in April 2019. It is requesting an effective date prior to it filing either of the applications and prior to the first customer being connected. Since EPCOR Southern Bruce is a greenfield utility, it would be appropriate to make

[27] Response to OEB staff IR#43.
[28] EB-2016-0137/38/39, Issue #3, Partial Decision on Issues List and Procedural Order No. 6, p.4, June 27, 2017
[29] EB-2016-0137/38/39
[30] Exh.1, T.2, Sched.1,p.21.

rates effective when the first customer is connected. The ten-year rate stability period would begin from this date. This approach would provide revenues over an additional 10-month period following the end of the originally proposed10-year rate stability period. The delay of the start date and the extension of the end date of the rate stability period would allow the utility to recover its entire revenue requirement as per the CIP, all other things being equal. The rate stability period in this case would be from November 1, 2019 to October 30, 2029. If the start date is expected to be something other than November 1, 2019, EPCOR Southern Bruce is requested to provide an update in its reply.

EPCOR Southern Bruce has requested a revenue deficiency of $1.764 million related to construction and approval delays. This is the net present value of the costs that EPCOR Southern Bruce claims that it will not be able to recover (as compared to the revenue requirement in the CIP) due to the delay in connecting customers. In its evidence, EPCOR Southern Bruce has provided the drivers of the revenue deficiency

Table 3: Summary of Revenue Deficiency[31]

Description	NPV of Revenue Deficiency ($‘000)
Change in customer connection profile – Forgone Revenues	2,324
Change in property taxes – Forgone Cost	(224)
Change in capital expenditure profile – Forgone Cost	(460)
Deferred recovery of upstream charges	124
	1,764

As can be seen from Table 3, the major driver of the revenue deficiency is forgone revenues ($2.3 million). These are the revenues that the utility will be unable to recover through rates from the proposed effective date of January 1, 2019 to when the first customer is connected as compared to what was included in the approved CIP revenue requirement. The evidence does not indicate any increase in actual construction costs. The evidence indicates that the delay in certain capital expenditures has reduced the revenue requirement. There is no information on additional capital expenditures related to delays such as increase in the cost of materials or cost of labour to speed up the actual construction of the distribution system. If there are actual increased construction costs related to the delay, EPCOR Southern Bruce in reply is requested to provide the appropriate reference in the evidence.

[31] Table 6-2, Exhibit 6, Tab 1, Sched. 1, p.3

Since the major driver of the claimed revenue deficiency is forgone revenues, OEB staff submits that its proposed approach of moving the 10-year rate stability period from January 1, 2019 to the actual date of connecting the first customer is an appropriate approach to eliminate the revenue deficiency. Moving the effective date would provide EPCOR Southern Bruce an additional 10 months of rate recovery. Since the 10-year rate stability period would begin when the first customer is connected, EPCOR Southern Bruce would be able to recover its entire revenue requirement as approved in the CIP.

OEB staff notes that Table 3 includes an additional cost of $124,000 related to upstream charges. These charges represent upstream transportation costs paid to Enbridge Gas Inc. This amount will be recorded in the appropriate deferral and variance account.

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

OEB staff submits that the rate rider to recover the stated $1.764 million revenue deficiency does not apply under OEB staff's proposed approach. In fact, there would be no rate rider as the effective date would begin from when the first customer is connected.

Issue 11: Stakeholder Engagement

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

This issue was partially settled. There was no agreement with respect to EPCOR's engagement with First Nations and Métis communities.

OEB staff has not seen the submissions of Anwaatin, and does not know what (if any) additional engagement with First Nation and Métis communities it will propose. To the extent that any of Anwaatin's arguments rely on the duty to consult, OEB staff adopts its submission related to the Issues List. In order for the duty to consult to be triggered, there must be a potential infringement to an Aboriginal or treaty right. To date no party has identified any potential impacts to any Aboriginal or treaty rights that could arise from this application.

– All of which is respectfully submitted –