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July 12, 2019

VIA RESS, EMAIL and COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms. Walli:

Re: EB-2018-0305 Enbridge Gas Inc. ("Enbridge Gas") – 2019 Rate Application Reply Argument

In accordance with Procedural Order No. 4 dated June 10, 2019, enclosed is the Reply Argument of Enbridge Gas for the above noted proceeding.

Please contact the undersigned if you have any questions.

Yours truly,

(Original Signed)

Rakesh Torul
Technical Manager, Regulatory Applications

cc: EB-2018-0305 Intervenors
Crawford Smith, Lax O'Sullivan Lisus Gottlieb

ONTARIO ENERGY BOARD

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 Enbridge Gas Inc., pursuant to section 36(1) of the *Ontario Energy Board Act, 1998,* for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2019.

REPLY ARGUMENT

July 12, 2019

1.0 INTRODUCTION

Enbridge Gas Inc. ("Enbridge Gas" or the "Applicant") filed an application with the Ontario Energy Board ("OEB" or the "Board") on December 14, 2018, under section 36 of the *Ontario Energy Board Act, 1998*, for an order approving just and reasonable rates for the sale, distribution, transmission and storage of gas for each of its Enbridge Gas Distribution, Union North and Union South rate zones to be effective January 1, 2019 (the "Application"). The Application was prepared in accordance with all relevant OEB guidance and included a request for incremental capital funding.

On May 29, 2019, Enbridge Gas submitted to the OEB for its consideration a Settlement Proposal in respect of certain of the issues in the proceeding. By Procedural Order No. 4, the OEB approved the Settlement Proposal and set out a schedule for written argument in relation to the unsettled issues. Pursuant to that schedule, on June 17, 2019, Enbridge Gas filed its Argument in Chief and received argument from the following parties: Board Staff, APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, LPMA, OGVG, OPI, QMA, SEC and VECC.[1]

[1] FRPO's submission simply adopts SEC's, while IGUA states that it defers to the submissions of other ratepayer groups.

This is Enbridge Gas's Reply Argument. With the exception of Issue 3, it addresses only the unsettled issues. The Reply Argument is organized based on the approved issues list in this proceeding. Where issues are connected or related, they are considered together.

For the reasons set out below and in the Argument in Chief, Enbridge Gas submits that the application should be approved as filed.

2.0 REPLY TO BOARD STAFF AND INTERVENOR SUBMISSIONS

Issue 1

Has Enbridge Gas responded appropriately to all relevant OEB directions from previous proceedings?

The Applicant has responded appropriately to all relevant OEB directions from previous proceedings, including from the MAADs proceeding.

The outstanding commitments and directives are shown at Exhibit B1, Tab 1, Schedule 1, Appendix G. No party points to a specific commitment or directive to argue that Enbridge Gas has not responded appropriately. Rather, a number of parties that take issue with Enbridge Gas's proposals in relation to a one-time adjustment for the capital pass-through Projects, the corresponding changes to the projects' deferral accounts or the request for ICM funding argue that these proposals are inconsistent with the Board's Decision and Order in the MAADs proceeding (the "MAADs Decision"). Enbridge Gas disagrees. The parties' submissions are discussed in relation to Issues No. 5, 7 and 10-12 below.

Issue 2

Is the Price Cap Index calculated appropriately?

This issue is settled.

Issue 3

Does the accounting order wording in the following new accounts appropriately reflect the OEB's MAADs Decision?

a. Earnings Sharing Mechanism Deferral Account (Enbridge Gas)
b. Tax Variance Deferral Account (Enbridge Gas)
c. Accounting Policy Changes Deferral Account (Enbridge Gas)

This issue is settled. Nevertheless, Board Staff's submission discusses the Tax Variance Deferral Account ("TVDA"), and the impacts to a tax incentive program, the Accelerated Investment Incentive ("AII"), which provides companies with an accelerated tax deduction through the Capital Cost Allowance ("CCA") on eligible capital assets.[2]

Board Staff submits that this issue should be addressed in Enbridge Gas's 2020 rate application, and that the applicant should provide details on why a 50/50 sharing of the tax impacts due to the AII program is appropriate. The treatment of tax changes was specifically dealt with as part of the MAADs Decision. In that proceeding, parties submitted that the Board should continue to capture any tax changes through the deferred rebasing period. As the Board summarized Staff's argument:

> OEB staff submitted that Union Gas' TVDA should not be closed and should continue to capture any tax variances resulting from factors such as changes in federal and/or provincial tax legislation during the deferred rebasing period.[3]

The Board agreed with Staff and expanded the TVDA to apply to both the EGD and Union rate zones:

> With respect to the TVDA, the OEB agrees that the applicants can cease recording the impact of the introduction of HST. The effort to track this is at odds with the materiality of the balances being recorded. However, the OEB will keep the TVDA but expand its applicability to record the impact of any tax rate changes for both Enbridge Gas and Union Gas legacy areas, i.e. all of Amalco.[4]

The only other party that made submissions related to the AII legislation was LPMA. In LPMA's submission, the Board should direct Enbridge to update the calculation of the CCA available for the ICM funding requests in 2019.

In Enbridge Gas's submission, there is no issue relating to the TVDA in this case and the matter was settled. The impact of the AII legislation will next arise in the context of Enbridge Gas's application to dispose of 2018 non-commodity deferral account balances and earnings sharing

[2] Board Staff Argument, pp. 5-7.
[3] EB-2017-0306/EB-2017-0307 Decision and Order, August 30, 2018, p. 45.
[4] *Ibid*.

which will be filed later this month. With respect to the ICM Projects, the relevant deferral accounts will capture any differences in cost between forecast and actual including any arising from the AII legislation.

Issue 4

Should the following deferral accounts be established?
a. Incremental Capital Module – EGD Rate Zone
b. Incremental Capital Module – Union Gas Rate Zones

This issue is settled. Board Staff made a submission under this issue in relation to Operating and Maintenance ("OM&A") and property tax costs and whether these should be included in the ICM deferral accounts. Enbridge Gas addresses the applicability of OM&A and property taxes as part of Issues No. 11 and 12.

Issue 5

Should the proposed changes be made to the accounting orders for the following deferral accounts?

<u>EGD Rate Zone</u>
a. 179.24 Post Retirement True-up Variance Account
b. 179.48 Open Bill Revenue Variance Account
c. 179.08 Ex-Franchise Third Party Billing Services Deferral Account
d. 179.70 Purchased Gas Variance Account
e. 179.88 Storage and Transportation Deferral Account
f. 179.94 OEB Cost Assessment Variance Account

<u>Union Gas Rate Zones</u>
g. 179-136 Parkway West Project Costs
h. 179-137 Brantford-Kirkwall/Parkway D Project Costs
i. 179-142 Lobo C Compressor/Hamilton to Milton Project Costs
j. 179-144 Dawn H/Lobo D/Bright C Compressor Project Costs
k. 179-149 Burlington Oakville Project Costs
l. 179-156 Panhandle Reinforcement Project Costs

The proposed changes for a and c-f were settled.

b. 179.48 Open Bill Revenue Variance Account

Enbridge Gas adjusted the wording of the existing EGD rate zone Account No. 179.48 Open Bill Revenue Variance Account to refer only to the most recently Board-approved Open Bill Access

Settlement Agreement in EB-2013-0099.[5] As clarified in the Technical Conference, this adjusted wording does not change how the balances in the account are calculated.[6]

MR. SHEPHERD: There is not intended to be any change in substance in this.

MR. SMALL: Absolutely not.

MR. SHEPHERD: The account is not supposed to act differently in any way?

MR. SMALL: Absolutely not.[7]

Enbridge Gas submits that the proposed changes to the wording of the account can be made in this annual rate setting proceeding given its administrative nature. However, should the Board prefer, the matter could also be addressed as part of the ongoing Open Bill Access proceeding.

g. to l. Union Rate Zones – Capital Pass-Through Projects

The proposed changes to the Union rate zones' deferral accounts are inextricably linked to the outcome of the Board's Decision with respect to the one-time capital pass-through base rate adjustment (Issue No. 7, part a) and responsive to the Board's direction in its MAADs Decision, as further described in Issue 7 below. Parties' arguments relating to the deferral accounts and the proposed adjustment are addressed as part of that issue.

Issue 6

Should the following deferral and variance accounts be discontinued as proposed?
a. 179-100 Union North Tolls and Fuel
b. 179-105 Union North PGVA
c. 179-103 Unbundled Services Unauthorized Storage Overrun Deferral Account

This issue is settled.

Issue 7

Are any rate design proposals appropriate in the context of previous OEB decisions, including:
a. One-time adjustment for Capital Pass-Through Projects
b. General service monthly customer charge
c. Parkway Delivery Obligation adjustment

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[5] Exhibit B1, Tab 1, Schedule 1, pp. 17-18.
[6] Transcript, Vol. 1, pp. 66-67.
[7] Transcript, Vol. 1, p. 67.

d. DSM budget allocations

With the exception of a., this issue is settled.

a. One-time adjustment for Capital Pass-Through Projects

Enbridge Gas has proposed a one-time adjustment to rates to include the revenue requirement of the capital pass-through projects, and continuation of the capital pass-through deferral accounts to capture the utility tax timing differences only. These changes are required to align the ICM threshold value with the capital investment that can be supported by rates, consistent with the Board Policy on ICM and with the MAADs Decision.

With exception of QMA, all parties oppose Enbridge Gas's proposal.

The main argument made by Board Staff, APPrO, BOMA, CME, LPMA, OGVG and SEC is that the Board rendered a decision on the issue of a one-time adjustment and changes to the capital pass-through deferral accounts in the MAADs Decision.[8]

In addition to its argument concerning the MAADs Decision, Staff further argues that the issues of the one-time adjustment and the changes to the capital pass-through deferral accounts are not linked.[9] In Staff's view, the load growth associated with the capital pass-through projects provides the incremental revenue that is available to fund capital additions during the deferred rebasing period and it is unnecessary (notwithstanding the evidence to the contrary) to include the revenue requirement associated with those projects in rates.[10] In the alternative, Staff suggests that if the proposed one-time adjustment is made, then the capital pass-through deferral accounts should be discontinued.[11]

CCC[12] and LPMA[13] further characterize the one-time adjustment as a partial rebasing, although it is not. LPMA theorizes the purpose of the adjustment is to make the amalgamation between the

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[8] Board Staff Argument, p.12; APPrO Argument, p. 5; BOMA Argument, p.6; CME Argument, p.5; LPMA Argument, p.5; OGVG Argument, p.7; SEC Argument, p.20.

[9] Board Staff Argument, p.12.

[10] Board Staff Argument, p.13.

[11] Board Staff Argument, p.13.

[12] CCC Argument, p.2.

[13] LPMA Argument, p.5.

utilities "look better financially".[14] APPrO makes a similar comment that the adjustment is "an unreasonable increase that adds to the burden of ratepayers"[15]

BOMA submits the proposal is a "major rate design change" that would result in a substantial rate increase.[16] In BOMA's view, the proposed rate design change is not required to transition to the Board-approved 2019-2023 IRM framework as the Union 2014-2018 IRM framework simply continues.[17]

OGVG also states the one-time adjustment should be rejected and the capital pass-through deferral accounts should continue during the deferred rebasing period, without amendment.[18]

Likewise, SEC characterizes the one-time adjustment as an extra rate increase[19] and believes the capital pass-through mechanism and related deferral accounts should be maintained.[20]

Finally, a number of parties seek to bolster their position by claiming that Enbridge Gas should have brought a motion to review and vary the MAADs Decision or commenced an appeal to the Divisional Court.

In Enbridge Gas's submission, none of the parties' submission have merit. The Board, in the MAADs Decision, did not deal with the consequence to base rates resulting from its determination on the ICM threshold for the Union rates zones. Indeed, it is apparent from the Decision that the Board considered only four rate adjustments (in each case proposed by the applicants) none of which addressed this issue. [21]

Simply put, the MAADs Decision addressed the inclusion of the capital pass-through project amounts in the threshold calculation[22] but was silent on the proper rate treatment of previous Y factor capital pass-through projects. The applicants' position in the MAADs proceeding (in reply

[14] LPMA Argument, p.7.
[15] APPrO Argument, p.7
[16] BOMA Argument, p.4.
[17] BOMA Argument, p.5.
[18] OGVG Argument, p.7.
[19] SEC Argument, p.19.
[20] SEC Argument, p.25.
[21] EB-2017-0306/ EB-2017-0307, Decision and Order, August 30, 2018, p.39.
[22] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, p.33.

argument) was to exclude the capital pass-through project amounts from the ICM threshold calculation and continue deferral treatment of the capital pass-through amounts as this treatment maintained alignment with rates and the ICM threshold. The Board disagreed with the Company's proposal to exclude the capital pass-through amounts from the ICM threshold, but it is wrong to say, as SEC does, that it considered and denied the one-time adjustment now proposed;[23] it was not before the Board and only arose as a result of the Decision.

For this reason, the claim that Enbridge Gas should have brought a motion to review or vary the MAADs Decision or commenced an appeal is equally wrong. Enbridge Gas accepts the decision to include the capital pass-through project amounts in the ICM threshold calculation. The issue, not previously dealt with, is what does that mean for rates?

Now is the appropriate time to address that issue through the Company's proposal that responds to and is consistent with the MAADs Decision. As CME recognizes "The materiality threshold is the amount of money that the utility must spend before it is eligible to ask for additional funding through rates for capital expenditures. The existence of the threshold is premised on the fact that the utility should be able to fund a certain amount of capital spending through existing rates."[24] For rates to support the capital funding contemplated by the ICM formula, there must obviously be an amount in rates that is escalated during the deferred rebasing period and not passed through as a Y factor. Unless rates are adjusted as Enbridge Gas has proposed, that will not be the case.

It is important to note and as discussed further below, that with the exception of certain limited complaints in relation to IT spending, parties generally took no issue with Enbridge Gas's USP or the proposed level of capital spending. This spending is necessary and prudent and the product of sound asset management principles. But, the consequence of denying the base rate adjustment would be to substantially deny the necessary funding.

As noted in Enbridge Gas's Argument in Chief, the 2019 ICM threshold value for the Union rate zone is $80.7 million higher than what rates can support. This is the equivalent of a 41% stretch on

[23] SEC Argument, p.19.
[24] CME Argument, p.14.

top of the typical 10% ICM stretch or 5.1 times, the amount applicable to any other utility.[25] This discrepancy will continue each year during the deferred rebasing period, to a cumulative amount of $410 million by 2023, without the proposed one-time adjustment. [26] Enbridge Gas has calculated the cumulative revenue requirement of the $410 million to be $69 million over the deferred rebasing period.

The one-time adjustment provides base rates with the ability to support the capital spending required by the ICM threshold during the remaining years of the deferred rebasing period.[27] Without applying an inflation factor, the cumulative revenue requirement difference is $33.8 million.[28] Using the inflation factor of 1.07%, the cumulative revenue requirement difference is $46.5 million.[29] Both of these amounts are still less than the $69 million cumulative revenue requirement impact associated with the higher ICM threshold value.

Board Staff's submission that the load growth associated with the capital pass-through projects is available to fund capital additions during the deferred rebasing period to the level as suggested by the ICM formula including the capital pass-through projects, while the Y factor treatment also persists, is incorrect.

Enbridge Gas's proposal, to recover the 2019 revenue requirement associated with the capital pass-through projects from Union's 2014-2018 IRM term as a component of base rates and no longer as a Y factor adjustment, responds to the MAADs Decision. As a component of base rates, the revenue requirement associated with the capital projects will be escalated over the deferred rebasing term and not subject to deferral account treatment, thus providing the ability to support incremental capital. The capital pass-through deferral accounts would continue to record utility tax timing differences; absent this, the higher utility taxes in the remainder of the deferred rebasing period will take away from the ability of rates to support capital already invested in the projects, let alone fund incremental capital**.**

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[25] The 10% stretch factor in the ICM formula, represents an additional capital of $19.6 million in the Union rate zones; therefore, the higher threshold of $80.7 million is equivalent to 41% stretch factor

[26] Exhibit I. STAFF.8, Attachment 1; and Transcript, Vol. 1, p.8.

[27] Enbridge Gas AIC, p.7.

[28] Exhibit I.SEC.6.

[29] Exhibit JT1.2.

The Company acknowledges that there is another possible interpretation of the MAADs Decision consistent with Board Staff's alternative to discontinue the capital pass-through deferral accounts. For the Union rate zones, the Board directed that the "rate base and depreciation associated with projects that were found eligible for capital pass-through treatment during the IRM term, shall be added to the 2013 OEB-approved rate base and depreciation in determining the eligible incremental capital amount for Union Gas' service territory".[30] For the EGD rate zone, the Board directed, "the rate base and depreciation to be used in the formula shall be the 2018 OEB-approved amounts from the most recent Custom IR update decision."[31] As noted earlier, the direction that capital pass-through rates support incremental capital on a going forward basis can best be carried out through the Company's proposal. The alternative interpretation is for the 2018 amounts currently built into rates to persist through the deferred rebasing period and escalated using the price cap, while also discontinuing the capital pass-through deferral accounts. Enbridge Gas is prepared to accept this treatment, but it is not the preferred option.

The presumption that capital pass-through rates can support incremental capital without providing the mechanics to do so is unduly punitive. There is no indication in the MAADs Decision that the directive was intended to be punitive. Neither did the Board indicate that its intent was to deviate from the Board's Policy on ICM of aligning the threshold value with the capital investment that can be supported by rates. Moreover, no party took issue with Enbridge Gas's USP or the proposed level of capital spending (with the exception of certain IT spending in the EGD rate zone). This spending is necessary and prudent and the product of sound asset management principles. But, the consequence of denying the base rate adjustment as proposed by the Company *and* the Board Staff alternative[32] would be to substantially deny the necessary funding to ensure safe and reliable service to existing and new customers over the deferred rebasing period.

Issue 8

Are there any necessary rate schedule changes, and if so, are the changes appropriate?

This issue is settled.

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[30] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, p.33.
[31] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, p.33.
[32] Unless adjusted as proposed above.

Issue 9

Do the USP and AMPs support approval of the ICMs?

As set out in the Argument in Chief, Enbridge Gas filed a Utility System Plan[33] ("USP") with the application in support of the request for ICM funding. The USP includes an Asset Management Plan ("AMP") for each of the EGD and Union rate zones. The evidence is that each AMP identifies how Enbridge Gas plans, manages and develops the distribution, transmission, and storage systems for each of the EGD and Union rate zones, and determines the capital investment requirement while balancing risk, performance and cost.[34]

To the extent parties made submissions in relation to this issue, they fell into two categories. First, some made generalized submissions in relation to the priority of projects. Second, others commented on Enbridge Gas's proposed spending on information technology.

Project priority

BOMA baldly asserts that, in the Union rate zones, low priority projects have been included in the capital expenditure plans and budgets "to act as buffer in the event unexpected projects require incremental funding. These, set aside, are substantial." In relation to the EGD rate zone, BOMA claims that EGD's method of constructing its capital plans, and its refusal to prioritize projects on an annual, or longer term basis "diminishes its usefulness in supporting any particular ICM project."[35]

BOMA cites no evidence in support of its submissions, and there is none. The undisputed evidence is projects are selected on the basis of their relative priority. All projects are evaluated and prioritized/optimized to ensure that capital resources are employed to address the highest priority items across all asset categories.

While making no submissions in relation to Enbridge Gas's approach to system planning, asset management or capital budgeting in general, Energy Probe submits that the USP and AMPs do not

[33] The USP for Enbridge Gas is filed at Exhibit C1, Tab 1, Schedule 1.
[34] The AMPs for Enbridge Gas are filed at Exhibit C1, Tab 2, Schedule 1 and Exhibit C1, Tab 3, Schedule 1.
[35] BOMA Argument, p. 8.

support approval of the ICM projects. There is no substance to Energy Probe's submission and it should be rejected.

Like Energy Probe, LPMA does not take issue with Enbridge Gas's USP or AMPs per se. Rather, LPMA submits the USP and AMPs do not support the request for ICM funding because they reflect capital in-service addition forecasts for the 2019 to 2023 period that are lower than the 2014 to 2018 period. This argument is a non-sequitur. The fact that Enbridge Gas proposes to spend less over the next 5 years than it did over the previous 5 year period has no connection to the ICM request, and no bearing on the application of the OEB's criteria of materiality, need and prudence.

IT Spending

Board Staff submits that it, "has reviewed the USP and AMPs for both rates zones in support of the ICM requests for 2019 rates and with the exception of spending on Information Technology (IT), has no other concerns with the forecast capital for 2019."[36]

Board Staff submits that $13.4 million in IT spending should be deferred to a future rate application pending Enbridge Gas's ongoing review of the integration of information technology across the two predecessor utilities. Board Staff focuses on two aspects of the IT budget. First, $7 million in spending in relation to the Customer Experience Transformation; and second, $6.4 million in spending in relation to the HANA project. Board Staff's suggestion that this spending can or should be deferred is without merit.

As described in Exhibit I.STAFF.32, the capital expenditures identified in the respective AMPs are essential. The proposed spending in relation to these projects is necessary to maintain current customer satisfaction levels.[37] Further, in relation to the Customer Experience Transformation project, its scope was defined prior to the amalgamation being approved, relates specifically to the EGD rate zone and has not been modified for any integration related purpose.[38] Moreover, the program commenced in 2017 and the remaining spend in 2019 simply carries through to deliver the final elements of functionality envisioned in the overall plan.[39] With respect to the HANA project it

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[36] Board Staff Argument, p.14.
[37] Exhibit C1, Tab 2, Schedule 1, p. 354.
[38] Exhibit I.Staff.67.
[39] Exhibit I.STAFF.55, part b).

is a software solution required to run hardware associated with the legacy EGD CIS system, which is the subject of a separately defined project. The software upgrade is essential to the hardware project (about which no party complains) and is required to keep the EGD CIS in safe and reliable operation.[40]

Issue 10

Are the costs of the ICM projects appropriate, to the extent that they differ from the costs considered by the OEB in granting leave to construct?

Issue 11

Is the NPS 30 Don River Replacement Project in the EGD rate zone eligible for Incremental Capital Module (ICM) funding?

a. If yes, is the ICM rate rider for the NPS 30 Don River Replacement Project calculated appropriately?

Issue 12

Are the Sudbury Replacement Project in the Union North rate zone and the Kingsville Transmission Reinforcement and Stratford Reinforcement projects in the Union South rate zone eligible for ICM funding?

a. If yes, are the ICM rate riders for the Sudbury, Kingsville and Stratford projects calculated appropriately?

Issues 10 to 12 are related and, therefore, as in the Argument in Chief, are discussed together below beginning with the eligibility for ICM funding and followed by a discussion of each of the four specific ICM projects. In Enbridge Gas's submission, each of the four projects meets the OEB's requirements, is eligible for funding at the level of costs proposed and should be approved.

Eligibility for ICM Capital

In the MAADs Decision, the Board confirmed the availability of ICM funding for Enbridge Gas.[41] As set out in section 4.1.5 of the "Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, EB-2014-0219" ("ACM Report"), to be eligible for recovery, capital projects must meet the following criteria: materiality, need and prudence.

[40] Exhibit C1, Tab 2, Schedule 1, p. 1379.

[41] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, pp.30-34.

Here, with the exception of QMA, all parties oppose at least some aspect of Enbridge Gas's ICM funding request. Their specific complaints are discussed below.

Materiality

Threshold Test

Parties take no issue with the materiality threshold of $468.5 million for the EGD rate zone for 2019, although they do complain about the manner in which it has been calculated. They further complain about the threshold of $375.2 million for the combined Union rate zones. Their submissions focus on Enbridge Gas's proposal to use a simple average of the actual annual PCI in determining the threshold value. In respect of the Union rate zones, this is the average of the PCI used to increase rates over the preceding IRM term (2014-2018).[42] In brief, the question is whether to use 0.72% (Enbridge's proposal) in the calculation of the threshold or 1.07% (parties' submissions).

Price Cap Index. The OEB's standard threshold value calculation uses PCI to recognize the increase in revenue generated through annual rate increases in a price cap plan that could be used toward capital investment. The calculation uses a current year PCI, which does not recognize the actual change in rates experienced over a multi-year price cap IR term and can result in a threshold value that does not represent the actual revenue increase during that period.

In Enbridge Gas's submission, the average PCI more accurately reflects the impact PCI has had on rates and revenue since the base year (2013 rates for Union and 2018 rates for EGD) than the use of the current year PCI. Further, the use of the average PCI also reduces the year-to-year fluctuations in the threshold value that would occur by using the current year PCI and helps the utility plan and prioritize capital investments through a more stable threshold value. This also aligns with customer preferences of a steady rate of investment, over a less predictable pace.[43]

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[42] As set out in the Argument in Chief, Enbridge Gas has also proposed to use an averaging approach in the EGD rate zone but because 2019 is the first year of the PCI formula it is an average of a single year.

[43] Exhibit I.STAFF.33; and Exhibit D1, Tab 2, Schedule 1, pp. 12-13: "They [customers] prefer a steady rate at a higher level, over a more reactive and less predictable pace of investment."

In opposing Enbridge Gas's proposal, all parties make the same argument: that it is contrary to standard Board policy to use an average. Enbridge Gas disagrees. Viewed in the context of Enbridge Gas's unique circumstances, and the rationale for the standard policy, the Company's modification to the standard policy is appropriate.

The rationale for the policy is helpfully set out in the ACM Report (and also cited in CME's submission). As the Board indicated:

> The original materiality threshold formula for an ICM was structured to support a single year-over-year change (i.e., from the cost of service rebasing to the first IRM rate adjustment application in the following year). However, a distributor could apply for an ICM as part of its annual IRM rate adjustment for any year subsequent to its cost of service application. <u>The single year-over-year formula does not take into account the passage of time over the subsequent IRM period (i.e. the cumulative impacts of cost, inflation, productivity and changes in customers and demand)…</u>
>
> …Having reviewed more than a dozen ICM applications since adopting the ICM, the OEB is of the view that the materiality threshold should change over time during the IR term. The amount of capital that is funded each year should change relative to what was funded in rebased rates to reflect the current price cap adjustment and growth in demand. [Emphasis added.]

The above passage admittedly refers to "current price cap adjustment" but it equally emphasizes the importance of taking account of the passage of time over the IRM period and the "cumulative" impacts of inflation, productivity and other changes. Moreover, it is important to recognize that the ACM Report was written with electricity distributors in mind. These utilities rebase regularly (every 5 years) and have their rates adjusted in the interim pursuant to a prescribed OEB formula, subject only to adjustment for their specific cohorts.

Enbridge Gas, and particularly, the Union rate zones, are in a fundamentally different position. Union last rebased in 2013. It was not required to rebase in 2019 and, indeed, the Board in the MAADs proceeding expressly rejected intervenor argument that it should then, or as soon as 2021. Moreover, over the 2014-2018 IRM period, Union's rates were not adjusted pursuant to the OEB's prescribed formula but rather a custom index. Under the Union formula, rates were increased annually by just 40% of inflation – well less than the rate of increase applicable to any electricity distributor.

Having regard to this context, applying the Board's standard policy for determining the threshold (as parties argue) fails to "take into account" changes over the subsequent IRM period and, respectfully, would be wrong.

Growth Factor, Rate Base and Depreciation. No party made submissions in response to Enbridge Gas's Argument in Chief.

Discrete and Material Projects

As defined in the Board ACM report, "amounts must be based on discrete projects, and should be directly related to the claimed driver. The amount must be clearly outside of the base upon which the rates were derived".[44] Further, pursuant to the MAADs Decision, any individual project for which ICM funding is sought must have an in-service capital addition of at least $10 million.[45]

Each capital project for which ICM funding is sought is a discrete project that exceeds the materiality level of $10 million.

In its submission, SEC attempts to characterize the ICM projects as "business as usual" and therefore ineligible, it says, for ICM treatment. There is no merit to SEC's argument. It has already been rejected by the Board.

The ICM is a mechanism available to distributors whose rates are established under the price cap incentive regime. The ICM is intended to address the treatment of a distributor's capital investment needs that arise during the rate-setting plan which are incremental to a materiality threshold. The ICM is available for discretionary and non-discretionary projects, as well as for capital projects not included in the distributor's previously filed Distribution System Plan (or USP). As the ACM Report makes clear, ICM it is not limited to extraordinary or unanticipated investments and may be applied to projects that might be considered to be 'routine' or 'business as usual'.[46]

Moreover, SEC's reliance on the Board's decision in Alectra's most recent ICM application concerning the Rometown rebuild is entirely misplaced. Rometown was far from a "substantial

[44] EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p.17.

[45] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, pp.32-33.

[46] ACM Report, pp. 5-8.

project" as SEC claims. As the Board noted in its Decision, SEC referred to Rometown as a "minor expenditure" ($3.2 million) and determined that Rometown concerned a more routine, programmatic rebuild of a subdivision. Further, a version of the program had already been included in Alectra's DSP a year earlier at the lower cost of $1.85 million. By comparison, the Kingsville project alone has a capital cost of $121.4 million or roughly 30% of the threshold calculation of $372 million.

Prudence

The capital expenditures for which Enbridge Gas is seeking ICM funding are prudent and represent the most cost effective option for ratepayers.

Leave to construct has already been granted by the OEB in respect of each of the ICM projects. The projects are in the public interest in the scope and timing proposed by Enbridge Gas and approved by the OEB in each of the LTC applications.

Costs of the Projects. This issue is limited to the costs of the projects to the extent they differ from the estimates in the leave to construct applications. Parties' complaints relate to:

- the inclusion of indirect overhead costs;
- the potential inclusion of incremental OM&A and property tax costs;
- the timing of rate rider credits; and
- other discrepancies between the estimates filed in the leave to construct proceeding and the costs reflected in this application.

In Enbridge Gas's submission, the costs of all of the ICM projects are appropriate. Parties' submissions in relation to the first three bullets above are addressed here, while the fourth bullet, which concerns certain minor discrepancies, is addressed as part of the project specific discussions below.

Indirect overhead costs. Board Staff agrees that it is appropriate to include indirect overhead costs as part of project costs for the purpose of determining the rate rider. As Staff submits in relation to the Kingsville Project:

> An additional issue is the variance between the original budget approved in the leave to construct application and the revised budget. The entire increase in the budget is attributed to indirect overhead costs. As noted earlier, Enbridge Gas clarified at the technical conference that the leave to construct application only included incremental costs and not fully burdened costs which includes indirect overheads. <u>OEB staff accepts the explanation for the variance and once again notes that this is a Union Gas rate zone project with an indirect overheads allocation of 14.8%.</u> [Emphasis added.]

All other parties that made submissions argue that indirect overhead costs should not be included. The main argument these parties make is that indirect overhead costs are not “incremental” and therefore ineligible for “incremental capital” funding. There is no merit to this argument.

“Incremental” in the context of the Board’s ICM policy plainly refers to incremental to the ICM materiality threshold, not incremental costing for rate recovery. ICM projects support the supply of gas (or electricity) distribution service to customers. The rates charged for distribution service are designed and approved on a fully allocated basis. It follows that ICM rate riders should be designed on a fully allocated basis as well. Nothing in the Board’s ICM policy guidance, including the ACM Report, suggests otherwise, nor is Enbridge Gas aware of any case in which the Board has set ICM rates on an incremental basis.

As set out in Enbridge Gas’s Argument in Chief, fully burdened costs include indirect overheads that are allocated to all projects, irrespective of whether these projects are ICM or not. Indirect Overheads are allocated to projects within the EGD and Union rate zones and are required for the successful completion of all projects. These costs represent the support costs for departments such as Planning, HR, Finance and TIS that support each project through to completion.[47] These costs are not self-sustaining and are incurred to support the implementation of capital projects required to deliver safe and reliable service to customers. Indeed, despite its argument focusing on the word, incremental, even SEC admits it is appropriate to include indirect overhead costs in the fully allocated cost of projects. As SEC says at para. 2.4.4:

> 2.4.4 <u>When the Applicant calculates the fully allocated costs of a capital project, it quite reasonably includes an appropriate allocation of general and administrative OM&A costs that are the “fair share” of those costs to be</u>

[47] The nature of the overhead, the components and overall burden rate are further detailed in Exhibit I. Staff. 32, Exhibit I. BOMA 21, 23 and 63 and Undertakings JT1.7 and JT 1.12.

> borne by that project. In the case of the former Union Gas territory, capital costs have 14.8% added to reflect overhead costs. In the case of the former EGD territory, capital costs have 36.4% added to reflect overhead costs. [Emphasis added.]

APPrO and others further argue that as the indirect overhead costs were not included in the leave to construct cost estimates (with the exception of Stratford), these costs should be denied. Again, the inclusion of indirect overhead costs reflects the nature of this Application compared to a leave to construct. In the latter, the OEB evaluates and approves (or denies) a project based on its purpose, need, timing, environmental assessment, and economic feasibility. Economic feasibility is conducted on an incremental basis and considers only the direct revenues and costs of the proposed project (E.B.O. 188 and E.B.O. 134). This approach allows the OEB a view of factors, including any forecast of new customers and volumes, costs and revenues (or cost savings), that are specifically triggered or arise as a result of the project being undertaken. But, the OEB does not examine, not does it need to consider or approve the rates the utility will charge to recover the cost of the project from customers. This is more appropriately dealt with in a rate or, as here, ICM application.

Incremental OM&A and Property Taxes. The potential inclusion of incremental OM&A and property taxes arises in two places. First, in the context of the ICM rate riders and, second, in the wording of the associate ICM deferral accounts. Parties object to the inclusion in either place. However, as a matter of fact, none of the proposed ICM projects give rise to incremental OM&A and the amount of property tax is not material (approximately $2 million across all four projects). For the purpose of this application, Enbridge Gas agrees to the exclusion of the taxes in the determination of the relevant rate riders, although they are undoubtedly a component of revenue requirement and should be included in the normal course. Accordingly, these costs are not an issue for the OEB in this case. Enbridge Gas reserves the right to revisit this issue in the event the amounts are material.

Timing of Rate Rider Credits. As set out in evidence, in the first calendar year of an ICM project's in-service date, the revenue requirement may be a credit balance due to utility income and taxable income differences. Enbridge Gas proposes to net this credit balance in the in-service year of its

ICM requests with the revenue requirement balance in the second year.[48] Board Staff, LPMA and BOMA disagree with the proposal, while IGUA and OGVG[49] agree with deferring ratepayer credits to offset ratepayer debits in future years.

Enbridge Gas submits that its proposal is aligned with customer preferences, which are to maintain stable and predictable rates. However, if the Board prefers, the rate rider credits can be included in 2019 rates. Please see Appendix A and Appendix B which shows the rate rider impacts for the EGD and Union rate zones' ICM funding requests.[50]

ICM Project Specific Discussion[51]

NPS 30 Don River Replacement Project. This Project involves the replacement of approximately 0.25 km of NPS 30 XHP on the Don River Bridge crossing with a new NPS 30 XHP under the Don River through the use of trenchless technology (microtunnel), and abandonment of the existing pipeline. Removal of the bridge and the abandoned pipeline will then follow. The Project is needed as a result of established structural concerns with the existing bridge. The pipeline is a critical feed to the Toronto area. Damage to the crossing at peak design temperature would result in the loss of ~92,500 customers, and may take days or weeks to restore service, once the pipeline issue has been addressed.

BOMA, LPMA and VECC oppose the project, in substance, on the basis that it amounts to "business as usual". This argument is addressed above and is without merit. The project is defined in scope and meets the OEB's criteria of materiality, need, and prudence. Indeed, at $35.4 million, the project well exceeds the project specific materiality threshold of $10 million, although only $13.1 million is sought in ICM funding.

For its part, SEC agrees that the project qualifies for ICM treatment but then argues that if indirect overheads are eliminated there is no need for any rate recovery. Again, the indirect overheads are properly included and SEC's argument should be dismissed.

[48] Exhibit B1, Tab 2, Schedule 1, pp.31-32.

[49] OGVG suggested the credit should be deferred, but that it should be pro-rated over the entire deferred rebasing period, instead of 2020 as proposed.

[50] Provided in response to Board Staff Argument, p.20.

[51] The business case summaries detailing each of the ICM projects are attached as Appendix C to this Argument.

Energy Probe similarly complains about the inclusion of indirect overheads but also complains about certain other costs of the projects, namely the increase in land costs from $300 thousand to $2.265 million between the leave to construct and this application. In making this argument, Energy Probe overlooks entirely the evidence that the increase simply reflects a shift in cost category from contingency to land, rather than a true increase. As the witness testified:

> So at the -- you identified it correctly, Mr. Ladanyi, that at various stages of the project, as the certainty and understanding of the project increases, the contingency, as you would expect, would come down. And you can see here that the, you know, the land--sorry, the contingency cost is very similar to that of the increase in the land costs.
>
> Again, at the time of defining it, they were unsure of what would be the land cost. They included a contingency and as they become more aware of what the anticipated costs will be, it's predominantly the land.[52]

Finally, Board Staff does not take a position on whether the Project meets the Board's ICM criteria. Rather, it argues that if IT costs of $13.4 million are excluded from the EGD AMP then there is no need for ICM funding for the project. As set above, Enbridge Gas fundamentally disagrees with Board Staff's discussion of the need for the Customer Experience and HANA project spending.

Kingsville. The Project involves approximately 19 kilometers of transmission pipeline in the Town of Lakeshore and the Town of Kingsville in the County of Essex. The cost of the Project is $121.4 million. It is needed to respond to increasing natural gas demand in the Kingsville-Leamington market as well as increasing demand on the overall Panhandle Transmission System. The Panhandle Transmission System is the primary pipeline to transport gas from Dawn to the Ojibway Valve Site in Windsor and feeds high pressure distribution pipelines servicing residential, commercial and industrial customers. The Project reinforces the high-pressure Panhandle Transmission System to serve customers in the Kingsville-Leamington market area and to serve future development in the market served by the Panhandle Transmission System.

OEB Staff supports the project. APPrO, Energy Probe, LPMA, OGVG, QMA and VECC also support or do not oppose the Project provided indirect overheads are excluded from the costs and any incremental revenues are included. The issue of indirect costs has already been addressed above. Moreover, with respect to any forecast revenues, the revenue requirement for the Project has

[52] Transcript, Vol. 2, pp. 9-10.

appropriately not been offset by these revenues. As intervenor argument fails to recognize, the revenue impact of the growth of the Project (and other projects) will be captured in the growth factor of the ICM materiality threshold value.

SEC opposes the Project on the basis that it is business as usual. Again, this is dealt with above and has no merit.

Lastly, BOMA opposes the Project on the theory that the PI for the Project of 0.45, reviewed by the Board in the leave to construct application, “is likely to understate the revenues for the line” and therefore the Project does not qualify for ICM treatment and that it “would be an imprudent use of funds.” There is no evidence to support BOMA’s position. In fact, BOMA did not ask a single IR or question at the Technical Conference to support its theory. As noted earlier, the PI was reviewed in the leave to construct application and approved and the ICM methodology accounts for revenue growth. BOMA’s submission should be rejected.

Stratford. The Project involves approximately 10.8 kms of NPS 12 pipeline and ancillary facilities in order to increase the capacity of Forest, Hensall and Goderich Transmission System serving the Northern portions of the Counties of Middlesex and Lambton and the Counties of Perth and Huron (“FHG Transmission System”). The cost of the Project is $28.5 million. It is required to meet the increasing demands for natural gas starting in winter 2019 as the FHG Transmission System is forecasted to be fully utilized with no excess capacity available as of winter 2019. In absence of the Project to increase capacity, Enbridge Gas will not be able to service additional customers.

APPrO has no objection to the Project, “provided the Board’s ICM Policy threshold are met.”[53] Board Staff and others oppose ICM recovery on the basis that the Project is a routine distribution project. In addition to the foregoing, LPMA also argues that because the annual revenue requirement associated with the Project is less than the (non-ICM) $5.5 million materiality threshold for Enbridge Gas determined by the Board in the MAADs Decision it should not qualify for ICM treatment. Lastly, LPMA argues that revenue associated with the demands on the new pipeline further diminish the need for ICM recovery. Enbridge Gas disagrees with all of the above objections to ICM recovery.

[53] APPrO Argument, p. 9.

To begin, as set out above, the fact that the Project involves reinforcement of an existing system, through the construction of a new line, does not disentitle it from ICM eligibility. This argument is just another variation on the claim that a project must be "extraordinary" to qualify. There is no such requirement.

With respect to LPMA's argument concerning materiality, respectfully, this amounts to an apples to oranges comparison. In the MAADs Decision, the Board expressly addressed the project specific materiality for any particular ICM project. Contrary to LPMA's submission, the Board determined that the appropriate figure was $10 million in total capital cost for a project to qualify. The Stratford Project well exceeds this amount.

Finally, as with Kingsville, any incremental revenues are already captured in the growth factor used to determining the materiality threshold.

Sudbury. The Project involves the construction of 20 km of NPS 12 pipeline in the Sudbury area to replace two sections of NPS 10 pipeline in the City of Greater Sudbury, predominately constructed in 1958. The total cost of the Project is approximately $95 million.

With the exception of Board Staff, parties that make submissions in relation to the Sudbury Project oppose ICM treatment. As expected, they argue that because the Project came into service in 2018 it is ineligible. Their position is best characterized as opportunistic.

Board Staff takes a more principled approach. Although Staff states that the Project does not meet the Board's ICM criteria, they recognize the "unique" circumstances of the case. As Staff argue:

> This is a unique case where a project falls between a previous capital funding mechanism and the incremental rate treatment under the ICM. In its evidence, Enbridge Gas noted that delaying the leave to construct application was not an option and if the project was delayed, integrity concerns could have become more serious. Given the magnitude of the investment, Enbridge Gas has indicated that incremental funding is required. The cumulative revenue requirement of the project from 2018 through 2023 is over $47 million.
>
> Given the unique circumstances in this case, OEB staff is of the opinion that Enbridge Gas should be eligible for recovery of the revenue requirement related to the project. However, it is clear that it does not qualify under the OEB's ICM policy as it did not go into service in the rate year (2019). But more importantly for OEB staff, this is a transitional matter that should recognize the framework

> that was in place at the time the project was approved for construction, and placed into service.
>
> Since the project went into service in 2018 and at the time Union Gas had access to the capital pass-through mechanism, OEB staff submits that the capital pass-through mechanism should apply and Enbridge Gas should be granted the appropriate deferral account to track and recover the revenue requirement related to the project...

Staff is right about the uniqueness of the Sudbury Project. The evidence is that there was a significant need to replace the pipeline in order to continue to maintain safe and reliable service to the Sudbury market. Delaying the leave to construct application and construction in order to confirm the funding mechanism for the Project was simply not an option. If the Project was delayed, integrity concerns could have become more serious, with the risk of a potential failure increasing over time.

Given the magnitude of the $95.3 million investment in the Sudbury Replacement Project, incremental funding of the Project is required. The cumulative revenue requirement of the Project from 2018 through 2023 is over $47 million. Union was not able to reprioritize 2018 Capital investment in order to fund this investment using existing rates. The purpose of the capital pass-through mechanism was to provide a means for Union to make significant investments under its price cap plan. Given that the timing of the investment in the Sudbury Replacement project occurred in late 2018, Enbridge Gas will be impacted by the first full year revenue requirement in 2019, during which time the ICM will apply.

In Enbridge Gas's submission, the Project should be subject to ICM treatment. Denying recovery would be overly formalistic. Moreover, concerns expressed concerning opening the door to other "out of period" projects are overblown. No comparable project or circumstance has been identified or exists.

In the event the Board disagrees with Enbridge Gas, it is respectfully submitted that Board Staff's proposal should be adopted.[54]

[54] In its submission, Board Staff asked Enbridge Gas to provide the net book value of the Project as at January 1, 2019. That figure is $88.3 million.

As a final matter, in its submission, LPMA suggests, that if the Project is approved recovery should be limited to $33.6 million, based on LPMA's calculation of a 2018 materiality threshold. Enbridge Gas disagrees with this approach but notes further that LPMA's math is wrong. The actual amount would be $82.8 million, as set out in the footnote below.[55]

Issue 13

Is Enbridge Gas' customer connection policy and Profitability Index calculation for consumers appropriate and in accordance with OEB guidelines?

As explained in Exhibit B1, Tab 1, Schedule 1, Appendix H, Enbridge Gas enhanced its approach to assess the economic feasibility of residential infill customers in the Enbridge Gas Distribution (EGD) rate zone during its previous custom IR term. The improvement was designed to better align the analysis with requirements of E.B.O. 188.

Board Staff, SEC, VECC and CCC oppose the continued use of Enbridge Gas's refined approach to assessing economic feasibility in the EGD rate zone. SEC and VECC also go a step further and argue that Enbridge Gas should identify any customers that were charged a higher amount as a contribution in aid of construction as a result of the refined approach and refund such amount to those customers.

The main arguments made by parties in opposition are that the refined approach was not the subject of prior Board review or approval; and, a claim that Enbridge Gas has realized additional revenues in the amount of approximately $8 million as a result of the change. Neither argument withstands scrutiny.

Pursuant to the requirements of E.B.O. 188, Enbridge Gas uses a portfolio approach to manage its system expansion activities and ensures that the required profitability standards are achieved at both the individual project and the portfolio level. Investment Portfolio and Rolling Project Portfolio are the two Board-prescribed portfolio approaches. The enhancement was required to ensure that the Company's Investment Portfolio achieves a PI of greater than 1.0 and to remain compliant with E.B.O. 188.

[55] 2018 capital expenditures were $432.1 million (excluding capital pass-through projects), and the 2018 ICM threshold is $349.3 million (calculated with the 2018 growth factor of 0.87% and 2018 PCI of 0.65%). This results in a 2018 maximum eligible incremental capital amount of $82.8 million ($432.1 million - $349.3 million).

Prior to August 2015, Enbridge Gas applied a simplified approach to assess the economic feasibility of residential service connections. Residential services were deemed feasible to a threshold length (20 metres) beyond which customers would be required to pay a contribution-in-aid-of-construction ("CIAC"). The approach assumed that the revenues and associated costs of all or the majority of residential services would be sufficiently consistent.

Under the refined approach there is no need for this underlying assumption. The CIAC amount for residential infill customers is now determined on an individual basis.

Contrary to parties' submission, there was no need for prior Board review or approval of the refined methodology. The calculation of CIAC is specific to the particular requirements of each customer. Indeed, as the Board held in its Decision with Reasons in EB-2012-0396 (page 15):

> The Board recognizes that, as a practical matter, the setting of a rate for a capital contribution cannot be conducted in the same manner as the rates set out in a utility's rate tariff. The amount owing for any capital contribution is fact specific, and will be different depending on the capital costs of the assets and the revenues that the utility is expected to receive through ordinary rates. The need for a capital contribution may arise at any time, and seldom will be the case where the timing allows the Board to review the proposed contribution through a routine rate case.

It is equally incorrect to refer to amounts relating to the refined approach as "incremental revenues." CIAC amounts are not revenue. CIAC amounts are used to offset the capital cost of a project and impact revenue requirement (i.e. rate base, depreciation, cost of capital and taxes). As LPMA correctly notes,

> …upon rebasing, benefits will flow to ratepayers because the rate base will be lower by the amount of the increase in the connection payments from the in-fill customers. This will also reduce depreciation expense upon rebasing.

Enbridge Gas's refined approach to feasibility analysis results in higher contributions than its prior approach while adhering to the Board's E.B.O. 188 guidelines. This means that, as compared to Enbridge Gas's prior approach to feasibility analysis, the rate base amounts for new residential infill customers will be lower. This will result in a lower cost of service. Upon rebasing, the refined approach to feasibility analysis will benefit ratepayers, because the new amounts being added to utility rate base for residential infill customers will be lower than would be the case under the prior approach. In contrast, if, as some intervenors argue, the amount in CIAC were returned, rate base would increase and, on rebasing, rates for all customers would be higher.

All of which is respectfully submitted this 12th day of July, 2019.

ENBRIDGE GAS INC.

By its counsel, Lax O'Sullivan Lisus Gottlieb LLP

(Original Signed)

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Crawford Smith

EGD RATE ZONE
Allocation of 2019 ICM Project Revenue Requirement

Line No.	Particulars	Delivery Demand TP > 4" Allocator (1) %	Don River Replacement Project (000's)
		(a)	(b)
	EGD		
1	Rate 1	46%	(171)
2	Rate 6	41%	(152)
3	Rate 9	0%	-
4	Rate 100	0%	-
5	Rate 110	2%	(8)
6	Rate 115	1%	(5)
7	Rate 125	8%	(30)
8	Rate 135	0%	(0)
9	Rate 145	0%	(0)
10	Rate 170	0%	(0)
11	Rate 200	1%	(4)
12	Rate 300	0%	(0)
13	Total	100%	(370)

Notes:
(1) EGD extra high pressure mains greater than 4 inch diameter are allocated according to the Board approved cost allocation methodology (EB-2017-0086), Delivery Demand TP > 4 inch allocator, reflecting 2019 forecast peak demand by rate class

EGD RATE ZONE

Deriviation of 2019 Incremental Capital Module ("ICM") Rates by Rate Class

Line No.	Particulars	ICM Revenue Requirement (1) (000's)	Delivery Volumes (2) (10^3 m^3)	ICM Unit Rates (cents / m³)
		(a)	(b)	(d) = (a / b * 100)
	General Service			
1	Rate 1	(171)	4,933,563	(0.0035)
2	Rate 6	(152)	4,923,606	(0.0031)
3	Rate 9	-	-	-

Line No.	Contract Service	ICM Revenue Requirement (1) (000's)	Delivery/Contract Demand Volumes (3) (10^3 m^3)	ICM Unit Rates (cents / m³)
		(a)	(b)	(d) = (a / b * 100)
4	Rate 100 - per 10^3m³ of contract demand	-	-	-
5	Rate 110 - per 10^3m³ of contract demand	(8)	48,218	(0.0171)
6	Rate 115 - per 10^3m³ of contract demand	(5)	20,166	(0.0228)
7	Rate 125 - per 10^3m³ of contract demand	(30)	111,124	(0.0272)
8	Rate 135 - per 10^3m³ of delivery volume	(0)	64,744	-
9	Rate 145 - per 10^3m³ of contract demand	(0)	9,242	(0.0035)
10	Rate 170 - per 10^3m³ of contract demand	(0)	32,846	(0.0010)
11	Rate 200 - per 10^3m³ of contract demand	(4)	14,801	(0.0270)
12	Rate 300 - per 10^3m³ of contract demand	(0)	187	(0.0272)
13	Total 2019 ICM Costs	(370)		

Notes:
(1) Exhibit B1, Tab 2, Schedule 1, Appendix D, Page 1, Column b.
(2) Exhibit F1, Tab 1, Rate Order, Working Papers, Schedule 9, Page 3, Line 1.2.
(3) Exhibit F1, Tab 1, Rate Order, Working Papers, Schedule 5, Page 9 - 23, Line 2.

UNION RATE ZONES
Allocation of 2019 ICM Project Revenue Requirement

		Union North		Union South			
Line No.	Particulars	Distribution Demand Allocator (1) (%)	Sudbury Replacement Project (2) ($000's)	Other Transmission Allocator (3) ($10^3m^3/d$)	Kingsville Reinforcement Project (4) ($000's)	Stratford Reinforcement Project (4) ($000's)	Total ICM Allocation ($000's)
		(a)	(b)	(c)	(d)	(e)	(f) = (b+d+e)
1	Rate 01	40	3,907	-	-	-	3,907
2	Rate 10	13	1,276	-	-	-	1,276
3	Rate 20	27	2,605	-	-	-	2,605
4	Rate 25	2	235	-	-	-	235
5	Rate 100	18	1,738	-	-	-	1,738
6	Total Union North	100	9,762	-	-	-	9,762
7	Rate M1	-	-	31,974	(1,334)	(305)	(1,639)
8	Rate M2	-	-	10,986	(458)	(105)	(563)
9	Rate M4 (F)	-	-	5,860	(245)	(56)	(300)
10	Rate M4 (I)	-	-	-	-	-	-
11	Rate M5 (F)	-	-	87	(4)	(1)	(4)
12	Rate M5 (I)	-	-	-	-	-	-
13	Rate M7 (F)	-	-	2,496	(104)	(24)	(128)
14	Rate M7 (I)	-	-	-	-	-	-
15	Rate M9	-	-	546	(23)	(5)	(28)
16	Rate M10	-	-	4	(0)	(0)	(0)
17	Rate T1 (F)	-	-	2,572	(107)	(25)	(132)
18	Rate T1 (I)	-	-	-	-	-	-
19	Rate T2 (F)	-	-	23,429	(978)	(223)	(1,201)
20	Rate T2 (I)	-	-	-	-	-	-
21	Rate T3	-	-	2,501	(104)	(24)	(128)
22	Total Union South	-	-	80,456	(3,358)	(766)	(4,124)
23	Excess Utility Storage	-	-	-	-	-	-
24	Rate C1 (F)	-	-	-	-	-	-
25	Rate C1 (I)	-	-	-	-	-	-
26	Rate M12	-	-	-	-	-	-
27	Rate M13	-	-	-	-	-	-
28	Rate M16	-	-	-	-	-	-
29	Total Ex-Franchise	-	-	-	-	-	-
30	Total Union	100	9,762	80,456	(3,358)	(766)	5,637

Notes:
(1) Union North distribution demand allocation for joint-use mains in proportion to 2019 forecast peak day and average day demands.
(2) Allocated in proportion to column (a).
(3) Union South other transmission demand allocation in proportion to forecast 2019 Union South in-franchise design day demands.
(4) Allocated in proportion to column (c).

UNION RATE ZONES
Deriviation of 2019 Incremental Capital Module ("ICM") Rates by Rate Class

Line No.	Particulars	ICM Revenue Requirement ($000's) (1) Sudbury Replacement Project	Kingsville Reinforcement Project	Stratford Reinforcement Project	Total	2019 Forecast Usage (2)	Billing Units	ICM Rate (cents/m³) Sudbury Replacement Project	Kingsville Reinforcement Project	Stratford Reinforcement Project	Total
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f)	(g)=(a)/(e)*100	(h)=(b)/(e)*100	(i)=(c)/(e)*100	(j)=(d)/(e)*100
	Union North										
	Rate 01 General Service										
1	Monthly Delivery Charge	3,907	-	-	3,907	975,438	10^3m^3	0.4006	-	-	0.4006
	Rate 10 General Service										
2	Monthly Delivery Charge	1,276	-	-	1,276	342,801	10^3m^3	0.3724	-	-	0.3724
	Rate 20 Medium Volume Firm Service										
3	Delivery Demand Charge	2,605	-	-	2,605	83,934	$10^3m^3/d$	3.1037	-	-	3.1037
	Rate 25 Large Volume Interruptible Service										
4	Monthly Delivery Charge	235	-	-	235	71,503	10^3m^3	0.3280	-	-	0.3280
	Rate 100 Large Volume Firm Service										
5	Delivery Demand Charge	1,738	-	-	1,738	41,307	$10^3m^3/d$	4.2082	-	-	4.2082
6	Total Union North In-Franchise	9,762	-	-	9,762						

Notes:
(1) Appendix B, p. 1.
(2) Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 10, pp. 2-4, column (b) and Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 11, pp. 7-9, column (b).

UNION RATE ZONES
Deriviation of 2019 Incremental Capital Module ("ICM") Rates by Rate Class

Line No.	Particulars	ICM Revenue Requirement ($000's) (1) Sudbury Replacement Project	Kingsville Reinforcement Project	Stratford Reinforcement Project	Total	2019 Forecast Usage (2)	Billing Units	ICM Rate (cents/m³) Sudbury Replacement Project	Kingsville Reinforcement Project	Stratford Reinforcement Project	Total
		(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f)	(g)=(a)/(e)*100	(h)=(b)/(e)*100	(i)=(c)/(e)*100	(j)=(d)/(e)*100
	Union South										
	Rate M1 - Small Volume General Service										
1	Monthly Delivery Commodity Charge	-	(1,334)	(305)	(1,639)	3,051,302	10^3m^3	-	(0.0437)	(0.0100)	(0.0537)
	Rate M2 - Large Volume General Service										
2	Monthly Delivery Commodity Charge	-	(458)	(105)	(563)	1,184,733	10^3m^3	-	(0.0387)	(0.0088)	(0.0475)
	M4 Firm Commercial/Industrial Contract Rate										
3	Monthly Demand Charge	-	(245)	(56)	(300)	47,502	$10^3m^3/d$	-	(0.5149)	(0.1175)	(0.6324)
	M5A Interruptible Commercial/Industrial Contract Rate										
	Firm contracts										
4	Monthly Demand Charge	-	(4)	(1)	(4)	792	$10^3m^3/d$	-	(0.4558)	(0.1040)	(0.5599)
	M7 Special Large Volume Contract Rate										
	Firm Contracts										
5	Monthly Demand Charge	-	(104)	(24)	(128)	25,784	$10^3m^3/d$	-	(0.4041)	(0.0922)	(0.4963)
	M9 Large Wholesale Service										
6	Monthly Demand Charge	-	(23)	(5)	(28)	4,700	$10^3m^3/d$	-	(0.4852)	(0.1108)	(0.5960)
	M10 Small Wholesale Service										
7	Monthly Delivery Commodity Charge	-	(0)	(0)	(0)	277	10^3m^3	-	(0.0603)	(0.0138)	(0.0741)
	Rate T1 Contract Carriage Service										
8	Monthly Demand Charge	-	(107)	(25)	(132)	25,824	$10^3m^3/d$	-	(0.4157)	(0.0949)	(0.5106)
	Rate T2 Contract Carriage Service										
9	Monthly Demand Charge	-	(978)	(223)	(1,201)	271,326	$10^3m^3/d$	-	(0.3604)	(0.0823)	(0.4427)
	T3 Contract Carriage Service										
10	Monthly Demand Charge	-	(104)	(24)	(128)	28,200	$10^3m^3/d$	-	(0.3701)	(0.0845)	(0.4546)
11	Total Union South In-Franchise	-	(3,358)	(766)	(4,124)						
12	Total Union In-franchise	9,762	(3,358)	(766)	5,637						

Notes:
(1) Appendix B, p. 1.
(2) Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 10, pp. 2-4, column (b) and Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 11, pp. 7-9, column (b).

Business Case Summaries for ICM Projects by Rate Zone

EGD Rate Zone

<table>
<tr><th colspan="2">NPS 30 Don River Replacement</th></tr>
<tr>
<td>Budget:
$35.4 million

In-Service Date:
December, 2019

In-Service Capital Spend:
$34.2 million 2019 in-service;
$1.1 million 2020 in-service</td>
<td><u>Category of Investment</u>: System Renewal

<u>Project Description and Drivers</u>:
Replacement of approximately 0.25 km of NPS 30 XHP on the Don River Bridge crossing with a new NPS 30 XHP under the Don River through the use of trenchless technology (microtunnel), and abandonment of the existing pipeline. Removal of the bridge and the abandoned pipeline to follow.
Studies have identified structural issues with the Bridge that can become further impaired during flood events which could cause the Bridge to fail resulting in catastrophic failure of the pipeline.
The pipeline is a critical feed to the densely populated urban Toronto area. Damage to this crossing at peak design temperature would result in the loss of ~ 92,500 customers, and may take days or weeks to restore service, once the pipeline issue has been addressed.
<u>Other Options Considered</u>:
Bridge Remediation:
This option would not require the NPS 30 pipeline to be replaced. Rather, the Bridge itself would be remediated to ensure structural stability against future flood events. Preliminary discussions identified the need for the use of some kind of sheet pile structures as a permanent remediation for the erosion around the bridge abutments. Based on the sensitivity of the adjacent 1911 (107 year old) twin bell and spigot 30” cast iron sanitary sewer mains (on wood piles), this option was deemed not viable. Due to the associated risk with working in the vicinity of these twin sanitary sewers, the option to remediate the bridge was not considered to be an acceptable alternative and therefore an estimated cost and timeline were not completed.
Bridge Rebuild & Pipe Replacement:
Through the consultation process, TRCA provided Enbridge with options to consider for the replacement of the NPS 30 Don River Bridge crossing. One of these options included the possibility of using another above ground crossing. Enbridge explains how City of Toronto Bridges and Structures does not allow pipelines to be installed on bridges. The installation of structural supports to install the pipeline adjacent to existing bridges and create a new bridge to cross over the river would require very</td>
</tr>
</table>

	large supports. These supports would require footings in the river or on the river bank and there are already a number of structures in this area that would conflict with this approach. In addition, from an Enbridge construction and maintenance perspective, the installation of a pipeline on a bridge is deemed to be a last resort. As a result of all the above, this was not considered a viable alternative and therefore, an estimated cost and timeline was not completed. • *Direct Pipe Construction Method*: Under this alternative, the bridge would not be utilized and it would eventually be removed. The difference with this alternative relative to the proposed Project is the utilization of a different construction method for replacing the NPS 30 pipeline below ground under the river. During consultation the Direct Pipe method of construction and route considered for that methodology did not satisfy stakeholder concerns and conditions related to possible impacts to the TRCA's existing West Flood Protection Landform (FPL) and/or their proposed East FPL. As such a cost estimate, timelines and environmental impacts were not completed for this option as it was not a viable option. The Don River Replacement project was subject to a leave to construct application in EB-2018-0108. In its Decision and Order dated November 29, 2018, the OEB found that this project is needed to ensure the safe operation and reliability of the Don Valley Pipeline, as failure to address the risk associated with potential damage to the 89-year old bridge and existing pipeline could have a significant adverse impact on the gas supply to a large number of residential, commercial and industrial customers. The OEB also found that EGD adequately addressed environmental issues, land matters, design and safety requirements and adequately discharged the duty to consult with impacted Indigenous communities.[1] The budget is updated from the EB-2018-0108 filing budget of $25.6 million. It covers all costs related to material, construction and labour, land costs, contingencies, overheads, and interest during construction.

[1] EB-2018-0108, Decision and Order, November 29, 2018, pp.1-9.

1 **Union Rate Zones**

Sudbury Replacement Project	
Budget: $95.3 million In-Service Date: October, 2018 In-Service Capital Spend: $91.9 million 2018 in-service; $3.4 million 2019 in-service	Category of Investment: System Service Project Description and Drivers: • Build 20 km of NPS 12 pipeline in the Sudbury area to replace two sections of NPS 10 pipeline in the City of Greater Sudbury, predominately constructed in 1958 • Union's Integrity Management Program identified multiple integrity issues through inspections and investigative digs • Increasing the size of the pipeline to NPS 12 provides capacity for future growth on the Sudbury system Options Considered: • Union considered replacing the existing pipeline with another pipeline of the same size (NPS 10), or only replacing those segments of the pipeline identified as having integrity concerns • In addition to not serving the forecasted growth in the Sudbury area, replacing the NPS 10 pipeline with NPS 10 pipeline would not solve the pigging issues of having dual diameter pipelines • Replacing only those segments identified as having integrity concerns would result in inefficiencies related to the individual replacements and future integrity concerns that may require replacement • This alternative would also not meet future growth in the Sudbury area • Increasing the pipeline size from NPS 10 to NPS 12 is consistent with Union's practice to provide capacity for anticipated demand growth • The incremental cost of the NPS 12 pipeline over the NPS 10 is forecast to be $1.5M (a 2% increase in the cost of project) resulting in an expected capacity increase of the Sudbury Lateral System of 5% • Installing NPS 12 pipeline is the lowest cost option to meet the capacity requirement in the Sudbury area The Sudbury Replacement project was subject to a leave to construct application in EB-2017-0180. In its Decision and Order dated September 28, 2017, the OEB found that the proposed pipeline was in the public interest. In reaching this decision, the OEB accepted Union's evidence that the project "is needed to maintain a safe and secure supply of gas in the Sudbury area"[2] and

[2] EB-2017-0180, Decision and Order, September 28, 2017, p.6.

	found the cost estimates "acceptable to address potential safety and security issues from the existing pipeline".[3] The OEB also found that Union adequately addressed environmental issues, land matters, design and safety requirements and adequately discharged the duty to consult with impacted Indigenous communities.[4] The budget is updated from the approved EB-2017-0180 filing budget of \$74.1 million. It covers all costs related to material, construction and labour, environmental protection measures, land acquisitions, contingencies, overheads, and interest during construction.
Kingsville Reinforcement Project	
Budget: \$121.4 million Projected In-Service Date: November, 2019 In-Service Capital Spend: \$118.2 million 2019 in-service; \$3.2 million 2020 in-service	Category of Investment: System Service Project Description and Drivers: • Approximately 19 kilometers of transmission pipeline in the Town of Lakeshore and the Town of Kingsville in the County of Essex • The Project is needed to respond to increasing natural gas demand in the Kingsville-Leamington market as well as increasing demand on the overall Panhandle Transmission System. • The Panhandle Transmission System is the primary pipeline to transport gas from Dawn to the Ojibway Valve Site in Windsor and feeds high pressure distribution pipelines servicing residential, commercial and industrial customers. • The Project reinforces the high-pressure Panhandle Transmission System to serve customers in the Kingsville-Leamington market area and to serve future development in the market served by the Panhandle Transmission System. Options Considered: • Union considered alternatives including: different diameter pipeline, increased deliveries from Ojibway, looping the Panhandle system with NPS 36 pipeline, and distribution reinforcement with delayed construction of the NPS 12 pipeline to 2020 • A NPS 16 pipeline would be more costly in the longer term in relation to the upfront cost for the NPS 20 pipeline due to future facility requirements • Increased deliveries at Ojibway would be more costly over both the near

[3] *Ibid*, p.7.
[4] *Ibid*, pp.8-11.

	and longer term with higher distribution reinforcement requirements, which could become underutilized in the long term • Looping the Panhandle system with NPS 36 requires the Kingsville lateral within the 20 year timeline and could result in underutilization of distribution reinforcement • Delaying the NPS 20 constructed in 2020 would result in the distribution facilities constructed in 2019 becoming underutilized • The Project is the preferred alternative to address the need in both the five-year and longer-term horizon. The Kingsville Transmission Reinforcement project was subject to a leave to construct application in EB-2018-0013. In its Decision and Order dated September 20, 2018 the OEB found that the proposed pipeline was in the public interest. In reaching this decision, the OEB found that Union "demonstrated the need for this Project - a transmission line with broad benefits to the Panhandle Transmission System"[5] and found that Union "appropriately followed the OEB's E.B.O. 134 test for transmission projects".[6] In finding that the project is the preferred alternative, the OEB noted the Project, "has the highest net present value, addresses incremental demand in the Kingsville-Leamington area in 2019 and is consistent with other, longer-term considerations for the Panhandle Transmission System."[7] The OEB also found that Union adequately addressed environmental issues and land matters, and adequately discharged the duty to consult with impacted Indigenous communities.[8] The budget is updated from the EB-2018-0013 filing budget of $105.7 million. It covers all costs related to material, construction and labour, environmental protection measures, land acquisitions, contingencies, overheads, and interest during construction.
Stratford Reinforcement Project	
Budget: $28.5 million Projected In-Service Date:	<u>Category of Investment</u>: System Service <u>Project Description and Drivers</u>: • Approximately 10.8 kms of NPS 12 pipeline and ancillary facilities in order to increase the capacity of Forest, Hensall and Goderich

[5] EB-2018-0013, Decision and Order, September 20, 2018, p.4.
[6] *Ibid*, p.5.
[7] *Ibid*, p.6.
[8] *Ibid*, pp.7-8.

November, 2019 In-Service Capital Spend: $27.9 million 2019 in-service; $0.6 million 2020 in-service	Transmission System serving the Northern portions of the Counties of Middlesex and Lambton and the Counties of Perth and Huron ("FHG Transmission System") • The Proposed Facilities are required to meet the increasing demands for natural gas starting in winter 2019 as the FHG Transmission System is forecasted to be fully utilized with no excess capacity available as of winter 2019 • In absence of the Project to increase capacity, Union will not be able to service additional customers • The budget covers all costs related to material, construction and labour, environmental protection measures, land acquisitions, contingencies, overheads, and interest during construction <u>Options Considered</u>: • Union considered many alternatives including: a different diameter pipeline, a different length of pipeline and upgrading the maximum operating pressure ("MOP") of a portion of the FHG Transmission System • A NPS 10 pipe provides seven years of growth but significantly reduces the future capacity of the Stratford Line when compared to the NPS 12 option, it also does not adequately alleviate the constraint along the Stratford Line • The growth does not justify a NPS 16 reinforcement, and this size pipe would also require easement as it is too large to construct within the road allowance • There is insufficient growth to justify installing 15 km of NPS 12 pipeline, with potential for underutilization and different requirements for future reinforcement • Installing 7.6 km of pipeline does not provide the minimum of five years of growth and cannot accommodate any contract or large commercial growth, this alternative also has a significantly higher cost per-meter when compared to the proposed project • Upgrading the MOP of a portion of the FHG Transmission System does not provide the minimum of five years of growth and cannot accommodate any contract or large commercial growth until a Stratford Line reinforcement is completed • The Proposed Project is the most efficient project to provide the market with higher pressures and more robust gas supplies in order to meet the growing demand across the market region The Stratford Reinforcement project was subject to a leave to construct application in EB-2018-0306. In its Decision and Order dated March 28, 2019

	the OEB found that the proposed pipeline was in the public interest. In reaching this decision, the OEB found that "the project is needed to meet increased gas requirements and eliminate pressure-related constraints in the Forest-Hensall-Goderich Transmission System" [9] and found the "estimated cost and project economics acceptable"[10]. The OEB also found that Enbridge Gas adequately addressed environmental issues and land matters, and adequately discharged the duty to consult with impacted Indigenous communities.[11]

1

[9] EB-2018-0306, Decision and Order, March 28, 2019, p.4 [10] *Ibid*, p.5.
[11] *Ibid*, p.7.