BOMA's COMPENDIUM

1. Excerpt from Decision and Order (EB-2017-0024) [pp 1-8].
2. Exhibit JT1.15 plus Attachment [pp 9-10].
3. Exhibit JT3.22 [p 11].
4. Excerpt from Application and Evidence (Exhibit B, Tab 1, Page 26 of 44) [p 12].
5. Excerpt from Application and Evidence (Exhibit B, Tab 1, Attachment 12) [p 13].
6. Excerpt from Technical Conference Transcript, Volume 3 [p 14].
7. IRR (BOMA.29) [pp 15-17].
8. Excerpt from Report of the Board - E.B.O. 195 (Union Gas Limited/Centra Gas Ontario Inc. Amalgamation) [p 18].
9. Charles River Associates Memorandum [pp 19-35].

means, but that Alectra Utilities had made no attempt to do so, and therefore should be expected to live within the IRM envelope.

Alectra Utilities submitted that the project-specific materiality threshold is defined by the OEB as 0.5% of distribution revenue requirement, in accordance with the Chapter 2 Filing Requirements.[30] Alectra Utilities calculated the threshold amount for each rate zone on this basis and included projects that exceeded the identified thresholds.

Findings

The OEB accepts Alectra Utilities' calculations for the ICM materiality threshold based on the OEB's ICM formula in the Funding of Capital Report. This includes:

- Brampton RZ - maximum eligible incremental capital amount of $7,113,613
- PowerStream RZ - maximum eligible incremental capital amount of $25,891,795
- Enersource RZ - maximum eligible incremental capital amount of $39,624,419

This does not mean that all capital spending up to the maximum eligible incremental capital amount will be granted incremental funding. The OEB has established its other criteria and tests so that the ICM does not become just a top-up to the ICM materiality threshold.

The OEB does not agree with SEC that a distributor must have done everything it can to live within its means. The ICM is not a mechanism to ensure the financial viability of a distributor. The ICM is a mechanism that removes a barrier to effective planning by providing rate relief to reduce the incentive to cluster capital investments at sub-optimal times around the rebasing year. A distributor is expected to have good distribution system planning, including optimizing, prioritizing and pacing capital expenditures to control costs and promote rate predictability, irrespective of its rebasing schedule.

The OEB disagrees with Alectra Utilities' interpretation of the second materiality test. The distributor in this ICM application is Alectra Utilities. This second test is whether a specific project is significant in comparison to the overall capital budget for Alectra Utilities, not individual rate zones. With Alectra Utilities' interpretation, a large distributor with a capital budget of hundreds of millions of dollars could acquire a small distributor

[30] Filing Requirements For Electricity Distribution Rate Applications - 2017 Edition for 2018 Rate Applications - Chapter 2 Cost of Service.

and seek ICM funding for a project of only $50,000. This would not be a reasonable request.

The OEB notes that the MAADs policy states that: "the materiality thresholds for purposes of the ICM policy shall be calculated based on the individual distributor's accounts, i.e. depreciation expense, and not the consolidated entity's".[31] The OEB finds that this statement is not relevant to the assessment of project-specific materiality. The reference to depreciation expense in the MAADs policy makes it clear that this policy statement pertains to the ICM materiality threshold formula that is calculated based on depreciation, not the project-specific materiality test that is based on a comparison of an expenditure to the overall capital budget.

Applying the Chapter 2 Filing Requirements materiality threshold test to Alectra Utilities as the distributor would result in a project-specific materiality threshold of $1 million to be applied across all rate zones. However, the OEB finds that the Chapter 2 Filing Requirements materiality threshold test is not the project-specific test set out in the ICM policy. The materiality thresholds in the Chapter 2 Filing Requirements[32] are for the purpose of variance explanations for annual changes to rate base, capital expenditures and operations, maintenance and administration costs as part of a cost of service rate application. Consistent with this purpose, the materiality threshold for the variance analysis is calculated from the revenue requirement. The project-specific materiality, per the ICM policy, is based on the capital budget.

The OEB recognizes that in an Enersource decision,[33] the OEB accepted the project-specific materiality calculated by Enersource based on 0.5% of revenue requirement. This was a project specific calculation of $0.59 million for an ICM approved of $40.5 million. There was no question that this project was not a minor expenditure in comparison to the overall capital budget i.e. the project specific calculation was not required to make the determination that this project was significant. The OEB does not find that the Enersource decision established a new condition precedent for future ICMs.

[31] "Report of the Board Rate-Making Associated with Distributor Consolidation," EB-2014-0138, March 26, 2015, p. 10.
[32] Section 2.0.8.
[33] Decision and Rate Order "Enersource Hydro Mississauga Inc. Application for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2016", EB-2015-0065, April 7, 2016.

In the Funding of Capital Report, the OEB adopted the approach for the ICM policy established in the Toronto Hydro decision which stated that: "minor expenditures in comparison to the overall budget" should not be considered eligible for ICM treatment.[34] The Toronto Hydro decision emphasized that the overall capital budget is the reference point for assessing the significance of ICM requests. The OEB determined that a: "certain degree of project expenditure over and above the threshold calculation is expected to be absorbed within the total capital budget", and this wording was included in the materiality criteria for an ICM. This decision disallowed ICM funding for several projects with capital spending in excess of $1 million, including a project with $2.14 million in capital expenditures and $1.68 million in capital additions. The decision stated that while the OEB accepted the need for the work: "the amount requested is not significant in the context of THESL's overall capital budget. THESL should be able to fund this project through its normal capital budget during the IRM period, and will not be permitted additional recovery for this project".[35]

The OEB finds that the basis for a project-specific materiality threshold should be the proposed capital budget of Alectra Utilities, the distributor in this ICM application. Adding the 2018 capital budgets for each rate zone results in a combined capital budget of $267.7 million.[36] While one could consider a percentage of the $267.7 million to be appropriate for the project-specific materiality test, the OEB finds that this is not consistent with the ICM policy. The ICM policy adopted the approach used in the Toronto Hydro decision, which assessed each project individually for its significance against the capital spending. The OEB therefore adopts this same approach for the ICMs for Alectra Utilities. Amending the ICM policy to include a mathematical materiality calculation for this second test should only be done through a policy review. In addition, there were no submissions on this issue during the proceeding. The OEB has applied its judgement consistent with the ICM policy. The OEB will consider whether each capital project proposed for an ICM is significant with respect to Alectra Utilities' total capital budget, not with respect to the capital budget by rate zone.

While the second materiality test may be further defined in the future, the OEB must make a decision based on the evidence and submissions in this proceeding. The OEB

---

34 Funding of Capital Report, p.17.
35 EB-2012-0064 Toronto Hydro Decision, several projects were not approved for funding for being not significant in the context of the overall capital budget (pages 31, 32, 39, 41, 42), one example is the Downtown Station Load Transfers, pages 41 and 42 with capital spending of $2.14 million and capital additions of $1.68 million.
36 $267.668 million = $72,683 (Enersource) + $109,773 (PowerStream) + $38,069 (Brampton) + $47,143 (Horizon Utilities EB-2014-0002 Settlement Table 18 – 2018 Capital Expenditure Plan).

4.

is guided by the words "significant influence on the operation of the distributor" and "minor expenditure in comparison to the overall capital budget" in assessing the project-specific materiality of each project.

The assessment of each specific project is in subsequent sections of this Decision.

Need

The Funding of Capital Report indicated that need must be demonstrated by (a) passing the Means Test, (b) the amounts must be based on discrete projects, and should be directly related to the claimed driver, and (c) the amounts must be clearly outside of the base upon which the rates were derived.[37]

Under the Means Test, if a distributor's regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, then the funding for any incremental capital project would not be allowed. Alectra Utilities submitted that based on the accounts of its predecessor utilities, it had satisfied the Means Test in each rate zone.

No party took issue with Alectra Utilities passing the Means Test.

Alectra Utilities submitted that each proposed ICM project is discrete and that it had performed detailed, project-specific cost estimates based on a specific scope of work and detailed design carried out for a particular location.

Furthermore, Alectra Utilities stated that the costs of the projects for which it is seeking recovery are incremental to its capital requirements that underpin its existing rates for each rate zone.

The distinction between a discrete project versus a program was raised in many submissions. AMPCO stated that it did not accept Alectra Utilities' distinction between a project and a program as all of the restructured initiatives have historically been part of typical annual capital programs and should not be approved. In particular, AMPCO noted that in the PowerStream RZ, 30% of the projects were disallowed by the OEB in its Custom IR decision.

CCC argued that with very few exceptions (transit projects), the proposed expenditures are essentially a continuation of normal annual capital programs, not discrete

[37] Funding of Capital Report, page 17.

incremental capital projects, and Alectra Utilities should have sufficient funds to undertake all of its required capital investments through its price cap adjustments.

Findings

The OEB finds that Alectra Utilities has passed the Means Test. Alectra Utilities provided evidence with respect to the earnings by rate zone. The OEB finds this is acceptable for assessing the earnings the year prior to merger, i.e. 2016. This test is, however, established to determine if a distributor requires funding in advance of the next rebasing. Earnings are therefore more appropriately assessed for the distributor, not the rate zone.

In addition, the OEB finds that a discrete project is not simply one that is distinguishable or defined at a new location - or all capital would be eligible. ICM projects do need to be different in kind from those that are carried out through typical base capital programs. Otherwise, the OEB would need to scrutinize all capital projects for optimization, not just the ICM projects. Further, the criteria in the ICM policy is clear that capital projects do not need to be non-discretionary[38] or unanticipated to be eligible for incremental funding.

The OEB finds that it is not relevant whether the capital project proposed for ICM treatment was included in a previously filed DSP. Requiring a project to have been included in a previous DSP would be re-introducing the requirement for projects to be unanticipated, which the OEB previously eliminated. In addition, there is no criteria excluding capital projects that were denied funding in a previous cost of service or ICM application. Circumstances may change with respect to load, demand, cost estimates or consumer preferences that affect the business case and the needed timing of the project.

Prudence

The Funding of Capital Report specifies that the amounts to be incurred must be prudent, which means that a distributor's decision to incur the amounts must represent the most cost-effective option (but not necessarily the least initial cost) for ratepayers.[39]

Alectra Utilities submitted that its eligible capital projects are prudent because in the case of the Brampton RZ, the project is non-discretionary in nature, while for the

[38] Funding of Capital Report, pp.18-19.
[39] Ibid, p. 17.

PowerStream and Enersource RZs, the projects represent the most cost effective options for ratepayers.

Alectra Utilities added that in each case, the projects are based on capital investment needs for the three rate zones for 2018 that are not funded through existing distribution rates.

Alectra Utilities submitted that to demonstrate the prudence of each capital project for which it is seeking approval, it had provided a business case summary that identifies the name, driver, cost and expected in-service date for the project, describes the project and its drivers, and sets out the various options considered for the project. In addition, Alectra Utilities stated that it had provided detailed business cases for each eligible capital project.

OEB staff argued that most of the ICM projects were not distinguishable from other expenditures that were part of normal year-to year capital programs for the rate zones.

Intervenors argued that it is not possible to determine prudence in the absence of cost information on alternative options. Alectra Utilities identified that it did provide cost estimates for alternative options for the majority of projects. Cost estimates were not provided for alternative options when the alternative options would not provide the required capabilities or meet applicable technical standards. Alectra Utilities also argued that conservation and demand management (CDM) is not an alternative for system renewal investments.

AMPCO, VECC and CCC submitted that the OEB should not approve the 2018 ICMs until Alectra Utilities has prepared a consolidated DSP. These intervenors submitted that one combined DSP would optimize need and spending across all rate zones to provide the greatest value to customers, for a merged entity with four rate zones.

AMPCO also noted that the PowerStream RZ's 2018 proposed capital budget is below the 2017 OEB approved budget, meaning that it should be able to accommodate the 2018 capital spend within the 2018 Price Cap IR adjustment.

VECC argued that for the PowerStream RZ, Alectra Utilities had not met the burden of proof as to the need for these projects, other than a rapid transit project, because it had not explained how these projects were (or were not) contemplated in its DSP.

Alectra Utilities argued that the OEB was well aware that Alectra Utilities would not be in a position to file a consolidated DSP until 2019. Alectra Utilities concluded that it is simply wrong to say that a consolidated DSP is required before it is eligible for ICM funding.

Findings

The availability of an ICM to Alectra Utilities was neither predicated on filing a consolidated DSP, nor limited to one ICM application for the deferred rebasing period.

While a consolidated DSP is not a prerequisite to filing an ICM, the OEB acknowledges the concerns expressed by intervenors and OEB staff that the value of the current DSPs for Alectra Utilities will diminish long before the 10-year deferral period has ended. The OEB accepts these limitations for 2018, and 2019 rates if required. It would not have been reasonable to expect a new fully integrated and consolidated DSP for this proceeding. The OEB finds that the prior DSPs are sufficient for the OEB to review and decide on capital projects for this proceeding.

The MAADs decision noted that Alectra Utilities would not be in a position to file a consolidated DSP until 2019, applicable to 2020 rates. The OEB finds this proposal reasonable. The OEB requires Alectra Utilities to file a consolidated DSP as a filing requirement with any ICM application requesting rate changes for 2020 rates and beyond.

Providing an assessment of options to meet an identified need is an important element of an application for funding of capital, whether it be in a rebasing application or for an ICM. The OEB accepts that costing and detailed analysis of an option is not required if an option does not meet the required capabilities or applicable technical standards. The OEB does not accept Alectra Utilities' assertion that CDM is not an alternative for system renewal investments options. Like-for-like asset replacements for aging infrastructure should not be the only option considered. Circumstances may have materially changed since an asset was first put into service. As a result, new options, including those that do not involve distribution infrastructure, should be considered when Alectra Utilities prepares its consolidated DSP.

The OEB recognizes that because the ICM materiality threshold formula is based on the ratio between a utility's approved rate base and depreciation, it can lead to circumstances in which there is eligible ICM capital even though the capital spending in the year of the ICM is lower than the last OEB-approved capital spending. While this does not disallow an ICM outright, this is a consideration when determining whether a project is significant to operations, and outside of the base upon which the rates were derived.

b) Eligibility of Individual Projects for ICM Recovery

Alectra Utilities requested total ICM funding of $56.18 million. Alectra Utilities provided the table reproduced as Table 2 below summarizing the proposed ICM projects by rate zone.[40]

The OEB agrees that it is important for a distributor to have programs to address aging infrastructure to ensure assets are replaced on a paced and prioritized schedule. Nevertheless, this application is about whether incremental funding for capital will be provided during the IRM term. ICM funding is not available for typical annual capital programs. It is also not available for projects that are not significant to the operations of the distributor. Where the OEB has not approved a project for incremental funding, this should not be interpreted as the OEB saying that it is not prudent to complete the project.

The OEB assessed each proposed project on an individual basis against the criteria from Section 4.5 a) of this Decision. The OEB approves total ICM funding of $28.79 million as discussed in the individual sections that follow.

[40] Alectra Utilities, "Applicant's Reply Submission", January 30, 2018, pp. 22-23.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Kitchen
To Mr. Brett

REF: Tr.1, p.145

To respond to BOMA 23.

Response:

The attached analysis presents a simple mathematical calculation which discounts both forecasted capital spend and O&M savings during the deferred rebasing period. The discount rate used is 3.5% as requested in the response to BOMA Interrogatory #23(a) found at Exhibit C.BOMA.23.

What this simplistic approach doesn't address is the timing differences between the year of capital spend and the year(s) that the associated O&M benefits are realized. For example, in 2021, the discounted capital spend amount of $48 million will generate O&M savings in 2022 and beyond. The discounted O&M savings in 2021 of $57 million is related to capital spend made in years prior to 2021.

Integration Capital investment and O&M Savings Schedule ($ Millions)

Item	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Capex											
Customer Care		$ 2	$ 22	$ 32	$ 8	$ -	$ -	$ -	$ -	$ -	$ 65
Distribution work management	$ 7	$ 21	$ 21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 50
Shared Services	$ 4	$ 5	$ 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13
Storage & transmission	$ -	$ 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8
Other functions	$ -	$ -	$ 5	$ 5	$ 5	$ -	$ -	$ -	$ -	$ -	$ 14
Sub-Total Costs	**$ 11**	**$ 36**	**$ 53**	**$ 37**	**$ 13**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 150**
Discounted Cash Flow of Costs (at 3.5%)	$ 10	$ 34	$ 48	$ 32	$ 11	$ -	$ -	$ -	$ -	$ -	$ 136
O&M savings											
Customer Care	$ -	$ 15	$ 15	$ 16	$ 16	$ 26	$ 26	$ 26	$ 26	$ 26	$ 192
Distribution work management	$ -	$ -	$ 11	$ 11	$ 11	$ 16	$ 16	$ 16	$ 16	$ 16	$ 113
Shared Services		$ 2	$ 2	$ 3	$ 3	$ 5	$ 5	$ 5	$ 5	$ 5	$ 35
Storage & transmission	$ -	$ 1	$ 3	$ 3	$ 3	$ 4	$ 4	$ 4	$ 4	$ 4	$ 30
Management	$ -	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 180
Other functions						$ 14	$ 14	$ 14	$ 14	$ 14	$ 70
Sub-Total Savings	**$ -**	**$ 38**	**$ 51**	**$ 53**	**$ 53**	**$ 85**	**$ 85**	**$ 85**	**$ 85**	**$ 85**	**$ 620**
Additional unidentified efficiencies	$ 3	$ -	$ 12	$ 17	$ 28	$ -	$ -	$ -	$ -	$ -	$ 60
Sub-Total Savings	**$ 3**	**$ 38**	**$ 63**	**$ 70**	**$ 81**	**$ 85**	**$ 85**	**$ 85**	**$ 85**	**$ 85**	**$ 680**
Discounted Cash Flow of Savings, including efficiencies (at 3.5%)	$ 3	$ 35	$ 57	$ 61	$ 68	$ 69	$ 67	$ 65	$ 62	$ 60	$ 548
Net Discounted Cash Flow (at 3.5%)	$ (7)	$ 1	$ 9	$ 29	$ 57	$ 69	$ 67	$ 65	$ 62	$ 60	$ 412

10

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Culbert
To Mr. Brett

REF: Tr.3 p.175.

To show what the change in revenue requirement would be in the stand-alone scenario.

Response:

The table below shows EGD's revenue requirement standalone excluding the impact of GTA capital cost overrun.

EGD $ Millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Revenue Requirement standalone with GTA overrun	1,300	1,357	1,428	1,473	1,516	1,546	1,592	1,629	1,693	1,738
Revenue requirement impact of GTA overrun	15	15	15	15	15	15	15	14	14	14
Revenue Requirement standalone excluding GTA overrun	1,285	1,342	1,412	1,458	1,501	1,531	1,578	1,615	1,678	1,724

million to deliver potential cost synergies of between $350 million and $750 million over the 10 year deferred rebasing period.

Table 4
High Level Minimum and Maximum Cost and Savings Estimate ($ Millions)

Item	Potential Capital Investment		Potential O&M Savings	
	Minimum	Maximum	Minimum	Maximum
Customer Care	$25	$110	$120	$250
Distribution Work Management	$10	$90	$30	$150
Utility Shared Services	$5	$20	$15	$50
Storage & Transmission	$5	$10	$15	$50
Management Functions & Other	$5	$20	$170	$250
Total	$50	$250	$350	$750

While the groups and functional areas that will generate synergies have been identified, the detailed implementation plans will be developed and implemented following the Board's Decision in the EB-2017-0306 and EB-2017-0307 proceedings. EGD and Union have only recently been able to share and discuss integration opportunities post the closing of the merger transaction between Enbridge and Spectra Energy in February, 2017. As such, it has not been feasible to develop an extensive and detailed integration plan. Many of the synergy opportunities are tied to the ability to align systems processes, procedures, standards and specifications.

Multiple Large Scale Software Implementations

Significant software system costs and implementations will take place over the deferred rebasing period from 2019 to 2028 to support the integration. Large scale system implementations will be planned to allow for staff to be resourced to these projects and to support change management

Capital Investment and High Level Estimated O&M Savings for Utility Integration

Integration Capital investment and O&M Savings Schedule ($ Millions)

Item	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Capex											
Customer Care		$ 2	$ 22	$ 32	$ 8	$ -	$ -	$ -	$ -	$ -	$ 65
Distribution work management	$ 7	$ 21	$ 21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 50
Utility Shared Services	$ 4	$ 5	$ 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13
Storage & transmission	$ -	$ 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8
Other functions	$ -	$ -	$ 5	$ 5	$ 5	$ -	$ -	$ -	$ -	$ -	$ 14
Sub-Total Costs	$ 11	$ 36	$ 53	$ 37	$ 13	$ -	$ -	$ -	$ -	$ -	$ 150
O&M savings											
Customer Care	$ -	$ 15	$ 15	$ 16	$ 16	$ 26	$ 26	$ 26	$ 26	$ 26	$ 192
Distribution work management	$ -	$ -	$ 11	$ 11	$ 11	$ 16	$ 16	$ 16	$ 16	$ 16	$ 113
Utility Shared Services		$ 2	$ 2	$ 3	$ 3	$ 5	$ 5	$ 5	$ 5	$ 5	$ 35
Storage & transmission	$ -	$ 1	$ 3	$ 3	$ 3	$ 4	$ 4	$ 4	$ 4	$ 4	$ 30
Management	$ -	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 180
Other functions						$ 14	$ 14	$ 14	$ 14	$ 14	$ 70
Sub-Total Savings	$ -	$ 38	$ 51	$ 53	$ 53	$ 85	$ 85	$ 85	$ 85	$ 85	$ 620
Additional unidentified efficiencies	$ 3	$ -	$ 12	$ 17	$ 28	$ -	$ -	$ -	$ -	$ -	$ 60
Sub-Total Savings	$ 3	$ 38	$ 63	$ 70	$ 81	$ 85	$ 85	$ 85	$ 85	$ 85	$ 680

MR. KITCHEN: Right. And it has to be economic to serve them.

MR. LADANYI: If I can add, I think it's in the Public Utilities Act.

MR. BRETT: Okay. All right. And that -- all right. So I'd like to ask you is, when you come forward -- and I realize this is -- this is not -- this is a little bit of -- it's not right now that you do this, but when you come forward, will you prioritize your ICM projects? In other words, you will indicate -- to give you an example, in the most recent Electra case that we had, we -- Electra agreed to effectively prioritize their ICM projects from -- let's say they had 40 projects. They prioritize them from 1 to 40. And they also prioritized how those projects fit within the longer list of capital projects, so that we got a feeling for what the overall priority of the -- how -- what the priority of the various ICM projects were in the overall scheme of things; is that something you intend to do?

[Witness panel confers]

MS. THOMPSON: So we would, both EGD and Union, optimize and prioritize the entire portfolio for any given year, and then should we balance to a budget and not be able to address the risks and opportunities identified by each of the companies, then we would have the further consideration where we would put forward a project or program for approval.

MR. BRETT: For the ICM?

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Rate Setting Issues List – Issue No. 1

Reference: *Ibid, p13*

Question:

(a) In calculating the ICM materiality threshold value, please explain why it is appropriate for Union to use a value for rate base from six years ago (2013), given the very rapid growth in Union's gas utility rate base since that time.
(b) The evidence states variously that Amalco "may" or "will" apply for rate adjustments using the ICM during any deferred rebasing period. Please confirm that the correct version is that Amalco will apply for ICMs. Will ICMs be used, or could they be used, to fund the implementation costs listed in Exhibit B, Tab 1, Attachment 12 in EB-2017-0306. Please discuss fully.
(c) Please provide a rate base continuity schedule for Union from 2012 to 2018, inclusive. Please show the relationship of the 2018 rate bases for Union and EGD to the 2019 pro forma rate base shown on Attachment 11 of EB-2017-0306.
(d) Please explain why the Board should not employ the method traditionally used by the Board to calculate the cost of capital for the IRM period as at the time of this application (debt and equity) and not change it simply because Amalco wishes to increase the ICM (deferred rebasing period) from five to ten years. Why should changes to the cost of capital not be a risk of doing business given the Amalco's proposed claim to 100% of the savings over a ten year period? (BOMA assumes the 300 basis point threshold for earnings sharing in years six to ten is unlikely to come into play because of its very large size).
(e) Please confirm that if the Board were to authorize a five-year custom IR for Amalco, Amalco would not be eligible for the ACM/ICM, but would be limited to the capital expenditures forecasted over the plan period.
(f) Please provide the actual ROEs achieved by each of EGD and Union in the years 2012 through 2017, inclusive. Please indicate whether these were actuals, or were "normalized" in any way.

Response

a) Please see the response VECC Interrogatory #29 at Exhibit C.VECC.29.

b) With respect to Amalco's plans to use the ICM, please see response to Board Staff Interrogatory #5 (a) found at Exhibit C.STAFF.5. With respect to costs associated with integration, please see response to Board Staff Interrogatory #24 found at Exhibit C.STAFF.24.

c) Please see Table 1 below.

EB-2017-0306, Exhibit B, Tab 1, Attachment 11, page 3 shows Amalco's pro forma balance sheet, not rate base. The pro forma balance sheet contains certain items not included in rate base, such as unregulated assets and certain other assets and liabilities. Conversely, rate base includes certain items not included on the pro forma balance sheet, such as working capital that is calculated using the Board-approved methodology. Also, the pro forma balance sheet is at a point in time, whereas rate base is an average of monthly averages consistent with Board-approved methodology.

Table 1
2012 – 2018 Union/EGD Rate Base ($millions)

Line No.	Particulars	2012 (1)	2013 (2)	2014 (3)	2015 (4)	2016 (5)	2017 (6)	2018 (7)
1	Rate Base – Union	3,749.1	3,783.9	3,976.8	4,228.4	4,758.4	5,473.6	6,152.8
2	Rate Base – EGD	4,010.6	4,293.2	4,701.3	5,079.8	5,909.0	6,465.2	6,703.2

Notes:
(1) Union's actual rate base figure from EB-2013-0109, Updated Evidence, Exhibit A, Tab 2, Appendix A, Schedule 18. EGD's actual rate base figure from EB-2013-0046, Application and Evidence, Exhibit B, Tab 2, Schedule 1.
(2) Union's actual rate base figure from EB-2014-0145, Revised Evidence, Exhibit A, Tab 2, Appendix A, Schedule 18. EGD's actual rate base figure from EB-2012-0459, Undertaking Response, Exhibit J1.2.
(3) Union's actual rate base figure from EB-2015-0010, Corrected Evidence, Exhibit A, Tab 2, Appendix A, Schedule 18. EGD's actual rate base figure from EB-2015-0122, Application and Evidence, Exhibit B, Tab 2, Schedule 1.
(4) Union's actual rate base figure from EB-2016-0118, Corrected Evidence, Exhibit A, Tab 2, Appendix A, Schedule 18. EGD's actual rate base figure from EB-2016-0142, Application and Evidence, Exhibit B, Tab 2, Schedule 1.
(5) Union's actual rate base figure from EB-2017-0091, Application and Evidence, Exhibit A, Tab 2, Appendix A, Schedule 18. EGD's actual rate base figure from EB-2017-0102, Application and Evidence, Exhibit B, Tab 2, Schedule 1.
(6) Union's 2017 actual rate base figure is expected to be included in the Application and Evidence for EB-2018-0105, but is draft at this time and may change. EGD's 2017 actual rate base figure is expected to be included in the Application and Evidence for EB-2018-0131, but is draft at this time and may change.
(7) Union's 2018 budgeted rate base. EGD's 2018 forecast rate base.

d) Please see response to Board Staff Interrogatory #14 at Exhibit C.STAFF.14.

e) The Applicants have not applied for a 5 year Custom IR mechanism and the information included in the amalgamation application cannot be interpreted as meeting Custom IR application requirements. The OEB's Handbook for Utility Rate Applications specifies that ICM or ACM mechanisms for funding capital are not available for utilities setting rates under Custom IR.

f) Please see response to LPMA Interrogatory #18 at Exhibit C.LPMA.18.

Regulatory Implications

4.1.25 Fundamental changes to two large regulated companies must also be examined with a view to ensuring that the Board will be able to continue to discharge its regulatory mandate. There was no evidence and no party argued that the Board's responsibilities would be compromised as a result of the merger.

4.1.26 The current existence of three major gas utilities in Ontario is valuable to the regulatory process in that comparisons can be made among the utilities. On the other hand, the merged company will become more comparable to Consumers Gas, making comparisons in certain ways more meaningful.

4.1.27 The merger of Centra and Union will reduce the regulatory burden as a result of fewer rates cases and other applications. However, the Board anticipates that rate reviews of the merged company over the next few years will entail some unique complexities, particularly in the areas of cost allocation and rate design. The Board will need to be prepared to examine, in future reviews of the merged utility, possible effects which could not be presently identified.

The Public Interest Generally

4.1.28 As the Board has commented in previous cases, one of the problems in assessing the public interest is that a benefit to one group is often a detriment to another. The Board's role is to weigh all the benefits against all the detriments and decide in the overall public interest.

4.1.29 The Board has had many occasions to consider the public interest as an accommodation of conflicting interests. Some situations were highly contested, others less so. Other than certain future cost allocation and rate issues, what is notable in the present case is the absence of serious conflicting interests.

4.1.30 At the conclusion of the evidence, the Board asked the Companies whether they could provide more concrete assurances to the Board regarding cost allocation and rate matters upon which it could base a positive recommendation to the Government. The

19

CRA Charles River Associates

Memorandum

To: Oliver Borgers, Jonathan Bitran (McCarthy Tétrault)
Cal Goldman, Richard Annan (Goodmans)

From: Margaret Sanderson, John Hayes, Hitesh Makhija

Date: February 8, 2017

Subject: **ENBRIDGE/SPECTRA: SECTION 96 TRADE-OFF ANALYSIS**

Further to your request, this memorandum discusses the application of the Canadian *Competition Act* section 96 efficiencies trade-off provision to the proposed merger of Enbridge Inc. ("Enbridge") and Spectra Energy Corp. ("Spectra" or "Union" when referring to its affiliate) (the "Proposed Transaction").

A number of submissions have been provided to the Competition Bureau ("Bureau") discussing competitive alternatives to the merging firms' merchant storage services at Dawn.[1] While merchant storage services are stand-alone services provided by the merging firms, customers are ultimately interested in acquiring natural gas. For many customers, natural gas can be obtained without the need for storage at Dawn. For example, some customers can choose to buy gas as needed, on a seasonal basis, so that no physical storage capacity is required. This purchasing option explains why the market price of storage tracks the seasonal value of natural gas, as measured by summer-winter spreads. Alternatively, customers can purchase balancing services from pipelines like TransCanada Pipeline or Vector. For customers who want to purchase storage, there are alternatives to the merging firms such as storage outside Ontario in neighbouring U.S. states such as Illinois, Michigan and New York, or storage purchased through marketers. Given the variety of options available for most customers of merchant storage, the Proposed Transaction is unlikely to materially increase prices for merchant storage services at Dawn, so there will be no resulting anticompetitive effects.

If, notwithstanding these submissions, the Bureau is concerned that there are some merchant storage customers at Dawn who do not have adequate access to alternatives and could be subject to a post-merger price increase (such as Ontario power generators), it remains the case that even for these customers there are unlikely to be any material quantifiable anticompetitive effects. First, changes in Ontario's electricity markets are expected to reduce Ontario power generators' need for committed storage at Dawn, such that Ontario power generators will be no

---

1 Including "Analysis of Merchant Natural Gas Storage Competition in Ontario," Michael Sloan, ICF, January 30, 2017 [hereafter referred to as the "ICF Report"], and "Statistical Analysis of Dawn Hub Gas Prices", memorandum from Margaret Sanderson, John Hayes and Hitesh Makhija to Oliver Borgers, Jonathan Bitran (McCarthy Tétrault), Joe Matelis (Sullivan Cromwell), Cal Goldman, Richard Annan (Goodmans), January 31, 2017.

20

different than marketers, traders and LDCs in their lack of need for storage at Dawn. Second, even if Ontario's electricity markets remain as they are today there are unlikely to be any material allocative inefficiencies or deadweight loss associated with any possible price increase to Ontario power generators (assuming this is possible) because the quantity of storage is unlikely to be materially reduced.[2] Under either scenario, modest efficiencies from the Proposed Transaction would very likely offset and outweigh any anticompetitive effects arising from the Proposed Transaction, should the Bureau have concerns about pricing to some customers.

As Mr. Steve Baker discussed at our meeting with the Bureau, if Ontario's electricity markets change in the manner that is expected given the government's desire to: (i) reduce gas-fired generation capacity in order to reduce greenhouse gas emissions; and (ii) increase competition among generators bidding into the power grid, Ontario power generators will have less need for committed storage at Dawn. The changes that are likely to be made to Ontario's electricity market will no longer require power generators to commit to meeting any bid into the power grid if the generator is called upon to supply power to the grid at a given hour. With a more flexible system in place to supply and bid power into the grid, Ontario power generators are expected to be less committed to having merchant storage at Dawn to meet any possible bid requirements. Ontario power generators will then be like marketers, traders, and local distribution companies ("LDCs") in their need for merchant storage, which increases their options beyond Ontario and beyond physical storage.

Under the second scenario that assumes Ontario's electricity markets remain as they are today and assuming that Ontario power generators are committed to using merchant storage at Dawn, the efficient level of storage is likely to be contracted with these customers even if the merged firm could operate as a monopolist supplier of storage at Dawn to these customers (which we do not believe is likely). The reasons for this conclusion are summarized below.

1) There are a limited number of merchant storage customers that may not have adequate access to alternatives to physical storage at Dawn. We understand that the Bureau's concerns are focused on Ontario power generators because they may have sufficiently high deliverability requirements that commit them to using merchant storage at Dawn. There are a total of eight Ontario power generator customers contracting with Enbridge or Union.

---

2 Whenever demand curves slope downward, any increase in price that may result from a merger is associated with a lower quantity demanded, and hence a lower quantity purchased at higher prices. The lower quantity that is purchased at the higher post-merger price generates two allocative inefficiencies, which are referred to as "deadweight loss." First, consumer deadweight loss represents the value of lost consumer surplus due to buyers reducing their purchases in response to the higher price, notwithstanding that buyers were willing to make purchases at pre-merger prices. The consumer deadweight loss is measured as the area under the demand curve that lies between the pre-merger and post-merger price levels and between the pre-merger and post-merger quantities purchased. Second, producer deadweight loss represents the value of lost producer surplus due to buyers reducing their purchases in response to the higher price when producers previously earned a variable margin on the forgone purchases at pre-merger price levels. The producer deadweight loss is measured as the variable margin earned on the pre-merger quantity multiplied by the change in the quantity demanded due to the higher post-merger price.

21

2) Only two of the eight Ontario power generator customers at Dawn have used both Enbridge and Union [redacted][3] With respect to the other five Ontario power generators, the rates that they currently pay are unlikely to be related to competition between Enbridge and Union because (i) many contracts with Union were entered into before Enbridge was a material provider of merchant storage services; and (ii) [redacted]

3) The combination of (1) and (2) means that any potential reduction in quantity demanded due to a post-merger price increase (and hence any resulting deadweight loss) would be restricted to a very limited number of potentially affected customers.

4) If there were to be no change in Ontario's electricity markets, we expect little to no change in the storage quantity demanded by Ontario power generators[4] even if their bargaining position vis-à-vis the merging firms is altered post-merger. Without any change in the quantity demanded, there is no deadweight loss. Various reasons exist for why storage quantities would be unlikely to change if there were to be no change in Ontario's electricity markets.

    a) Storage costs represent a fraction of any affected power generator's costs of natural gas and a smaller fraction of the customer's total costs of operation, which makes demand for storage less responsive to small changes in storage prices (i.e., demand is relatively inelastic).

    b) Storage prices are set through negotiations between the merging firms and Ontario power generators over contracts that include both fixed and quantity-based payments. We expect such bargaining to result in the efficient quantity of storage services being supplied, regardless of the number of supply options available to the customer.[5] To the extent that the Proposed Transaction removes some customers' ability to threaten to shift suppliers from Union to Enbridge, or vice versa, this would only change the negotiation of the fixed price component without affecting the per-unit pricing or contracted quantity of storage.

---

3 Greenfield Energy Centre purchases storage from both Enbridge and Union. Greenfield South Power Corporation purchases storage from Enbridge [redacted]

4 If the Bureau concludes that the customers of concern have few alternatives to merchant storage at Dawn then these customers cannot switch to other storage locations or to using alternatives to storage. For those customers who have access to alternatives to merchant storage at Dawn, their demand for storage at Dawn will be more elastic.

5 If the merging firm and customers do not negotiate the efficient quantity, then they will not have maximized the joint surplus available to them, when they have every incentive to do so. They can bargain over the division of the maximum joint surplus by varying the fixed payment and leaving the per-unit price at a level that induces consumption of the efficient quantity of merchant storage.

22

c) Regulatory incentives limit the merging firms' ability and incentive to reduce the capacity available for merchant storage services at Dawn.

5) In addition to there being limited to no deadweight loss associated with any possible price increase, there is also no socially adverse wealth transfer because Ontario power generators are large corporate entities. Any wealth transfer from these customers to shareholders of the merging firms would not be considered "socially adverse" under the Competition Tribunal's standard adopted in the *Superior Propane Redetermination* case.[6]

6) With no quantifiable anticompetitive effects owing to no deadweight loss and no socially adverse wealth transfer, any efficiencies associated with the Proposed Transaction will satisfy the requirements of the section 96 efficiencies defence under the *Competition Act*.

7) There are cognizable, merger-specific efficiencies associated with the Proposed Transaction, including cost savings from merging the companies' merchant storage lines of business. With respect to Ontario merchant storage, Enbridge estimates that the Proposed Transaction will allow it to eliminate the majority of three of its administrative functions – Sales/Marketing, Contracting and Customer Administration – for its merchant storage line of business without reducing the quantity of merchant storage available or the number of merchant storage customers. There are also very substantial synergies associated with the Proposed Transaction overall.

We elaborate on this summary below.

Limited Pre-Merger Competition between Enbridge and Union

Most natural gas storage at Dawn is used by the parties to supply natural gas to their regulated utilities.[7] There is no competition between Enbridge and Union to provide this storage to their regulated utility customers.[8]

With respect to merchant storage, Union has been the predominant supplier at Dawn since the Ontario Energy Board, in its 2006 NGEIR decision, determined that such services could be provided on an unregulated basis.[9] Union has 79.9 Bcf of merchant gas storage capacity at Dawn. Enbridge remains a small player in the supply of merchant gas storage services at

6 *Commissioner of Competition v. Superior Propane Inc. and ICG Propane Inc.* [2002]. "Reasons and Order Following the Reasons for Judgment of the Federal Court of Appeal Dated April 4, 2001." Competition Tribunal.

7 ICF Report, p. 16. Enbridge informs us that 85 percent of its storage is under regulated rates as part of its use for In-Franchise customers.

8 Merchant storage capacity cannot be physically separated from the storage used for regulated services.

9 Ontario Energy Board Decision with Reasons, EB-2005-0551 Natural Gas Electricity Interface Review (NGEIR Decision), November 7, 2006.

23

Dawn,with only 16.3 Bcf of merchant gas storage capacity. Thus, Enbridge's merchant storage capacity share at Dawn is 17 percent, while Union has the remaining 83 percent.

Reflecting its smaller share of third-party capacity, Enbridge has not bid on many merchant storage contracts. Enbridge's bid database, which includes all contracts on which a customer has solicited a formal RFP from Enbridge, includes only six bids since 2010.[10] In contrast, Union has bid on 34 contracts since 2010.[11]

Very Small Number of Potentially Affected Customers

Focusing on the merchant storage customers in Ontario, which we are informed is the set of customers of potential concern to the Bureau, the ICF Report finds that 21 of 42 customers[12] also hold storage contracts with other storage providers in Michigan, New York, Illinois, or Iowa.[13] These customers appear to have ready access to alternative storage services, so the Proposed Transaction is unlikely to materially increase prices to these customers.[14]

The remaining 21 customers that may only hold storage contracts at Dawn[15] purchased a total of 31.2 Bcf storage capacity from Union and 8.44 Bcf storage capacity from Enbridge, accounting for 36.2 percent of the storage capacity sold by Enbridge and Union (see Exhibit 1). Of these 21 customers, only two [redacted] are included in the Enbridge bid database, [redacted] Customers that have only used Union [redacted] may not experience a change in their competitive options due to the Proposed Transaction (see Exhibit 2).

10 These six bids relate to [redacted]

11 The Union bid data file contains all storage requests received by Union from January 1, 2010 to November 1, 2016 via a formal RFP or other communication method, including email.

12 Exhibit 4-2 of the ICF report lists 43 customers that purchase merchant storage from Union or Enbridge. From this list of 43 customers, we have excluded Centra Gas and Energy Source Natural Gas from our analysis. We understand that Centra Gas is a subsidiary of Union Gas. Enbridge is co-developing a storage pool with Centra. We also understand that Energy Source Natural Gas has not contracted for any merchant storage capacity at Enbridge or Union. Energy Source Natural Gas purchases 0.03 Bcf of excess utility space at Union. Finally, the St. Clair Energy Service purchases market deliverability from Union and is included in our analysis but is not listed in Exhibit 4-2 of the ICF report. We understand that St. Clair Energy Service does not purchase any storage from FERC regulated storage providers.

13 Most of the customers with storage capacity contracted outside Ontario are marketers and traders. We understand that the Bureau has indicated that it does not have competition concerns with respect to marketers and traders. We understand that marketers and traders hold capacity at multiple locations and also hold a very significant share of the pipeline capacity into and out of Ontario. This gives the traders and marketers greater flexibility to serve Ontario markets and to compete against Union and Enbridge.

14 ICF Report, at v.

15 Some of these customers may also hold storage contracts outside Dawn, which ICF was unable to verify.

24

Ontario power generators, which we understand are the only merchant storage customers in Ontario that have a need for higher deliverability, make up a small fraction of Enbridge and Union merchant storage customers. Enbridge has two power generator customers and Union has seven power generator customers[16] (see Exhibits 3A and 3B), for a total of eight unique customers across Enbridge and Union.[17] These customers accounted for only 6.1 percent of Enbridge's merchant storage revenues in 2016 (January – October) and only 15.6 percent of Union's merchant storage revenues in 2016 (January – October),[18] as reported in Exhibit 4. Combined, Ontario power generators represented 14.5 percent of Enbridge and Union merchant storage revenues in 2016 (January – October), amounting to annualized 2016 storage revenues of CAD$16.1 million.[19]

Among the eight unique power generator customers at Dawn, only two have used Enbridge and Union, [redacted][20] These two customers paid a total of CAD$2.3 million for merchant storage to Union and Enbridge in 2016 (January – October), which represents only 2.5 percent of the parties' combined total merchant storage revenues.

In summary, any possible competition concerns with respect to merchant storage prices at Dawn are limited to very few customers and involve very little revenue.

Demand for Storage Is Unlikely to Change with a Change in Price

For any power generator customers requiring storage at Dawn, storage costs represent a fraction of the costs of acquiring natural gas and an even smaller fraction of a customer's overall costs of operation. While we do not have details on customers' operating costs, it is likely that the costs of storage at Dawn are a small fraction of these firms' total costs of operation. It is well understood in economics that the demand for a component that represents a small share of total costs and that is used to produce a highly valuable end product will be relatively inelastic. We expect this to be true for merchant storage. Relatively inelastic demand is generally associated with a smaller deadweight loss, although we note that inelastic demand also allows for larger price increases relative to more elastic demand.

---

16 Union's power generator customers include two customers (St. Clair Energy Service and TransCanada Power) that have no contracted storage capacity but have contracted maximum daily injection and withdrawal capacity.

17 Greenfield Energy Centre purchases storage from both Union and Enbridge.

18 We only have Enbridge and Union merchant storage revenue data for the first 10 months of 2016.

19 January – October 2016 revenues for Union contracts with Ontario power generators were CAD$12.65 million, which is an average of CAD$1.265 million per month. Thus, the annualized amount over 12 months is CAD$15.18 million. According to Enbridge, 2016 revenues from Ontario power generators were CAD$0.873 million. Hence, combined Enbridge and Union 2016 revenues from Ontario power generator were $15.18 million + $0.873 million = CAD$16.1 million.

20 Greenfield Energy Centre purchases storage from both Enbridge and Union. Greenfield South Power Corporation purchases storage from Enbridge [redacted]

25

Negotiated Contract Structure Implies No Quantity Reduction

The structure of the contracts negotiated between the merging parties and their Ontario power generator customers provides another reason why the quantity of merchant storage would not be reduced below the efficient level, even if the merger resulted in a price increase to some customers. The contracts negotiated by providers of storage services and individual customers include both a fixed payment and a variable, or quantity-based, payment. Economists call this type of payment a "non-linear" price or a "two-part tariff." In markets where a small number of buyers and sellers negotiate individualized contracts with two-part tariffs, economists expect the negotiating parties to reach agreements to buy and sell the efficient quantity.[21]

Merchant storage contracts with Ontario power generators provide for maximum storage capacity, as well as maximum daily and hourly injection and withdrawal rates depending on each customer's specific requirements. As such, contracts are highly individualized. Pricing terms have a fixed and variable component. The variable component of Union's contracts with power generator customers has been the same amount since the NGEIR decision and is the same across customers, at CAD 0.7 cents per GJ,[22] while the fixed component of the contract (which Union refers to as the "demand rate") varies across customers and over time.

Only the variable component of the storage costs will influence the quantity of merchant storage demanded by Ontario power generators because the fixed costs are independent of the quantity chosen.[23] Regardless of the number of supply options, a merchant storage seller and its customer will always have the incentive to negotiate payment terms that result in the efficient quantity of storage being consumed because this is the storage quantity that maximizes the joint surplus available for the negotiating parties to share. The division of that surplus can then be adjusted by manipulating the fixed component of the payment. Indeed, as explained above, Union's contracts feature the same, low variable cost of CAD 0.7 cents per GJ, while the fixed components vary across customers and over time. There is no reason to believe the merger would alter that variable cost. Instead, if the Proposed Transaction were to increase the bargaining power of one of the merging parties in negotiations with certain power generators, we would expect the increased bargaining power to result in a higher fixed payment. When this

---

21 An "efficient" outcome is one that involves trade, or a purchase, such that the sum of the customer's consumer surplus and the supplier's producer surplus is maximized. That is, trade is efficient if there is no deadweight loss.

22 Union informs us that the CAD 0.7 cents/GJ is reflective of the fuel charged in Union's MPSS rate schedule and the M12/C1 rate schedules. The variable rate is composed of the commodity rate on the MPSS rate schedule of CAD 0.6 cents/GJ plus CAD 0.1 cents/GJ for dehydration (CAD 0.4 cents/GJ x 90 days average usage / 365 days = CAD 0.7 cents/GJ. The fuel and commodity cost is the same for long-term storage and power generator customers. These costs can be considered a proxy for the marginal cost of existing storage.

23 The fixed component of storage costs will affect the overall profitability of the power generators, but a negotiation should not result in fixed costs so high as to drive a power generator out of business because this would not be in the interest of either the generator or the merging parties, who would lose a valuable customer.

26

happens, the effect of any merger-related price increase is entirely a "transfer" from buyers to sellers with no associated deadweight loss.[24]

Storage prices are negotiated by sophisticated purchasers and suppliers of merchant storage services, so we would expect the parties to be capable of bargaining to reach economically efficient outcomes. Otherwise, they are missing out on potential surplus that they could easily capture by restructuring the contract to have a higher fixed payment and lower variable cost. Storage is a stable technology and Union and Enbridge have been providing service to most of the same customers for some time. Therefore, informational asymmetries that can sometimes prevent the negotiation of efficient quantities are not present in this case. Contracts provide for long-term commitments by both parties to meet the buyer's storage, injection and withdrawal requirements. Contracts are entered into at different times with different customers and have lengthy initial terms.[25] Union's contracts with its power generator customers are 10 or 20 year contracts.[26]

Moreover, even if the merging parties and the power generators were not necessarily negotiating efficient contracts, the Proposed Transaction would be unlikely to impact many Ontario power generator customers because their current contracts were negotiated without competition between Union and Enbridge. Four of Union's seven contracts with Ontario power generators were entered into in 2008 and 2009,[27] before Enbridge was an active supplier of third-party storage at Dawn, and as such the contract terms for these customers are unlikely to have been influenced by Enbridge. Three of Union's Ontario power generator contracts expire in 2022, 2027 and 2028, respectively, and as such these customers would not have the opportunity to use Enbridge as an alternative storage supplier to Union for some time to come.[28] The three Union Ontario power generator contracts with near-term expiry dates generated storage revenues of CAD$5.1 million in 2016 (January – October).[29] This puts an upper bound on the volume of

---

25 Renewal terms may be much shorter than the initial contract length.

26 Union's contracts with Thorold CoGen, Greenfield Energy Centre, Portlands Energy Centre, and York Energy Centre have 10 year terms. Union's contract with Goreway Station Partnership has a 20 year term.

27 Union's contracts with Thorold CoGen, Greenfield Energy Centre and Goreway Station Partnership were entered into in 2008. Union's contract with Portlands Energy Centre was entered into in 2009. Union's contract with York Energy Centre was entered into in 2012.

28 Union's contract with York Energy Centre expires on October 31, 2022, its contract with St. Clair Energy Service' expires on October 31, 2027 and its contract with Goreway Station Partnership expires on October 31, 2028.

29 Union's contract with Greenfield Energy Centre expires on October 31, 2018. Union's contracts with Thorold CoGen and Portlands Energy Centre expire on March 31, 2019.

27

Union customer revenues that could potentially be impacted by the Proposed Transaction. In the case of Enbridge, its two Ontario power generator contracts expire in the next two years.[30]

Non-linear and non-uniform pricing that is established between a sophisticated buyer and a sophisticated seller through a negotiation that covers a lengthy term will be flexible enough to meet a variety of future market conditions and will result in an efficient outcome. There is no reason to believe the current contracts are inefficient despite the fact that most were negotiated without bids from both Union and Enbridge. We fully expect the efficient outcomes following the Proposed Transaction, for these Ontario power generator customers as well as others. In sum, there would be no (or very little) change in the quantity of merchant storage services acquired at Dawn even if the Proposed Transaction alters the bargaining position that Union and Enbridge have with the limited number of customers of concern to the Bureau.[31]

Regulation Limits Incentive and Ability to Remove Storage Capacity

While the OEB has forborne from regulating the rates for merchant storage at Dawn, there remain some regulatory conditions that limit the parties' incentive and ability to reduce the storage capacity that is available in the merchant market. Of particular relevance, the parties are required by the OEB to post operating capacity and contracted capacity publicly.[32] As a result, customers can monitor the removal of storage capacity and can lodge a complaint with the OEB if they are unable to contract because storage has been withdrawn.

No Socially Adverse Anti-Competitive Effects

Ontario power generators, which we understand are the customers of concern to the Bureau, are large corporate entities. As such, any wealth transfer from these customers to the merging firms would not meet the requirements of the Competition Tribunal for a "socially adverse" anticompetitive effect.

Moreover, the magnitude of any wealth transfer from Ontario power generators to the merging firms would be small. As noted above, Enbridge and Union's combined merchant storage revenues from Ontario power generators using Dawn amounted to CAD$16.1 million on an annualized basis for 2016. Not all of these customers – or even any of these customers – are

30 Enbridge's contract with Greenfield Energy expires on March 31 2018 and its contract with Greenfield South expires on August 31 2019.

31 We have also considered the possibility that demand is not perfectly inelastic such that there would be some small change in the quantity of storage purchased by Ontario power generators in the event of a price increase. If we assume a demand elasticity equal to -0.10 or -0.25, and assume variable margins of 50% or 70%, the annual deadweight losses (in consumer and producer surplus) are below the annual expected cost savings (using the midpoint of 2016 and 2017 cost savings) even if prices were to increase by 20% across all Ontario power generator customer revenues of CAD$16.1 million. As we expect that prices would not increase by this amount and would not increase to all Ontario power generator customers, and that demand is likely to be very inelastic (closer to -0.10 than -0.25), the quantifiable anticompetitive effects will certainly be less than the quantifiable efficiencies even if there is some change in the quantity demanded.

32 OEB's Storage and Transportation Access Rule (December 9, 2009), sections 4.1 and 4.2.

28

likely to face higher prices for their storage at Dawn following the Proposed Transaction for the reasons described herein. Even if we assume a 5 percent increase in price across all eight Ontario power generator customers this would result in a transfer of CAD$802,884 from Ontario power generators to the merging firms.

If a 5 percent increase impacted only the three Ontario power generator customers with Union contracts that expire in the next two years, it would result in a transfer of about CAD$304,279 to the merging firms on an annualized basis in 2016.[33] The two Ontario power generator customers with Enbridge contracts that either use Union as well [redacted] generated Enbridge storage revenues of CAD$0.873 million in 2016. A 5 percent increase in price for these customers would result in a transfer of about CAD$43,650 to the merging firms.

Whether one considers just the Ontario power generators with near-term expiring contracts or all Ontario power generators, any transfer associated with a 5 percent increase in price (assuming a price increase of 5 percent is even possible) would be small in magnitude relative to the value of the Proposed Transaction. Furthermore, any such transfers would be payments from one set of large corporate entities – the Ontario power generators – to another – the merging firms. As a result, the transfers would not be considered socially adverse for the reasons discussed herein.

We have also considered the hypothetical possibility that socially adverse consequences could arise if changes in the price of storage were to affect power prices in Ontario.[34] We find that this hypothetical is implausible and should be of no concern to the Bureau. Though gas power generators are marginal suppliers of power during some hours and, therefore, set the market price at some hours of the day, it is highly unlikely that a change in storage costs at Dawn would change the gas power generators' bid prices of power.

As noted above, Ontario power generators' storage contracts have a fixed and variable component. Economic theory predicts that only the variable component of the cost of storage (which would be part of the marginal cost of supplying electricity) would be directly passed through in power generators' offers to sell electricity. Fixed storage charges should not affect power generators' marginal costs or bid prices for electricity.

---

33 The three Union Ontario power generator contracts with near-term expiry dates generated storage revenues of CAD$5.1 million in 2016 (January – October), which is an average of CAD$0.51 million per month. Thus, the annualized amount over 12 months is CAD$6.1 million. A 5% increase in price would be 0.05*$6.1 million, which is CAD$304,279.

34 Our understanding of this issue has benefitted from information provided by Mr. George Vegh of McCarthy Tétrault and Mr. Robert Cary, Senior Consultant to CRA. Mr. Vegh is the head of McCarthy Tétrault's Toronto energy regulation practice. Prior to joining McCarthy Tétrault, Mr. Vegh was General Counsel of the Ontario Energy Board. Mr. Cary has more than 20 years of experience in the electricity industry and has been instrumental in the development and advancement of a number of Canadian provinces' electricity markets. Prior to founding his own consulting practice, Mr. Cary held positions at Westcoast Power, AGRA Monenco, and Darchem Limited.

29

The fixed component of contract terms with power generators is by far the largest cost. For Union, storage revenues from Ontario power generators associated with fixed charges amount to 99 percent of total revenues from these customers. Union's total variable revenues in 2016 (January – October) were only CAD$114,862. Similarly for Enbridge, the fixed component of contract terms with power generators is the largest. Storage revenues from Ontario power generators associated with variable charges amount to 7 percent of Enbridge's 2016 (January – October) revenues from these customers. Enbridge's variable revenues from Ontario power generator contracts in 2016 (January – October) were only CAD$48,333.

To the extent that generators were to incorporate increased variable merchant storage charges into their electricity offers, and that these higher offers were to result in higher electricity market prices when such generators were the marginal suppliers of electricity, the end effect on consumers would be strongly muted, and in any event would not result in materially higher costs of electricity for residential and other small customers. Electricity consumers pay two components of energy generation costs: the energy market price (often referred to as the Hourly Ontario Electricity Price or "HOEP"), which is set by the market; and the Global Adjustment ("GA"), which covers all the costs for payments under long-term supply contracts. The long-term energy supply contracts are all structured so that the net payments are reduced as the HOEP increases, all else equal. Therefore, the combined total of HOEP and GA would be substantively unchanged by the addition of variable storage costs into generator offers. The GA's charge mechanism allocates proportionately more of the GA cost to energy used by small consumers than to that used by large consumers. The net effect of an increase in the HOEP would thus be at worst a small redistribution of total cost from small consumers to large consumers. In the competition trade-off analysis, the only electricity consumers that might be affected are large, enterprise customers and any transfer from such consumers would not be considered to be socially adverse.

Anticipated Cost Savings

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

35 Some expenses have been reclassified between categories for Enbridge between 2016 and 2017.

30

Enbridge Cost Saving Categories, 2016 Costs and 2017 Budget

	2016 Costs (CAD)	2017 Budget (CAD) [no transaction]
All salary and benefits costs	[redacted]	[redacted]
Temporary labour	[redacted]	[redacted]
Computer software, supplies, postage, reproduction services	[redacted]	[redacted]
Legal fees	[redacted]	[redacted]
Travel + conferences (airfare, accommodation, sponsorships)	[redacted]	[redacted]
Internal expense allocations and charges associated with the expenses for merchant storage line of business	[redacted]	[redacted]
Total	[redacted]	[redacted]

In addition to the costs described in the table, there are two other categories of expenditures with potential savings. First, Enbridge had professional consulting services costs of [redacted] in 2016 with a planned 2017 budget of [redacted] At this juncture, Enbridge does not know how much of this category would be saved under the Proposed Transaction. Second, a portion of the regulated business' costs for managing injection and withdrawal are allocated to the merchant storage business based on usage. To the extent that the merger allows the combined entity to optimize its management of injection and withdrawal, these charges would be reduced. The costs for managing injection and withdrawal that were allocated to the merchant storage business were [redacted] in 2016 and are budgeted at [redacted] in 2017.

While the efficiencies that can currently be quantified are modest in totality, they represent [redacted] of Enbridge's 2017 budget for its merchant storage business that would be saved through the Proposed Transaction. Moreover, as noted above, there are no (or extremely limited) quantifiable anticompetitive effects from the Proposed Transaction given the lack of deadweight loss and the lack of any socially adverse wealth transfer.

Exhibit 1

Ontario Storage Customers Purchasing Merchant Storage at Michigan, New York, Illinois, or Iowa

As of January 2017

	Customers		Capacity	
	Count	Share of Total	Amount (Bcf)	Share of Total
Ontario Storage Customers That Don't Purchase Storage at Michigan, New York, Illinois, or Iowa	21	50.0%	39.64	36.2%
Ontario Storage Customers That Also Purchase Storage at Michigan, New York, Illinois, or Iowa	21	50.0%	69.84	63.8%
Enbridge Storage Customers That Don't Purchase Storage at Michigan, New York, Illinois, or Iowa	6	46.2%	8.44	51.7%
Enbridge Storage Customers That Also Purchase Storage at Michigan, New York, Illinois, or Iowa	7	53.8%	7.87	48.3%
Union Gas Storage Customers That Don't Purchase Storage at Michigan, New York, Illinois, or Iowa	19	50.0%	31.2	33.5%
Union Gas Storage Customers That Also Purchase Storage at Michigan, New York, Illinois, or Iowa	19	50.0%	61.97	66.5%

Notes:

[1] Centra and Energy Source Natural Gas have been excluded from this analysis.

[2] St. Clair Energy Service purchases market deliverability from Union and is included in this analysis but is not listed in Exhibit 4-2 of the ICF report.

Sources:

[a] ICF, Analysis of Merchant Natural Gas Storage Competition in Ontario, January 30, 2017, Exhibit 4-2 and supporting worksheets.

[b] Union Gas Data.

Exhibit 2

Enbridge and Union Gas Customers With Storage at Dawn Only

As of January 2017

Customer Name	Union Gas 2016 Revenues ($ CAD)	Enbridge 2016 Revenues ($ CAD)	Used Both EGD & Union In 2016	Uses Union, [redacted]	Uses Enbridge, [redacted]
AltaGas	$2,863,404	$0	No	[redacted]	[redacted]
Exelon Generation	$942,032	$0	No	[redacted]	[redacted]
Freepoint Commodities	$450,433	$0	No	[redacted]	[redacted]
Gaz Metro	$8,377,813	$0	No	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Greenfield Energy Centre LP	[redacted]	$511,699	Yes	[redacted]	[redacted]
Greenfield South Power Corporation	$0	$146,132	No	[redacted]	[redacted]
Iberdrola Energy Services	$0	$4,426,729	No	[redacted]	[redacted]
MIECO INC	$596,545	$0	No	[redacted]	[redacted]
NextEra Energy Power Marketing	$61,358	$0	No	[redacted]	[redacted]
NJR Energy Services Company	$1,322,951	$0	No	[redacted]	[redacted]
Noble Americas Gas & Power Corp.	$771,697	$0	No	[redacted]	[redacted]
Petrochina International	$1,074,291	$952,040	Yes	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Powerex Corp.	$5,528,679	$0	No	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
St. Lawrence Gas	$286,649	$262,035	Yes	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TransCanada Power	$897,600	$0	No	[redacted]	[redacted]
Utilities Kingston	$209,669	$85,618	Yes	[redacted]	[redacted]
York Energy Centre LP	$1,977,043	$0	No	[redacted]	[redacted]

Notes:

[1] Enbridge customer revenue converted from US Dollars to Canadian Dollars using data on average montly exchange rates published by Bank of Canada.
[2] Uniong Gas 2016 revenues and Enbridge 2016 revenues refer to the January - October 2016 time period.

Sources:

[a] ICF, Analysis of Merchant Natural Gas Storage Competition in Ontario, January 30, 2017, Exhibit 4-2.
[b] Union Gas Data.
[c] Enbridge Data.

Exhibit 3A

Enbridge Merchant Storage Contracts With Ontario Power Generators

As of January 2017

Customer Name	Contracted Storage Capacity (Bcf)	Contracted Peak Deliverability (Mcf)	Contract Start Date	Contract End Date
Greenfield Energy Centre	0.12	11,999	1-Jun-08	31-Mar-18
Greenfield South Power Corp.	0.15	15,571	1-Apr-16	31-Aug-19

Source:
[a] ICF, Analysis of Merchant Natural Gas Storage Competition in Ontario, January 30, 2017, Exhibit 1-6.

Exhibit 3B

Union Gas Merchant Storage Contracts With Ontario Power Generators

As of January 2017

Customer Name	Contracted Storage Capacity (Bcf)	Contracted Peak Deliverability (Mcf)	Contract Start Date	Contract End Date
Goreway Station Partnership	0.57	121,321	1-Jul-08	31-Oct-28
Greenfield Energy Centre	0.20	40,000	1-May-08	31-Oct-18
Portlands Energy Centre	0.47	37,913	1-Jan-09	31-Mar-19
St. Clair Energy Service	0.00	26,092	1-Jan-13	31-Oct-27
Thorold CoGen	0.16	41,704	1-Nov-08	31-Mar-19
TransCanada Power	0.00	33,264	1-Oct-14	14-Jan-20
York Energy Centre	0.17	83,080	1-Apr-12	31-Oct-22

Note:

[1] St. Clair Energy Service purchases market deliverability from Union and is included in this analysis but is not listed in Exhibit 1-6 of the ICF report.

Sources:

[a] ICF, Analysis of Merchant Natural Gas Storage Competition in Ontario, January 30, 2017, Exhibit 1-6.
[b] Union Gas Data.

Exhibit 4

Share of Enbridge and Union Gas Storage Revenue Associated with Ontario Power Generators

January 2016 - October 2016

Company	Revenues (Thousands of CAD) Power Generators [a]	All Customers [b]	Share of Revenue Associated With Power Generators [c]=[a]/[b]
Enbridge	$ 658	$ 10,842	6.1%
Union Gas	$ 12,654	$ 81,062	15.6%
Total	***$ 13,312***	***$ 91,904***	***14.5%***

Note:

[1] Enbridge customer revenue converted from US Dollars to Canadian Dollars using data on average montly exchange rates published by Bank of Canada.

Sources:

[a] ICF, Analysis of Merchant Natural Gas Storage Competition in Ontario, January 30, 2017, Exhibit 1-6.
[b] Union Gas Data.
[c] Enbridge Data.