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April 23, 2019

Delivered by Courier, Email & RESS

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

Dear Ms. Walli:

Re: Energy+ Inc.
2019 Rate Application (EB-2018-0028)
Energy+ Inc.'s Reply Submissions

Please find enclosed Energy + Inc.'s Reply Submissions in this proceeding. Paper copies of this letter and the accompanying Reply Submissions will be delivered to you by courier.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Per:

Original signed by John A. D. Vellone

John A.D. Vellone

cc: Intervenors of record in EB-2018-0028

EB-2018-0028

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

AND IN THE MATTER OF an Application by Energy+ Inc. under Section 78 of the Act for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2019.

REPLY SUBMISSIONS OF ENERGY+ INC.

April 23, 2019

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A. INTRODUCTION

1. On April 30, 2018, Energy+ Inc. ("**Energy+**") filed an Application, as amended, under Section 78 of the *Ontario Energy Board Act, 1998* (the "**Act**") seeking an order of the Ontario Energy Board (the "**OEB**" or "**Board**") approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2019 (the "**Application**"). The Board assigned file number EB-2018-0028 to the Application.

2. On March 15, 2019, Energy+ filed its written argument-in-chief in respect of the Application (the "**AIC**"). Capitalized terms used in this reply but not otherwise defined herein have the meaning ascribed to those terms in the AIC.

3. Energy+ is pleased to submit this written reply to the written submissions of OEB Staff, CCC, Hydro One, SEC, TMMC and VECC received March 29, 2019, the reply submissions of OEB Staff, Hydro One, SEC, TMMC and VECC received April 5, 2019, and the reply submissions of CCC received April 8, 2019.

4. This reply is organized in the same manner as the AIC:

   A. Introduction
   B. The Southworks ACM Request (Issue 1.1)
   C. Cost Allocation (Issue 3.2)
   D. Rate Design (Issues 3.3 & 3.4)
   E. RTSR & LV Rates, including gross load billing of RTSR (Issues 3.5 & 3.6)
   F. Standby (Issue 3.7)
   G. Group 2 DVAs (Issue 4.2)
   H. Load Forecast (Issue 3.1)

5. As of the date of filing the AIC, Energy+ had not yet received a copy of the TMMC responses to undertakings that arose during the oral hearing. On March 18, 2019, TMMC filed its responses to oral hearing undertakings. To the extent the additional information is relevant to the matters raised in submissions, Energy+ will address this additional information in this reply.

B. THE SOUTHWORKS ADVANCED CAPITAL MODULE REQUEST (ISSUE 1.1)

1.1 Is the level of planned capital expenditures appropriate and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to:

- *customer feedback and preferences*
- *productivity*
- *benchmarking of costs*
- *reliability and service quality*
- *impact on distribution rates*
- *trade-offs with OM&A spending*
- *government-mandated obligations*
- *the objectives of the Applicant and its customers*
- *the distribution system plan, and*
- *the business plan.*

6. OEB Staff agreed that the Board should approve Energy+'s request for Advanced Capital Module ("**ACM**") approval for a proposed $8.1 million capital expenditure in 2022 to complete the proposed renovations at a proposed administrative building located in the former downtown Galt known as the "**Southworks**" facility.[1]

7. SEC, VECC and CCC disagreed. HONI and TMMC took no position on this issue.

8. Energy+ will address the submissions of each of the parties with respect to each of the ACM criteria:

    - discrete,
    - material,
    - need; and
    - prudence.

B.1 Discrete

"The Board is of the view that projects proposed for incremental capital funding during the IR term must be discrete projects, and not part of typical annual capital programs."[2]

9. No party argued that the proposed Southworks facility failed to meet the discrete criteria. Energy+ submits that the Board should find that Southworks is a discrete project that is not part of the typical Energy+ annual capital program.

B.2 Material

"*The amounts must exceed the Board-defined materiality threshold and clearly have a*

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[1] OEB Staff Submissions dated March 29, 2019 at pg. 10.
[2] See the Original Report at Section 4.1.1.

significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing."[3]

10. No party suggested that the proposed capital expenditure of $8.1 million for the Southworks facility failed to meet the materiality criteria. Each of VECC,[4] SEC,[5] and OEB Staff[6] agreed with Energy+ that the materiality criteria is satisfied.

11. OEB Staff confirmed that it had no concerns with Energy+'s calculation of the materiality threshold and agreed that the $8.1 million capital expenditure falls within the eligible incremental capital envelope available to Energy+.[7]

12. Energy+ submits that the Board should find that the proposed $8.1 million investment in the Southworks facility is above the materiality threshold and is therefore eligible for ACM funding.

B.3 Need

13. Both OEB Staff[8] and SEC[9] agreed that Energy+ has produced sufficient evidence to demonstrate that the Southworks facility is needed.

14. The need for the Southworks facility is detailed in the Energy+ Facilities Business Plan,[10] which was updated in an evidence update[11] on December 13, 2018 to reflect the best available information including a recently completed Class C estimate for the work (collectively, the "**Facilities Plan**").

15. VECC, on the other hand, makes two arguments that challenge the need of the Southworks facility.

16. First, VECC argues that the Energy+ Facilities Plan is "unusual" in that it will separate

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[3] Ibid at Section 4.1.5.
[4] VECC Submissions dated March 29, 2019 at para. 2.1.
[5] SEC Submissions dated March 29, 2019 at para. 6.
[6] OEB Staff Submissions dated March 29, 2019 at pg. 5-6.
[7] Ibid.
[8] OEB Staff Submissions dated March 29, 2019 at pg. 7.
[9] SEC Submissions dated March 29, 2019 at para. 6.
[10] Exhibit 2, Appendix 2-1 – Distribution System Plan, Appendix N: Facilities Business Plan.
[11] Energy+ Update to the Evidence filed December 13, 2018.

administrative functions from operations.[12]

17. Energy+ does not agree. VECC acknowledges this arrangement is not unusual for utilities with multiple service areas,[13] but VECC fails to recognize that with the acquisition of Brant County Power Inc. ("**BCPI**") in 2014 this is now exactly the situation Energy+ finds itself in. VECC also fails to recognize that separating administrative and operational functions was **by-far** the most cost-effective facilities solution that Energy+ was able to identify after spending 5 years exploring alternatives.[14] VECC also fails to recognize the other advantages of this approach identified by both Ms. Hughes and Mr. Miles in testimony.

18. Specifically, Ms. Hughes explained that "*there are groupings of administrative that deal on a more regular basis with one another, certainly in the finance area dealing with regulatory, as well as customer care, billing, regulatory matters.*" [15] Ms. Hughes went on to explain how consolidating these different administrative functions into a single facility will lead to increased efficiencies and decrease administrative waste.

19. Finally, Mr. Miles explained that "*the other aspect of this that was attractive to us we felt that this strategy kind of future proofed us, in the sense that by separating our administrative group from our engineering and operations, we have some flexibility to grow within that space in the future if we need to. But with respect to what may happen in the -- other the next 60 years with respect to mergers and amalgamations, we felt it was preferable to have an asset like this that could be sold or leased out in the event that it was no longer required in the future versus building a special purpose, you know, combined operation and administrative centre, which is more difficult to market if we had to do something in the future.*" [16]

20. Second, VECC argues that the Facilities Plan is "unusual" in that it will result in a 50% increase in administrative space but only an 8% increase in operations space, resulting in

[12] VECC Submissions dated March 29, 2019 at para. 2.3.
[13] Ibid.
[14] See AIC at Table 1.
[15] Transcript Vol. 1 dated March 7, 2019 at pg. 42, lines 7-12.
[16] Transcript Vol. 1 dated March 7, 2019 at pg. 35, lines 15-28.

88,247 sq. ft. in total operations and administrative space.[17] VECC goes on to argue that "there is no clear evidence" why Energy+ needs the new office space.[18]

21. Energy+ does not agree. VECC fails to acknowledge that the space needs analysis conducted in 2013-2014 for the former CND recommended that 102,762 sq. ft. for administrative and operations space was needed at that time.[19] This was before Energy+ acquired BCPI, and the additional staff that came with that acquisition.

22. Energy+'s Facilities Plan, in this context, is modest. Energy+'s plan will result in combined facilities that will increase the existing 72,630 sq. ft. to 88,247 sq. ft. (i.e. only 86% of 102,762 sq. ft.) to accommodate the needs of **both** the former CND and BCPI.

23. Moving BCPI administrative employees into a single location with CND staff was required to accommodate the substantial OM&A efficiencies arising directly from the consolidation of previously separate administrative functions. In addition, and as explained by Ms. Hughes in the quote above, consolidating administrative employees from Thompson Drive and Bishop Street into a single building is also required to drive further efficiencies.

24. Unfortunately, and as shown in the Facilities Plan, the existing Bishop Street Building is too small to accommodate this historical growth in employees, including the addition of BCPI employees, which has resulted in workstations being built without access to natural light, in hallways, closets, vaults and meeting rooms.[20] In addition, expanding the existing Bishop Street Building proved to be cost prohibitive due in large part to the restrictions imposed by the neighboring wetland and the requirement to build "up" (add a third floor) rather than "out".

25. Energy+ submits the evidence in the Facilities Plan clearly demonstrates that the Southworks facility is needed. In addition, there is nothing "unusual" about what Energy+ is proposing. The proposed Southworks ACM is the result of a lengthy five (5) year

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[17] VECC Submissions dated March 29, 2019 at para. 2.4 – 2.5.
[18] Ibid. at para. 2.24.
[19] Facilities Plan at Section 3, page 1087 of 1497.
[20] Transcript Vol. 1 dated March 7, 2019 at pg. 13, lines 13-18. See also Facilities Plan filed April 30, 2018 at pages 1034-1035.

process exploring a wide range of different facilities options, as detailed in the Facilities Plan, before arriving on a solution that is right sized to meet Energy+s specific needs with a low cost solution for customers.

B.4 Prudence

26. OEB Staff agrees with Energy+ that the proposed Southworks facility meets the Board's prudence test.

27. In arriving at this conclusion, OEB Staff examined the evidence of Energy+'s five (5) year-long comprehensive options analysis. OEB Staff also examined Energy+ management's efforts to benchmark its plan against known comparators to ensure the prudence of its facilities plan. In reviewing this evidence, OEB Staff noted that:

    a. Energy+'s planned-for space is not excessive as it results in the lowest square foot per FTE;[21]

    b. The aggregate cost of $164.32 per sq. ft. to complete all three facilities (Southworks, Bishop Street, and Garden Ave) is the second lowest among all comparators;[22]

    c. The cost of $370 per sq. ft. to complete Southworks will, by its very nature as administrative space, be more expensive on a cost per sq. ft. basis than the costs to build combined operations and administrative space;[23] and

    d. The cost of $370 per sq. ft. to complete Southworks is comparable to other similar investments that have been approved by the OEB.[24]

28. To support its conclusion that the costs to complete Southworks are comparable to other similar investments that have been approved by the OEB, OEB Staff cite publicly available information from the OEB's prior approval of a 2008 Powerstream administrative

[21] OEB Staff Submissions dated March 29, 2019 at pg. 9.
[22] Ibid.
[23] Ibid. at pg. 10.
[24] Ibid.

building[25] and a 2012 Enersource administrative building.[26] Energy+ would like to thank OEB Staff for ensuring that this additional benchmarking evidence is available for the Board panel's consideration.

29. Energy+ agrees with OEB Staff's reservation on the use of these comparators, in particular the fact that they do not account for the presence of inflation in the construction sector since 2008 or 2012.[27] Energy+ expressed a similar reservation about its own comparators in its AIC.[28]

B.4.1 The challenge with focusing on a cost per square foot benchmark without also factoring in inflationary cost increases and utilization (i.e. square foot per FTE)

30. Each of SEC[29] and CCC[30] express concerns over the forecasted cost of $370/sq. ft. for the Southworks facility when compared to the benchmarks on the evidentiary record.

31. Neither party acknowledges that administrative space is more expensive on a cost per sq. ft. basis than the costs to build combined operations and administrative space, even though OEB Staff clearly acknowledges this truth.[31]

32. In reply submissions, SEC comments on the OEB staff's new administrative building comparators but fails to account for known inflationary cost increases when comparing the Southworks cost per sq. ft. directly with Powerstream and Enersource projects.[32] SEC chooses not to account for inflation in its cost comparisons, despite the fact that its cost comparison spans across over a decade.

33. By contrast, the OEB's IRM inflationary measures over this same period of time is shown below:

[25] EB-2008-0244, Exhibit B1, Tab 5, Schedule 1 (page 2) and Schedule 3 (page 12 of 18).
[26] EB-2012-0033, Decision and Order, December 13, 2012, pp. 13-18.
[27] OEB Staff Submissions dated March 29, 2019 at pg. 10.
[28] Energy+ Argument-in-Chief dated March 15, 2019 at para. 43.
[29] SEC Submissions dated March 29, 2019 at para. 13-14.
[30] CCC Submissions dated March 29, 2019 at pg. 4.
[31] OEB Staff Submissions dated March 29, 2019 at pg. 10.
[32] SEC Reply Submissions dated April 5, 2019 at para. 2.

Year	IRM Inflation Factor
2017	1.50%
2016	1.20%
2015	1.90%
2014	2.10%
2013	1.60%
2012	1.70%
2011	1.60%
2010	2.00%
2009	1.30%
2008	1.30%

34. There is also another reservation which the Board panel should consider when using the cost per sq. ft. comparison.

35. This reservation is particularly relevant to both the Enersource (EB-2012-0033) and Milton Hydro (EB-2015-0089) comparators, which both have very low capital costs per square foot ($228/sq. ft. and $136.33/sq. ft. respectively). It is easier to achieve a low cost per square foot if one acquires a larger (potentially oversized) building. Despite these incredibly low per square foot costs, in both final decisions the OEB found that the utilities had been imprudent in large part because the buildings were viewed as being too large compared to need.

36. Effective utilization of space matters. In these cases, Enersource's administrative building was designed to 527 sq. ft. per FTE and Milton Hydro's combined operations and administrative building was designed to 1,494 sq. ft. per FTE.

37. In contrast, Energy+'s planned-for space of 327 sq. ft. per FTE in administrative space at Southworks, and 674 sq. ft. per FTE of combined operations and administration space overall, is the <u>lowest</u> among any of the comparators.

38. Energy+ management focused on ensuring its facilities solution was right sized to meet its needs, and in so doing minimizing costs to customers. This ability to right size the administrative space to match Energy+'s needs was a unique feature of the Southworks arrangement that made this option particularly attractive to management.

39. This is why, when assessed on a cost per FTE basis (which accounts for both utilization

and per square foot costs) the proposed Southworks facility cost of $120,896 per FTE compares favorably to both the Powerstream ($110,800 per FTE) and Enersource ($120,000 per FTE) benchmarks – even before taking into account any inflationary cost increases since 2008 and 2012.

B.4.2 The Board now has the benefit of the best available information when making its decision on this ACM request.

40. Each of SEC,[33] VEC[34] and CCC[35] expressed concerns over a 62% increase in Energy+'s original ACM proposal of $5.0 million filed with the original Facilities Plan on April 30, 2018, which was based on a Class D estimate based on a high-level conceptual design that was prepared before the property was acquired and before any due diligence was completed.[36]

41. Energy+ filed its revised ACM proposal of $8.1 million with its evidence update on December 13, 2018.[37]

42. Energy+ took steps to ensure the parties had adequate opportunity to conduct discovery to explore the reasons for this change in cost at the technical conference and again at the oral hearing. In general, the drivers for the changes in costs are tabulated in response to SEC-TCQ-2 and are explained as follows:

   a. Due diligence on the existing building and site has now been completed, the condition of building is known,[38] the work required to make the building fit for use is known,[39] and the costs for that work is now much more accurate.[40]

   b. Environmental due diligence has been completed, a copy of the Record of Site Condition is filed on the evidentiary record,[41] the environmental mitigation solution

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[33] SEC Submissions dated March 29, 2019 at para. 10.
[34] VECC Submissions dated March 29, 2019 at para. 2.7.
[35] CCC Submissions dated March 29, 2019 at pg. 3.
[36] Transcript Vol. 1 dated March 7, 2019 at pg. 73, lines 11-15.
[37] Energy+ Update to the Evidence filed December 13, 2018.
[38] Transcript Vol. 1 dated March 7, 2019 at pg. 73, lines 21-24.
[39] SEC Interrogatories to Applicant SEC-TCQ-2, Appendix SEC-2 – Design Brief dated January 14, 2019.
[40] SEC Interrogatories to Applicant SEC-TCQ-1.
[41] VECC Interrogatories to Applicant VECC-TCQ-63 (c).

(a vapor management system in the floor) is known and specified,[42] and the costs for this solution are now much more accurate.[43]

c. The 30% design has been completed and filed on the evidentiary record,[44] and the costs estimates are now based on a Class C estimate which is much more accurate.[45] In addition, Energy+ ensured that additional costs such as the new firewall (which is complete and the costs are known),[46] furniture, building permit fees, and professional fees were properly accounted for in the ACM request.[47]

43. In short, the evidence update filed by Energy+ on December 20, 2018 ensured the Board panel had the benefit of the most up-to-date and accurate information available to support the Southworks ACM request.

44. As is detailed in the AIC, even with the updated cost forecast, the proposed Southworks facility at $8.1 million is still **by-far** the most cost efficient option as against any of the other options that were assessed.

45. This was explained by Mr. Miles in testimony:

> "*We believe that the 8.1 is fairly certain at this stage. As I mentioned earlier, a lot of the uncertainty has now been cleared up with respect to the environmental, the condition of the base building, even the construction of the firewall which has already occurred, and we know exactly what it cost.*
>
> *So the certainty has been improving quite a bit.*"[48]

46. Energy+'s budget also includes a contingency of $400,000.[49]

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[42] SEC Interrogatories to Applicant SEC-TCQ-2, Appendix SEC-2 – Design Brief dated January 14, 2019, at Appendix C – Risk Management Summary.
[43] SEC Interrogatories to Applicant SEC-TCQ-1 filed January 22, 2019.
[44] SEC Interrogatories to Applicant SEC-TCQ-2, Appendix SEC-2 – Design Brief dated January 14, 2019.
[45] Ibid. at Appendix H - Class C Cost Estimate.
[46] Transcript Vol. 1 dated March 7, 2019 at pg. 95 lines 24-26.
[47] SEC Interrogatories to Applicant SEC-TCQ-1.
[48] Transcript Vol. 1 at pg. 59 at lines 10-16.
[49] Transcript Vol 1 at pg. 65 at lines 16-19.

47. To the extent there is a risk of cost overruns over and above this contingency, Mr. Miles explained that Energy+ intends to make decisions around the final fit and finish of the materials used to stay within the $8.1 million budget.[50]

48. Finally, to the extent the Board continues to be concerned about residual uncertainty in the updated Southworks cost forecasts, those concerns have been anticipated and addressed directly in the Board's ACM policy.

49. Energy+ agrees with OEB Staff submissions[51] that distributors (including Energy+) are obligated to explain and justify any changes in project costs when they apply to the OEB for approval of actual costs and the establishment of rate riders during the subsequent Price Cap IR term. Specifically:

> "*In particular, if costs are 30% (or more) above what was documented in the DSP, the distributor has the option of seeking approval for the incremental costs but would typically treat the project as a new ICM and re-file the business cases and other relevant material in the applicable IR year. It is expected that the Board will include this condition as part of the ACM approval. This would provide the applicant and parties an opportunity to argue for a different (higher or lower) percentage depending on the nature of the project.*
>
> *If costs are less than 30% above what was documented in the DSP, the distributor should still explain the need for the increased costs, whether and how re-prioritizing of capital projects has been considered, how impacts on the rates and bills of the distributor's customers have been taken into account and finally, whether the project is still the best option. Any changes in project scope must be clearly explained and justified.*" [52]

B.4.3 The Facilities Plan evidence is clear, Southworks was by-far the best option available to meet Energy+'s facility needs.

[50] Ibid at lines 16-19.
[51] OEB Staff Submissions dated March 29, 2019 at pg. 10-11.
[52] The ACM Reports at page 12.

50. Each of SEC,[53] VECC,[54] and CCC[55] also express concerns that Energy+ did not produce an analysis that the proposed Southworks facility was the "best option for a dedicated administrative facility".

51. This is perhaps unsurprising. The increase in costs to $8.1 million filed as part of the December evidence update likely surprised the parties. And a natural reaction to that surprise is to second guess the decision making that led to the conclusion that the Southworks facility was the preferred option to begin with.

52. In particular, each of SEC, VECC and CCC cited concern over the lack of a direct comparison of leasing an administrative space as against the Southworks project on the evidentiary record.

53. The challenge is that the parties' submissions fail to account for or simply ignore the multi-year year process over which Energy+ conducted a detailed analysis of six (6) different facilities options. This was explained at a high level in Energy+'s AIC,[56] and is supported by the Facilities Business Plan, which includes 474 pages of analysis on the evidentiary record.

54. Specifically, the evidence demonstrates that:

> "*CBRE was engaged as a commercial broker to assist in the search for suitable sites. Over 50 potential sites were explored. Many were eliminated due to either site specific issues or a very high cost per acre. No offers to purchase land were made.*"[57]

55. The June 2015 CBRE *Market Overview* identified potential sites in Cambridge is included on the evidentiary record attached to the Facilities Plan as Appendix D.[58] Detailed costing information from the Market Overview was later filed on the public record on September

[53] SEC Submissions dated March 29, 2019 at para. 11.
[54] VECC Submissions dated March 29, 2019 at para. 2.23.
[55] CCC Submissions dated March 20, 2019 at pg. 4.
[56] Energy+ Argument-In-Chief at paras 29 – 45.
[57] Exhibit 2, Appendix 2-1 – Distribution System Plan, Appendix N – Facilities Business Plan at pg. 1027-1028 of 1497.
[58] Ibid. at page 1419 of 1497.

21, 2018 (the "**Market Overview**").[59] This was filed following the Board's September 14, 2018 decision on certain confidentiality requests, where the OEB noted that the cost information is publically available on CBRE's website.[60]

56. As detailed in the Facilities Plan under Options 3, 4 and 5 – the CBRE Market Overview did not identify any existing buildings that could be adapted for an operations centre (since sites generally had a small office and a large space for manufacturing or warehousing), the costs to purchase land was found to be significant (in the range of $300,000 to $400,000 per acre), and the costs associated with constructing a new building was also significant (on the order of $31-33 million). [61]

57. However, the Market Overview did identify three sites that were available for lease in the Cambridge area that could be compared to Southworks. This was noted by Mr. Miles during testimony: "*It was one of the scenarios that we looked at back in, I think, in 2015 or 2016. We did look at a few buildings that were available for lease.*"[62]

58. First, 320 Pinebush Road is a 21,000 sq. ft. facility that was available for lease for $16.97 gross rent.[63] This would result in an incremental OM&A leasing costs of $356,370 per year ($16.97 * 21,000).

59. Second, "485 Pinebush Road" is a 17,000 sq. ft. facility that was available for lease for $21.45 gross rent.[64] At 17,000 square feet, this facility was noted as being too small to meet Energy+'s needs (which continues to be true even when considering Energy+'s administrative only office space requirements of 21,000 sq. ft.). In any event, the incremental OM&A cost to lease 485 Pinebush is $364,650 per year (17,000 * $21.45) – which is more expensive than 320 Pinebush Road.

60. Third, "73 Water Street" is a 35,000 square foot facility that is available for lease for $20.83

[59] http://www.rds.oeb.ca/HPECMWebDrawer/Record/620649/File/document
[60] Board's Decision on Confidentiality Request dated September 14, 2018 at pg. 5.
[61] Ibid. at page 1039 of 1497.
[62] Transcript Vol. 1 dated March 7, 2019 at pg. 48, lines 7-9.
[63] Market Overview at pg. 1 of 3.
[64] Ibid.

gross rent.[65] This facility is admittedly larger than what Energy+ management believe it needs, and results in an incremental OM&A cost to lease of $729,050 per year ($20.83 * 35,000) – which again is more expensive than 320 Pinebush Road.

61. Energy+ concluded based on this market information that the costs of leasing an administrative space was, from a revenue requirement perspective, more expensive than the costs of ownership. This is because each of these facilities also required expensive leasehold improvements to make the space suitable to meet Energy+'s needs prior to moving in.

62. This was the state of the evidence as of the date that Energy+ filed its Application on April 30, 2018. As more fully detailed in the Facilities Plan and the AIC, Southworks was <u>**by-far**</u> the most prudent option when compared to all of the other alternatives assessed by Energy+ <u>at that time</u>.

B.4.4 The impact of the increase in costs to $8.1 million on the previous Facilities Plan prudence analysis.

63. Energy+ submits that the evidence is clear that it had made a prudent decision to proceed with the Southworks facility as the most cost-effective alternative, and that this decision was made <u>**before**</u> Energy+ filed its Application with the Board on April 30, 2018.

64. The disagreement in this case relates to how to the Board should address a factual circumstance where the options analysis was completed (as detailed in the Facilities Plan), a prudent decision was made, and based on those decisions Energy+ signed contracts[66] and incurred substantial fees ($232,000 as of December 31, 2018)[67] to complete additional site due diligence and a 30% design brief.

65. This additional work effort resulted in an increase in cost certainty but it also resulted in an increase in estimated costs from $5.0 million to $8.1 million.

66. Energy+ submits that when considering this disagreement, it is important to keep in mind

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[65] Ibid.
[66] Appendix 2-Staff-12(c)(i) – (iv).
[67] Interrogatory Response from Energy+ - Staff-TCQ-1(b) filed January 22, 2019.

the Board's traditional prudence test, as most recently articulated by the Supreme Court of Canada in *Ontario (Energy Board) v. Ontario Power Generation:*[68]

a. Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.

b. To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.

c. Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.

d. Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.

67. The evidence is clear that Energy+'s decision to proceed with the Southworks facility was prudent at the time the decision was made. It was **<u>by-far</u>** the most cost effective facilities option available after a 5 year long exhaustive search of alternatives.

68. In this context, Energy+ submits that hindsight should not be used in determining prudence. Rather, prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with <u>the time the decision was made</u>.

69. The prudence assessment must be based on facts about the element that could or did enter into decisions <u>at the time the decision was made</u>.

70. Not proceeding with Southworks is not, at this stage, an option. Comparisons to leases or other alternatives outside of what was already considered in the Facilities Plan are largely academic.

[68] Ontario (Energy Board) v. Ontario Power Generation at para. 99.

71. Energy+ is already contractually committed to the Southworks project.[69] In its submissions, CCC argues that Energy+ is not contractually committed to the Southworks project.[70] CCC has, unfortunately, misinterpreted the evidence. Mr. Miles' testimony was that the only reason there wasn't, at the time of the oral hearing, a binding commitment is because the contract <u>had not yet closed</u>.[71]

72. The evidence filed as part of the Evidence Update on December 13, 2018 was that the contract was already signed and was subject to just two <u>conditions of closing</u>: (i) approved severance application from the City of Cambridge; and (ii) environmental due diligence including peer review of approved Record of Site Condition.[72] These are not subjective closing conditions which give rise to a discretionary right to terminate the contract prior to closing. To the contrary, they are objective conditions which Energy+ has an obligation to assess in good faith (all contracting parties have a common law duty to discharge their contractual obligations in good faith).

73. As previously noted, environmental due diligence has now been completed, a copy of the Record of Site Condition is filed on the evidentiary record,[73] the environmental mitigation solution (a vapor management system in the floor) is known and specified,[74] and the costs for this solution are now much more accurate.[75] The peer review was completed in the latter part of March and the proposed mitigation solution was confirmed. In Energy+'s view, this condition has been satisfied.

74. In addition, and as was explained by Mr. Miles, as of the date of the oral hearing the severance application was still outstanding and was anticipated to be completed during the month of April 2019.[76]

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[69] The executed Real Property Purchase Agreement, and subsequent amendments, was filed on September 14, 2018 in the IRRs as Appendix 2-Staff-12(c)(i) – (iv).
[70] CCC Submissions dated March 29, 2019 at pg. 4.
[71] Transcript Vol. 1 at pg. 59 line 23.
[72] Energy+ Update to Evidence filed December 13, 2018 at pg. 7-8.
[73] Interrogatory Response from Energy+ - VECC-TCQ-63 (c) filed January 22, 2019.
[74] SEC-TCQ-2, Appendix SEC-2 – Design Brief dated January 14, 2019, at Appendix C – Risk Management Summary.
[75] Interrogatory Response from Energy+ - SEC-TCQ-1 filed January 22, 2019.
[76] Transcript Vol. 1 dated March 7, 2019 at pg. 36, lines 10-12.

75. In this context, the principle area of disagreement between Energy+ and each of VECC, SEC and CCC appears to be to what extent the Facilities Plan analysis must be re-done in light of the updated costs for Southworks of $8.1 million.

76. It is somewhat surprising that none of VECC, SEC or CCC bothered to ask Energy+ to file an updated comparison of the known market lease costs that are available on the evidentiary record, as discussed above, as against the updated $8.1 million Southworks costs either in written discovery,[77] during the technical conference,[78] or during the oral hearing.[79] One would've expected that they would simply ask for this analysis to be done if they thought it would be relevant to the Board.

77. This is what Mr. Miles was addressing at the oral hearing when he said:

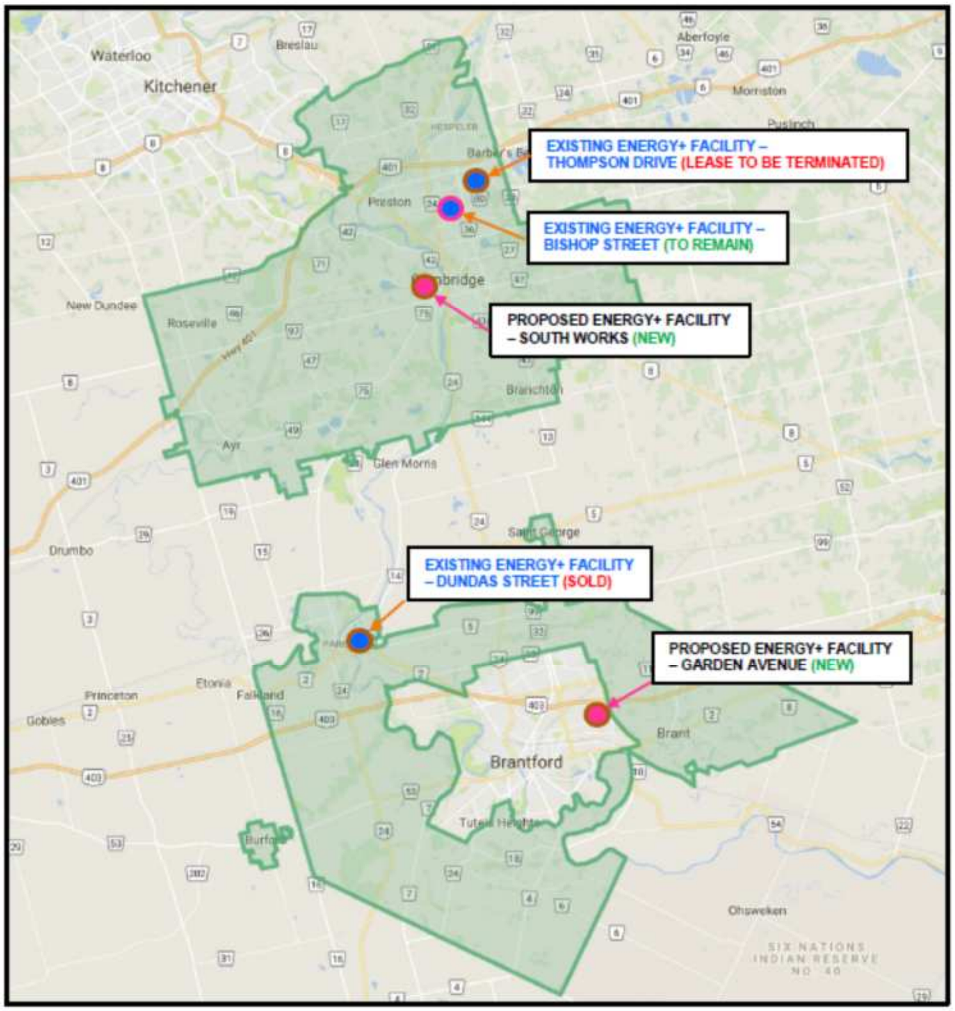
"*We did not do it **after we choose this as a viable option**, and a couple reasons.*"[80]

78. Mr. Miles went on to explain his rationale. The first reason is implicit in the quote above – the decision had already been made. Energy+ is already committed to proceed with Southworks.

79. Second, "we like the location of this facility […]".[81] The administrative offices in Galt (Southern Cambridge) is much closer to Energy+'s Brant service area and is central to both the CND and Brant service areas. This is shown in Figure 2 included in the Energy+ Facilities Plan and reproduced again below for ease of reference.

[77] In accordance with Procedural Order No. 7, parties were required to file their questions in advance of the technical conference – by January 16, 2019.
[78] Technical Conference Transcript dated January 28, 2019.
[79] Oral Hearing Transcript Vol. 1 and Vol. 2 dated March 7 and 8, 2019.
[80] Oral Hearing Transcript Vol. 1 dated March 7, 2019 at pg. 49, line 22.
[81] Oral Hearing Transcript Vol. 1 dated March 7, 2019 at pg. 49 at line 28.

Figure 2: Location of Buildings



80. Third, and consistent with a utility that has already made a decision and thus is assessing prudence on a going forward basis, Energy+ plans to carefully control its Southworks costs closely by tendering out the entire project with the exception of approximately $400,000 for construction management services, to ensure a prudent market price for the project.[82]

81. Energy+ submits that it would not be appropriate to reject the ACM simply because the options analysis used by management at the time its made its decision to proceed with Southworks used a $5.1 million cost for Southworks, rather than an updated $8.1 million Southworks forecast that was not known at the time the options analysis was completed.

82. As explained by the Supreme Court of Canada, an analysis of prudence must be assessed

[82] Ibid at pg. 50, lines 1-5.

at the time a decision was made.

83. Energy+ notes that consideration of the outcome of its decisions may legitimately be used to overcome the presumption of prudence.

84. Energy+ updated its Facilities Plan with the $8.1 million estimate in its December 2018 evidence update, using the exact same comparisons and analysis to show that the Southworks facility, even at $8.1 million, continues to be by-far the most cost effective of any of the alternatives explored.

B.4.5 Energy+ should not be obligated to file an ICM Application for Southworks, which would be inefficient and would not result in a better decision.

85. It is noteworthy that both SEC and CCC were careful to qualify their critiques of the Southworks ACM:

> "[…] *With that said, there is no evidence that the project is necessarily imprudent, and due to the need for some solution to its administrative space needs, Energy+ should be allowed to apply again once it has undertaken an appropriate verifiable assessment that the Southworks option is the most appropriate.* […]"[83]

and

> "*The Council is not making an argument that at the end of the day the Southworks Project should not necessarily proceed. The Council is not making an argument that this project could not under certain circumstances qualify for ACM treatment, which is a regulatory instrument approved by the OEB.* […]"[84]

86. Neither SEC nor CCC state outright that the proposed Southworks project is imprudent. Rather, and similar to VECC, they ask the Board to reject the ACM request and suggest that Energy+ should instead file additional evidence in a subsequent ICM Application.

87. Energy+ does not agree with these suggestions.

88. What these submissions ignore is that, as detailed above, the market based evidence on all available options (including leasing and purchase options) is already readily available on the evidentiary record and must be assessed on the merits <u>at the time the decision was</u>

[83] SEC Submissions dated March 29, 2019 at para. 16.
[84] CCC Submissions dated March 29, 2019 at pg. 4.

made.

89. Any new information added in an ICM Application (such a new comparison of leasing costs against the updated $8.1 million cost) would, by its very nature, constitute an improper hindsight review of a prior management decision.

90. In this context, Energy+ submits that rejecting its ACM request for Southworks simply because Energy+ could later file the same project again as an ICM would greatly undermine the regulatory efficiency that the ACM policy framework was expressly intended to facilitate.

91. Specifically:

> *"The ACM approach should also facilitate regulatory efficiency by placing the requirement to establish the need and prudence for any additional incremental capital spending within a cost of service proceeding. This is well suited to such forms of review and when the five-year DSP is tested.*
>
> *[...]*
>
> *The ACM approach will also assist in large part to preserve the regulatory efficiency of IR applications, as many qualifying capital projects should be identifiable through the DSP. More importantly, it provides greater assurance of recovery for prudent and appropriately prioritized capital projects regardless of when the investments might be made."*[85]

B.4.6 Energy+'s Contractual Relations with Melloul Blamey Construction

92. Both CCC[86] and SEC[87] also cite concerns over Energy+'s contractor – Melloul Blamey Construction – noting that the planned $400,000 in construction management work will not be the subject of a net new tender.

93. This concern fails to recognize that Energy+ has been working closely with Melloul-Blamey to assess its facilities needs since 2013.[88] A review of the Facilities Plan shows that Melloul-Blamey Construction helped Energy+ with its assessment of various different

[85] ACM Report at Section 4, pages 11-12.
[86] CCC Submissions dated March 29, 2019 at pg. 4.
[87] SEC Submissions dated March 29, 2019 at para. 15.
[88] Exhibit 2, Appendix 2-B: Distribution System Plan, Appendix-N: Facilities Plan at pg. 1037 of 1497.

options at every stage of the analysis conducted over the last five years. Through this work, the firm developed a deep understanding of Energy+'s needs and preferences. In addition, and as noted in the Facilities Plan, Energy+ originally selected Melloul-Blamey because they had been in the construction trade for over thirty years and they had relevant industry experience (they were the contractor for the Energy+ Bishop St. facility, as well as Waterloo North Hydro service centre).[89] Finally, and as noted by Mr. Miles during the oral hearing, the firm is also working on the balance of the Southworks development,[90] which helps with coordination across the larger construction site.

B.4.7 Conclusions

94. In conclusion, Energy+ submits that the evidence clearly demonstrates that its proposed Southworks facility was the prudent choice at the time the decision was made. It was only decided on after Energy+ completed a five (5) year-long comprehensive options analysis. In addition, the Southworks facility compares well against all known benchmarks on all relevenat measures.

C. COST ALLOCATION (ISSUE 3.2)

3.2 Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios appropriate?

95. In general, the parties are divided on TMMC's proposals as it relates to both: (i) directly allocating certain costs to the Large User rate class; and (ii) creating a separate rate class for TMMC as distinct from the other Large User.

96. Energy+ will address the submissions of the parties as they relate to direct allocation under this Issue 3.2. Energy+ will address the submissions of the parties with regards to creating a separate rate class for TMMC under Issue 3.3 below.

C.1 Direct Allocation to the Large User Class

97. HONI took no position with regards to the direct allocation of cost associated with TMMC.

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[89] Ibid. see footnote number 1 on pg. 1037 of 1497.
[90] Oral Hearing Transcript Vol. 1 dated March 7, 2019 at pg. 58 lines 1-7.

98. The good news is that each of the parties[91] that did take a position on the issue of direct allocation to TMMC, agree with Energy+ that the costs of the M24 and M30 feeders and the associated capital contribution of TMMC should be directly allocated to the class.[92]

99. This is where the agreement among the parties ends.

C.1.1 Meter Costs

100. Energy+, VECC (supported by CCC) and SEC all agree that cost associated with meters should not be directly allocated to the Large Use class. TMMC is the only party in the proceeding that proposes meter costs should be directly allocated to the rate class which includes TMMC. OEB Staff did not address the issue of meter costs directly.

101. With regards to meter costs Energy+ agrees specifically with the position of VECC that meter costs should not be directly allocated to TMMC.

> "*First, they are not a "significant" distribution facility. Second, there is nothing unique about TMMC having dedicated meters. All customers have dedicated meters. Finally, as with all customers, TMMC's meter costs are not recorded in a separate account or sub-account. In order to identify the costs, Energy+ had to make reference to the related work order to determine the costs. In theory there is no reason why a similar exercise could not be undertaken for other customers/customer classes. However, VECC is not proposing that this be done.*" [93]

102. The cost allocation model addresses the fact that different customers use different types of meters with different costs. There are three types of meter costs assumed in the cost allocation model. These include meter capital (account 1860), operating costs associated with the meters account (5065) and meter reading costs (account 5310). With regards to meter capital and operating costs associated with meters, these cost are allocated to each rate class based on the number of meters in each class which are weighted by the

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[91] VECC (supported by CCC), SEC, OEB Staff and TMMC.
[92] Energy+ Argument-in-Chief dated March 14, 2019 at Paragraph 60.
[93] VECC Final Argument dated March 29, 2019 at Paragraph 3.23

installation cost of the type of meters in the class.

103. In the case of meter reading costs these costs are allocated to each rate class based the number of meters in each class which are weighted by the relative cost of reading each type of meter. The relative cost is based on the cost of reading a meter as compared to the cost of reading a meter for the Residential class. In the case of Energy+ there are only two type of meter reads. A smart meter and an interval meter read. The smart meter read applies to the Residential class. An interval meter read cost 9 times that of the residential smart meter read. As a result, the interval meter reads have been weighted with a factor of 9 and the smart meter with a factor of 1.

104. Energy+ has provided the above details on meter costs to illustrate that the cost allocation model represents an *"appropriate balance between cost causality and the need for a consistent approach for all customers that is practical and workable."*[94]

105. It is Energy+'s submission that the need to directly allocate TMMC meter costs to the class which includes TMMC is not warranted.

C.1.2 O&M Costs

106. Energy+, and SEC agree that no O&M costs should be directly allocated to the Large Use class. OEB staff and VECC do not explicitly make submissions with regards to the direct allocation of OM&A. However, VECC does refer to the alleged high margin for error in the O&M cost estimate. TMMC is the only party in the proceeding that proposes O&M costs should be directly allocated to the rate class which includes TMMC.

107. In the case of O&M Expenses, TMMC states the following:[95]

> *It is ironic that parties oppose the direct assignment of O&M expenses. On average, Energy+'s total OM&A Expense ($18,210,648) comprises 10% of Energy+ Gross Fixed Assets ($182,594,277). In contrast, Energy+ attributes O&M expenses of $93,115 to the dedicated TMMC feeders, or 33.9% of their Gross Fixed Asset value*

[94] VECC Submission dated March 29, 2019, Paragraph 3.24
[95] TMMC's Reply Argument dated April 5, 2019, Page 5 of 13, Paragraph 8

of $274,493. In other words, a direct assignment of O&M costs would result in a potential over-contribution by TMMC of over 200% ($93,115 ÷ ($274,493 x 10%) -1).

108. This TMMC analysis compares O&M expense to Gross Fixed Assets. Energy+ submits that such a comparison is misleading since the actual value of the Gross Fixed Assets has very little correlation to O&M expenses for TMMC. TMMC has produced no evidence that its analysis represents a valid correlation in this or any other proceeding.

109. The following table[96] outlines the justification of the $93,115 reference above.

TMMC - Directly Allocated O&M				
	Hours	**Rate**		**Cost**
Overhead Maintenance				
Labour	1,500	44.49	$	66,735
Vehicles	375	39.00	$	14,625
Total Overhead Maintenance			$	81,360
Tree Trimming			$	6,900
Control Room Services	73	66.29	$	4,855
Total Operations Expenses			$	93,115

110. Regarding overhead maintenance, in the 2019 Test Year Energy+ will be completing a project that will require Energy+ to work on the circuit poles that are used by TMMC. Energy+ has historically performed maintenance activities on weekends in order to avoid any potential risk and/or impact to TMMC's operations during its peak production hours. Energy+ has not undertaken a detailed study to determine the exact number of maintenance hours that would be completed on the poles and/or other elements of the distribution system that are within TMMC's proximity on an annual basis. The 1,500 hours represents the estimated premium hours only to complete the work that has been identified for the 2019 Test Year (i.e. only the overtime component of the estimated hours). There may be other specific operations and maintenance activities that have not been specifically identified at this time.

111. The number of vehicle hours (375) is based on the estimated number of labour hours (1500)

[96] Excel Spreadsheet filed as 2019 EnergyPlus TMMC Direct Allocation_20190122, Tab O&M

divided by 4, assuming one large truck for every 4 powerline technicians. In addition to the above, Energy+ received the following information from its head of operations: Working on TMMC circuit poles after Hours – Energy+ generally schedules any work on the supply lines for Sundays when TMMC is not in production. This may occur 4 or 5 times per year.

112. In the case of tree trimming costs, Energy+ only completes trimming on the circuits supplying TMMC during their shutdown each year in July. On average Energy+ completes the work with 1.5 crews for an annual cost of $6,900 per year. Since TMMC is one of Energy+'s customers most sensitive to outages, Energy+ works on the lines each year during TMMC's shutdown to ensure that faster tree growth is trimmed back to eliminate any outages. Over the four years tree trimming cycle, the cost to trim the poles related to the TMMC feeders is 4 x $6,900 = $27,600.

113. Energy+ notes that the total value of Control Room services estimated for TMMC is $4,855. This represents approximately 0.58% of the total 2019 Control Room budget of $828,000. The Control Room Services hours of 73 (0.35% of a total of 20,800 total hours for the Control Room) represents an estimate of time spent by the Control Room Operators to co-ordinate maintenance, as well as for various services provided to TMMC identified by our Control Room staff.

114. The above was provided in Energy+'s response to TCQ TMMC IR-2. It has been included to support the position that O&M is not related to the value of Gross Fixed Assets. It has also been included to support Energy+'s position that estimated of O&M cost associated with the dedicated feeders has a fairly high margin for error due to the fact that there was no detailed time study completed to create these estimates.

115. Based on the discussion above, Energy+ submits that the estimated O&M expenses for the dedicated should not be directly allocated to the Large User class.

C.1.3 Underground conduit and bulk facilities

116. Energy+, OEB Staff, CCC, SEC and VECC agree that costs such as underground conduit and bulk facilities costs should be allocated to the Large Use class on a pooled basis

consistent with the design of the cost allocation model. Bulk facilities costs are related to the cost associated with the transformer station owned by Energy+. TMMC is the only party in the proceeding that proposes these costs should not be allocated to the rate class that includes TMMC.

117. With regards to underground conduit, OEB Staff, CCC, SEC and VECC all support Energy+'s position that, if the costs of the dedicated feeders are directly allocated, then TMMC should be allocated a share of the cost of the underground conduit but not the underground conductor. TMMC is the only party advocating that, in such circumstances, it be exempt from the allocation of underground conduit costs since they are not using these facilities.

118. Energy+ would specifically agree with OEB staff:

> *"With respect to underground conduit, OEB staff is of the view that the use of overhead poles and underground conduit serve the same role in the system, i.e. to hold conductor, the selection of which is dictated only based on whether the conductor is overhead or underground, and that is largely out of the control of the customer. Both of these assets are typically allocated to all customers on the basis of their usage. OEB staff submits that both poles and underground conduit be allocated to the Large Use rate class on the combined requirements of both Large Use customers"*[97]

119. The TMMC approach assumes that cost causality is based on an asset usage basis but as outlined by VECC[98] the OEB's policy on cost allocation reflects a pooling approach to cost causality. Energy+ agrees with the pooling approach to cost allocation since to do otherwise would mean it would be unfair the allocate cost to each customer unless the assets used by each customer was known.

120. It is almost impossible to determine the assets used by each customer. As a result, the only fair and reasonable approach to allocate the underground conduit on a pooled basis.

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[97] OEB Staff Submission dated March 29, 2019, Page 20.
[98] VECC Submission dated March 29, 2019, Paragraph 3.11

121. Regarding bulk facilities all parties, except TMMC, submit the Large Use class should be allocated a share of the pooled costs of bulk facilities. It is TMMC position that the Large Use class should not be allocated any costs associated with bulk investments since the Large Use customers do not use the transformer station owned by Energy+.

122. Energy+ again disagrees with the TMMC's position. All Energy+ customers are served either by Energy+ owned transformer stations and funded through distribution rates or Hydro One owned transformers stations funded through the Retail Transmission Service Rates ("**RTSRs**"). These rates assume transformer station costs are allocated to all customers based on the total load of all customers, regardless of which transformer station serves them.

123. In TMMC's reply argument it states[99]:

> *"RTSR-related issues, including the basis on which they are passed through to customers and the costs that they recover from customers, are complex issues that have not been well-litigated, if at all, in this proceeding."*

124. Nothing could be further from the truth.

125. The issue of RTSR have been an active issue in this proceeding since the very beginning. Issue 3.5 - Retail Transmission Service Rates and LV Rates and issue 3.6 Gross load billing for Retail Transmission Rates for customers who have load are two distinct issues in this Application that are directly related to the RTSR and have been fully and properly addressed or 'litigated' in this proceeding.

126. In fact the issue of RTSR was discussed with TMMC many times as part of the customer engagement exercise before the Application was filed.[100]

127. In addition, RTSR-related charges are well understood. They are largely matters of law. Energy+ cited the OEB's approved Uniform Transmission Rates tariff at paragraphs 73-75 of its AIC. TMMC could also have referred to IESO Market Manual 5.5, where at Section

[99] TMMC's Reply Argument dated April 5, 2019, Paragraph 25,
[100] Energy+ Inc., EB-2018-0028, Exhibit 1 Page 1116 to 1134, dated April 30, 2018

1.6.6 the IESO specifies how it settles transmission service charges for embedded generation.

128. It appears that TMMC does not want to pay for the cost of the transformer station owned by Energy+ **and** they also do not want their RTSR charges adjusted to reflect that they are using it but other Energy+ customers are not. They suggest that the basis for not making such an adjustment is that the RTSR related issues are "complex issues" that have not been well ligated, if at all, in this proceeding. This simply is not the case.

129. For TMMC to not consider the impact on RTSRs when they suggested the distribution rate for TMMC should not include the cost of transformer station owned by Energy+ is inconsistent with their asset usage approach to cost causality discussed above. As a result, Energy+ submits the proposal to not allocate the costs of the transformer stations owned by Energy+ to the Large Use customers is unfair and unreasonable and should be rejected.

C.1.4 Demand allocators

130. Finally with regards to the issue of demand allocators, TMMC does not agree with the adjustment made by Energy+ to demand allocation factors (12CP and 4NCP) used in the cost allocation model to reflect the contract capacity standby service.

131. In order to support the TMMC position on demand allocators TMMC states in their submission:[101]

> *Finally, grossing up the LU class 12 CP and 12NCP loads ignores Board policy and directions with respect to cost allocations to the LDG classification:*
>
> > *The total costs to be allocated to the LDG classification will consist of costs associated with providing distribution service to the base load that is the same as a standard distribution customer, along with the distribution costs required to support the incremental load when the load displacement generator is not operating.*[102]
>
> *In other words, the first step in the cost allocation process is to determine a proper cost-based rate for providing base or Supplementary distribution service to the class, irrespective of the impact of LDG. Energy+ skipped this step when it grossed up the LU*

[101] TMMC Submission dated March 29, 2019, Page 12 of 36, Paragraph 32.
[102] EB-2005-0317, Cost Allocation Review, Board Directions on Cost Allocation Methodology for Electricity Distributors at 23 (Sept. 29, 2006) ("**Board Cost Allocation Direction**") at page 92.

class demand allocation factors.

132. Energy+ submits that the quoted section in the preceding paragraph does support the adjustment made by TMCC to the demand allocators for the contract capacity standby service.

133. Energy+ started with the base load allocators which would allocate costs associated with providing distribution service for the base load and then adjusted the base load allocators to reflect the impact of the standby service to allocate distribution costs required to support the incremental load when the load displacement generator is not operating.

134. TMMC is suggesting that the standby service should only reflect those cost associated when the standby service is actually required or when there is an outage. It should not reflect the cost of having the facilities "standby" for the time when they are not actually used.

135. It is Energy+'s submission that the impact of the proposed contract capacity standby service should reflect the fact that the "standby" facilities needs to be in place whether they are used or not. To not make this adjustment to the demand allocators would not allocate the proper cost to the class that is requesting the standby service. As a result the TMMC proposal on demand allocators should be rejected.

136. Finally, VECC suggested that, if the Board decides to create two Large Use classes, then it should also direct Energy+ to adjust the 4NCP demand allocation factors used in the cost allocation methodology to account for this loss in diversity[103] Energy+ agrees with this position by VECC.

C.2 Embedded Distributor Cost Allocation

137. On March 4, 2019 the Board issued a decision on direct allocation for embedded distributors for this proceeding, stating:

> "In these circumstances, the OEB finds that consideration of the adoption of a proposed alternative embedded distributor cost allocation methodology is out of

[103] VECC Submission dated March 29, 2019, Paragraph 3.31

scope in this proceeding. However, the OEB requests that parties provide in their final submissions their recommendations as to the consideration and possible adjudication of this issue by the OEB on a going forward basis."

138. In both VECC and SEC's submission they noted that the current 2019 Filing Guidelines do not require the use of Appendix 2-Q if the host distributor has established a separate embedded distributor customer class[104] [105], and cited several recently approved rate applications where Appendix 2-Q was not used for embedded distributor cost allocation.[106] [107]

139. VECC submitted that in lieu of "adjudication" on this issue, the Board should reinforce in future Filing Guidelines the practice of allocating costs to embedded distributors using the Board's cost allocation model.[108]

140. SEC submitted that the Board should have a consistent treatment of the allocation of costs to embedded distributors on a going forward basis. SEC noted that if the Board's decision on scope in this proceeding was a signal that it is considering changing its policy regarding the cost allocation of embedded distributors, then it should undertake a policy consultation so that there is consistency in approach across distributors.[109]

141. OEB staff submitted that this matter can best be considered at the time of the OEB's next cost allocation policy review. They also noted that the current cost allocation methodology and model have the capability and adaptability to implement reasonable allocation proposals for embedded distributors.[110]

142. Energy+ agrees with OEB Staff's view that the Board's current cost allocation methodology and model allow for flexibility in how distributor's implement their proposals for embedded distributors. This flexibility enabled Energy+'s proposal to incorporate the

[104] VECC Submission dated March 29, 2019, paragraph 3.53
[105] SEC Submission dated March 29, 2019, paragraph 66
[106] VECC Submission dated March 29, 2019, paragraph 3.52
[107] SEC Submission dated March 29, 2019, paragraph 67
[108] VECC Submission dated March 29, 2019, paragraph 3.54
[109] SEC Submission dated March 29, 2019, paragraph 68
[110] OEB Staff Supplementary Submission dated April 5, 2019, page 3

results of Appendix 2-Q in the cost allocation model. Energy+ does not dispute that Appendix 2-Q is not required if separate embedded distributor customer classes have been established per the 2019 Filing Guidelines. However, the 2019 Filing Guidelines do not preclude the use of the appendix for purposes of cost allocation to embedded distributors.

143. Energy+ is aware of the broader policy implications that may arise from the inconsistent approaches to cost allocation by host distributors and are in support of a policy review on a generic basis.

D. RATE DESIGN, INCLUDING RESIDENTIAL RATE DESIGN (ISSUES 3.3 & 3.4)

3.3 Are the applicant's proposals for rate design appropriate, including the proposal for distribution rate harmonization?

3.4 Has the applicant appropriately applied the OEB's policy on residential rate design?

D.1 Rate Harmonization

144. VECC[111] and CCC[112] agree that Energy+'s proposal for rate harmonization is appropriate. None of the other parties took objection to the rate harmonization proposal.

145. Energy+ submits that the Board should approve Energy+'s proposal for rate harmonization, including Distribution Service Charges, Specific Service Charges, Retail Service Charges, and Loss Adjustment Factors.

D.2 Residential Rate Design

146. OEB Staff[113], VECC[114] and CCC[115] support Energy+'s mitigation proposal to defer the transition to a fully fixed monthly service charge for the Residential class by one additional year to reduce the total bill impacts to less than 10%.

147. None of the other parties took objection to Energy+'s mitigation proposal.

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[111] VECC Submission dated March 29, 2019, page 27.
[112] CCC Submission dated March 29, 2019, page 2 and page 5.
[113] OEB Staff Submission dated March 29, 2019, page 24.
[114] VECC Submission dated March 29, 2019, page 27.
[115] CCC Submission dated March 29, 2019, page 2 and page 5.

148. Energy+ submits that the Board should approve Energy+'s mitigation proposal to defer the transition to a fully fixed monthly service charge for the Residential class by one additional year to reduce the total bill impacts to less than 10%.

D.3 Large Use Class Rate Design

D.3.5 One Large Use Class vs. Two Large Use Class

149. OEB Staff supports Energy+s proposal for one Large User class. SEC states that it does not take a strong view on the issue. VECC observed that there is a case for two Large Use classes if the costs related to the two feeders are directly allocated, but otherwise there is not.[116]

150. TMMC has proposed two Large User classes, with TMMC as a separate Large Use customer class.

151. Energy+ currently has only two Large Use customers in the Large Use class, which is currently designed for customers with monthly demand > 5,000 kW. TMMC's proposal would result in Energy+ having two separate Large Use classes, with only one customer in each class.

152. Energy+ does not agree with TMMC that a separate class for TMMC is "required". TMMC's assertion is based on an OEB Staff Discussion Paper[117].

153. Energy+ does not agree. Energy+'s Large User Class has been in existence for many years, has received Board approval in prior rate applications, and has been established in accordance with Board policy. In addition, it is consistent with the Large User class used by most other LDCs in Ontario.

154. Energy+ does not consider two separate Large User customer classes as appropriate, and submits that the adoption of two separate Large User customer classes, with what would currently amount to one customer in each class, does not meet generally accepted principles

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[116] VECC Reply Submission, April 5, 2019, page 3.
[117] EB-2007-0031, "Rate Design for Recovery of Electricity Distribution Costs", March 31, 2008 Revised June 6, 2008, page 22

of public utility ratemaking, which include:

- Simplicity, understandability, public acceptability, and feasibility of application and interpretation;
- Fairness in apportioning cost of service among different customers (equals treated equally, and costs allocated based on causality principles); and
- Avoidance of undue discrimination (including avoidance of cross-subsidies).

155. With respect to the principle of simplicity and feasibility of application, Energy+ identified the following concerns with the implementation of two Large Use classes:

(a) increased regulatory and administrative costs. This is a practical objection, reflecting the fact that Energy+'s budgeted (and settled) OM&A cost structures do not reflect the incremental effort involved in administering a separate rate class (including increases in regulatory and billing costs).[118]

(b) challenges with deciding which would be the appropriate large user rate class to apply to any future large user in Energy+'s service territory.[119]

(c) ongoing problems with confidentiality of customer information (as there would only be one customer in each of the two rate classes).

156. With respect to the concern expressed by Energy+ with respect to the potential challenges with deciding which would be the appropriate large user rate class to apply to any future large user in Energy+'s service territory, or the potential that other customers could request similar treatment in the future, TMMC dismissed both Energy+'s and OEB Staff concerns, noting that the Board can decide, at that time, whether the application of cost causality principles to the specific factors support a case for a separate class.[120]

157. This submission fails to recognize that in reality, for the vast majority of customer requests,

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[118] Oral Hearing Transcript Vol. 2 dated March 8, 2019 at page 17, lines 2-8.
[119] Oral Hearing Transcript Vol. 1 (Public, redacted) dated March 7, 2019 at line 26 – page 20, line 6.
[120] TMMC's Reply Submission dated April 5, 2019, Line 33, page 11.

it is Energy+, not the Board, that must make the customer classification decision. Thankfully, Board involvement to adjudicate customer classification disputes is currently the exception rather than the rule (although, if the Board does grant TMMC's request for a separate rate class, it risks establishing a precedent that invites other large customers to bring similar disputes in other proceedings).

158. As part of the interrogatory process, TMMC was specifically asked by OEB Staff to describe the defining characteristics of the new Large Use customer class so that in the future if a new large use customer were to connect to Energy+, this description would enable a reader to understand whether the new customer should be added to the existing Large Use rate class or the one proposed for TMMC.[121]

159. In its response TMMC provided the following response:

> "*If a new customer with similar characteristics (i.e. LDG, size of load, served by a radial overhead system, and directly assignable costs) were to materialize, then, based on the principles described in Mr. Pollock's evidence, Energy+ would have the option of creating a new and separate LU class for that customer or adding it to the TMMC LU class (recognizing that if the latter, there would have to be a three-part rate because the M24 and M30 Feeders cannot serve other customers (i.e. shared) and accordingly, their costs cannot be pooled).*"

160. TMMC appears to be of the view that simplicity, understandability, and feasibility of application for Energy+ to other Energy+ customers is not a relevant consideration.

161. As identified in OEB Staff's submission[122], with Energy+'s proposal for a single large use customer class with allocation of all costs, there is less concern with confidentiality of individual customer data. The proposed cost allocation model has been filed on the public record without the need for redaction.[123]

162. This is in stark contrast to the level of confidentiality requested and required by TMMC throughout this entire rate application process, including the filing of several cost allocation models, interrogatory responses, and well as its consultant's reports in confidence with

[121] OEB Staff Interrogatories to TMMC Updated Evidence dated February 22, 2019, Staff-TMMC-5(c).
[122] OEB Staff Submission dated March 29, 2019, page 17.
[123] Ibid, page 17.

redacted versions filed on the public record. While TMMC agreed at the oral hearing that its load data can be provided on the public record once aggregated or "rolled up" to an annualized level[124], such agreement has not been solicited or received from Energy+'s other Large Use customer which would also be directly affected by TMMC's proposal.

163. With respect to fairness in apportioning cost of service among different customers, Energy+ agrees with OEB Staff that the decision to create a new rate class requires the balancing of many factors and that there needs to be a balance between the number of rate classes created and the level of cross subsidization within a class. Inherently, no two customers are identical.[125] This would be true of customers in any rate class.

164. TMMC has identified what it considers unique circumstances that justify the requirement for a separate Large Use Class for TMMC, that in TMMC's opinion, translate into significant differences in costs of providing services, including:

- TMMC operates a load displacement generation (LDG) facility;
- TMMC's load is in excess of 20 MW and larger than the other large user customer;
- TMMC receives primary substation services, whereas the other large use customer receives primary distribution services; and
- With the sole exception of primary poles, all of the distribution facilities that serve TMMC are used exclusively by TMMC.

165. Energy+ agrees with VECC that the fact that TMMC operates an LDG facility should have no impact on the decision as to whether one or two Large Use customer classes are required. In fact, Mr. Pollock has stated that the results of his cost of service study are not meant to capture the cost of providing both Supplementary and Standby Service.[126]

166. Energy+ agrees with both VECC and SEC that customer size, by itself, should not be a

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[124] Oral Hearing Transcript Vol. 2 dated March 8, 2019 at page 10.
[125] OEB Staff Submission dated March 29, 2019 at page 17.
[126] TMMC Response to Interrogatories dated March 2, 2019 - VECC IR 5.2.

determining factor for establishing customer classes.[127]

167. As noted by VECC, the fact that TMMC is larger than the other Large Use Customer and that some costs are fixed on a per customer basis is already recognized in the Board's cost allocation methodology through the use of both customer count and volume as allocators where appropriate. SEC also commented that the nature of the cost allocation model, through the various demand allocators, apportions costs to each.[128]

168. Energy+ submits that the fairness of apportioning cost of service among different customers is achieved through the Board's approved Cost Allocation Model, without having to create an additional rate class.

169. As outlined in Section C, Energy+ is not opposed to utilizing direct allocation where the facts support such an approach. Energy+ believes that there is sufficient and credible evidence available to justify the direct allocation of the dedicated TMMC feeder costs to the Large User customer class.[129] Energy+ submits that the direct allocation of the dedicated feeder to the Large User customer class achieves the objective of costs allocated to a customer class on a cost causality basis, without the need for a separate rate class for TMMC.

D.3.6 Fixed Charge

170. OEB Staff[130] disagrees with Energy+'s proposal to adjust the Monthly Fixed Charge for the Large Use Class to $9,210.42[131], and submits that the Monthly Fixed Charge should remain at the existing level of $8,976.07. OEB Staff premise their submission on their reading of Section 2.8.1 of the Filing Requirements.[132]

171. TMMC has proposed a fixed charge of $8,976.07[133] as part of the its proposed rate design

[127] VECC Submission dated March 29, 2019, page 21 and SEC Submission dated March 29, 2019, page 18, line 63.
[128] SEC Submission dated March 29, 2019, page 18.
[129] Oral Hearing Transcript Vol. 1 (Confidential, Unredacted) dated March 7, 2019 at page 166, lines 16-22.
[130] OEB Staff Submission dated March 29, 2019, page 23.
[131] VECC-TCQ-76, RRWF Tab 13.
[132] OEB Filing Requirements For Electricity Distribution Rate Applications – 2018 Edition for 2019 Rate Applications, Chapter 2, Section 2.8.1
[133] TMMC Updated Evidence dated February 15, 2019, Table 10, page 23.

for Supplementary Distribution Service provided to TMMC.

172. Energy+ agrees with OEB staff and TMMC that the Fixed Charge for the Large User Class should remain at $8,976.07, in accordance with the Filing Requirements. Energy+ submits that the monthly Variable Charge will need to be revised to ensure that Energy+ receives the approved revenue requirement depending on the Board's decision on the other areas in dispute.

D.4 Additional Mitigation

173. Energy+ has proposed the disposition of Group 2 DVA balances on a harmonized basis consistent with the request to harmonize the distribution rates.

174. OEB Staff submit that the Group 2 DVA balances should be disposed of by rate zone and that additional mitigation may be required if the OEB determines that the Group 2 DVA account balances should be disposed separately by rate zone. OEB staff asked Energy+ to confirm this as part of its reply submission. [134]

175. Energy+ submits that it is not possible to confirm at this time whether additional mitigation would be required because material issues related to cost allocation and rate design are still subject to the Board's final determination. As a result, the final distribution rates have not yet been determined. For this reason, Energy+ submits that this issue will need to be addressed during the draft rate order phase of this proceeding.

D.5 Embedded Distributor Revenue-to-Cost Ratio

176. OEB staff submitted that where the revenue to cost ratio for the embedded distributor class is above the ceiling or below the floor, which is 80% to 120%, it be set to the nearest boundary. OEB staff noted that a past decision of moving revenue to cost ratios to 100% does not justify moving revenue to cost ratios to 100% in future proceedings. [135]

177. Energy+ is open to the approach suggested by OEB Staff and agrees there are merits in

[134] OEB Staff Submission dated March 29, 2019, page 24.
[135] OEB Staff Submission dated March 29, 2019, page 22

applying the same methodology to all rate classes for setting revenue-to-cost ratios.

E. RETAIL TRANSMISSION SERVICE RATES AND LV RATES (ISSUE 3.5), INCLUDING GROSS LOAD BILLING FOR RETAIL TRANSMISSION RATES FOR CUSTOMERS WHO HAVE LOAD DISPLACEMENT GENERATION (ISSUE 3.6)

3.5 Are the proposed Retail Transmission Service Rates and LV Rates appropriate?

3.6 Is the proposal for using gross load billing for Retail Transmission Rates for customers who have load displacement generation appropriate?

178. None of the parties objected to Energy+'s proposal to harmonize the RTSRs.

179. Energy+ proposes to harmonize the RTSR rates utilizing the steps outlined in Exhibit 8, page 16. To account for the proposed gross load billing methodology, Energy+ adjusted the billing demand by 74,376 kW for the Large Use Class for determining RTSRs.[136] Energy+ proposes to apply its RTSRs to all customer classes with the exception of one embedded distributor – HON#2.[137]

180. OEB Staff identified that the revised load forecast model that was updated to correct the 2019 forecast demand for Hydro One No.1 in the BCP service territory, was not reflected in the RTSR workform for the BCP service territory. OEB staff asked Energy+ whether a revision is required for the proposed harmonized RTSRs.[138]

181. Energy+ confirms that the demand for Hydro One No. 1 in the BCP service territory should be updated in the RTSR workform to reflect the revised the load forecast. Energy+ will provide a revised RTSR workform for the BCP service territory, and the harmonized RTSR model, as part of the draft rate order process.

182. OEB staff noted that the adjustment of 74,376 kW to the Large Use class billing demand

[136] Energy+ Interrogatory Response to VECC-TCQ-80 (a) dated January 22, 2019.
[137] Energy+ Argument-in-Chief dated March 15, 2019, page 23.
[138] OEB Staff Submission dated March 29, 2019 at page 25.

would not be required if the OEB determines not to implement gross load billing for RTSRs in this proceeding.[139]

183. Energy+ agrees that the adjustment identified by OEB Staff may be required, pending the final decision of the Board with respect to Gross Load Billing. If Energy+'s proposal for gross load billing is not approved, the load adjustment for the Large Use class in the RTSR workforms would need to be removed to utilize the net load for the class in the RTSR rate calculation.

184. VECC stated they have no concerns with Energy+'s proposal to harmonize[140] and apply its RTSRs to all customers except embedded distributor HON#2, which is consistent with the "pooling" approach to cost causality/cost allocation discussed under Issue 3.2, as it pools the costs of providing each type of transmission service and recovers them from all customers using the service.[141]

185. VECC noted that if the Board does not accept the recovery of Energy+'s bulk costs on a similar "pooled" basis as proposed by Energy+ (and supported by VECC), then the loads used to allocate and charge RTSRs to each customer class would have to be adjusted to exclude the portion of the load served from Energy+'s bulk facilities.[142]

186. Energy+ agrees that the adjustment identified by VECC may be required, pending the final decision of the Board with respect to Cost Allocation, and Rate Design.

187. If Energy+'s proposal for cost allocation of bulk facilities is not approved, and TMMC's costs allocation proposal is selected, Energy+ agrees with VECC that the load in the RTSR models should be adjusted to exclude the portion of the load served from Energy+'s bulk facilities for each customer class. This adjustment would be required to avoid cross-subsidies on transmission services from customer's served solely by Energy+ owned transformer stations.

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[139] OEB Staff submission dated March 29, 2019 at page 25
[140] VECC Submission dated March 29, 2019 at paragraph 3.60
[141] VECC Submission dated March 29, 2019 at paragraph 3.63
[142] VECC Submission dated March 29, 2019 at paragraph 3.63

188. Energy+ notes that this would be a time consuming and cumbersome exercise. Energy+ is also unsure whether it could actually be accomplished to a reliable degree of accuracy since some customers served by Hydro One stations may be backed-up by Energy+ bulk facilities, and vice-versa.

E.1 Gross Load Billing Of RTSRs

189. VECC,[143] SEC,[144] and CCC[145] support the approval of the use of gross load billing for RTSRs, whereas OEB Staff[146] and TMMC[147] support deferring any implementation of gross load billing, pending further direction from the OEB.

190. Each of OEB Staff,[148] VECC,[149] CCC,[150] and SEC[151] agree with Energy+'s reasoning and the merit with respect to the use of gross load billing of RTSRs. Such approach aligns the amounts charged to an LDG customer with what the distributor is billed by the IESO and Energy+'s proposed methodology would ensure that there are no cross-subsidies between customers.

191. Energy+ submits that its proposal for the use of gross load billing for RTSRs should be approved.

192. Despite supporting the reasons and merits of Energy+'s proposal, OEB Staff explain that in their view the issue of gross load billing is "a complex matter" and that Energy+ should continue to use the same settlement approach it has been using to date pending any further direction from the OEB.[152]

193. Energy+ does not agree. Energy+ is billed by the IESO line and transformation connection service charges on a gross-load basis for embedded generation located in Energy+'s service

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[143] VEC Reply Submission dated April 5, 2019, pages 8-9.
[144] SEC Final Reply Submission dated April 5, 2019, page 5.
[145] CCC Submission dated March 29, 2019, page 5.
[146] OEB Staff Submission dated March 29, 2019, page 27.
[147] TMMC Submission dated March 29, 2019, pages 21-22.
[148] OEB Submission dated March 29, 2019, page 26.
[149] VEC Submission dated March 29, 2019, page 30.
[150] CCC Submission dated March 29, 2019, page 5.
[151] SEC Submission dated March 29, 2019, page 20.
[152] OEB Staff Submission dated March 29, 2019, page 27.

territory in a manner consistent with the OEB's approved Uniform Transmission Rates.[153]

194. This is clearly seen in Section 1.6.6.6 of the IESO's Market Manual 5.5 under the heading "***Calculation Methodology***" which states:

> "Line and transformation connection service charges need to be calculated monthly for all delivery points with embedded generation facilities registered under the Alternative Metering Installation Standards for Embedded Generation Facilities (Chapter 6, Section 4.5 of the market rules).
>
> On a monthly basis, the host transmission customer will:
>
> • download the participant transmission tariff data file;
>
> • add the hourly generation values for the embedded generator to the hourly demand data for the delivery point associated with the embedded generation; and
>
> • determine the new monthly maximum hourly peak value for the delivery point and compare it to the settled monthly maximum hourly peak value; if the new peak is higher, then:
>
> • calculate the incremental line connection service charges (if applicable) by multiplying the line connection tariff by the incremental peak value; and
>
> • calculate the incremental transformation connection service charges (if applicable) by multiplying the transformation connection tariff by the incremental peak value.
>
> On an annual basis, the host transmission customer must sum all monthly line and transformation connection service charges and obtain agreement of the transmitter to the proposed adjustment, if any. Submit the totals to us via the Submit Settlement Claim action available through Online IESO within the month of April following calendar year end."[154]

195. Energy+ is not proposing to any changes to how the Uniform Transmission Rates are calculated, pursuant to the Board approved UTRs, or how they are calculated and charged by the IESO in accordance with the Market Rules and Market Manual 5.5. Certainly, if the Board was being asked to consider these much broader public policy issues – OEB Staff's comments have some merit.

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[153] Energy+ Argument-in-Chief dated March 15, 2019 at para. 74.
[154] IESO Market Manual 5.5 at Section 1.6.6.1.

196. But Energy+'s proposal is much simpler than this. Energy+ takes no position on how the UTRs should, or should not, be calculated and charged (on a gross load basis or otherwise).

197. Energy+'s position is simply that the way that Energy+ calculates and charges RTSRs should align directly with the OEB's approved UTRs – whatever those may be from time to time. Failing to align how Energy+ charges RTSRs with the UTRs results in a known and easy to correct cross subsidy.

198. The evidence is clear. Currently, line and transformation connection rates are charged to Energy+ on a gross load basis. However, the customers that have and benefit from that load displacement generation are not being charged RTSR on an equivalent basis. Energy+ is seeking to simply fix that asymmetry.

199. OEB staff supported their view by referencing a letter from the OEB dated March 29, 2016 ("**Board Letter**") to all Licensed Distributors and the recent decision on Enwin Utilities' 2018 rates.

200. TMMC similarly argue that the issue of gross load billing for RTSR deserves a thorough examination that should take place in the context of a generic policy review that considers the de-incentivizing effects of gross load billing on the development of distribution generation. TMMC also notes that their position is consistent with the Board Letter and the Board's decisions on this matter in requests by each of Guelph Hydro Electric Systems Inc., Niagara-on-the-Lake Hydro Inc. and Erie Thames Powerlines Corporation.[155]

201. The Board Letter informed electricity distributors that the OEB's project on Rate Design for Electricity Commercial and Industrial Customers (EB-2015-0043) will address how commercial and industrial customers should be billed when they have a Load Displacement Generator behind the meter, and will undertake a review of the appropriate billing for other rates including RTSRs.

202. This is a **<u>much broader</u>** consultation than what Energy+ is proposing. The Board Letter is asking what the appropriate billing is for transmission rates overall. In other words, the

[155] TMMC submission dated March 29, 2019 at page 21 to 22.

Board's consultation is asking whether or not the current UTR rate structure is correct when it bills line and transformation rates on a gross load basis.

203. Energy+ takes no position on this much broader public policy issue at this time. Rather, Energy+'s would accept the outcome of the EB-2015-0043 consultation, whatever that may be.

204. In the interim, however, Energy+ submits that it is important to ensure that how Energy+ charges RTSRs to customers with embedded generation aligns directly with how the IESO actually bills Energy+ for those charges. Otherwise a known cross-subsidy will persist.

205. It is important to note that the EnWin decision[156] cited by OEB Staff arose during what was otherwise a routine, and formulaic, IRM application. It did not arise during a more comprehensive cost-of-service rate application – and is clearly distinguishable from the Energy+ Application in this regard. With EnWin, the Board did not have the benefit of evidence of extensive customer engagement activities, multiple rounds of written and oral discovery, numerous active and engaged customer groups (including customers with and without load displacement generation), and a multitude of different viewpoints on this issue.

206. Energy+ submits that the OEB's plan to review the matter on a generic basis is not an adequate reason to refrain from approving Energy+'s proposal in this proceeding. Energy+'s proposal to utilize gross load billing for RTSRs is founded on the principles of cost causality. It is not appropriate for other customers to pay costs caused by a customer with LDG, when such costs can be directed to the LDG customer. The merit and fairness of Energy+s proposed approach was acknowledged by OEB Staff, VECC, CCC, and SEC.

207. In fact, a recent Decision of the Board for Niagara-on-the Lake Hydro Inc.'s 2019 Cost of Service Application approved the use of gross load billing for RTSR charges.[157] Energy+ submits that the basis of that Decision, which follows, is similar to the facts in this proceeding:

[156] EnWin Utilities Ltd., EB-2017-0037, pages 12-13.
[157] EB-2017-0037 Decision and Order, Niagara-on-the-Lake Hydro Inc, page 18,

> *"the proposal prevents a potential subsidy to the NOTL Hydro's Large Use customer that will be solely served by a proposed combined heat power plant to be installed by this customer. Hydro One's practice of "gross load billing" will otherwise fail to recognize that only one customer will benefit from the generation from the plant. This same result might obtain for future LDG customers without adoption of the proposed transmission charge."*[158]

208. Energy+ also understands that the use of gross load billing for RTSR is currently used by other LDCs, and has been permitted since 2001 as outlined in Chapter 11 of the EDR Handbook:

> *"**Retail Transmission Connection Service Rate***
> *In the case of a demand metered customer (either interval or non-interval), the connection rate shall apply to the individual end-use customer's non-coincident peak demand in the month <u>on a gross load basis for load customers with new embedded generation for which required approvals were obtained on or after October 30, 1998 ("New Embedded Generation").</u> Demand metered customers with existing embedded generation and New Embedded Generation under 1MW shall be billed on a net load basis. For customers with energy only meters, the connection charge rate will be based on monthly energy, adjusted for losses, subject to a distributor's election under section 11.3.2.4."* [159]

209. With respect to the Board Decisions quoted by OEB Staff and TMMC to support the position that gross load billing should be deferred in Energy+'s application, consistent with the Board's Decisions in other rate cases, Energy+ would note the following:

- Similar to EnWin, the Board's Decision on Niagara-on-the-Lake Hydro ("**NOTL**") EB-2017-0064 was in the context of an IRM Application (2018) as compared to a Cost of Service Application. The Board made a very different decision in NOTL's cost-of-service application, as noted above.
- The Board's Decision on Guelph Hydro (EB-2015-0380) was in the context of a separate application by Guelph Hydro submitted in December 2015, and not as part of a cost-of-service application.

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[158] EB-2018-0056 – Decision and Order
[159] EDR Handbook, Chapter 11, March 29, 2001, Pages 12-14.

210. Energy+ submits that the Board's Decisions on the IRM Applications referenced are consistent with the Board's filing requirements for IRM Applications, wherein it states:

> *"The IRM Application process is intended to mechanistic in nature. For this reason, the OEB has determined that the IRM process is not the appropriate way for a distributor to seek relief on issues that are specific to only one or a few distributors, more complicated relative to issues typical of an IRM application, or potentially contentious.*[160] *These items are to be addressed in the distributor's next cost of service application.*[161]

211. Energy+ submits that the Board's most recent Decision for NOTL was in the context of a 2019 Cost of Service Application (EB-2018-0056), which is consistent with the approach identified in the filing guidelines.

212. In respect of the Erie Thames Powerlines Corporation ("**Erie Thames**") Application quoted by TMMC, while Energy+ acknowledges that the Erie Thames application was a Cost of Service Application, Energy+ would highlight important factual differences in the Erie Thames case compared to Energy+:

- The Board's Decision was to accept Erie Thames Settlement Proposal, wherein Erie Thames had reached a settlement on all issues in the proceeding. Energy+, by contrast, was not able to reach settlement with the parties in this proceeding on this issue.
- As part of the Settlement Proposal, Erie Thames agreed to withdraw its proposals for standby charges and gross load billing. The consent by CCC, SEC, and VECC in that case "reflects the fact that the current dollar impact on customers is not material" and "the intervenors take no position regarding the appropriateness of gross load billing or standby charges and the parties are free to take any position in regards to these issues in future proceedings." TMMC was also a

[160] Filing Requirements for Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications, July 20, 2017, page 24.
[161] Ibid, page 25.

party to the proceeding with its interest solely in respect of the gross load billing and standby rates issue.

213. In its evidence, Erie Thames indicated that it had one customer with LDG in the GS 1,000-4,999 customer class and was not aware of any further approved load displacement generation investments.[162]

214. By contrast, (i) Energy+ has not agreed to withdraw its proposal for standby and gross load billing; (ii) Energy+ has provided detailed evidence on the record[163], and directly to TMMC[164], that the RTSR amounts with respect to LDG are material; and (iii) Energy+ has an existing LDG customer in the Large Use customer class (GS > 5,000 kW), and expects additional customers to implement LDG in 2018 and 2019.[165]

215. Energy+ agrees with VECC and SEC's views and comments with respect to the Board's pending review of gross load billing. Energy+ submits that the OEB has provided no definitive timeline for this review, and in fact, the OEB's wording states that it "<u>may</u> review this matter…". This provides no certainty to Energy+ or its customers as to when this issue will be addressed.

216. In VECC's submission, they noted that the Staff Report to the Board dated February 21, 2019 (EB-2015-0043) does not deal at all with the question of gross load billing for RTSRs, and to their knowledge the Board has not initiated a separate process to deal with gross load billing for RTSRs. VECC submitted that in light of the passage of time, and the uncertainty as to when this issue will be dealt with on a generic basis, it is reasonable to address Energy+'s proposal to bill customers with load displacement generation RTSR on a gross load billing basis in this proceeding and to not defer the matter.[166]

217. SEC also commented on the Board's Letter noting that the letter was dated more than three years ago[167] and that it is not aware of any review or consultation on the issue having since

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[162] Erie Thames Power Lines, Exhibit 7, Tab 1, page 2 of 4, lines 8 through 21.
[163] Interrogatory Response to 8-Staff-92 dated September 14, 2018.
[164] Response to TMMC Questions, July 2018, Pages 10-15.
[165] Response to TMMC Question 5 (iii), July, 2018, page 20.
[166] VECC Reply Submission, March 29, 2019, page 39, paragraph 3.71- 3.72.
[167] SEC Submission dated March 29, 2019, page 20, paragraph 70.

commenced.[168] SEC noted that the consequences of not approving the proposal is that TMMC's fair share of RTSR costs will continue to be unfairly subsidized by all other customer classes. This is especially unfair in the context of this proceeding, where through its expert TMMC is seeking a significant shifting of costs to other customer classes[169].

218. Energy+ is disappointed in the position taken by TMMC with respect to gross load billing as it relates to RTSR charges on LDG. In particular, TMMC's arguments appear to be centred around: (i) not having a deep understanding of the topic as they have not gone very deeply in understanding the RTSRs; and (ii) the issue requires a more thorough examination of how and why retail transmission charges are passed through to local distribution companies.[170]

219. Energy+ submits that its proposal for gross load billing of RTSR was a known and live issue since the very start of this Application. Given that TMMC has spent considerable time and effort on other aspects of the Energy+ Application, it is not clear why it now does not have a good understanding of this known live issue.

220. Energy+ has answered a significant amount of questions from TMMC both before and during the Application process that are specifically related to RTSRs. It is somewhat surprising that TMMC would take the position that they have not had an opportunity to obtain an understanding of the RTSRs.

221. In fact, TMMC also intervened in Energy+'s 2015 IRM Application whereby the former CND proposed gross load billing, which was acknowledged by Ms. Pollard, Vice President of Administration and Corporate Secretary for TMMC.[171]

222. Energy+ submits that the question of "why retail transmission charges are passed through to local distribution companies" is not relevant in this proceeding. As noted above, that would be properly in scope of the much broader consultation that the Board already has

[168] SEC Submission dated March 29, 2019, page 20, paragraph 71.
[169] Ibid, page 20, paragraph 72.
[170] Oral Hearing Transcript Vol. 2 dated March 8, 2019at page 40 lines 12-16 and lines 22-24.
[171] Oral Hearing Transcript Vol. 2 dated March 8, 2019 at Page 29-30.

underway.

223. The narrow issue that Energy+ is attempting to address in this proceeding is that Energy+ is currently being charged RTSR on LDG that is specific to TMMC and that, in the absence of gross load billing, currently those charges are being subsidized by other customers through the disposition of the RTSR deferral and variance accounts.

224. In TMMC's own evidence, they make the statement that "…we truly want to improve the accuracy with which utilities are charged to users. It will involve work and further study and, perhaps the most challenging, it will require a willingness to change methods that have become the norm."[172] Energy+ submits that changing the method of charging RTSR on a gross load billing basis for customers with LDG achieves this outcome, as it is in fact a change in the method, and improves the accuracy of the amounts charged to customers.

E.2 Low Voltage Rates

225. None of the parties objected to Energy+'s proposal to harmonize the Low Voltage Rates ("**LV**").

226. OEB staff agreed that when a distributor is both a host and embedded on a feeder to the same distributor, it is appropriate to not apply LV charges if a reciprocal agreement with the other distributor is in place to not apply sub transmission charges. In all other instances, OEB staff submitted that LV charges should apply to embedded distributors on the basis of the precedent of other LDCs with approved tariffs with LV charges being applied for rate classes dedicated to embedded distributors.[173]

227. VECC submitted that in the interest of fairness and consistency, embedded distributors should be allocated a share of LV costs using the same approach that is used for all other classes.[174] VECC anticipated that HON may argue that the impact of embedded distributor load to the LV charges incurred by Energy+ is immaterial and should be excluded from the allocation/recovery of Energy+'s LV costs.[175] VECC stated that this type of approach is

[172] Oral Hearing Transcript Vol. 2 dated March 8, 2019 at page 32, line 12-16.
[173] OEB Staff Submission dated March 29, 2019 at page 28
[174] VECC Submission dated March 29, 2019 at paragraph 3.67
[175] VECC Submission dated March 29, 2019 at paragraph 3.65

consistent with the view of cost causality as put forward by Mr. Pollock, where if a customer/customer class does not use an asset then it should not be allocated any of the associated costs. VECC noted that this approach would be fundamentally different from the current Board approved methodology that aligns with the "pooling" approach and allocates LV costs based on the RTSR revenues for each customer class which are calculated based on the class' total load.[176]

228. Hydro One notes that its settlement arrangement with Energy+ ensures that none of Hydro One's load that is embedded with Energy+ contributes to the ST charges (LV) that Hydro One levies to Energy+. Hydro One references Energy+'s total LV cost forecast of $507,967, with embedded distributor classes contributing only $41,445 or 8.2% of that amount. Hydro One submitted that it is not reasonable that all embedded distributor classes to pay for recovery of LV costs that are 92% driven by the needs of other customers.[177]

229. Energy+ submits that its proposal to not allocate LV charges to embedded distributors is reasonable, and is consistent with the settlement arrangement that Energy+ has with Hydro One currently.

230. If the Board elects to direct Energy+ to allocate LV charges to all embedded distributors, Energy+ will need to work with Hydro One to adjust the current settlement methodology, which will very likely increase the total ST charges that Hydro One bills to Energy+. Energy+ submits that both the change in allocation of LV charges to embedded distributors, as well as the corresponding change in forecasted ST charges would need to be reflected in final rates.

[176] VECC Submission dated March 29, 2019 at paragraph 3.66
[177] Hydro One Submission dated January 16, 2019 page 2 to 3

F. STANDBY CHARGE FOR CUSTOMER CLASSES WITH LOAD DISPLACEMENT GENERATION (ISSUE 3.7)

3.7 Is the proposal for implementing a standby charge for the Large Use, GS 1,000 to 4,999 kW and GS 50 to 999 kW customer classes with load displacement appropriate?

231. OEB Staff supports Energy+'s proposed standby rate and methodology as compared to the TMMC proposed standby rate and methodology[178].

232. VECC[179], SEC[180], and CCC[181] do not support either of Energy+'s or TMMC's standby proposal.

233. While TMMC did not support Energy+'s proposed standby rate methodology, TMMC has requested the implementation of a "just, reasonable, and cost-based rate Standby Distribution service rate design for TMMC." TMMC has proposed its own standby rate methodology.

F.1 Timing of Implementation

234. Energy+ agrees with OEB staff that a standby charge is appropriate at this time and that Energy+'s proposal for standby charges should be applicable until its next rebasing application or until such time as the OEB may opine on the applicability and timing of any generic standby charge policy going forward.[182]

235. Both VECC and SEC have argued against the implementation of a standby charge on the basis that the Board should await the outcome of the current Rate Design for Commercial and Industrial Customers consultation (EB-2015-0043).[183] TMMC, while acknowledging that the Board may decide not to approve any standby rate or rate methodology and instead await the outcome of the C&I consultation, requested Board approval for its alternate methodology.

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[178] OEB Staff Submission dated March 29, 2019, page 30.
[179] VECC Submission dated March 29, 2019, page 33.
[180] SEC Submission dated March 29, 2019, page 14
[181] CCC Submission dated March 29, 2019, page 5.
[182] OEB Staff Submission dated April 5, 2019, page. 4.
[183] VECC Reply Submission dated April 5, 2019, page 9 and SEC Submission dated March 29, 2019, page 14.

236. Energy+ disagrees with VECC and SEC that the implementation of a standby charge or methodology should be deferred pending the outcome of the C&I consultation. Energy+ agrees with OEB staff that a staff paper is not the policy of the OEB.[184]

237. Energy+ submits that the fact that there is currently an OEB Staff paper on this topic is not adequate reason to refrain from approving Energy+'s proposal. Approving Energy+'s standby proposal would not impair the OEB's ability to adopt a similar or an alternative methodology for standby rates in a future decision.

238. Energy+ took careful note of the Presiding Member's comments at the oral hearing:

> *"First of all, that report was issued February 21st for rate design for commercial and industrial customers is a draft document and does not currently reflect policy until it is adopted. In addition, we understand that that document, at the earliest, will go into effect in 2021. It does not provide the OEB with direction or guidance in this proceeding. It can be referred to in cross-examination like any article or report for purpose of asking a witness to comment on its provisions, but it is not to be received for truth of what's in that report and it is not evidence or a guideline deciding this issue or proposal."* [185]

239. The implementation of a standby rate for LDG is not a new concept. Currently, eleven other Ontario distributors have approved standby rates. The applications have been made at different times with different approaches and the OEB has considered each one on a case-by-case basis.

240. Energy+ submits that it should not have to wait until 2021, or later, to implement a standby rate for LDG. Energy+ has already been waiting quite a long time. Energy+ has been considering the implementation of a Standby Charge at least as early as 2014 as a result of the implementation of a large co-generation project by one of its large use customers, and more recently due to a growing demand by commercial customers to install LDG.[186]

241. In fact, as part of its 2015 IRM Application (EB-2014-0060), Energy+ (the former Cambridge and North Dumfries Hydro Inc. ("**CND**")) requested permission from the Board to begin to charge distribution to its Large Use customer with LDG on the basis of

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[184] OEB Staff Submission dated March 29, 2019, page 31.
[185] Oral Hearing Transcript Vol. 1 dated March 7, 2019, lines 1-13, page 29.
[186] Oral Hearing Transcript Vol. 1 dated March 7, 2019, page 16 lines 18-23.

Gross Load Billing. Conceptually, this is similar to charging a standby rate for the amount of generation. At that time, the former CND identified that it would experience a material loss in distribution revenue (approximately $225,000 per year). While the former CND understood that this lost revenue would be recovered in the future through an LRAM claim, the allocation of the LRAM to the Large Use customer lass, which consists of two customers, would result in unequitable allocation of LRAM to the non LDG customer.

242. In late November 2014, the Board determined that the gross load billing proposal was inappropriate in the context of the IRM Application. However, the Board stated that:

> "*CND is able to apply for a standby rate or for gross load billing as a separate application in order to deal with load displacement generation.*"[187]

243. This is exactly what Energy+ has done in this 2019 Cost of Service Application. Energy+ submits that this is the appropriate time in which to approve the proposed standby rate and to implement gross load billing with respect to RTSR charges.

F.2 Energy+ Proposed Standby Rate Methodology

244. Energy+ has proposed a contracted capacity method where a customer contracts for a peak load requirement, initially based on the actual historical peak demand of the customer. The contracted capacity amount could be reduced if the customer demonstrates an ability to shed load. Energy+ proposes to implement the standby rate for the GS> 50-999 kW, GS > 1,000-4,999 kW, and the Large Use Class, for customers with load displacement generation ("**LDG**") that require Energy+ to act as backup supply of electricity in the event the source of generation is unavailable. The standby rate is proposed to be the same as the volumetric rate of the customer's rate class.

245. Energy+'s proposal to use a contracted capacity approach for standby is actually very similar to how TMMC, and other large users, currently pay for natural gas services from Enbridge Gas Inc. This was confirmed by TMMC during an exchange at the oral hearing.[188]

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[187] EB-2014-0060, Procedural Order No. 2, Page 3.
[188] Oral Hearing Transcript Vol. 2 dated March 8, 2019 at pg. 111, line 2 to pg. 113, line 14.

246. Energy+ has proposed a monthly contracted capacity amount for its Large Use customer, TMMC, of 26.2 MW.[189] TMMC acknowledged that this Contract Demand reflects TMMC's maximum demand during calendar year 2017.[190]

247. Consistent with Energy+s overall approach to rate design, as described in Section D, Energy+ submits that its proposed standby rate methodology also meets a number of generally accepted principles of public utility ratemaking including simplicity and understandability, and feasibility of application and interpretation.

248. As previously noted, OEB Staff supports Energy+'s proposed standby rate and methodology as compared to the TMMC proposed standby rate and methodology. OEB Staff summarized the merits of Energy+'s proposal, including:

- Utility is not required to identify when standby service is called upon;
- Utility does not need to have the ability to measure the portion of metered demand that is the result of a full or partial LDG generator outage;
- By including the full contract capacity including standby in the demand allocators in the cost allocation model, it ascribes a tangible charge to the provision of standby services. This reflects the real costs that the provision of standby service imposes on the distributor.
- The use of a single rate for delivered power and standby power simplifies rate design.

249. Concerns raised by SEC with respect to Energy+'s proposal centered around the requirement for customers to negotiate the level of standby capacity, the little guidance for how the contracted capacity should be determined, and the dispute resolution process.[191] TMMC also suggested that Energy+ had provided no explanation for how it determined the standby contract demand for TMMC and, contrary to SEC's submission, suggested that the determination should be made in consultation with the LDG customer.[192]

[189] Energy+ Response to IR-TMMC-4 dated September 19, 2018
[190] TMMC Submission dated March 29, 2019 at para. 64.
[191] SEC Submission dated March 29, 2019, paragraph 32, page 10.
[192] TMMC Submission dated March 29, 2019, paragraph 67, page 23.

250. Energy+ submits that its proposal for a standby capacity charge is intended to ensure that customers are engaged in the process, that there is some flexibility with respect to the needs of the customer, which enhances consumer choice and control, and Energy+ has identified a number of factors that both the customer and Energy+ will take into consideration in setting the level of contracted capacity, as well as a number of contractual provisions that will be designed to protect both the customer and Energy+.[193,194]

251. Energy+ disagrees with SEC and TMMC that there is little guidance for how the contracted capacity should be determined or that Energy+ has provided no explanation for how it determined the contract demand for TMMC.

252. Energy+'s proposal includes an initial computation to be used in determining the initial basis for the standby charge that is based on the actual historical peak demand of the customer, with the customer having the ability to request a lower contracted amount if the customer can demonstrate an ability to shed load when the LDG is not operating. With respect to TMMC, Energy+ did in fact engage with its customer with respect to providing information and obtaining feedback with respect to its standby proposal, as outlined in detail in Exhibits 1 and Exhibit 7 of the Application, as well as Energy+ has continued to engage with TMMC and other intervenors throughout this process through detailed responses to TMMC questions before and after the rate application was submitted, multiple rounds of interrogatories, the Settlement conference, Technical Conference and Oral Hearing process.

253. SEC also raised concerns with Energy+'s proposal on the basis that a customer will be required to pay the standby charge if demand is below the contracted capacity for reasons that may have nothing to do with LDG (e.g. new energy efficiency or conservation measures or general reductions in use)[195]. VECC raised a similar concern that the customer's monthly bill will be based on the contracted capacity without reference to the actual load level or the reasons why the actual load levels vary from the contracted capacity. VECC sited an example in 2016 data where there was one month where the difference

[193] Interrogatory Responses to IR 7-SEC-39, 7-SEC-40 dated September 14, 2018.
[194] Interrogatory Responses to VECC-TCQ-83(iii) dated January 22, 2019.
[195] SEC Submission dated March 29, 2019, paragraph 35, page 11.

exceeded the installed capacity of the customer's generation.[196]

254. Energy+ submits that, where customers are expecting the Energy+ distribution system to be available in the event that the load displacement generation is not functioning, Energy+ needs to provide the contracted peak load at any time. The value to the customer with respect to standby is that Energy+ stands ready to serve when called upon. Energy+ needs to operate, maintain, and ensure that an appropriate amount of capacity is available when customers require it. Localized assets in the distribution system are designed and built to be large enough to service all of its local customers when demand is at its highest peak.

255. VECC in its own submission acknowledged that *"the standby rate should be set so as to recognize the cost incurred by the utility as result of having to have the capability to meet customer demands normally supplied by its own generation"*.[197]

256. The purpose of the standby/capacity charge is to ensure that Energy+'s costs are covered, even if the customer does not actually use the service. In the absence of the introduction of standby or capacity, those costs are ultimately shifted to other customers.

257. Energy+'s acknowledges that there are factors that should be considered in determining whether the contracted capacity could be increased or decreased on an annual basis, including a material change in the amount of peak load required due to changes in business conditions, implementation of new technology, and/or conservation initiatives that are persistent[198]. In fact, Energy+'s proposal includes an annual review of the customer's monthly peak loads and the possibility to adjust the contracted capacity reserve value based on discussions with the customer.

258. With respect to the example cited by VECC where there was one month of data in 2016 where the standby rate would be applied to a quantity that exceeded the installed capacity of the customer's generation, Energy+ notes the following:

- The difference was 9.958 MW, which compares to the assumed nameplate capacity

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[196] VECC Submission dated March 29, 2019, page 31.
[197] VECC Submission dated March 29, 2019, page 32.
[198] Interrogatory Response to IR 7-SEC-39(a) dated September 14, 2018.

of 9.2MW;

- Although the nameplate capacity has been identified as 9.2 MW (2 units at 4.6 MW each), the output of the generation sometimes exceeds the nameplate capacity.[199]
- The LDG can and has dropped off-line or reduced output, resulting in Energy+ having to pick up the full load of the TMMC plant.[200] This would include the level of output of the generation, irrespective of its nameplate rating.

259. Energy+ submits that based on its proposal to negotiate the level of contracted capacity with its customers, Energy+ would be open to setting a monthly capacity amount that takes into consideration a customer's load requirement that fluctuates from month to month, if requested by the customer.

260. TMMC has also stated that another problem with Energy+'s proposed standby rate design is that Energy+ ignored the reduction in the amount of capacity it has to reserve as a result of TMMC's LDG and that with LDG reducing TMMC's net peak demand, more capacity is available to serve Energy+'s customers.[201]

261. Energy+ submits that its proposed contract capacity for TMMC was estimated based on the amount of peak capacity that is required in the absence of the LDG (based on the historical peak demand in 2017) and that, based on the current supply arrangements with TMMC, more capacity is <u>not available</u> to serve Energy+'s customers.

262. The argument provided by TMMC is counter to the concern it raised at the oral hearing wherein TMMC stated "…the statement from the panel yesterday alarmed my client…we had understood that we paid for the spare capacity for reasons of reliability and security of supply, and so it was the first time we had heard that you might take that exclusivity away from us". This was in response to Energy+ noting that the TMMC dedicated supply feeders have capacity on a regular basis, and that with protection setting changes, and the addition of a typical normal operating point between the two feeders, this capacity could be utilized to supply part of the new east side lands. While Energy+ acknowledged that it was not

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[199] Interrogatory Response to IR-TMMC-13 (1) dated January 9, 2019.
[200] Interrogatory Response to IR-TMMC-13 (6)(a) dated January 9, 2019
[201] TMMC Submission dated March 29, 2019, page 23.

something that it was contemplating doing, it was being raised as a practical implication.[202]

263. Finally, LRAMVA has historically been a mechanism in place to address revenue shortfalls as a result of conservation initiatives and is intended to recover revenue from the rate class who benefits from participating in CDM programs, such as LDG. Energy+ management is quite concerned that recent changes announced by the Ontario government to eliminate the role of LDCs in delivering conservation programs may result in changes to an LDCs ability recover LRAMVA claims and ensure that such amounts are recovered from the appropriate rate classes. In particular, Energy+ notes that the IESO has announced that it will no longer continue to provide verified savings reports to LDCs, which are the reports used by LDCs to compute its LRAMVA claims. In the absence of approving Energy+'s standby proposal, and with uncertainty around LRAMVA funding, Energy+ stands to be directly harmed financially if future LDG projects come on-line. This is not in the public interest.

F.3 TMMC Proposed Standby Rate Methodology

264. None of the parties to this proceeding support the TMMC proposed standby rate methodology, citing a number of issues with the proposal[203]. Energy+ agrees that there are a number of the issues in implementing the TMMC proposal. Energy+ does not propose to repeat all of the issues that have been identified by the parties. Instead, Energy+ provides the following comparisons between the two proposals to highlight the benefits to the Energy+ proposal as compared to the TMMC proposal:

- Energy+'s proposal for a standby rate based on the same volumetric rate of the class is easy for customers to understand.

  By contrast, the two-part standby rate proposed by TMMC is complex and would require amongst other things: (i) a new means of tracking outages; (ii) implementation of a two-part billing process and procedures that would likely result

[202] Oral Hearing Transcript Vol. 1 dated March 7, 2019 at lines 15-21.
[203] OEB Staff Submission dated March 29, 2019 page 31; SEC Submission dated March 29, 2019, pages 11-14; VECC Submission dated March 29, 2019, pages 32-33.

in incremental costs to Energy+, not contemplated as part of its Application process[204]; and (iii) clear criteria and definitions with respect to what defines a "local" versus "shared distribution facilities" for purposes of allocating costs for the setting of each of the two proposed rates. The lack of clarity was identified by both VECC[205] and SEC[206]. Energy+ agrees with these concerns.

- The methodology proposed by Energy+ can be utilized for all customers with LDG in a variety of rate classes.

  By contrast, the TMMC proposal was designed for TMMC[207]. As noted by SEC, there would be significant practical challenges for Energy+ to adopt the methodology for other customers[208]. In its own submission, TMMC acknowledged the practical difficulties that would need to be addressed if TMMC's proposed methodology were applied to small LDG facilities that were not separately metered in the same way as TMMC's LDG.[209] Energy+ submits that TMMC's standby rate proposal does nothing to address Energy+'s need for a standby rate for other customers with LDG.

- As explained by OEB Staff, by including the full contract capacity including standby in the demand allocators in the cost allocation model, it ascribes a tangible charge to the provision of standby services. This reflects the real costs that the provision of standby service imposes on the distributor.

- The standby rate proposed by Energy+ is consistent with the approach adopted by at least two other LDCs.[210]

  By contrast, of the eleven LDCs in Ontario who have implemented standby rates,

[204] TMMC Response to Interrogatories 7-EnergyPlus-12 dated October 25, 2018.
[205] VECC Submission dated March 29, 2019, page 32.
[206] SEC Submission dated March 29, 2019, page 13.
[207] Oral Hearing Transcript Vol. dated March 8, 2019 at page 70.
[208] SEC Submission dated March 29, 2019, pages 11-12.
[209] TMMC Submission dated April 5, 2019, page 13.
[210] Energy+, Exhibit 7, page 14.

there is no other LDC using a standby methodology that incorporates a multi-part calculation as proposed by TMMC.

G. GROUP 2 DEFERRAL AND VARIANCE ACCOUNTS (ISSUE 4.2)

4.2 Are the applicant's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, and the continuation of existing accounts appropriate?

G.1 Recovery of D&V Accounts on a Harmonized Basis

G.1.1 Group 2 Harmonized Disposition

265. With the exception of OEB staff, no other parties objected to Energy+'s proposal to dispose of the Group 2 DVA account balances on a harmonized basis.

266. Energy+ does not agree with OEB staff's submission that the DVA account balances be disposed of on a service territory, and not on a harmonized basis.

267. Energy+ submits that its proposal to dispose of the DVA account balances on a harmonized basis is appropriate so that all Energy+ customers will be subject to a single Schedule of Rates and Charges. Energy+ submits that the disposition of the DVAs on a harmonized basis is the best approach for the following reasons[211]:

- Energy+ is fulfilling its promise and obligation made to its customers and to the OEB when, in the former CND's application to purchase the outstanding shares of Brant County Power Inc. (EB-2014-0217), it stated it would "*…use commercially reasonable efforts to harmonize rates for customers of CND and BCP in 2019 at the time of CND's next scheduled cost of service application*."
- A single, harmonized disposition allows for a much less complex tariff sheet and facilitates the energy literacy and ease of understanding by customers;
- Harmonization reduces administrative time spent on the DVA reconciliation process.

268. As part of its augmented customer engagement actions, Energy+ specifically engaged its customers on the proposed rate harmonization plan. Between 67% and 86% of low-volume customers agreed with the concept that customers should pay the same rates, regardless of

[211] Exhibit 9, Page 20 of 80.

where they live or work in the Energy+ service territory. While customers in the CND service territory were less supportive than customers in the Brant service territory, this is understandable, as the rate harmonization showed a proposed increase in rates for the CND customers versus a proposed decrease in rates for Brant customers.[212]

269. Energy+ submits that a decision that requires the disposition of the Group 2 variance accounts on a service territory basis, but approves the distribution rate harmonization and disposition of Group 1 variance accounts, would very confusing to explain and be understood by customers.

270. Energy+ would need to explain why, even though rates have now been harmonized, there are still two different OEB approved tariffs: one for CND customers and one for BCPI customers.

271. OEB Staff argue that the DVA balances should be disposed of by service territory on the basis that: (i) the amounts were actually accumulated individually by service territory[213]; and (ii) based on cost causality, meaning that costs or benefits should accrue to the customers that were directly responsible for incurring them.[214]

272. With respect to amounts being actually accumulated individually by service territory, Energy+ would note that this not the case with respect to all Group 2 accounts including the LRAMVA claim, as specifically noted by OEB staff in its submission. Energy+ has in fact prorated the CDM savings by service territory using project specific information for 2016 and 2017 lost revenue computations and in the event project-specific information was not available, Energy+ apportioned the CDM savings based on relative consumption of the service territories.[215] This was due to the fact that Energy+ was one legal entity commencing in 2016.

273. In making its argument with respect to cost causality, OEB Staff cited a specific example with respect to the disposition of *Account 1576 Accounting Changes Under CGAAP*

[212] Energy+ Inc., EB-2018-0028, Exhibit 1, Section 1.3 Customer Engagement, Page 90.
[213] OEB Staff Submission, March 29, 2019, page 42.
[214] Ibid.
[215] OEB Staff Submission, March 29, 2019, page 34.

Balance + Return Component Group 2 DVA which relates entirely to the BCP service territory.[216]

274. Energy+ submits that its proposal for the disposition of the balances in Account 1575 IFRS-CGAAP Transition PP&E and Account 1576 Accounting Changes under CGAAP on a harmonized basis would better reflects the principle of cost causality, when taking into consideration Energy+'s overall rate harmonization proposal. More specifically, the harmonized distribution rates for all of Energy+ customers proposed in this proceeding have been derived from the total rate base of Energy+ on a harmonized basis, which includes the average fixed asset balances for the 2019 Test Year. The average fixed asset balances used in the 2019 rate base have not been computed by service territory. The average fixed asset value for the 2019 Test Year incorporates the full transition to MIFRS for both the Brant and CND service territories. The effect of the transition was captured by both of Accounts 1575 and 1576.[217]

275. Under Energy+'s rate harmonization proposal, the Brant customers benefit from lower distribution rates as a result of the consolidated fixed asset balances, which includes the adjustments made to the fixed assets for the change in capitalization policies and the adoption of MIFRS.

276. To assist the Board in understanding the differences in approach, Energy+ has prepared a table which provides for the estimated total bill impact by customer class based on the typical consumption and demand levels under two scenarios: (i) of the disposition of the Group 2 DVA accounts on a harmonized basis (Total Bill Harmonized Group 2) as proposed by Energy+; and (ii) the disposition of the Group 2 DVA accounts by service territory as proposed by OEB Staff.

277. Energy+ would note that total bill impact for a typical CND residential customer is $1.10 higher if DVA balances are disposed of on a service territory basis, compared to $5.40 lower for a Brant customer. The total differential between the CND and Brant customer total bill

[216] OEB Staff Submission page 42
[217] IR 9-Staff-96

is $6.49 under the OEB staff proposal.

278. Estimated Bill Impacts: Disposition of DVA Balances – Harmonized vs. By Service Territory

CND Service Territory	Billing Units		Current 2018		Total Bill Harmonized Group 2		Total Bill Unharmonized Group 2		$ Change Unharmonized vs Harmonized	
Residential	750	kWh	$	96.02	$	102.35	$	103.45	$	1.10
Residential	313	kWh	$	52.99	$	59.68	$	60.86	$	1.18
GS < 50 kW	2,000	kW	$	243.70	$	255.49	$	257.91	$	2.41
GS >50 to 999 kW	60	kW	$	3,415.31	$	3,422.90	$	3,457.52	$	34.62
GS >1,000 to 4,999	2,000	kW	$	124,738.16	$	126,103.86	$	127,541.54	$	1,437.68
Large Use	16,000	kW	$	959,490.65	$	1,000,943.39	$	1,011,240.55	$	10,297.16
Unmetered Scattered Load	100	kWh	$	17.39	$	17.78	$	17.96	$	0.18
Street Lighting	700	kW	$	101,505.50	$	98,051.30	$	92,496.39	$	(5,554.91)
EMB - WNH	8,280	kW	$	47,845.40	$	38,238.57	$	44,780.65	$	6,542.09
EMB - HONI	2,574	kW	$	207,486.91	$	201,500.92	$	203,631.76	$	2,130.84

Brant Service Territory	Billing Units		Current 2018		Total Bill Harmonized Group 2		Total Bill Unharmonized Group 2		$ Change Unharmonized vs Harmonized	
Residential	750	kWh	$	102.93	$	102.35	$	96.96	$	(5.40)
Residential	357	kWh	$	63.07	$	63.98	$	58.17	$	(5.80)
GS < 50 kW	2,000	kWh	$	262.81	$	255.49	$	242.49	$	(13.00)
GS >50 to 999 kW Interval <1000	60	kW	$	3,512.04	$	3,425.36	$	3,248.23	$	(177.13)
GS >50 to 999 kW	60	kW	$	3,496.48	$	3,422.90	$	3,245.78	$	(177.13)
GS >1,000 to 4,999	2,000	kW	$	134,337.28	$	126,103.86	$	119,387.07	$	(6,716.79)
Unmetered Scattered Load	100	kWh	$	14.84	$	17.78	$	16.92	$	(0.86)
Sentinel Lighting	29	kW	$	2,378.60	$	2,774.44	$	2,575.76	$	(198.68)
Street Lighting	176	kW	$	104,532.03	$	92,816.82	$	106,156.22	$	13,339.40
EMB - BPI	27	kW	$	7,849.35	$	7,229.70	$	7,161.36	$	(68.34)
EMB - HON #1	2,340	kW	$	212,927.34	$	186,396.95	$	178,608.04	$	(7,788.91)
EMB - HON #2	4,050	kW	$	276,731.57	$	268,125.65	$	253,658.19	$	(14,467.46)

279. Energy+ submits that the OEB staff proposal would not be fair and reasonable to Energy+'s customers and would be inconsistent with rate harmonization. In particular, customers in the Brant service territory would benefit from lower distribution rates due to rate harmonization, as well as the full amount of the disposition of Account 1576 D&V account, whereas the customers in the CND service territory, who are already impacted by higher distribution rates due to rate harmonization, would be further penalized with the majority of the recovery in Account 1575 directed to CND customers.

280. In the alternative, if the Board agrees with OEB staff that the Group 2 DVAs should be disposed of separately by rate zone, Energy+ submits that this should be limited solely to the 2019 test year and should not apply on a going forward basis. Energy+ submits that

continuing to require Energy+ to track and dispose of Group 2 DVAs separately on a going forward basis would undermine the purpose of rate harmonization and would create incremental administrative work that would reduce the net efficiencies gained from the consolidation of the former BCPI and CND.

G.1.2 Group 2 DVA Balances

G.1.2.1 Account Balances

281. OEB Staff submitted that they have no concerns with the December 31, 2017 Group 2 DVA balances as presented, with the exception of the balances in Account 1575 and 1576 [218] and the interest on the principal DVA balances[219].

282. VECC, CCC and SEC disagreed with the DVA balances proposed for disposition by Energy+ with respect to two Account 1508 Sub-Accounts: (i) Other Regulatory Assets – Monthly Billing; and (ii) Other Regulatory Assets – OEB Assessment Costs.

283. No other parties raised any other concerns with respect to the DVA balances as part of the Reply Submissions.

G.1.2.2 Interest on Principal DVA Balances

284. Energy+ agrees with OEB staff submissions with respect to the interest on principle DVA balances. OEB staff submitted that Energy+ should update its 2018 projected interest calculation using the published Q3 and Q4 2018 OEB prescribed DVA rates that became available after filing the Application. OEB staff further submitted that Energy+ should also forecast interest up to the implementation date of the rate riders from this proceeding and update the disposition amounts of the Group 2 DVA accounts accordingly.[220]

285. Energy+ proposes to make these updates as part of the draft rate order process following the Board's Decision in this proceeding.

[218] OEB Staff Submission dated March 29, 2019, page 41.
[219] Ibid, page 42.
[220] OEB Staff Submission dated March 29, 2019, page 41.

G.2 LRAMVA BALANCES

G.2.1 Generation Project Disposition Methodology

286. OEB Staff[221], VECC[222], CCC[223], and SEC[224] agreed with the methodology used by Energy+ to compute the LRAMVA claim with respect to a large user generation project ("**CHP**") undertaken as part of the IESO's Process and Systems Upgrade Initiative.

287. OEB Staff, VECC, CCC, and SEC also agreed with Energy+'s proposed disposition of the LRAMVA claim for the CHP project to the Large User class.

288. Energy+ notes that TMMC did not appear to take a final position with respect to the methodology with respect to the computation of the LRAMVA claim or the proposed disposition of the LRAMVA claim for the CHP project in its Final Reply Submission, despite having raised an observation about the general policy of how LRAMVA balances are recovered on a class by class basis as opposed to across classes.[225]

289. OEB staff noted that without further analysis or studies showing that the demand savings from the CHP project have benefitted all customers, OEB staff cannot support TMMC's proposal to dispose of the CHP project savings to all customer classes. OEB staff submitted that the approach proposed by TMMC is not consistent with the allocation of lost revenues in other LRAMVA claims. The continued approach to allocate LRAMVA claim at the participating rate class level is consistent with the cost causality principle, where the user who benefits from participating in IESO's CDM program would be subject to their applicable share of lost revenues.[226]

290. SEC's support for the disposition of LRAMVA to the Large Use class was due to fact that: i) the policy on recovery of the LRAMVA is well established and has been applied consistently to all distributors and all rate classes for years; and ii) LRAM only recovers the impact of approved conservation measures not built into distribution rates, meaning it

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221 OEB Staff Submission dated March 29, 2019, page 36.
222 VECC Reply Submission dated March 29, 2019, page 36.
223 CCC Reply Submission dated March 29, 2019, page 5.
224 SEC Reply Submission dated March 29, 2019, page 9.
225 Oral Hearing Transcript Vol. 2 dated March 8, 2019 at pages 41-42.
226 OEB Staff submission dated March 29, 2019 at page 38.

does not recover all other TMMC avoided costs due to its LDG facility.[227]

291. VECC submitted that it would be a fundamental deviation from Board policy and patently unfair to some customers for the LRAMVA claim to be recovered from any customer classes other than the customer class representing the customer(s) participating in the project.[228]

G.2.2 Streetlighting Project

292. OEB Staff[229], VECC[230], and CCC[231] agree with the methodology used by Energy+ to compute the LRAMVA claim with respect to a streetlighting project. None of the other parties objected to the computation of the LRAMVA claim with respect to the streetlighting project.

G.2.3 Conclusion

293. Energy+ submits the Board should approve its request for recovery of LRAMVA balances attributable to Energy Efficiency Programs as at December 31, 2017 in the amount of $1,545,771.

G.3 OTHER D&V ACCOUNTS

G.3.1 Other Regulatory Asset - Monthly Billing Costs

294. OEB staff expressed no concerns with Energy+'s request for recovery $416,346 for *Account 1508 Other Regulatory Assets – Sub-Account – Monthly Billing.*[232]

295. SEC submitted that they do not take issue with the costs included in the account, only the calculation of the cash flow benefits.[233] VECC and CCC supported the arguments of SEC on this matter in their submissions.

296. Energy+ does not agree with SEC's suggestion that Energy+ has not computed the cash

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[227] SEC Submission paragraph 30
[228] VECC Submission paragraph 4.11
[229] OEB Staff Reply Submission, March 29, 2019, page 39.
[230] VECC Reply Submission, March 29, 2019, page 37.
[231] CCC Reply Submission, March 29, 2019, page 5.
[232] OEB Staff Submission page 41
[233] SEC Reply Submission, March 29, 2019, page 6, paragraph 21.

flow benefits correctly. The actual cash flow benefit Energy+ received resulting from the transition to monthly billing was the incremental interest income received from the one-time cash influx from advanced collections and this benefit has been reflected in the updated evidence submitted.

297. Energy+ disagrees with SEC's argument that the appropriate way to measure the cash flow benefit of moving to monthly billing is to determine what the change in working capital would be compared to that built into the rates.[234]

298. Energy+ submits that SEC's approach constitutes retroactive ratemaking. Energy+ submits that the existence of a DVA can create an exception to this general prohibition on no retroactive ratemaking. However, the actual wording of the DVA becomes the most relevant unit of analysis. What is, and what is not, permitted from a retroactivity perspective?

299. In the Board's Decision and order dated March 17, 2016 (EB-2015-0057), the OEB approved the Energy+'s (former CND) request for an accounting order to establish a new deferral account to record incremental costs directly related to the implementation of monthly billing. As part of that Decision, the OEB noted that:

> "*the account will be used to record any incremental OM&A costs directly attributable to the transition to monthly billing. Costs will be net of any associated cost reductions resulting from the transition, including efforts towards paperless billing, improvements in cash flow, or reductions in bad debt.*"

300. Energy+ would highlight the following with respect to the Energy+ Decision and SEC's arguments:

- The OEB did not prescribe how the improvements in cash flow should be measured;

[234] SEC Submission dated March 29, 2019 at paragraph 22 to 28.

- The Board's Letter specifically states that the changes to working capital allowance will be implemented only in cost of service and Custom IR applications unless otherwise determined by the OEB in a prior decision[235]; and
- The date of Energy+'s Decision is dated almost one year after the Board's Letter dated June 3, 2015.

301. Energy+ submits that the Board, in its Decision in EB-2015-0057, did not make reference to computing the improvements in cash flow based on a change in the working capital allowance.

302. Rather, the Board identified improvements in cash flow as being listed together with (i) incremental OM&A costs, (ii) reductions in bad debt, and (iii) efforts towards paperless billing. Given this wording, it is reasonable to conclude that each of these calculations should be done on the similar basis - whether an actual cost basis, or on a retroactive rate based inquiry.

303. Energy+ submits that it is not reasonable to conclude, as suggested by SEC, that actual incremental OM&A costs be used for (i), actual reductions in bad debt be used for (ii), actual cost reductions due to paperless billing be used for (iii) – but only in respect of improvements in cash flow should the Board go back to look at how rates were previously established.

304. Energy+ submits that a change to the working capital component of revenue requirement does not constitute a cost, or cost reduction, resulting from the transition to monthly billing in the meaning of the accounting order.[236]

305. As part of its submission, SEC references a Board letter dated June 3, 2015 "Allowance for Working Capital for Electricity Distribution Rate Applications", whereby the Board updated its working capital default value to 7.5% from 13% for electricity rate applications.

306. Energy+ submits that utilizing an estimated change in working capital allowance for purposes of computing a proxy for cost reductions in the DVA balance would constitute

[235] OEB Letter dated June 3, 2015, page 3.
[236] Response to Interrogatories SEC-TCQ-10 dated January 22, 2019.

improper retroactive rate making as it relates to the working capital allowance previously approved for Energy+ Inc, as part of the former CND and BCP's rate base.

307. Energy+ submits that the Board should approve the balance of $416,346 for *Account 1508 Other Regulatory Assets – Sub-Account – Monthly Billing* for disposition.

G.3.2 Other Regulatory Asset - OEB Cost Assessment

308. OEB staff expressed no concerns with Energy+'s request to dispose of $174,262 for *Account 1508 Other Regulatory Assets – Sub-Account – OEB Cost Assessment.*[237]

309. Energy+ disagrees with SEC[238], VECC[239], and CCC[240] that the balance of $174,262 should not be recovered from customers. These parties argue that the amount is below Energy+'s purported materiality threshold of "250,000".

310. Energy+ does not agree.

311. Energy+ submits that the materiality threshold that should be used for purposes of assessing the recoverability of this account is $125,000. The $125,000 used by Energy+ represents the materiality threshold applicable at the time of Energy+'s last rebasing, which was 2014. The OEB Cost Assessment last included in rates was in 2014.

312. Energy+ submits that the use of $125,000 aligns and is consistent with the purpose of the account, which is to record any material difference between OEB Cost Assessments currently built into rates, and cost assessments that will result from the application of the new cost assessment model effective April 1, 2016.[241]

313. If the Board would prefer to use the actual materiality threshold for Energy+ in 2019, then in accordance with the Chapter 2 Filing Requirements this amount is calculated as 0.5% of the distribution revenue requirement. This results in a materiality threshold of $171,639, which is 0.5% of the distribution revenue requirement agreed to in the

[237] OEB Staff Submission dated March 29, 2019, page 41.
[238] SEC Submission dated March 29, 2019, page 6.
[239] VECC Submission dated March 29, 2019, page 34.
[240] CCC Reply Submission dated April 7, 2019, page 2.
[241] OEB Letter, February 9, 2016, Revisions to the Ontario Energy Board Cost Assessment Model, page 2.

Settlement Proposal of 34,327,788.[242]

314. In either case, the amount requested for disposition in the OEB Cost Assessment account exceeds the Energy+'s materiality threshold.

315. Finally, Energy+ notes that an additional $80,302[243] was estimated by Energy+ to be recorded in this account in 2018, resulting in a cumulative total of approximately $254,564, up to December 31, 2018. This exceeds SEC's alternative materiality threshold of $250,000.

316. Energy+ does not agree with VECC's submission that Energy+ should distinguish in the variance account between the variance caused by the change in methodology and the natural variance that occurs as between the last cost of service forecast of OEB assessment cost and actual cost.[244]

317. Energy+ has followed the OEB's direction in terms of the amounts to be recorded in the variance account as follows:

> "Entries into the variance accounts are to be made on a quarterly basis when the OEB's cost assessment invoice is received. Amounts should be prorated to take into account the effective date of rebased/reset rates, payment amounts or fees"

318. Energy+ notes that there is no suggestion from the Board with respect to distinguishing the nature of the variances in the OEB Cost Assessment as submitted by VECC.

319. Energy+ also submits that its computation of the variance account is consistent with the approach used in EB-2018-0050[245] and EB-2017-0032[246], which were approved for disposition as part of a Settlement Agreement.

320. Energy+ submits that the Board should approve the disposition of the account as requested by Energy+ as the amount meets the materiality threshold and Energy+ has followed the

[242] Settlement Proposal dated December 12, 2018 at Table 2 – Revenue Requirement Summary.
[243] Response to Interrogatories 9-Staff-104 dated September 14, 2018.
[244] VECC Submission dated March 29, 2019, page 34.
[245] EB-2018-0050 Lakeland Power Distribution Ltd., Response to IR 9-Staff-88
[246] EB-2017-0032 Centre Wellington Hydro Ltd. Response to IR 9-Staff-94

Board's guidance with respect to the computation of the amounts to be included in the variance account.

G.3.3 Discontinued and New DVA Accounts

321. OEB Staff supported Energy+'s proposal to discontinue certain DVA Accounts[247] with the exception of Account 1575 IFRS-CGAAP Transition PP&E Amounts, Account 1576 Accounting Changes under CGAAP, and Account 1557 MIST Cost Deferral Account.

G.3.3.1 Accounts 1575/1576

322. Energy+ agrees with OEB staff that Accounts 1575/1576 should remain open to capture the differences in the balances and any material residual balance be brought to the OEB for disposition at the next cost-based rate application.

323. OEB Staff have proposed that in the event that the audited 2018 account balances for these accounts are not available, these accounts should remain open to track the actual 2018 transactions and any material residual balance in the account compared to what was approved as part of the current Application should be brought forward to the OEB for disposition at the next cost based rate application. OEB Staff submission is based on the fact that estimates were used by Energy+ to project the 2018 closing balances for Account 1575 and 1576 at the time the application was initially prepared and filed. OEB Staff also submitted that provided the Applicant is able to update the proposed disposition amounts with the 2018 audited financial statements, the OEB staff would have no concerns with Energy+'s proposal to discontinue these accounts.[248]

324. Energy+ is not proposing to update the balances in the accounts to reflect 2018 actuals, although the audited 2018 results are available. Energy+ submits that the estimates used for the 2018 transactions, and corresponding PP&E balances at the end of December 31, 2018 and 2019 reconcile with the fixed asset balances used to derive the agreed upon rate base for purposes of the Settlement Proposal. Energy+ submits that updating the values for 2018 actuals in Account 1575 and 1576 without a corresponding adjustment to rate

[247] Energy+ Inc., EB-2018-0028, Exhibit 9, Table 9-20
[248] OEB Staff Submission dated March 29, 2019 page 42

base would create inconsistencies and reconciliation issues in future applications.

G.3.4 Account 1557 Meter Cost Deferral Account – Mist Meters

325. OEB staff noted in its submission that it is not clear as to why Energy+ would be seeking to discontinue this account when it appears that the related work is yet to be completed and that further costs are to be incurred in 2018 and 2019.[249]

326. Energy+ submits that MIST meter capital projects for 2018 and 2019 have been included in rate base as part of this Application.[250] In this Application, Energy+ has proposed the disposition of the balance in account 1557 up to December 31, 2017. Energy+ does not expect to record any further costs in this account post December 31, 2017 and therefore has requested that this account be discontinued.

H. LOAD FORECAST (ISSUE 3.1)

3.1 Are the proposed load and customer forecast, loss factors, CDM adjustments and resulting billing determinants appropriate, and, to the extent applicable, are they an appropriate reflection of the number and energy and demand requirements of the applicant's customers?

327. Pursuant to the Settlement Proposal filed December 12, 2018 this issue was partially settled. As noted in the AIC, the Board's determination on the unsettled issues could affect the final load forecast, including the large user Standby adjustment, the CDM adjustments and the LRAMVA threshold value, and the resulting billing determinants.

328. OEB Staff supported the adjustments to the load forecast and the resulting billing determinants as appropriate if the Board approves Energy+'s standby charge proposal. Board staff also agreed that these adjustments should be removed if the Board determines not to implement a standby charge to LDG in this proceeding.[251]

329. TMMC did not take a position on this issue specifically, however, as outlined in Section

[249] OEB Staff Submission dated March 29, 2019, page 44.
[250] Energy+ Inc., EB-2018-0028, Exhibit 2, Chapter 2 Appendix Appendix 2-AA.
[251] OEB Staff Submission dated March 29, 2019, page 45.

F, TMMC has proposed a different methodology for the Standby Charge, that includes, amongst other differences, a contracted capacity level that is different than Energy+'s proposal.

330. None of the other parties objected to the appropriateness of the adjustments required should the Board approve Energy+'s standby charge proposal as requested, nor the removal of the adjustments should the Board determine not to implement a standby charge to LDG.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 23RD DAY OF APRIL, 2019

BORDEN LADNER GERVAIS LLP

Per:

Original signed by John A. D. Vellone

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