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March 15, 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 Argument-in-Chief

Please find enclosed Energy + Inc.'s Argument-in-Chief in this proceeding. Paper copies of this letter and the accompanying Argument-in-Chief 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.

ARGUMENT-IN-CHIEF OF ENERGY+ INC.

March 15, 2019

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A. INTRODUCTION

1. Energy+ Inc. ("**Energy+**") submits this written argument-in-chief in respect of an Application filed by Energy+ on April 30, 2018, 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 July 26, 2018, the OEB issued Procedural Order No. 1 approving Brantford Power Inc. ("**BPI**"), Consumers Council of Canada ("**CCC**"), Hydro One Networks Inc. ("**Hydro One**"), School Energy Coalition ("**SEC**"), Toyota Motor Manufacturing Canada Inc. ("**TMMC**" or "**Toyota**") and Vulnerable Energy Consumers Coalition ("**VECC**") as intervenors in this proceeding.

3. On October 31, 2018, the OEB issued Procedural Order No. 4 and Decision on Issues List with the final and approved issues list for the Application attached as Schedule A (the "**Issues List**").

4. On December 12, 2018, Energy+ filed a Settlement Proposal with the OEB representing a partial settlement of the issues in this Application (the "**Settlement Proposal**").

5. This argument-in-chief is organized to address each of the unsettled issues, with a direct link to the Issues List, as follows:

   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)

6. As of the date of filing this argument-in-chief, we have not received a copy of the TMMC responses to undertakings that arose during the oral hearing. Energy+ reserves the right to address any new information arising from those undertaking responses in its reply submissions.

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.*

7. The parties were able to reach agreement on all aspects of Issue 1.1 in the Settlement Proposal with the exception of 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.

8. Section 2.2.2.3 of the *Chapter 2 Filing Requirements For Electricity Distribution Rate Applications* issued July 12, 2018 provides that, as part of a cost of service application, a distributor may propose qualifying Advanced Capital Module ("**ACM**") projects that are expected to come into service during the subsequent Price Cap IR term.

9. An ACM proposal must comply with the *Report of the Board: New Policy Options for the Funding of Capital Investments: the Advanced Capital Module* (EB-2014-0219) issued September 18, 2014 (the "**Original Report**") and the *Report of the Board: New Policy Options for the Funding of Capital Investments: Supplemental Report* (EB-2014-0219) issued January 22, 2016 (the "**Supplemental Report**", and together with the Original Report the "**ACM Reports**").

10. As stated in the ACM Reports, the ACM:

> *"… advances the review and approval process for incremental capital from the year in which the proposed projects will be entering service (i.e. the IR term) to the preceding cost of service application in which a distributor is required to file a five*

> *year Distribution System Plan encompassing the cost of service test year and the four subsequent incentive rate-setting ("IR") years*."

11. The Handbook to Utility Rate Applications dated October 13, 2016 states in the glossary of terms for the ACM:

> "*An ACM proposal is made during a cost of service application to identify, based on the 5-year capital plan in the Distribution System Plan, qualifying incremental capital expenditures during the subsequent IRM period that are necessary but require funding beyond what is sustained by IRM-adjusted rates and customer and load growth. Reviewing ACM projects as part of a cost of service application allows for testing of the need, pacing and prioritization of projects as part of the more comprehensive review that occurs in processing a cost of service application.*"

12. Energy+ has taken a longer term view to its investments in its facilities and has made considerable efforts to extend the period over which to make these investments in order to mitigate customer bill impacts, while at the same time recognizing the need to invest in upgrades to its facilities.

13. The review and approval of business cases for ACM requests are subject to the criteria of:

- 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."[1]

14. The proposed Southworks facility is a discrete $8.1 million investment in a proposed new administrative office that is not part of the typical Energy+ annual capital program.

[1] See the Original Report at Section 4.1.1.

B.2 Material

"*The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.*"[2]

15. The OEB ACM/ICM materiality threshold formula is set out in Section 4.5 of the Supplementary Report as:

Threshold Value (%) = $1 + [(RB/d) \times (g + PCI \times (1 + g))] \times ((1 + g) \times (1 + PCI))^{n-1} + 10\%$

where:

- RB = proposed test year rate base from the distributor's Cost of Service application.
- d = proposed depreciation expense for the test year from the distributor's Cost of Service application.
- g = growth is calculated based on the percentage difference in distribution revenues between the forecast distribution revenues for the test year from the distributor's cost of service application and the distribution revenues from the most recent complete year.
- PCI = Price Cap Index (IPI stretch factor) fixed at 1.2%.
- n = number of years since the effective year of the Cost of service application.

16. Tables 1 and 2 below provide the calculation of the Threshold Capital Expenditure and Eligible Incremental Capital amounts based on the OEB's ACM model, which was updated to reflect the settlement between the parties in the Settlement Proposal.[3]

[2] Ibid at Section 4.1.5.
[3] *2019 EnergyPlus ACM_Model_OEB – Settlement_20181212.xlsm*

Table 1: Threshold Capital Expenditures

Threshold Capital Expenditure Calculation - As per ACM Model		
Parameter		**Amount**
Price Cap Index		1.20%
Growth factor over 2 years		0.54%
Rate Base		$173,825,304
Depreciation		$6,269,103
Threshold Value for 2020		158%
Threshold Value for 2021		159%
Threshold Value for 2022		160%
Threshold Value for 2023		161%
Threshold CAPEX 2020		$9,923,533
Threshold CAPEX 2021		$9,976,263
Threshold CAPEX 2022		$10,029,912
Threshold CAPEX 2023		$10,084,495

Table 2: Eligible Incremental Capital

Eligible Incremental Capital	
	Year 3
	2022
Capital Expenditures, as per DSP	$22,071,000
Materiality Threshold	$10,029,912
Maximum Eligible Incremental Capital	$12,041,088
Proposed Capital Projects	**$8,100,000**
Maximum Allowed Incremental Capital	**$8,100,000**

17. As can be seen above, 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

18. There is no longer any requirement that the project must be non-discretionary to be eligible for ACM funding. Any discrete project (discretionary or otherwise) adequately supported in the Application is eligible for ACM funding subject to capital funding availability

flowing from the formula results.[4]

19. In its 2014 Cost of Service Application (EB-2013-0116), the former Cambridge and North Dumfries Hydro Inc. ("**CND**") identified that it was undertaking a comprehensive space study with respect to its corporate offices and operating facilities.[5] At that time, it was noted that the existing facilities were constructed in the 1980's and since that time, the utility and the industry had undergone significant change.

20. The need for the Southworks facility is detailed in the Energy+ Facilities Business Plan,[6] which was updated in an evidence update[7] on December 13, 2018 to reflect the best available information following the completion of the Settlement Proposal including a recently completed Class "C" estimate for the work (collectively, the "**Facilities Plan**").

21. The growth in CND's business over the years, as well as an increase in the number of full-time employees, has resulted in insufficient office space. This is detailed in a comprehensive space-needs analysis dated March 24, 2014 and included as Appendix A to the Facilities Plan.[8]

22. The November 2014 acquisition of Brant County Power Inc. ("**BCPI**") made the need for a new facilities strategy paramount. The new facilities plan would need to accommodate the substantial OM&A efficiencies arising directly from a consolidation of administrative staff in Cambridge while ensuring that the operational needs in both the former CND and BCPI service areas are met. Customers are now benefiting from these efficiencies.

23. Energy+ continued to review the status of its current facilitates to ensure it is effectively meeting its customers' and employees' needs and prudently managing facilities related expenses.

24. Energy+ currently operates out of three facilities.

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[4] See the Original Report at Section 4.1.3.
[5] Response to 7.1-SEC-41 filed February 25, 2014 in EB-2013-0116.
[6] Exhibit 2, Appendix 2-1 – Distribution System Plan, Appendix N: Facilities Business Plan.
[7] Energy+ Update to the Evidence filed December 13, 2018.
[8] Exhibit 2, Appendix 2-1 – Distribution System Plan, Appendix N: Facilities Business Plan, Appendix A – Space Needs Analysis (Printed pages 1056-1276, pdf pages 962-1183).

25. The first is the head office and operations centre located at 1500 Bishop Street North, Cambridge (the "**Bishop Street Building**"). This 53,000 square foot facility is 37 years old, 12 years past its intended 25-year lifespan when the original building was constructed in 1981. This facility has proven to be too small to accommodate Energy+'s growth in employees over the past 5 years (see Thompson Drive below). To accommodate administrative employees from the BCPI acquisition in 2014, workstations had to be built in areas of the building which were never intended for this type of use, including hallways, closets, vaults, and meeting rooms. The current state of the facility does not provide comfortable or reasonable space to many administrative employees. Thirty-five (35) workstations (42% of total workstations) do not have any access to natural light.[9]

26. The second is the administrative office located at 135 Thompson Drive, Cambridge (the "**Thompson Drive Building**"). This 5,147 square feet of office space was leased in 2013 to accommodate employees in the finance, regulatory and energy efficiency departments.[10] This created a physical separation between administrative departments that routinely need to interact for day-to-day business operations: finance, accounting and regulatory are located at the Thompson Drive Building, while customer care, billing and the executive leadership team (except finance) are located at the Bishop Street Building, as was explained by Ms. Hughes at the oral hearing.[11] This causes inefficiencies including duplicate meetings between the two locations, and results in employees frequently having to travel back and forth between two locations for certain meetings and work requirements.

27. The third is an administrative and operational building located at 65 Dundas St. E., Paris (The "**Dundas St Building**"), which previously served as the head office for the former BCPI. This building is more than 34 years old and is in very poor condition, requiring numerous repairs to fix roof leaks, flooding and mold growing in part of the building. Following the amalgamation of BCPI and CNDHI, the facility provided functionality that is no longer required by the utility. Specifically, the administrative portion of the building (approximately 5000 square feet) is unused by Energy+ since those employees were

[9] Facilities Plan filed April 30, 2018 at pages 1034-1035.
[10] Ibid.
[11] Transcript Vol. 1 dated March 7, 2019 at pg. 42, lines 7-15.

relocated to Cambridge. The operational space, on the other hand, is too small to accommodate the customer needs and expected growth in the Brant County service territory.

28. The three existing facilities provide for a current 72,630 square feet in operations and administrative space across the three buildings, as shown in Table 3 of the Facilities Plan, which the Energy+ Facilities Plan proposes to expand to 88,243 square feet in dedicated operations and administrative space, as shown in Table 4 of the Facilities Plan.

B.4 Prudence

29. Starting in 2013, Energy+ completed a comprehensive, multi-year review of various alternatives including renovating/rebuilding currently owned buildings, purchasing/renovating alternative facilities, leasing alternative facilities and construction of new facilities. This is fully detailed in the Facilities Plan.

30. Specifically, Energy+ assessed six (6) different alternatives to meet its space needs in the CND service territory:[12]

a. Build a third floor on the Bishop Street Building ("Option 1")

b. Expand the Bishop Street Building ("Option 2")

c. Retain the Bishop Street Building for an administrative office and build a new operations centre ("Option 3")

d. Build a combined operations centre and administrative office at a new location ("Option 4")

e. Renovate an existing building in Cambridge for both administration and operations ("Option 5")

f. Renovate an existing building in Cambridge for administrative space and retain the

[12] Exhibit 2, Appendix 2-1: Distribution System Plan, Appendix B – Facilities Business Plan, Section 6 (pages 1035-1041, pdf pages 941-947).

Bishop Street Building for operations ("Option 6")

31. In assessing these alternatives, Energy+ applied the following decision criteria:

a. Maintain operational facilities to provide construction, maintenance, and emergency restoration services in Energy+'s service territory. Given the geography of the service territory, it is necessary to maintain two facilities – one to service the Brant County territory (256 square kilometers) and one to service the Cambridge and North Dumfries territory (306 square kilometers);

b. Consolidate all administrative functions to one location to allow for rationalization and more efficient processes between departments;

c. Minimize costs to ratepayers by avoiding high cost facility solutions (cost of land, premium building construction / renovation);

d. Meet the needs of a growing utility in the future and maintain future flexibility by separating operational space from administrative space, allowing for: (a) administrative space to be expanded in the case of mergers or acquisitions or (b) greater options in the case a merger or sale that involves consolidating administrative functions in another city. Regardless of which scenario emerges, the two operations facilities will continue to be required to support operations, maintenance, restoration, and customer service;

e. In the case of the Brant County facility, align considerations with BPI wherever possible to maximize shared service opportunities; and

f. Provide a comfortable and safe work environment for Energy+ employees.

32. The multi-year analysis conducted by Energy+ is summarized in the Facilities Plan.[13]

33. It included completing two detailed third-party feasibility assessments completed by MTE Consultants Inc. (2013 and 2014) on Options 1 and 2.[14] These feasibility assessments

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[13] Exhibit 2, Appendix 2-1: Distribution System Plan, Appendix B: Facilities Business Plan at page 1037-1039.
[14] Exhibit 2, Appendix 2-1: Distribution System Plan, Appendix N – Facilities Business Plan at pg. 1037-1038 and

focused on whether or not Energy+ could cost effectively utilize the existing Bishop Street Building to meet increased space needs. Why build new if you don't have to? The feasibility assessment identified a number of challenges with this approach, the biggest arising from the fact that the Bishop Street Building is located adjacent to a wetland and known setback requirements greatly limit the ability to expand the Bishop Street Building. Because of these limitations, the costs of Options 1 and 2 came in higher than expected.

34. Energy+ next retained CBRE in 2015 to conduct a detailed market analysis to assess the viability of Options 3, 4, and 5.[15] Following a detailed assessment of market options, Energy+, with the assistance of CBRE, was unable to identify any suitable existing facilities that could be renovated to meet Energy+'s needs. There were some opportunities for new builds, however the cost estimates for Options 3 and 4 once again came in higher than expected.

35. All costing estimates were prepared by an independent third party advisor (Melloul-Blamey Construction Inc.) for each of the viable options to ensure a like-for-like comparison across different options, all of which are all included in the Facilities Plan. The results are summarized in Table 1: CND Option Summary table filed December 13, 2018, which is summarized below for ease of reference.

36. As can be seen below, Energy+'s preferred option will cost a total of $10,100,000 to service the CND service territory, which is $18,538,555 less than the next cheapest alternative (renovating Bishop Street) and is $21,434,277 less than the costs of building a new operations centre.

at Appendix B.

[15] Exhibit 2, Appendix 2-1: Distribution System Plan, Appendix N – Facilities Business Plan at pg. 1038-1039 and Appendix D.

Table 1: CND Option Summary

Option	Description	Building Costs	Notes
1, 2	(1) Build a third floor on the Bishop Street Building. (2) Expand the Bishop Street Building.	$28,638,555 or $33,078,530 for LEED building.	Considerable site approval challenges due to proximity to wetlands. Cannot easily build on older (1989) portion of the building.
3, 4	(3) Retain the Bishop Street Building for an administrative office and build a new operations centre. (4) Build a combined operations centre and administrative office at a new location.	$31,534,277 or $32,980,677 for LEED building.	Land not included at $300,000 to $400,000 per acre.
5	Renovate an existing building in Cambridge for both administration and operations.	Not applicable.	Lack of suitable sites due to need for outside storage, garage and proximity to major roads.
6	Renovate an existing building in Cambridge for administrative space and retain the Bishop Street Building for operations.	Southworks (administrative): $8,100,000 (exclusive of HST) Bishop Street (operations): $2,000,000	**Preferred option.**

37. Upon completing this comprehensive, multi-year review of various alternatives, Energy+ developed the following plan in respect of its land and buildings in the Cambridge and North Dumfries service area, as described in greater detail in the Facilities Plan:

a. Centralize all administrative functions to a new head office building in the Southworks facility in Cambridge. Energy+ has entered into a Purchase and Sale Agreement to acquire a portion of an existing building for $1.00. Energy+ plans to renovate the building to make it suitable to be an administrative office. All administrative staff will be relocated to this building. Energy+ expects to occupy this new space in 2022.

b. The existing building at the Bishop Street Facility will be renovated and modernized. This building will continue to be utilized as the operations centre to service customers in the CND service territory. Renovations to the existing building are planned for a period beyond the existing five year plan, most likely in 2023-2024.

c. The lease for office space at the Thompson Drive Facility will be terminated. The employees at this location will be relocated to the Southworks Facility in 2022.

38. While outside the scope of the current Application, Energy+ also decided on a plan to sell the land and building at the Dundas Street Facility (which was no longer fit for the intended use) in a sale-leaseback transaction on April 3, 2018. Energy+ is currently working very closely with its neighboring utility, BPI, to identify a cost-effective shared facility which Energy+ can utilize as an operations centre to service customers in the Brant County area while enabling the sharing of inventory, warehousing, a purchasing manager, stores person, fueling stations and vehicle maintenance in the new shared location.

39. Prior to proceeding, Energy+ also conducted benchmarking of its proposed Facilities Plan against publically available information of other LDCs. This benchmarking exercise is shown in the updated version of Table 6 filed December 13, 2018, reproduced again below as Table 2.

Table 2: Cost and Utilization Comparison to Other Distributors

LDC	Energy+ (Southworks, Bishop Street & Garden Avenue Combined)	Waterloo North Hydro Inc.	InnPower	Milton Hydro Distribution Inc.	PUC Distribution Inc.
OEB Docket	EB-2018-0028	EB-2015-0108 EB-2010-0144	EB-2014-0086	EB-2015-0089	EB- 2012-0162
Year of Occupancy	2020/2022/2024	2011	2015	2015	2012
Functions	Administration & Operations	Administration & Operations	Administration & Operations	Administration & Operations	Administration & Operations
Type of Project	Purchase/ Refurbish	Custom Build	Custom Build	Purchase/ Refurbish	New Build
Capital Cost	$14,500,000	$26,682,000	$10,896,704	$12,524,798	$23,000,000
Square Footage	88,243	105,000	36,172	91,872	110,382
FTEs	131	125	41	61.5	87
Square Foot per FTE	674	840	882	1,494	1,269
Capital Cost per FTE	$110,687	$213,456	$252,139	$203,655	$264,368
Capital Cost/Square Foot	$164.32	$254.11	$285.79	$136.33	$208.37

40. The comparison demonstrates that Energy+ is proposing a Facilities Plan that is appropriately sized for its work force. Energy+'s proposal results in 674 sq.ft./FTE. The next closest comparator has facilities space that is **25% larger** than Energy+.

41. In terms of costs, Energy+'s Facilities Plan results in a capital cost per FTE of $110,687. The next closest comparator **spent 84% more per FTE** than Energy+ is proposing to

spend.

42. Finally, with regards to capital cost/sq.ft., the Energy+ Facilities Plan results in a capital cost/sq.ft. of $164.32, which is cheaper than all of the comparators with the sole exception of Milton Hydro.[16]

43. Any such benchmarking comparisons are not a perfect exercise. Costs for the comparators are from 2011, 2012 and 2015, which have not been adjusted for known inflationary increases in materials or construction costs. Consequently the costs of the comparators are understated when comparing to a Facilities Plan for the period 2020-2024.

44. In addition, each of the comparators moved into a combined operations and administration facility. Operations space generally has a higher cost/FTE and lower cost/sq. ft. (large spaces for garages and indoor storage) while administrative space generally has a higher cost/sq.ft. and a lower cost/FTE (building workspaces to house a large number of employees is more costly). To facilitate an apples-to-apples comparison, Energy+ compared its comprehensive Facilities Plan (including all operations and administrative space) against the combined operations and administrations space utilized by its comparators.

45. The cost efficiencies that arise directly from the proposed Southworks facility arise from the ability to eliminate the Thompson Drive lease and to more effectively utilize the Bishop Street Facility space at a very low cost. It would not be appropriate to consider the proposed Southworks facility, without also accounting for the efficiencies gained at Thompson Drive and the Bishop Street Facility.

C. COST ALLOCATION (ISSUE 3.2)

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

[16] Milton Hydro achieved this very low cost/sq.ft. by acquiring an existing building that was much larger than they actually needed. As is described in the Facilities Plan, Energy+ focused first on "right sizing" its facilities plan to ensure total costs to ratepayers are appropriate. In addition, Energy+ explored existing buildings with CBRE and no other viable alternatives were available.

46. The OEB outlined its cost allocation policies in its reports of November 28, 2007 titled "*Application of Cost Allocation for Electricity Distributors*" (EB-2007-0667) and of March 31, 2011 titled "*Review of Electricity Distribution Cost Allocation Policy*" (EB-2010-0219). These are referred to here as the Board's "**Cost Allocation Policies**".

47. In the Application, Energy+ used the 2018 version of the cost allocation model released by the OEB on July 14, 2017 to conduct a 2019 test year cost allocation study consistent with the OEB's Cost Allocation Policies. The model was loaded with 2019 test year costs, customer numbers and demand values for Energy+. The 2019 demand values were determined based on the description provided under Exhibit 7 of the Application. The various weighting factors used in the 2019 study have also been explained in Exhibit 7.

48. An updated version of the Board's cost allocation model, which was revised to reflect the Settlement Proposal, was filed on December 12, 2018. The Applicant's proposal was further revised as updated in response to TCQ VECC 76 to address several other minor adjustments.

49. There are a number of factors weighing in favor of using the Board's standard cost allocation model and approach for all customer classes. First, while it is by no means simplistic, it is based on established policies and procedures that are well understood across the sector as a whole. This has a practical benefit - staff at Energy+, board staff and all customer groups can readily understand, assess and evaluate the model inputs and outputs. Second, it creates consistency with how costs are allocated by a wide number of different LDCs across the Province (subject to some noteworthy exceptions).

50. That said, Energy+ recognizes that the Board may determine that other approaches may be simple, understandable, acceptable, feasible, fair and reasonable. The exercise of cost allocation is, and should be, revenue neutral to Energy+.

51. As the Application has progressed, Energy+ has been asked to prepare a number of alternative scenarios to the original cost allocation model as requested by various intervenors. In addition, one intervenor (Toyota) filed the evidence of Mr. Pollock which contained at least two other alternative scenarios (referred to as "JP-5" and "JP-11").

52. These scenarios proposed variations with respect to one versus two Large User rate classes, a wide variety of approaches to direct allocation and indirect allocation to the Large User rate class (in the one Large User rate class approach) or to TMMC (as part of a two Large User rate class approach), and allocation to the embedded distributors as per Appendix 2Q or similar to other rate classes.

53. In response to technical conference question SEC-11, Energy+ summarized the bottom-line bill impacts arising from each of these different scenarios. Exhibit K1.6 reflects an updated version of this summary table, which also includes the most recent proposal from Mr. Pollock in Schedule JP-11 as filed March 1, 2019. Each scenario results in a different allocation of costs as between different classes of customers, as shown in Exhibit K1.6.

54. Energy+ is open to considering alternative cost allocation scenarios, provided they achieve a just and reasonable rate that is consistent with the following relevant generally accepted principles of public utility ratemaking:

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

55. With regards to simplicity / understandability / feasibility: Several of the scenarios proposed are very complicated. Numerous errors have come to light during multiple rounds of discovery, particularly on the intervenor evidence which has been filed, and refiled, numerous times throughout this process. While parties in this proceeding have taken steps to correct errors once identified, this demonstrates just how complicated this exercise is and how easy it is to make a mistake.[17]

56. Energy+ also noted a number of other practical concerns it had during its evidence in-

[17] Corrections have continued to be necessary even up to the oral hearing. (See, for example, Undertakings J2.1 and J2.2).

chief.[18] Perhaps most directly, because Energy+ has not undertaken a detailed direct allocation study, there remains uncertainty with whether Energy+ has correctly identified and quantified all of the appropriate direct costs for TMMC – particularly with respect to OM&A costs.[19] For this reason, Energy+ believes that there would at best be both directly and indirectly allocated costs regardless of which approach the Board chooses.

57. With regards to public acceptability: we expect each of the other intervenors will provide relevant input. To this, Energy+ would highlight the comments received from its only other large use customer, which was filed on March 6, 2019 and stated:

> "[CUSTOMER NAME REDACTED] should not be responsible for infrastructure costs put in to meet the needs of a big company like TMMC. When they choose to find alternate sources of power, it is unfair to burden other businesses with the costs, especially in a high electricity cost market. This action will prompt us to move business out of this plant to lower the impacts of costs long term, and move it to more business-friendly jurisdictions where we already have capacity to absorb more work.
>
> This additional cost only increases this Cambridge plant's uncompetitive electricity rates versus its two other plants, and adds cost that our customers are unwilling to absorb."

58. With regards to fairness: Energy+ believes that there are a number of different issues that must be addressed in submissions. Specifically:

- Is Toyota's proposal to create two separate Large User rate classes appropriate?
- Is Toyota's proposal to directly allocate feeder costs to the Large User customer class appropriate?
- Should any other costs (other than feeder costs) be directly allocated to the Large User customer class?
- Is Toyota's proposal to allocate $0 in costs for bulk distribution facilities to TMMC appropriate?
- Is Toyota's proposal to allocate $0 in costs for underground distribution facilities to TMMC appropriate?

[18] Transcript Vol. 1 (Public, redacted) dated March 7, 2019 at page 19, line 19 to page 20, line 27.
[19] Ibid. at page 20, lines 7-27.

59. Energy+ does not consider two separate Large User customer classes as appropriate due to a number of factors, including increased regulatory and administrative costs entailed by this, ongoing problems with confidentiality of customer information (as there would only be one customer in each of the two rate class), and challenges with deciding which would be the appropriate large user rate class to apply to any future large user in Energy+'s service territory.[20] 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).[21]

60. 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,[22] and that such direct allocation should also account for the capital contribution paid by TMMC in support of those feeder costs.[23] This is shown in Table TMMC-IR-2(d) as the net of the Feeders line and the Contribution line. However, Energy+ also noted that its estimate of O&M costs associated with those feeders has a fairly high margin for error, since there was not a time study completed to create these estimates.[24]

61. Energy+ is of the view that no other costs should be directly allocated to the Large User customer class. Energy+ agrees with Toyota's expert that pooled assets, including poles, should continue to be allocated indirectly in accordance with the Board's standard cost allocation model.[25]

62. Energy+ does not agree that Toyota's proposal to allocate $0 in costs for bulk distribution facilities[26] to TMMC is appropriate. All Energy+ customers are served either by Energy+ owned transformer stations (which are referred to as bulk distribution facilities, and funded through distribution rates) or Hydro One owned transformers stations (funded through

[20] Ibid. at page 19, line 26 – page 20, line 6.
[21] Transcript Vol. 2 page 17, lines 2-8.
[22] Transcript Vol. 1 (Confidential, Unredacted) at page 166, lines 16-22.
[23] Energy+ response to Technical Conference TMMC IR-1 filed January 22, 2019.
[24] Transcript Vol. 1 (Confidential, Unredacted) at page 171, line 6 – page 172, line 13.
[25] Transcript Vol. 2 at page 129, line 28 – page 130, line 18.
[26] As defined in the Energy+ response to Technical Conference TMMC IR-3 filed January 22, 2019.

RTSR).27 Currently, both bulk distribution costs and RSTR charges are allocated across all customer classes in accordance with the Board's cost allocation model and RTSR model without consideration of specific source of supply for each customer or class. In this context, Energy+ does not agree that Toyota should be excused from paying for bulk distribution facilities. Toyota is not proposing to pay a corresponding increase in RTSR charges to reflect the fact that it is served exclusively by a Hydro One owned transformer station. We are concerned that Toyota would be cross-subsidized by other Energy+ customers that utilize an Energy+ transformer station as their source of supply but must also pay RTSR charges to fund the Hydro One owned transformer station even though they are not utilizing that source of supply.

63. Energy+ also does not agree that Toyota's proposal to allocate $0 in costs for underground distribution facilities to TMMC is appropriate. All of Energy+ customers are served by overhead and/or underground distribution facilities.28 Currently the costs of both overhead and underground facilities are allocated to all customer classes in accordance with the Board's cost allocation model without considering, on a customer-by-customer basis, exactly what types of assets are used to serve them. We are concerned, again, that Toyota would be cross-subsidized by other Energy+ customers that use primarily underground assets to receive service but must also pay for a share of overhead assets in accordance with the Board's cost allocation model.

64. The approach explained above by Energy+ was explored during the interrogatory process, in response to TCQ VECC-72(c). The bill impacts associated with this approach are shown in Exhibit K.1.6.

65. A fundamental principle of public utility ratemaking is that equals are treated equally. This is a fairness principle. If changes are made for Toyota, other customers who request29 similar changes should expect similar treatment. With improvements in corporate

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[27] Exhibit 2, Appendix 2-1: Distribution System Plan at Section 1.3.1. See also Table 3-2: Summary of Energy+ system configuration.
[28] Exhibit 2, Appendix 2-1: Distribution System Plan at Section 3.2.1.
[29] It is likely not reasonable to expect that customer who would be entitled to similar treatment would even understand or know enough to make such a request. Not all customers are as well financed as Toyota, to retain legal counsel and expert consultants, to make a request.

information systems and with the introduction of an increasingly detailed asset registry, direct allocation could, in theory, be done for a wide variety of other Energy+ customers. For example, Energy+ has other customers in the commercial and industrial rate classes that are served only from the Energy+ overhead system. Should those customers also be allocated $0 for underground assets? As another example, Energy+ has other customers in the commercial and industrial rate classes that are served only from Hydro One owned transformer stations. Should those customers also be allocated $0 for bulk distribution assets? Should costs be allocated to all customers differently based on method of supply?

66. Finally, with regards to the avoidance of cross-subsidies: if the Board agrees to make changes to the cost allocation model to Toyota's benefit the Board should also eliminate other known circumstances where other customers are currently subsidizing Toyota. This would include: (i) approving Energy+'s proposal for Gross Load Billing for Retail Transmission Service Rates for customers who have load displacement generation (Issues 3.5 and 3.6); (ii) approving Energy+'s proposal to introduce a new Standby Rate for customers with Load Displacement Generation (Issue 3.7); and (iii) approving Energy+'s request to dispose of the LRAMVA account balances as discussed further below.

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?

67. A core component of the Application is the proposed harmonization of distribution rates for customers in the Cambridge and North Dumfries and Brant County service territories based on its existing rate classes. This approach is consistent with the commitment made as part of the purchase and sale agreement for the acquisition of Brant County Power and is outlined in MAADs application that was ultimately approved by the Board (EB-2014-0217 and EB-2014-0223).

68. For Energy+, 2019 represents the fourth and final year of the transition to a fully fixed monthly service charge for the Residential rate class. However, the total bill impact on low

volume residential consumers for all of the scenarios considered in Exhibit K1.6 exceeds 10%. For this reason, Energy+ is proposing mitigation by deferring the transition to a fully fixed monthly service charge for the Residential class by one additional year to reduce those total bill impacts to less than 10%.

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?

69. Energy+ receives wholesale transmission service from metered points that are directly connected to the grid. Energy+ is billed Uniform Transmission Rates ("UTRs") by the IESO on all capacity delivered through these points. Energy+ passes these charges on to customers with OEB-approved Retail Transmission Service Rates ("RTSR").

70. To calculate the proposed RTSR, Energy+ has utilized the most recent version of the Board's RTSR Workform. During the discovery process, Energy+ determined that based on the facts, Energy+ should not apply RTSR charges to HONI No. 2.[30] An updated version of that the RTSR workform was filed together with the response to Technical Conference Undertaking JTC 1.4.

71. Energy+ is proposing to bill customers with load displacement generation RTSR on a gross load billing basis in a manner that directly aligns the amounts charged to those customers with what is actually being charged to Energy+ by the IESO for UTRs associated with that load displacement generation.

72. Failing to make this correction will result in the continuation of a direct and known RTSR cross-subsidy in favor of customers with load displacement generation. Energy+ submits

[30] Response to Technical Conference Undertaking JTC1.4 filed February 5, 2019.

that the continuation of a known and easy to correct cross-subsidy is not appropriate.

73. Energy+ is billed the Line Connection Service Rate and the Transformation Connection Service Rate components of the UTR on a gross load billing basis for load displacement generation that meet specific criteria as set out in the UTR order. The TMMC load displacement generation meets this criteria, and consequently Energy+ is billed on a gross load basis for Line Connection Service Rate and Transformation Connection Service Rate components of the UTR.

74. This can be seen in Ontario's 2019 interim UTRs approved December 20, 2018 (EB-2018-0326) which provides in the Appendix B terms and conditions that:

> "**(G) EMBEDDED GENERATION** The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non- renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments approved after October 30, 1998, to a generator unit that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO- administered energy markets."

75. It can also be seen in the UTR Rate Schedule which indicates that the approved Line Connection Service Rate (PST-L) and Transformation Connection Service Rate (PTS-T) are both subject to the following footnote:

> "3. The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer

demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by an embedded generator unit for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation, on the demand supplied by the incremental capacity associated with a refurbishment approved after October 30, 1998, to a generator unit that existed on or prior to October 30, 1998. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio- oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses."

76. Finally, Energy+ forecasted low voltage (LV) charges of $507,967 for 2019 which have been allocated to each rate class based on the proportion of proposed retail transmission connection revenue collected from each class.[31] Energy+ utilized actual 2017 LV Rates (the most recent information available about LV rates at the time of preparing the IRRs) multiplied by its 2019 load forecast quantities to arrive at the $507,967 in LV charges.[32]

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?

77. Energy+ has been considering the implementation of a standby charge since at least as early as 2014 as a result of the implementation of a large cogeneration project by one of its large-use customers and more recently due to a growing demand by commercial customers to install load displacement generation.[33]

78. In this context, Energy+ is proposing to implement a new Standby charge for all GS 50-999kW, GS 1000-4999kW, and Large Use customers that have load displacement generation and that require Energy+ to act as a backup supply of electricity in the event the source of generation is unavailable.[34]

79. Where customers are expecting Energy+ distribution system to be available in the event

[31] Exhibit 8 as Section 8.2.6.
[32] Response to 8-Staff-90.
[33] Transcript Vol. 1 page 16, lines 18-23.
[34] Exhibit 7, Section 7.1.3.8.

that load displacement generation is not functioning, Energy+ needs to dedicate, 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 serve all of its local customers when demand is at its highest peak. Energy+ continues to invest in its distribution system and incurs operations, maintenance, and administrative costs to operate the distribution system based upon the expected capacity required.

80. In the absence of the introduction of a Standby charge, costs will be shifted to other customers due to decreasing metered volumes for those customers with load displacement generation.

81. Energy+'s proposal is to utilize the contract capacity methodology for standby. Under Energy+'s proposed contract capacity method, the customer contracts for a peak load requirement (the "**Contracted Capacity**").

82. On a monthly basis, if the customer's actual peak load is greater than or equal to the Contracted Capacity, the customer is charged the volumetric rate on the actual load. If the customer's actual peak load is less than the Contracted Capacity, the customer is charged on the actual load at the volumetric rate plus a standby rate (which is based on the volumetric rate for that class) on the difference between the Contracted Capacity and the actual load.

83. Energy+ has proposed a Standby rate that is based on the same volumetric rate of the class, as it was considered to be a reasonable estimate of the value of Standby service. It is also simpler for customers to understand.

84. Energy+ proposes to establish the initial Contracted Capacity based on 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 load displacement generation is not operating.

85. Prior to arriving at this proposal, Energy+ assessed the cost impacts on the existing large-use customer with load displacement generation under a number of different alternative

approaches to Standby (gross load billing, etc.) and Energy+ can confirm that the Contracted Capacity approach proposed by Energy+ was identified as the most cost-effective option for the customer.

86. Energy+ believes that the proposed Contracted Capacity method is the most reasonable and fairest approach since it is intended to represent the peak load distribution requirement of the customer. In other words, it represents the maximum capacity amount that the customer needs from Energy+ to support their operation.

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

87. Energy+ is seeking the recovery of the Group 2 Deferral and Variance Accounts ("D&V"), including Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA"), in the amount of $2,134,541 as at December 31, 2017 on a harmonized basis over a one year period. The amounts requested for recovery reflect adjustments through the interrogatory process, as well as an adjustment to LRAMVA as part of Response to Undertakings JTC1.8.

88. The following table outlines the Group 2 D&V account balances to be recovered:

USoA	Account Name	Amount of Recovery (Disposition)	Evidence Reference
1575	IFRS-CGAAP Transition PP&E Amounts	1,908,269	Exhibit 9, Pg. 14-15
1576	Accounting Changes under CGAAP Balance	(2,456,018)	Exhibit 9, Pg. 10-14
1568	LRAM Variance Account	1,545,771	Exhibit 4, Section 4.11; IR 4-Staff-64; Undertaking JTC1.8.
1508	Other Regulatory Assets - Monthly Billing	416,346	Exhibit 9, Pages 27-29; Updated Evidence, December 13, 2018
1557	Meter Cost Deferral Account (MIST Meters)	178,500	Exhibit 9, Pages 34-35
1508	Other Regulatory Assets - OEB Cost Assessment	174,262	Exhibit 9, Pages 29-30
1518	Retail Cost Variance Account - Retail	142,467	Exhibit 9, Page 30
1555	Smart Meter Capital and Recovery Offset Variance - Stranded Meter Costs	107,068	Exhibit 9, Pages 31-33
1555	Smart Meter Capital and Recovery Offset Variance - Capital	95,898	Exhibit 9, Page 31
1508	Other Regulatory Assets - Deferred IFRS Transition Costs	25,494	Exhibit 9, Page 17
1548	Retail Cost Variance Account - STR	2,580	Exhibit 9, Pages 30-31
1508	Other Regulatory Assets - Ontario Clean Energy Benefit Variance	(239)	Exhibit 9, Page 26
1572	Extra-ordinary Event Costs	(5,857)	Exhibit 9, Page 34
		2,134,541	

89. Energy+ has proposed to recover the Group 2 D&V balances on a harmonized basis, consistent with the request to harmonize the distribution rates as outlined above in D. Rate Design.[35] As outlined in its evidence[36], Energy+ believes the disposition of the D&V accounts on a harmonized basis is the best approach for the following reasons: (i) 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"; (ii) a single, harmonized recovery allows for a much less complex tariff sheet and facilitates the energy literacy and ease of understanding by customers; (iii) harmonization reduces administrative time spent on the DVA reconciliation process; and (iv) a consistent approach to the recovery of the Group 1 variance accounts, as agreed to as part of the Settlement Proposal.

90. With respect to Accounts 1575 and 1576 in particular, Energy+ noted in its Response to IR 9-Staff-96 that the harmonized distribution rates proposed in this Application have been derived from the total rate base of Energy+. The 2019 rate base is comprised of the average

[35] Exhibit 9, Pg. 22 of 80.
[36] Response to Interrogatories 9-Staff-96

asset balances for the 2019 Test Year. The average asset balances are not separated by service territory and the asset values incorporate the full transition to MIFRS, including the adjustments that were made for both the Brant and CND service territories, the effect of which were captured by accounts 1575 and 1575. Energy+ submits that the disposition of the total of Account 1575 and 1576 to all of Energy+'s customers as one rate rider is consistent and aligns with the rate harmonization proposal which incorporates the impact of the change in asset values underlying rate base across all customers.

G.2 LRAMVA

91. In accordance with the Filing Guidelines, Energy+ must apply for the clearance of its LRAMVA balances attributable to energy efficiency programs in a Cost of Service Application. The OEB established Account 1568 as the LRAMVA to capture the variance between the OEB-approved CDM forecast and the actual CDM results at the customer rate class level. Distributors must continue to track the variances between the OEB-approved LRAMVA threshold and actual CDM results in the LRAMVA for the 2015-2020 period, as noted in the OEB's "Conservation and Demand Management Requirement Guidelines for Electricity Distributors" issued December 19, 2014 (EB-2014-0278).

92. Energy+ is requesting approval for the recovery of LRAMVA balances attributable to Energy Efficiency Programs as at December 31, 2017 in the amount of $1,545,771. The LRAMVA value was updated during the proceeding from the initial submission to reflect the IESO verified results up to the end of 2017 in Response to Interrogatories 4-Staff-64 and to correct an inconsistency in Response to Undertaking JTC 1.8.

93. Energy+ engaged Indeco Strategic Consulting Inc. ("Indeco") to assist with the LRAMVA computations. Energy+ has filed the LRAMVA computations, including the LRAMVA workforms, by rate class.

94. As part of the interrogatory and technical conference processes, a number of questions were asked by Board staff and intervenors with respect to the computation of the LRAMVA related to: (i) a large user generation project undertaken as part of the IESO's Process and Systems Upgrade Initiative ("PSUI"), which was in-service as of December 2015; and (ii)

a streetlighting project.

G.2.1 Generation Project

95. The Report of the Board "Updated Policy for Lost Revenue Adjustment Mechanism Calculation" (EB-2016-0182) indicates that demand savings for PSUI projects are determined by the IESO's Evaluation, Measurement & Verification ("EM&V") protocols and that the average demand savings figure should generally be multiplied by 12 to represent the demand savings the distributor has experienced over the entire year.

96. In computing the LRAMVA claim for the generation project, Energy+ proposed an alternative computation for the demand savings attributable to this project, utilizing actual metering data, compared to the EM&V average demand savings figure, as reported by the IESO, and as provided by TMMC in Response to Technical Conference Question Energy Plus-TC-1(B). Energy+ submits that the alternative computation of the demand savings represents a verifiable proxy for the actual demand savings and lost revenue to Energy+ attributable to the generation project. The alternative computation for the demand savings results in a reduction to the monthly savings of approximately 11%.[37] This translates to a lower LRAMVA claim, which benefits customers.

97. For billing purposes, Energy+ has Measurement Canada approved meters installed to measure: (i) the quantity of power taken from the customer on Energy+'s distribution system; and (ii) the output of the generation facility. With this metering arrangement, Energy+ is able to determine the exact demand of the entire facility by adding the quantity of power used from the two metering points together. [38]

98. To compute the demand savings for the generation project, Energy+ computed the values for two separate peaks in each month for the years 2016 and 2017, the years in which the LRAMVA claim is attributable to. The first peak was the hour in the month when the customer had the highest demand off the Energy+ distribution system, which represents the demand that Energy+ used to bill the customer during this period. The second peak

[37] Transcript Vol. 1 dated March 7, 2019 at pg. 21, lines 11-13.

[38] Transcript Vol. 1 dated March 7, 2019 at pg. 25, lines 14-20.

was the hour in the month when the customer had the highest demand of the entire facility, inclusive of the generation. This represents a verifiable proxy for the demand that the customer would have been billed for in the absence of the generation project. The difference in the two peaks provides an accurate calculation of the demand savings attributable to the generation project.

99. As the generation project was undertaken by a customer in the large user class, and the amount claimed represents the computation of the lost revenue from the rate class, the amount of the LRAMVA claim attributable to the generation project has been allocated to the large use customer class.

100. Energy+ recognizes that the computation of the demand savings for the generation project varies from the approach identified by the Board in EB-2016-0182, and as described above. If requested by the Board, Energy+ would revise its computation of the LRAMVA claim with respect to the generation project to utilize the demand savings as reported in the EM&V Report.

G.2.2 Streetlighting Project

101. Energy+'s LRAMVA claim includes demand savings from a streetlighting retrofit project that was undertaken in 2016 in the Brant County service territory. Energy+ incurred distribution revenue losses from June 2016 to December 2016, and these losses persist for the life of the LED lights.

102. As the IESO's Annual Final Verified Results Report includes Demand Savings relative to the provincial system peak, the IESO did not report any demand savings attributable to the streetlight project. With streetlights operating strictly during off-peak hours, there is no impact on the provincial system peak and therefore there are no demand savings attributed to them.

103. Streetlighting is billed on a customer demand basis by Energy+ and therefore the implementation of LED lights as part of the streetlighting retrofit project has resulted in lost revenue to Energy+. Energy+ has proposed a methodology to compute the estimated demand savings for this project utilizing actual streetlight billing demand reductions.

104. Energy+ provided detailed computations of the demand savings for the streetlight project in Response to Technical Conference Question Staff-TC Question #5.

105. Energy+ submits that the methodology utilized by Energy+ in computing the streetlighting billing demand reductions has been utilized by other distributors in successful LRAMVA claim decisions, including Veridian Connections Inc. (EB-2016-0107).

G.3 Other Regulatory Assets – Monthly Billing

106. On April 15, 2015, the OEB announced that by the end of 2016, all electricity distributors in Ontario will be required to bill their customers on a monthly basis. In Energy+'s 2016 IRM Application (EB-2015-0057), Energy+ (former CND) indicated that it would be in a position to begin billing all customers on a monthly basis, beginning January 1, 2017 and requested an accounting order to establish a new deferral account to record the incremental costs associated with moving to the monthly billing method, as the former CND did not include the costs of monthly billing in its last (2014) Cost of Service ("CoS") Application. One-time capital and OM&A costs identified as a result of the transition to monthly billing included: programming costs, customer communication, increased paper, printing and mailing/postal expenditures, and potentially resources due to the anticipated increased billing volumes and customer care requirements.[39] The materiality threshold for Energy+ (CND) at the time, based on its 2014 CoS Application, was $125,000.

107. Energy+'s request for a new deferral account was approved by the Board in its Decision and Order in EB-2015-0057. The approved accounting order indicated "The account will be used to record any incremental OM&A costs directly attributable to the transition to monthly billing. Costs to be recorded will be net of any associated cost reductions resulting from the transition, including efforts towards paperless billing, improvements in cash flow, or reduction in bad debt."[40]

108. Energy+ is seeking the recovery of $416,346, including carrying charges, for the period up to December 31, 2017 with respect to incremental costs incurred, net of any associated

[39] EB-2015-0057 IRM Application, Pg. 17.
[40] Decision and Rate Order EB-2015-0057, Pg. 11.

benefits, as a result of the transition to Monthly Billing.

G.3.1 Incremental Costs and Cost Reductions

109. Incremental costs incurred by Energy+ in the transition to monthly billing comprise incremental labour, postage, envelopes and stationary, project management during the transition, and advertising costs.[41] In determining the incremental postage, envelope and stationary costs, Energy+ computed the incremental customer bills by determining the baseline of how many additional monthly bills would be produced at the time of the monthly billing conversion based on customer accounts, and adjusting for new or lost customers on a monthly basis, including those customers that converted to paperless billing.

110. Energy+ did not experience a reduction in bad debt expense related to residential and GS< 50 kW customers in 2016 and 2017 and therefore has not made any adjustments for bad debts.[42]

G.3.2 Improvements in Cash Flow

111. On December 13, 2018, Energy+ provided an update to its original evidence with respect to the balances in Account 1508 Other Regulatory Assets - Sub-Account Monthly Billing ("Monthly Billing Account"). Energy+ updated the balance in the Monthly Billing Account to record the estimated cash flow benefit to Energy+ attributable to the transition to monthly billing for the period October 2016 through to December 31, 2017.

112. Energy+ estimated the cash flow benefit resulting from the one-time collection advancement of one month's billing for CND customers that transitioned to monthly billing (i.e. Energy+ would have collected the gross billing amount one month sooner as a result of moving to a monthly billing cycle versus a bi-monthly billing cycle). As Energy+ was in a positive cash flow position prior to the transition to monthly billing, the increased cash inflow as a result of the transition to monthly billing would have generated additional interest income.

[41] Exhibit 9, Pages 28-29
[42] Update to Evidence, December 13, 2018, Pages 16-21.

113. The one month's billing was determined based on the average monthly gross revenue for residential customers in the CND rate zone in 2016. The cash flow benefit was then computed based on the average monthly billing amount multiplied by the interest rate earned on cash balances for the period October 1, 2016 to December 31, 2016 and the period January 1, 2017 to December 31, 2017. Energy+ used the historical prescribed D&V interest rates for the period.

114. Energy+ has also incurred incremental costs in 2018, and as such has requested that Account 1508 Other Regulatory Assets – Sub Account Monthly Billing continue.[43] In a Response to Interrogatory from Board Staff (9-Staff-104), Energy+ was asked to estimate the remaining amounts for 2018. The estimated amount for 2018 was $256,043[44], which will is subject to true up once actuals are known. As part of the response to 9-Staff-104, Energy+ also indicated that it would consider including estimates for 2018 in the balances being sought for disposition.

115. Energy+ has captured all applicable items listed in the Accounting Order for the Monthly Billing Account.

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?

116. Pursuant to the Settlement Proposal filed December 12, 2018 this issue has been partially settled. However, 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.

117. Regarding the large user Standby adjustment, this adjustment has been made to the 2019 kW billing determinant forecast for the large user class to reflect the additional kW

[43] Exhibit 9, Table 9-20, Pg. 37 of 80.
[44] Update to Evidence, December 13, 2018, Page 21.

associated with the standby service proposed by Energy+. If Energy+'s standby proposal is not accepted the 2019 large user kW forecast will need to be adjusted accordingly.

118. In addition, Exhibit 3, page 22 outlines that the CDM savings for 2019 have been reduced by the amount of savings associated with new load displacement generation that will be charged a standby charge. Since the standby charge will collect revenues associated with the load displacement generation, the kWh savings for the load displacement generation are not currently included in the CDM adjustment for 2019. The CDM adjustment represents the 2018 and 2019 planned savings from the Process and Systems Upgrades Program outlined in the current Energy+ 2015 to 2020 CDM plan. This program is associated with savings from new load displacement generation anticipated in 2018 and 2019. The 2019 LRAMVA threshold is directly related to the 2019 CDM adjustment. If Energy+'s standby proposal is not accepted by the Board the reduction to the CDM adjustments and the LRAMVA threshold will need to be reversed.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 15TH DAY OF MARCH, 2019

BORDEN LADNER GERVAIS LLP

Per:

Original signed by John A. D. Vellone

John A. D. Vellone

TOR01: 7864181: v4