

ONTARIO ENERGY BOARD

IN THE MATTER the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15 (Schedule B);

AND IN THE MATTER OF an application to the Ontario Energy Board by Energy+ Inc. pursuant to Section 78 of the *Ontario Energy Board Act* for approval of its proposed distribution rates and other charges effective January 1, 2019.

REDACTED VERSION

Updated Written Evidence

of

**Jeffry Pollock
(J. Pollock Incorporated)**

On behalf of

Toyota Motor Manufacturing Canada Inc.

February 15, 2019



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LIST OF SCHEDULES

Schedule	Description
JP-11	2019 Cost Allocation Model: Two Large Use Classes/Direct Assignment
JP-12	4NCP and 12CP Allocation Factors With and Without TMMC
JP-13	TMMC Recommended Supplementary Distribution Service Rate Design
JP-14	TMMC Recommended Standby Distribution Service Rate Design
JP-15	Recommended Standby Distribution Service Rate Design Applicable to the GS 50 – 999 kW Customer Class
JP-16	Revenues from TMMC Recommended Standby Distribution Service Rate

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Term	Definition
4NCP	Four Non-Coincident Peak
12CP	Twelve Coincident Peak
Application	Energy+'s 2019 Cost of Service Application
CCOSS	Class Cost-of-Service Study
Energy+	Energy+ Inc.
Hydro One	Hydro One Networks Inc.
kW	Kilowatt
kV	Kilovolt
LDG	Load Displacement Generation
M24 and M30 Feeders	Energy+'s 27.6 kV Overhead Conductors connecting TMMC to Hydro One's Preston TS that are used exclusively to provide distribution service to TMMC
O&M	Operation and Maintenance
OEB or Board	Ontario Energy Board
Preston TS	Preston Transformer Substation
Settlement Proposal	Partial Settlement Proposal and related supporting documentation in respect of Energy+'s 2019 Cost of Service Application, filed with the Board on December 12, 2018
TCQ	Technical Conference Question
TMMC	Toyota Motor Manufacturing Canada Inc.

UPDATED WRITTEN EVIDENCE OF JEFFRY POLLOCK

1. INTRODUCTION AND SUMMARY

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. Jeffry Pollock; 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

3 **Q. ARE YOU THE SAME JEFFRY POLLOCK WHO SUBMITTED EVIDENCE IN THIS**
4 **PROCEEDING DATED SEPTEMBER 27, 2018, ADDRESSING ENERGY+'S CLASS**
5 **COST-OF-SERVICE STUDY, LARGE USE CLASS RATE DESIGN AND STANDBY**
6 **DISTRIBUTION SERVICE RATE DESIGN?**

7 A. Yes.

8 **Q. WHAT IS THE PURPOSE OF YOUR UPDATED WRITTEN EVIDENCE?**

9 A. The purpose of this updated written evidence is to present the results of a new class
10 cost-of-service study (CCOSS) based on a separate TMMC Large Use class and the
11 direct assignment to that class of the specific costs to serve TMMC. I refer to this new
12 study as the "Two Large Use Classes/Direct Assignment" study. Based on the Two
13 Large Use Classes/Direct Assignment study, I also recommend TMMC-specific rate
14 designs for both Supplementary (*i.e.*, regular) Distribution service and Standby
15 Distribution service.

16 In addition, for reference only and to provide both continuity and completeness,
17 I have updated the CCOSS and the Supplementary and Standby rate designs
18 presented in **Schedules JP-5, JP-6, JP-8, and JP-9** of my original written evidence
19 filed on September 27, 2018. I refer to the originally filed CCOSS as the "One Large
20 Use Class/Partial Direct Assignment" study. These updated schedules are included
21 in **Appendix C**.

1. Introduction and Summary

1 To be clear, although revised **Schedules JP-5, JP-6, JP-8 and JP-9** are
2 included in **Appendix C** of this updated evidence, new **Schedules JP-11, JP-12, JP-**
3 **13, JP-14 and JP-16**, which are based on the Two Large Use Classes/Direct
4 Assignment CCROSS, reflect the cost allocation and rate designs that I am now
5 recommending.

6 **Q. WHAT IS THE STATUS OF YOUR ORIGINAL EVIDENCE DATED SEPTEMBER 27,**
7 **2018?**

8 A. My original evidence remains on the record of this proceeding and, together with this
9 updated evidence and all of my responses to interrogatories and Technical
10 Conference undertakings, comprises the totality of my written evidence in this
11 proceeding to date. However, as described above, the One Large Use Class/Partial
12 Direct Assignment study in my original evidence has been replaced with the Two Large
13 Use Classes/Direct Assignment CCROSS included in this updated evidence. The
14 balance of my original evidence and, in particular, my detailed critiques of Energy+'s
15 CCROSS and proposed standby rate design, is not amended or replaced by this
16 updated evidence.

17 **Q. WHY DID YOU DEVELOP A NEW CLASS COST-OF-SERVICE STUDY?**

18 A. Since submitting my original evidence, three new circumstances have arisen. First, in
19 an interrogatory dated October 11, 2018, the OEB Staff asked TMMC to provide an
20 alternative cost allocation model that treats TMMC and the other Large Use customer
21 as separate customer classes (*i.e.*, Two Large Use classes). TMMC filed its response

1 on October 29, 2018.¹ Although, my original evidence was based on a One Large Use
2 Class/Partial Direct Assignment study, my recommended rate design for the single
3 class included separate volumetric rates for TMMC and the other Large Use customer.
4 Separate rates were designed in order to specifically recognize that TMMC receives a
5 different (and less costly) type of distribution service (*i.e.*, Primary Substation service)
6 than the other Large Use customer (*i.e.*, which receives Primary Distribution service).
7 This original proposed rate design was, in effect, a proxy for a two Large Use class
8 structure. After further consideration, I now believe that the One Large Use
9 Class/Partial Direct Assignment study and the rate designs derived from that study
10 would not be consistent with the Board's current practice and policy.

11 Second, since the time of my original evidence and in response to a written
12 interrogatory from TMMC, Energy+ filed a CCROSS that reflects the settlement of the
13 revenue requirement elements of its Application, a separate TMMC customer class,
14 and direct assignment of all of the costs of providing distribution service to TMMC (*i.e.*,
15 the "Direct Assignment Study").² The Direct Assignment Study identifies the cost of
16 the facilities that are used *exclusively* to serve TMMC, namely: two 27.6 kilovolt (kV)
17 feeders and associated facilities such as load-break switches, lightning arrestors and
18 clamps, bolts and bracket connectors (together, the "M24 and M30 Feeders"); four
19 upgraded meters; and TMMC's capital contribution. It also includes an analysis of the
20 costs of the primary poles, towers and fixtures (booked to USoA 1830-4) that support
21 the dedicated M24 and M30 Feeders but also serve other loads.³ Finally, the Direct

¹ TMMC Response to OEB Staff Interrogatory 1(b).

² Energy+ Response to TMMC TCQ IR-2(c).

³ *Id.*

1 Assignment Study identifies operation and maintenance (O&M) activities and
2 associated expenses that could be directly allocated to TMMC.

3 Third, during the Technical Conference held on January 23, 2019, I learned
4 that Energy+ does not own any high voltage (>50 kV) Bulk distribution facilities at the
5 Preston Transformer Substation (Preston TS), which is owned by Hydro-One
6 Networks Inc. (Hydro One). This fact is notable because the M24 and M30 Feeders,
7 which are used exclusively to serve TMMC, are directly connected to the Preston TS.
8 If the Preston TS were to sustain an outage, TMMC would be without power.⁴

9 In light of all of the above, I developed a new CCROSS with two Large Use
10 classes that, *with the sole exception of the “shared” poles*, directly assigns all other
11 distribution-related costs to the TMMC Large Use Class (*i.e.*, Two Large Use
12 Classes/Direct Assignment). This approach follows Board policy, which mandates
13 direct allocation if 100% of the use of a clearly identifiable and significant distribution
14 facility can be tracked directly to a single rate classification.⁵

15 To be clear, although Energy+’s Direct Assignment Study assigned 100% of
16 the cost of the poles that support TMMC’s dedicated M24 and M30 Feeders to the
17 TMMC Large Use Class, the Two Large Use Classes/Direct Assignment study that I
18 am proposing recognizes that the Energy+ poles supporting the M24 and M30 Feeders
19 are shared assets. Accordingly, as *per* Board policy, I have allocated the costs of
20 Primary Poles, Towers and Fixtures recorded in USoA 1830-4 across all rate classes,
21 including the TMMC Large Use rate class. The results of the Two Large Use

⁴ Technical Conference Transcript at 37-38 (Jan. 23, 2019).

⁵ EB-2005-0317, Cost Allocation Review, *Board Directions on Cost Allocation Methodology for Electricity Distributors* at 31 (Sept. 29, 2006).

1. Introduction and Summary

1 Classes/Direct Assignment CCOSS are provided in **Schedule JP-11** to this updated
2 evidence.

3 **Q. WHY IS IT APPROPRIATE TO ESTABLISH A SEPARATE CUSTOMER CLASS**
4 **FOR TMMC?**

5 A. Separate customer classes are required when the per-unit customer or demand-
6 related costs are sufficiently different between identifiable groups of customers to
7 justify different rates.⁶ That is the case here because there are four key differences
8 between how TMMC and the other Large Use customer receive distribution service
9 and the characteristics of these services. These differences result in substantial
10 differences in the costs of providing distribution service.

11 First and importantly, TMMC operates a load displacement generation (LDG)
12 facility. The other Large Use customer does not have any LDG facilities. The
13 presence of LDG means that TMMC would have different load characteristics than the
14 other Large Use customer, which does not have LDG.

15 Second, TMMC's load is in excess of 20 MW, while the other Large Use
16 customer's load is only about 5 MW. Size creates scale economies; that is, the larger
17 the customer, the lower the fixed costs per customer. Recognizing TMMC's larger
18 size is also consistent with how the OEB uses size to define the other general service
19 customer classes. Further, the Two Large Use Classes/Direct Assignment study
20 shows that the per-unit customer-related cost to serve TMMC is substantially below

⁶ EB-2007-0031, Staff Discussion Paper, *Rate Design for Recovery of Electricity Distribution Costs* at 22 (Mar. 31, 2008 Revised Jun. 6, 2008).

1 the corresponding per-unit customer-related cost to serve the other Large Use class
2 customer.

3 Third, as discussed in my original written evidence and documented in
4 **Schedule JP-2**, TMMC receives Primary Substation service whereas the other Large
5 Use customer receives Primary Distribution service. These are two *different* types of
6 service. Primary Substation service is provided when the customer is served from
7 dedicated feeder lines that are directly connected to a transformer substation. The
8 dedicated M24 and M30 Feeders that serve TMMC are directly connected to Preston
9 TS. This is TMMC's only electrical connection to the Energy+ distribution system.
10 This is in contrast to the other Large Use customer, which receives Primary Distribution
11 service using Energy+'s integrated primary distribution network. Hence, there are no
12 Energy+ assets that are used exclusively to serve this customer. Primary Substation
13 service is less costly than Primary Distribution service.

14 Fourth, with the sole exception of primary poles, all of the distribution facilities
15 that serve TMMC are exclusively used by TMMC, and no other Energy+ customers
16 can be served from these facilities. This means that all distribution facilities used to
17 serve TMMC, other than poles, can be directly assigned to TMMC.

2. REVISED CLASS COST-OF-SERVICE STUDY

1 **Q. DO YOU AGREE WITH ENERGY+'S CLASS COST-OF-SERVICE STUDY FILED IN**
2 **ITS APPLICATION, AS UPDATED IN THE SETTLEMENT PROPOSAL?**

3 A. No. The cost allocation methodologies used by Energy+ in both its Application and
4 the Settlement Proposal (*i.e.*, "Settlement CCOSS") are not consistent with the
5 principles of cost causation for the reasons explained in my original written evidence.⁷
6 For ease of reference, I have summarized my critique of Energy+'s CCOSS in
7 **Appendix D-1**. The same criticisms equally apply to the Settlement CCOSS.
8 Accordingly, for purposes of setting rates in this proceeding, the Board should not
9 accept the Settlement CCOSS and should accept my Two Large Use Classes/Direct
10 Assignment study as presented in **Schedule JP-11**.

11 **Q. WHAT CHANGES DID YOU INITIALLY MAKE TO ENERGY+'S COST**
12 **ALLOCATION METHODOLOGIES?**

13 A. The One Large Use Class/Partial Direct Assignment study presented in **Schedule**
14 **JP-5** of my original written evidence included the following changes to the cost
15 allocation methodologies used by Energy+:

- 16 • I removed Energy+'s LDG adjustments to the Large Use class demands that
17 are used to develop the 12CP, 4NCP, and 12NCP demands that are used to
18 allocate demand-related costs in the CCOSS.
- 19 • The direct and indirect costs of the M24 and M30 (dedicated) Feeders were
20 directly assigned to the Large Use class.

21 These changes are discussed in **Appendix D-1**.

⁷ The Settlement CCOSS was filed by Energy+ in its Settlement Proposal dated Dec. 12, 2018, file name: "2019 EnergyPlus Cost_Allocation_Model – Settlement.xlsm."

1 **Q. WHAT FURTHER CHANGES HAVE YOU MADE TO SCHEDULE JP-5 THAT ARE**
2 **NOW REFLECTED IN SCHEDULE JP-11?**

3 A. First, **Schedule JP-11** corrects several inadvertent errors and incorporates more up-
4 to-date information. Second, as previously stated, **Schedule JP-11** is based on two
5 Large Use classes in contrast to the Settlement CCOSS and my One Large Use
6 Class/Partial Direct Assignment study (**Schedule JP-5**), which are both based on one
7 Large Use class. Third, in **Schedule JP-11**, I directly assigned all distribution costs
8 (with the sole exception of the primary poles) to TMMC using Energy+'s Direct
9 Assignment Study, whereas only the costs of the M24 and M30 Feeders were directly
10 allocated in **Schedule JP-5**. Finally, unlike in **Schedule JP-5**, I did not allocate any
11 >50 kV (Bulk) distribution costs to TMMC and to the other Large Use customer in
12 **Schedule JP-11**.⁸

13 **Q. PLEASE DESCRIBE THE SPECIFIC CHANGES IN SCHEDULE JP-11.**

14 A. There are two specific changes. The first change is a correction to the demands and
15 associated allocation factors due to the inadvertent removal of the wholesale market
16 participants' adjustments to the GS >50 kilowatt (kW) classes. The second change
17 reflects the use of more up-to-date data, namely the revenue requirement settlement
18 reached by Energy+ and intervenors and filed with the Board on December 12, 2018
19 (Settlement Proposal).

⁸ In **Schedule JP-5** as updated in **Appendix C** of this evidence, the >50 kV distribution costs were allocated to all retail customer classes, including the Large Use class.

1 **Q. DID YOU MAKE THE SAME TWO CHANGES TO SCHEDULE JP-5 AS UPDATED**
2 **IN APPENDIX C?**

3 A. Yes.

4 **Q. YOU USED ENERGY+'S DIRECT ASSIGNMENT STUDY TO DIRECTLY ASSIGN**
5 **DISTRIBUTION COSTS TO THE TMMC CLASS IN SCHEDULE JP-11. CAN YOU**
6 **DESCRIBE THAT STUDY?**

7 A. Yes. Energy+'s Direct Assignment Study identified and quantified the costs of the
8 Energy+ facilities used to provide distribution service to TMMC. These facilities
9 include:

- 10 • The M24 and M30 Feeders that are used exclusively to serve TMMC;
- 11 • The primary poles, towers and fixtures recorded in USoA 1830-4 that support
12 those feeders; and
- 13 • The metering equipment that is similarly dedicated to TMMC.

14 In addition, the Direct Assignment Study identified the specific capital contributions
15 made by TMMC to the original capital cost of the dedicated distribution assets that
16 Energy+ uses to deliver electricity to TMMC.

17 **Q. DID ENERGY+ ALSO QUANTIFY DIRECTLY ASSIGNED EXPENSES?**

18 A. Yes. Energy+ also quantified the O&M expenses incurred by Energy+ solely for the
19 account of TMMC. These directly assigned O&M expenses include:

- 20 • Maintenance of the directly assigned infrastructure comprising direct labor
21 costs, general plant (use of Energy+ vehicles) and tree trimming; and
- 22 • Control room services incurred to coordinate maintenance schedules and
23 outages of TMMC's LDG facility.

2. Revised Class Cost-of-Service Study

1 **Q. WOULD YOU CHARACTERIZE ENERGY+'S DIRECT ASSIGNMENT STUDY AS**
 2 **DEFINITIVE?**

3 A. Yes. Although, Energy+ acknowledged that the Direct Assignment Study did not
 4 include Energy+'s investments in certain equipment (*i.e.*, guys, anchors, and
 5 grounding/neutral conductors) that support the direct assigned overhead feeders.⁹
 6 There is no indication that these omissions would materially change the amount of
 7 costs directly assigned to TMMC. Moreover, as discussed later in this evidence, the
 8 rate design that I am now recommending for TMMC would establish a target revenue
 9 requirement based on a 1.15 revenue-to-cost ratio. This will provide a more than
 10 ample cushion above a purely cost-based rate to offset any additional incidental costs
 11 that the Direct Assignment Study does not account for. For these reasons, the Board
 12 should accept the results of Energy+'s Direct Assignment Study for the purpose of
 13 setting rates in this proceeding.

14 **Q. WHAT ARE THE RESULTS OF ENERGY+'S DIRECT ASSIGNMENT STUDY?**

15 A. The results of Energy+'s Direct Assignment Study are summarized in Table 8.

Table 8 Adjustments for TMMC Direct Assignment Study¹⁰					
Description	Fixed Assets	Capital Contrib.	Accumulated Amortization	O&M Expense	Depreciation Expense
Dedicated Feeders		\$-		\$-	
Poles		\$-		\$-	
Dedicated Metering Equipment		\$-		\$-	
TMMC Capital Contribution	\$-			\$-	

⁹ Energy+ Response to TCQ TMMC IR-1(c) and 1(d). In Undertaking JTC1.5 Energy+ stated that it had no investment in either current or potential transformers associated with TMMC's metering equipment.

¹⁰ Energy+ Response to TCQ TMMC IR-2(c).

2. Revised Class Cost-of-Service Study

Table 8 Adjustments for TMMC Direct Assignment Study ¹⁰					
Description	Fixed Assets	Capital Contrib.	Accumulated Amortization	O&M Expense	Depreciation Expense
O&M on Dedicated Feeders	\$-	\$-	\$-		\$-
Total					

1 Q. WHAT DO THE COSTS ASSOCIATED WITH THE POLES IN TABLE 8
2 REPRESENT?

3 A The costs of the poles shown in Table 8 represent the total fixed assets, accumulated
4 depreciation and depreciation expense associated with all primary poles that support
5 the dedicated M24 and M30 Feeders.

6 Q. ARE YOU AWARE THAT THERE ARE OTHER ENERGY+ DISTRIBUTION
7 FEEDERS THAT USE THE SAME POLES AS THE DEDICATED M24 AND M30
8 FEEDERS?

9 A. Yes. Energy+ has advised that there are three other distribution feeders (M23, M27,
10 and M29) that are supported, in part, by the same primary poles that support the
11 dedicated M24 and M30 Feeders. These other feeders collectively serve more load
12 than TMMC's load.¹¹ Hence, from TMMC's perspective, the primary poles are clearly
13 "shared" (as opposed to "local") facilities because they are not used exclusively to
14 serve TMMC. As discussed later in my evidence, the primary poles are the only
15 shared distribution facilities used to serve TMMC.

¹¹ Energy+ Response to TCQ TMMC IR-1(e).

1 **Q. HOW ARE SHARED DISTRIBUTION FACILITIES DIFFERENT FROM LOCAL**
2 **DISTRIBUTION FACILITIES?**

3 A Shared distribution facilities are generally used by all customers, whereas local
4 distribution facilities serve only a specific customer or customer groups. To use an
5 analogy, shared facilities are the highway and byway, while local facilities are the side-
6 street and driveway.

7 **Q. WERE ANY OTHER CHANGES MADE AS A RESULT OF USING ENERGY+'S**
8 **DIRECT ASSIGNMENT STUDY?**

9 A. Yes. As discussed previously, for the Two Large Use Class/Direct Assignment
10 CCOSS in **Schedule JP-11**, I directly assigned the costs of the facilities that are
11 exclusively used by TMMC (*i.e.*, the M24 and M30 Feeders, meters, capital
12 contribution). Because all costs are being directly assigned to TMMC, with the
13 exception of the primary poles, I also removed TMMC's loads from the four non-
14 coincident peak (4NCP) demand allocation factors that are used to allocate primary
15 distribution costs. This adjustment is shown in **Schedule JP-12**. Removing TMMC's
16 loads is consistent with OEB policy. Specifically:

17 When direct allocation is used, the distributor should consider whether
18 it needs to adjust the appropriate allocation factors so that the rate
19 classification to which costs for a specific function are directly allocated
20 is not allocated further costs related to that function, except where there
21 are joint costs that apply to the customer classification. For example, if
22 a customer classification has all its assets and O&M costs directly
23 allocated to the classification, then the load data used to allocate

2. Revised Class Cost-of-Service Study

1 “common” assets and O&M costs should exclude the load data
2 associated with this customer classification.¹²

3 **Q. DID YOU USE THE SAME ALLOCATION FACTORS AS ENERGY+ IN**
4 **ALLOCATING THE COSTS ASSOCIATED WITH THE PRIMARY POLES?**

5 A. No. In allocating the primary poles, which are booked to USoA 1830-4, I removed
6 Energy+'s LDG facility adjustment. This is because there is no evidence that TMMC
7 would always use Standby Distribution service that is 100% coincident with TMMC's
8 4NCP demands. The reasons for removing Energy+'s LDG adjustment are further
9 discussed in **Appendix D-1**.

10 **Q. HAVE YOU CHANGED YOUR RECOMMENDATION ON ALLOCATING**
11 **UNDERGROUND FACILITIES IN SCHEDULE JP-11?**

12 A. No. As was the case with my One Large Use Class/Partial Direct Assignment study
13 (**Schedule JP-5**), I did not allocate any underground investment (*i.e.*, conduit and
14 conductors) and related expenses (including overhead costs) to TMMC. TMMC is
15 served entirely from an overhead “radial” distribution system, and Energy+ does not
16 use any underground equipment to serve TMMC. Further, because the radial system
17 is not electrically connected to any underground facilities, TMMC cannot possibly
18 benefit from any system integration function that these facilities provide, if any.
19 Accordingly, allocating zero underground costs to TMMC is consistent with cost-
20 causation principles.

¹² EB-2005-0317, Cost Allocation Review, *Board Directions on Cost Allocation Methodology for Electricity Distributors* at 32 (Sept. 29, 2006).

1 **Q. IS COST CAUSATION AN ACCEPTED PRACTICE?**

2 A. Yes. The Board has stated:

3 The primary criterion in developing the cost allocation methodology is
4 to follow sound cost causality. Secondary considerations include the
5 availability and reliability of the data to support the exercise, as well as
6 concerns of materiality, practicability and consistency.

7 The key objective of the cost allocation is to allocate costs among
8 classifications appropriately reflecting cost causality. This objective is
9 furthered by separating distribution assets into bulk, primary and
10 secondary functions.¹³

11 **Q. WHAT DO THE RESULTS IN SCHEDULE JP-11 DEMONSTRATE?**

12 A. Table 9 below shows the revenue requirement and the revenue-to-cost ratios at
13 present rates under the Two Large Use Classes/Direct Assignment study. The
14 corresponding information from Energy+'s Settlement CCROSS is also shown for
15 comparison purposes.

Table 9 Summary of TMMC's Recommended and Energy+'s Settlement CCROSS Results¹⁴				
Customer Class	Revenue Requirement (\$000)		Revenue-To-Cost Ratio at Current Rates	
	TMMC	Energy+	TMMC	Energy+
Residential	\$22,784.7	\$22,646.9	84.9%	85.4%
GS < 50 kW	\$4,166.5	\$4,104.4	107.1%	108.7%
GS: 50 – 999 kW	\$5,839.4	\$5,633.4	135.4%	140.3%
GS: 1,000 – 4,999 kW	\$2,118.4	\$2,012.7	108.0%	113.5%
Large Use	N/A	\$1,108.3	N/A	100.7%
Large Use 1	\$206.1	N/A	133.9%	N/A
TMMC (Large Use 2)	\$393.5	N/A	211.3%	N/A

¹³ *Id.* at 3 and 35.

¹⁴ TMMC Schedule JP-11; Energy+ Settlement CCROSS, Rows 40 and 75.

2. Revised Class Cost-of-Service Study

Table 9 Summary of TMMC's Recommended and Energy+'s Settlement CCOSS Results¹⁴				
Customer Class	Revenue Requirement (\$000)		Revenue-To-Cost Ratio at Current Rates	
	TMMC	Energy+	TMMC	Energy+
Street Light	\$493.2	\$494.7	151.2%	150.8%
Sentinel	\$23.2	\$23.4	70.1%	69.6%
Unmetered Load	\$78.1	\$78.3	90.0%	89.7%
Hydro One 1 CND	\$43.5	\$43.4	120.7%	120.9%
Waterloo No. CND	\$157.9	\$157.9	144.9%	144.8%
Hydro One BCP	\$29.5	\$30.5	401.2%	401.4%
Brantford Power	\$12.9	\$12.9	44.6%	44.6%
Hydro One 2 BCP	\$3.0	\$3.0	167.9%	167.9%

1 Table 9 demonstrates that TMMC's revenue-to-cost ratio at the current OEB-approved
2 rates is 211.3%. This clearly demonstrates that current Large Use class rates are
3 significantly above the cost of providing service to TMMC and should be significantly
4 reduced to more closely reflect the actual cost of providing distribution service to
5 TMMC.

6 **Q. WHY SHOULD THE BOARD ADOPT THE TWO LARGE USE CLASSES/DIRECT**
7 **ASSIGNMENT CLASS COST-OF-SERVICE STUDY PRESENTED IN SCHEDULE**
8 **JP-11?**

9 A. The Two Large Use Classes/Direct Assignment CCOSS presented in **Schedule JP-11**
10 is consistent with the principles of cost causation while the Settlement CCOSS is not.
11 This is because the Two Large Use Classes/Direct Assignment CCOSS recognizes
12 TMMC's unique circumstances as follows:

2. Revised Class Cost-of-Service Study

- TMMC operates an LDG facility;
- TMMC is served directly from the Preston TS, and an outage at the station will shut down TMMC's operations;
- The M24 and M30 Feeders serve only TMMC, and an outage of these feeders would shut down TMMC's operations;
- The four upgraded meters serve only TMMC;
- Energy+ does not use any high voltage or underground distribution facilities (either conduit or conductors) to serve TMMC;
- TMMC made a specific capital contribution to pay for the radial distribution system installed by Energy+ to serve TMMC. This radial system is not part of an integrated distribution network; and
- The costs of these dedicated facilities that serve only TMMC (*i.e.*, the M24 and M30 Feeders, the meters, and TMMC's capital contribution) can be identified and directly assigned to TMMC.

These unique circumstances applicable to TMMC are clearly recognized in **Schedule JP-11**.

3. SUPPLEMENTARY DISTRIBUTION SERVICE RATE DESIGN

1 Q. HAVE YOU UPDATED YOUR RECOMMENDED SUPPLEMENTARY
2 DISTRIBUTION SERVICE RATE DESIGN?

3 A. Yes. I have updated my rate design based on the results of my Two Large Use
4 Classes/Direct Assignment study (**Schedule JP-11**). I have also revised my
5 recommendations in order to reflect what I now understand to be Board policy.

6 The first revision was to set the Large Use class target revenue requirement to
7 achieve a 1.15 revenue-to-cost ratio as opposed to the 1.0 ratio assumed in my original
8 evidence. This reflects the Board's policy that out-of-range revenue-to-cost ratios
9 should be brought to the edge of the OEB-approved range (85% to 115%) as opposed
10 to the mid-point of the range.

11 The second revision is with my recommendation that the monthly Large Use
12 class Service Charge be reduced by 50%. I am now recommending no change in the
13 current OEB-approved Service Charge in order to reflect the Board's guidance in this
14 regard. Under this guidance, if a distributor's current fixed charge for any non-
15 residential class is higher than the calculated ceiling, there is no requirement to lower
16 the fixed charge to the ceiling, nor are distributors expected to raise the fixed charge
17 further above the ceiling for any non-residential class at the current OEB-approved
18 rate.¹⁵ As discussed later, I still have concerns about whether the current Service
19 Charge should be retained based on the results of my revised CCOS.

¹⁵ OEB Filing Requirements for Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications, Chapter 2 at 50 (Jul. 12, 2018).

1 Q. ARE THE SAME TWO CHANGES ALSO REFLECTED IN UPDATED SCHEDULE
2 JP-6 PROVIDED IN APPENDIX C?

3 A. Yes.

4 Q. WHAT ARE YOUR SPECIFIC CONCERNS ABOUT APPLYING THE BOARD'S
5 GUIDANCE ON ADJUSTMENTS TO FIXED CHARGES IN THIS PROCEEDING?

6 A. I would observe that applying the OEB's guidance would result in a *maximum* monthly
7 fixed charge for TMMC of approximately \$140 per month based on the Two Large Use
8 Classes/Direct Assignment study shown in **Schedule JP-11**.¹⁶ By contrast, the
9 maximum monthly fixed charge for the other Large Use customer would be \$878 per
10 month.¹⁷ Not only is there a substantial difference in the cost-based monthly fixed
11 charge between TMMC and the other Large Use customer, the current OEB-approved
12 \$8,976.07 Large Use Service charge is clearly excessive. Thus, my first concern is
13 that retaining the current Service Charge would not be consistent with designing cost-
14 based rates. My second concern is that there is a significant difference between the
15 TMMC and other Large Use customer monthly fixed charge. This difference supports
16 establishing a separate TMMC customer class.

17 Q. PLEASE DESCRIBE YOUR REVISED RATE DESIGN RECOMMENDATIONS.

18 A. **Schedule JP-13** shows the derivation of my recommended rate design for
19 Supplementary Distribution service provided to TMMC. To be clear, the term
20 "Supplementary" refers to the "regular" Distribution service provided to a customer for
21 load that is not otherwise supplied from the customer's LDG facilities.

¹⁶ **Schedule JP-11** Workpaper, Sheet O2: Monthly Fixed Charge Min & Max Worksheet.

¹⁷ *Id.*

1 Q. PLEASE DISCUSS SCHEDULE JP-13.

2 A. **Schedule JP-13** is based on a target revenue requirement of \$422,043. This amount
 3 was derived from **Schedule JP-11** and adjusted to result in a 1.15 revenue-to-cost
 4 ratio. A summary of my recommended TMMC rate design is provided in Table 10.

Table 10 Recommended TMMC Rate Design					
Rate	Allocated Cost	Target Revenues	Rate	Units	Reference
	(1)	(2)	(3)	(4)	(5)
Revenue Requirement	\$393,607	\$422,043			Sch. 11, Row 40 Sch. 13, pg. 1, Line 5
Service Charge		\$107,713	\$8,976.07	Per Month	Sch. 13 pg. 1, Line 6
Distribution Volumetric Rate		\$314,330		Per kW	Sch. 13, pg. 1, Line 10

5 The Distribution Volumetric Rate would recover \$314,330 (based on using the
 6 currently OEB-approved Service Charge).

7 Q. HOW WAS THE DISTRIBUTION VOLUMETRIC RATE WITH STANDBY SERVICE
 8 DERIVED?

9 A. The proposed Distribution Volumetric Rate was designed to recover the cost of the
 10 M24 and M30 Feeders used exclusively by TMMC. The cost of these Feeders is fixed
 11 because they were installed prior to when TMMC energized its LDG facilities and,
 12 consequently, there is more than sufficient capacity to serve TMMC's total
 13 (Supplementary and Standby service) requirements even if one or both of its LDG
 14 units were out of service. In other words, there are no incremental costs to provide
 15 Standby service to TMMC. Accordingly, the Distribution Volumetric Rate should
 16 account for the amount of TMMC's Contract Standby Demand. As discussed later, I
 17 have assumed that TMMC would contract for 6,900 kW of Standby service.

3. Supplementary Distribution Service Rate Design

1 Q. IN YOUR ORIGINAL WRITTEN EVIDENCE, YOU RECOMMENDED THREE
2 SEPARATE VOLUMETRIC RATES FOR SUPPLEMENTARY DISTRIBUTION
3 SERVICE. WHY ARE YOU NOW RECOMMENDING A SINGLE VOLUMETRIC
4 RATE?

5 A. The three volumetric rate structure set out in **Schedule JP-6** of my original written
6 evidence served two purposes:

- 7 • It recognized the different types of distribution service (and different associated
8 costs) provided to the two Large Use class customers; and
- 9 • It separated the local distribution costs (*i.e.*, the costs associated with facilities
10 that only serve a specific customer) from the shared distribution costs (*i.e.*, the
11 costs associated with facilities that serve multiple customers).¹⁸

12 In my original written evidence, the >50 kV distribution facilities were assumed to be
13 shared assets while all other distribution facilities were assumed to be local. Based
14 on new information provided to me since my initial written evidence was submitted, it
15 is clear that the only shared distribution facilities used to serve TMMC are the poles
16 that support multiple feeders, including the M24 and M30 Feeders that are exclusively
17 used to serve TMMC. Moreover, there are no Energy+ >50 kV distribution facilities
18 connected to the TMMC radial distribution system. Finally, it is now unnecessary to
19 distinguish between Primary Substation and Primary Distribution services because the
20 rate design presented in **Schedule JP-13** only applies only to TMMC.

¹⁸ The three volumetric rates were designed to recover (1) the costs of the shared (*i.e.*, Bulk Distribution) facilities, (2) the costs of the local (*i.e.*, Primary Substation) distribution facilities used to serve TMMC, and (3) the costs of the local (*i.e.*, Primary Distribution) facilities used to serve the other Large Use customer.

4. STANDBY DISTRIBUTION SERVICE RATE DESIGN

1 Q. DO YOU AGREE WITH THE STANDBY RATE DESIGN PROPOSED BY ENERGY+
2 IN THIS PROCEEDING?

3 A. No. I have many concerns with Energy+'s proposed rate for Standby Distribution
4 service. These concerns are described in detail in my original evidence. For ease of
5 reference, I have summarized my concerns in **Appendix D-2** of this updated evidence.
6 My principal concern is that Energy+'s proposed Standby rate design does not reflect
7 cost-causation principles and, accordingly, should not be accepted by the Board.

8 Q. ARE YOU RECOMMENDING A TMMC-SPECIFIC RATE DESIGN FOR STANDBY
9 DISTRIBUTION SERVICE BASED ON THE TWO LARGE USE CLASSES/DIRECT
10 ASSIGNMENT STUDY?

11 A. Yes. **Schedule JP-14** is a new version of **Schedule JP-8** from my original evidence.
12 It shows the derivation of my recommended rate design for Standby Distribution
13 service applicable to TMMC.¹⁹ As in my original evidence, the Standby Distribution
14 service rate design is derived from my recommended rate design for Supplementary
15 Distribution service. To be clear, the term "Standby" refers to the additional delivery
16 service required when TMMC's LDG sustains an outage and there is a net increase in
17 TMMC's peak demand as a result of the outage.

18 Q. IS YOUR PROPOSED STANDBY DISTRIBUTION RATE DESIGN CONSISTENT
19 WITH COST-CAUSATION PRINCIPLES?

20 A. Yes. **Appendix E** of this updated evidence provides an overview of the cost-causation

¹⁹ For continuity and completeness, **Schedule JP-8** from my original evidence was further updated to reflect the changes made to **Schedule JP-6**. These updated schedules are provided in **Appendix C**.

1 principles that underlie my proposed design of cost-based rates for Standby
2 Distribution service. The cost-causation principles recognize the following.

3 Standby Distribution is the *additional* delivery service required when a
4 customer's LDG sustains an outage *and* there is a net increase in the customer's peak
5 demand previously established during the billing month when there were no outages.
6 Generator outages can be either *forced* or *scheduled*. Forced outages are random,
7 non-recurring events, while scheduled outages are typically planned (sometimes well)
8 in advance. For this reason, it cannot be assumed that forced outages always occur
9 coincident with a system peak, while scheduled outages would seldom, if ever,
10 coincide with a system peak. Accordingly, Standby Distribution service has much
11 greater "diversity" than Supplementary Distribution service.

12 This greater diversity should be recognized in designing a cost-based Standby
13 Distribution service rate. Local distribution costs are allocable to LDG regardless of
14 the amount of Standby Distribution service actually provided. However, because of
15 diversity, the amount of shared distribution costs allocable to LDG should reflect the
16 amount of service provided; that is, the more that Standby Distribution service is used,
17 the more likely an outage will coincide with a system peak and the higher the allocable
18 distribution costs.

19 Applying the above cost-causation principles, a cost-based rate for Standby
20 Distribution service should then consist of two separate charges:

- 21 • A Contract Volumetric Rate to recover the cost of local distribution facilities;²⁰
- 22 and

²⁰ In my original written evidence, I used the term Maximum Volumetric Rate, which has the same meaning as Contract Volumetric Rate.

- A Daily Volumetric Rate to recover the cost of shared distribution facilities.

The Contract Volumetric Rate would apply regardless of when or how often Standby Distribution service is provided. The Daily Volumetric Rate would apply when Standby Distribution service is actually used. Thus, customers using more Standby Distribution service would pay more than customers that use little or no Standby Distribution service. Further, to ensure that a LDG customer does not pay more for Standby Distribution service than for a comparable amount of Supplementary Distribution service, the sum of the Contract and Daily Volumetric Rate applied in any month would not exceed the otherwise applicable Distribution Volumetric Rate. In other words, a customer that uses Standby Distribution service for an entire month would pay the same total volumetric charges as would a similarly sized customer taking only Supplementary Distribution service.

Q. REFERRING TO SCHEDULE JP-14, HOW DID YOU DERIVE THE CONTRACT VOLUMETRIC RATE?

A. The recommended Contract Volumetric rate is \$ [REDACTED] per kW. This rate recovers the cost of the local distribution facilities directly assigned to TMMC and the corresponding overhead costs. The derivation of the rate is shown in **Schedule JP-13**, page 1 (line 12). It assumes that TMMC will establish a Standby Contract Demand of 6,900 kW. This would be in addition to TMMC's Supplementary service billing demand which is derived in **Schedule JP-13**, page 2.

1 Q. HOW DID TMMC DETERMINE THAT IT WOULD ESTABLISH A STANDBY
2 CONTRACT DEMAND OF 6,900 KW?

3 A. I am advised by TMMC that the 6,900 kW Standby Contract Demand reflects a
4 combination of factors:

- 5 • TMMC's outage history (*i.e.*, **Schedule JP-7**);
- 6 • The fact that outages are unlikely to coincide with the monthly peak demand;
- 7 and
- 8 • The low probability of a simultaneous outage of both LDG units.

9 Q. HOW DID YOU DERIVE THE DAILY VOLUMETRIC RATE?

10 A. As previously explained, the Daily Volumetric Rate applicable to TMMC is designed to
11 recover shared facilities costs, which in the case of TMMC are the costs of the primary
12 poles allocated to TMMC. The allocated costs were derived from the Two Large Use
13 Classes/Direct Assignment study. As shown on **Schedule JP-14** (line 2), the
14 corresponding annual unit cost is \$[REDACTED] per kW-month. The \$[REDACTED] monthly charge
15 was then restated into a Daily Volumetric Rate by dividing \$[REDACTED] by the number of
16 weekdays in a typical billing month, or 20.9 (line 3). Thus, the Daily Volumetric rate
17 applicable to TMMC would be [REDACTED] per kW-Day line 4).

18 Q. WHEN WOULD THE DAILY VOLUMETRIC RATE APPLY?

19 A. The Daily Volumetric Rate would apply when the customer uses Standby Distribution
20 service; that is, when the customer establishes a higher monthly peak demand while
21 it is also experiencing a generator outage. The customer would have to notify Energy+
22 when an outage occurs and when the LDG has been fully restored. The daily demand
23 would be the difference between the monthly peak demand established during an
24 outage and the previously established monthly peak demand.

1 Further, the Daily Volumetric Rate would only apply during weekdays,
2 excluding public holidays. This would provide a price signal to encourage a customer
3 to schedule or defer outages to the off-peak hours.

4 **Q. CAN THE GENERAL APPROACH DESCRIBED IN SCHEDULE JP-14 ALSO BE**
5 **USED TO DESIGN STANDBY RATES FOR OTHER CUSTOMER CLASSES?**

6 A. Yes. The Contract Volumetric Rate for each class would be designed to recover the
7 costs of local distribution facilities used to serve that class. Because Energy+'s other
8 end-use customer classes are served from an integrated (rather than radial) system,
9 the local distribution facilities could include primary and secondary distribution, while
10 the shared facilities would include >50 kV (and, possibly, certain primary distribution
11 facilities). The derivation of the applicable rate for the GS 50 – 999 kW class is
12 illustrated in **Schedule JP-15**.

13 **Q. HOW DID YOU DERIVE THE CONTRACT VOLUMETRIC RATE FOR THE GS 50 –**
14 **999 KW CLASS?**

15 A. Referring to **Schedule JP-15**, page 1, the Contract Volumetric Rate is based on the
16 assumption that local distribution facilities include both Primary and Secondary
17 demand-related costs (line 1) and on the test-year billing demand (line 2). Using the
18 CCOSS in **Schedule JP-11**, the GS 50 – 999 kW class was allocated local distribution
19 costs of \$4.793 million (line 1). The derivation of the \$4.793 million of allocated local
20 distribution costs is shown in **Schedule JP-15**, page 2. The Contract Volumetric Rate

1 of \$3.055 per kW (page 1, line 3) was derived by dividing the allocated local distribution
2 costs (line 1) by the test-year billing determinants (line 2).²¹

3 **Q. HOW DID YOU DERIVE THE DAILY VOLUMETRIC RATE FOR THE GS 50 – 999**
4 **KW CLASS?**

5 A. The Daily Volumetric rate is based on the cost of Energy+'s shared distribution
6 facilities (**Schedule JP-15**, page 1, line 4). Based on the Settlement Proposal, the
7 cost of these facilities is \$1.523 million. The components of the \$1.523 million are
8 shown in **Schedule JP-15**, page 3.

9 Referring again to **Schedule JP-15**, page 1, I then divided this amount by the
10 total 12CP demand of 2,528,721 (line 5) to derive a system unit cost of \$0.602 per
11 kW-month (line 6). The final step was to restate the system unit cost to an equivalent
12 cost for secondary voltage by applying the applicable secondary voltage distribution
13 loss factor (line 7). This resulted in a charge of \$0.618 per kW-month (line 8). The
14 \$0.618 monthly charge can then be restated into a Daily Volumetric Rate by dividing
15 the former by the number of weekdays in a typical billing month, or 20.9 (line 9). This
16 will result in a Daily Volumetric rate of \$0.030 per kW-Day (line 10).

17 **Q. COULD THE SAME PROCESS BE USED TO ESTABLISH STANDBY RATES FOR**
18 **ANY CUSTOMER CLASS?**

19 A. Yes. The process illustrated in **Schedule JP-15** would apply equally to all (non-
20 TMMC) customer classes. In fact, because the Daily Volumetric rate is based on

²¹ In the work papers to **Schedule JP-11**, I have created a new worksheet (Local Shared Costs) that can be used to derive the Contract Volumetric Rate for the other general service classes using the same methodology as shown in **Schedule JP-15**.

1 system-wide costs, the same rate would apply to all classes taking Secondary
2 Distribution service.

3 **Q. ARE THERE ANY OTHER FACETS OF YOUR PROPOSED TMMC STANDBY**
4 **RATE DESIGN?**

5 A. Yes. First, TMMC's proposed Daily Volumetric Rate would have a "demand
6 forgiveness" provision. If a customer establishes a higher peak demand during off-
7 peak hours, that higher demand would be ignored and would not result in resetting the
8 Contract Demand or establishing a higher daily demand in the billing month.

9 However, if the daily demand were to exceed the Standby Contract Demand
10 and absent any extenuating circumstances (such as a safety issue or other emergency
11 condition on either the TMMC or Energy+ facilities), the Standby Contract Demand
12 would be increased. This "ratchet" provision would provide an incentive for TMMC to
13 manage its operating load during generator outages. The Standby Contract Demand
14 could be reset for the following calendar year by mutual agreement between Energy+
15 and TMMC.

16 **Q. WHY SHOULD THE BOARD ADOPT YOUR RECOMMENDED STANDBY**
17 **DISTRIBUTION SERVICE RATE DESIGN FOR TMMC?**

18 A. My proposed Standby rate design methodology appropriately recognizes the
19 characteristics of Standby Distribution service (*i.e.*, forced outages are random, non-
20 recurring events) while adhering to the same cost-causation principles used to design
21 cost-based rates for Supplementary Distribution service. Further, the methodology is
22 consistent with the ratemaking practices adopted by several U.S. state regulatory

1 commissions and with the U.S. Federal Energy Regulatory Commission rules that
2 apply to the provision of standby service to Qualifying Facilities.²²

3 **Q. WOULD APPLYING YOUR RECOMMENDED TMMC STANDBY DISTRIBUTION**
4 **SERVICE RATE RESULT IN ADDITIONAL REVENUES FOR ENERGY+?**

5 A. Yes. **Schedule JP-16** is an update of my original **Schedule JP-9**. It quantifies the
6 revenues that would be derived from implementing my recommended TMMC Standby
7 Distribution service rate during the test year. As discussed in my original written
8 evidence, any revenues derived from the Daily Volumetric Rate should be used to
9 offset Energy+'s test-year revenue requirement. The revenues from the Contract
10 Volumetric Rate were already accounted for in my recommended TMMC rate design
11 for Supplementary Distribution service (**Schedule JP-13**).

²² 18 C.F.R. §.292.305 (Apr. 2018).

5. CONCLUSION

1 **Q. BASED ON YOUR UPDATED WRITTEN EVIDENCE AND RECOMMENDATIONS,**
2 **WHAT FINDINGS SHOULD THE BOARD MAKE?**

3 **A.** The Board should make the following findings in lieu of the findings identified in my
4 original written evidence:

- 5 • Reject the Settlement CCROSS;
- 6 • Adopt the Two Large Use Classes/Direct Assignment CCROSS in which: (i)
7 TMMC is a separate customer class; (ii) all costs incurred to serve TMMC (with
8 the sole exception of primary poles) are directly assigned to TMMC; (iii)
9 TMMC's loads are removed from the allocation of Primary Distribution costs
10 (i.e., overhead lines and conductors; underground conduit; and underground
11 conductors); (iv) TMMC's 4NCP demands are derived from the historical load
12 profiles and do not include an LDG adjustment; and (iv) all Large Use class
13 loads are removed from the allocation of >50 kV Distribution costs.
- 14 • Establish a target revenue requirement for TMMC based on a 1.15 revenue-
15 to-cost ratio.
- 16 • Approve a just and reasonable cost-based rate design for Supplementary
17 Distribution service provided to TMMC consisting of a cost-based Service
18 Charge consistent with the Board's guidance and a Distribution Volumetric
19 Rate to recover the remaining revenue requirements not already collected in
20 the Service Charge.
- 21 • Implement a just and reasonable cost-based Standby Distribution service rate
22 design for TMMC comprised of Contract Volumetric and Daily Volumetric
23 Rates, where the former recovers the cost of local distribution facilities applied
24 to TMMC's designated Standby Contract Demand and the latter is based on
25 the cost of the shared distribution facilities applied to the amount of daily
26 Standby Distribution service (and is capped at the otherwise applicable TMMC
27 Distribution Volumetric Rate).

5. Conclusion

- 1 • Define Standby Distribution service as the *additional* delivery service required
2 when a customer's LDG sustains an outage *and* there is a net increase in the
3 customer's peak demand previously established during the billing month when
4 there were no outages.

5 **Q. DOES THIS COMPLETE YOUR UPDATED WRITTEN EVIDENCE?**

6 **A. Yes.**

APPENDIX C

Updated Schedules of Jeffry Pollock

Updated Schedule	Begins on Page No.
Schedule JP-5	36
Schedule JP-6	38
Schedule JP-8	42
Schedule JP-9	43

Schedule JP-5 Update
Page 1 of 2



Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0028

**Sheet 01 Revenue to Cost Summary Worksheet -
1 Lg Use Class/Partial Direct Assignment**

Class Revenue, Cost Analysis, and Return on Rate Base

Line	Description	Total	1 Residential	2 GS <50	3 GS> 50- 999 kW	5 GS> 1,000 - 4,999 kW	6 Large Use	7 Street Light	8 Sentinel
1	Distribution Revenue at Existing Rates	\$33,458,220	\$17,528,595	\$4,131,617	\$7,466,138	\$2,140,493	\$1,040,061	\$671,811	\$14,573
2	Miscellaneous Revenue (mi)	\$2,025,568	\$1,371,171	\$222,157	\$237,420	\$86,915	\$42,333	\$56,500	\$1,325
	Miscellaneous Revenue Input equals Output								
3	Total Revenue at Existing Rates	\$35,483,788	\$18,899,765	\$4,353,775	\$7,703,558	\$2,227,408	\$1,082,393	\$728,311	\$15,898
4	Factor required to recover deficiency (1 + D)	1.0250							
5	Distribution Revenue at Status Quo Rates	\$34,296,049	\$17,967,529	\$4,235,078	\$7,653,098	\$2,194,094	\$1,066,105	\$688,634	\$14,938
6	Miscellaneous Revenue (mi)	\$2,025,568	\$1,371,171	\$222,157	\$237,420	\$86,915	\$42,333	\$56,500	\$1,325
7	Total Revenue at Status Quo Rates	\$36,321,617	\$19,338,700	\$4,457,235	\$7,890,518	\$2,281,009	\$1,108,437	\$745,134	\$16,263
	Expenses								
8	Distribution Costs (di)	\$4,813,774	\$2,872,134	\$488,219	\$893,859	\$354,635	\$98,795	\$88,526	\$4,049
9	Customer Related Costs (cu)	\$4,893,912	\$3,856,744	\$634,958	\$289,309	\$88,275	\$16,000	\$1,531	\$181
10	General and Administration (ad)	\$8,632,229	\$5,880,495	\$985,913	\$1,063,153	\$396,853	\$175,903	\$82,128	\$3,853
11	Depreciation and Amortization (dep)	\$6,369,513	\$3,704,737	\$781,088	\$1,206,879	\$412,231	\$130,914	\$102,912	\$5,021
12	PILs (INPUT)	\$774,133	\$442,228	\$85,073	\$153,713	\$54,735	\$16,560	\$14,756	\$683
13	Interest	\$4,384,511	\$2,504,676	\$481,836	\$870,598	\$310,005	\$93,792	\$83,575	\$3,870
14	Total Expenses	\$29,868,071	\$19,261,013	\$3,457,089	\$4,477,511	\$1,616,734	\$531,963	\$373,427	\$17,657
15	Direct Allocation	\$233,895	\$0	\$0	\$0	\$0	\$91,933	\$0	\$0
16	Allocated Net Income (NI)	\$6,219,650	\$3,553,009	\$683,509	\$1,234,987	\$439,758	\$133,048	\$118,555	\$5,490
17	Revenue Requirement (includes NI) Rate Base Calculation	\$36,321,617	\$22,814,022	\$4,140,598	\$5,712,498	\$2,056,492	\$756,944	\$491,981	\$23,148
	Net Assets								
18	Distribution Plant - Gross	\$198,250,615	\$114,387,820	\$22,303,770	\$39,049,018	\$13,898,585	\$4,067,025	\$3,767,383	\$173,042
19	General Plant - Gross	\$15,515,902	\$8,905,403	\$1,711,344	\$3,056,443	\$1,080,860	\$316,820	\$297,781	\$13,776
20	Accumulated Depreciation	(\$25,192,183)	(\$14,378,065)	(\$3,086,912)	(\$4,765,519)	(\$1,783,009)	(\$616,792)	(\$422,523)	(\$18,321)
21	Capital Contribution	(\$32,252,689)	(\$19,098,242)	(\$3,650,469)	(\$6,137,144)	(\$2,088,838)	(\$500,835)	(\$645,415)	(\$29,701)
22	Total Net Plant	\$156,321,645	\$89,816,915	\$17,277,732	\$31,202,798	\$11,107,599	\$3,266,218	\$2,997,226	\$138,795
23	Directly Allocated Net Fixed Assets	\$874,567	\$0	\$0	\$0	\$0	\$90,038	\$0	\$0
24	Working Capital	\$16,695,208	\$5,238,320.83	\$1,953,193	\$4,706,578	\$2,181,790	\$1,368,873	\$47,999	\$1,779
25	Total Rate Base	\$173,891,421	\$95,055,236	\$19,230,925	\$35,909,375	\$13,289,389	\$4,725,129	\$3,045,225	\$140,574
26	REVENUE TO EXPENSES STATUS QUO%	100.00%	84.77%	107.65%	138.13%	110.92%	146.44%	151.46%	70.26%

Schedule JP-5 Update
Page 2 of 2



Ontario Energy Board

2019 Cost Allocation Mode

EB-2018-0028

Sheet 01 Revenue to Cost Summary Worksheet -
1 Lg Use Class/Partial Direct Assignment

Class Revenue, Cost Analysis, and Return on Rate Base

Line	Description		9	10	12	13	14	15
		Total	Unmetered Scattered Load	Embedded Distributor Hydro One - CND	Embedded Distributor Waterloo North Hydro - CND	Embedded Distributor Hydro One 1 - BCP	Embedded Distributor Brantford Power BCP	Embedded Distributor Hydro One 2 - BCP
1	Distribution Revenue at Existing Rates	\$33,458,220	\$64,042	\$50,527	\$221,287	\$119,034	\$5,388	\$4,655
2	Miscellaneous Revenue (mi)	\$2,025,568	\$4,676	\$631	\$1,655	\$359	\$200	\$225
		M						
3	Total Revenue at Existing Rates	\$35,483,788	\$68,718	\$51,157	\$222,942	\$119,393	\$5,588	\$4,880
4	Factor required to recover deficiency (1 + D)	1.0250						
5	Distribution Revenue at Status Quo Rates	\$34,296,049	\$65,646	\$51,792	\$226,828	\$122,014	\$5,523	\$4,772
6	Miscellaneous Revenue (mi)	\$2,025,568	\$4,676	\$631	\$1,655	\$359	\$200	\$225
7	Total Revenue at Status Quo Rates	\$36,321,617	\$70,322	\$52,422	\$228,484	\$122,374	\$5,723	\$4,997
	Expenses							
8	Distribution Costs (di)	\$4,813,774	\$13,558	\$0	\$0	\$0	\$0	\$0
9	Customer Related Costs (cu)	\$4,893,912	\$1,388	\$2,394	\$405	\$405	\$701	\$1,620
10	General and Administration (ad)	\$8,632,229	\$13,568	\$6,029	\$17,539	\$3,601	\$1,820	\$1,375
11	Depreciation and Amortization (dep)	\$6,369,513	\$16,819	\$2,897	\$4,555	\$863	\$598	\$0
12	PILs (INPUT)	\$774,133	\$2,289	\$680	\$2,703	\$512	\$200	\$0
13	Interest	\$4,384,511	\$12,966	\$3,850	\$15,310	\$2,900	\$1,133	\$0
14	Total Expenses	\$29,868,071	\$60,589	\$15,850	\$40,511	\$8,281	\$4,453	\$2,995
15	Direct Allocation	\$233,895	\$0	\$22,003	\$95,172	\$18,028	\$6,758	\$0
16	Allocated Net Income (NI)	\$6,219,650	\$18,393	\$5,461	\$21,717	\$4,114	\$1,608	\$0
17	Revenue Requirement (includes NI)	\$36,321,617	\$78,981	\$43,314	\$157,401	\$30,423	\$12,819	\$2,995
	Rate Base Calculation							
	Net Assets							
18	Distribution Plant - Gross	\$198,250,615	\$579,115	\$21,634	\$0	\$0	\$3,224	\$0
19	General Plant - Gross	\$15,515,902	\$46,015	\$14,550	\$57,702	\$10,931	\$4,278	\$0
20	Accumulated Depreciation	(\$25,192,183)	(\$62,452)	(\$15,601)	(\$33,167)	(\$6,283)	(\$3,537)	\$0
21	Capital Contribution	(\$32,252,689)	(\$97,756)	(\$3,732)	\$0	\$0	(\$556)	\$0
22	Total Net Plant	\$156,321,645	\$464,921	\$16,851	\$24,535	\$4,648	\$3,408	\$0
23	Directly Allocated Net Fixed Assets	\$874,567	\$0	\$121,596	\$525,953	\$99,631	\$37,349	\$0
24	Working Capital	\$16,695,208	\$23,144	\$117,397	\$539,490	\$113,187	\$3,503	\$399,954
25	Total Rate Base	\$173,891,421	\$488,065	\$255,844	\$1,089,979	\$217,466	\$44,260	\$399,954
26	REVENUE TO EXPENSES STATUS QUO%	100.00%	89.04%	121.03%	145.16%	402.24%	44.65%	166.86%

Schedule JP-6 Update
Page 1 of 4

ENERGY+, Inc.
Recommended Large Use Class Rate Design

Line	Description	Cost	Billing Units	Rate	Reference
		(1)	(2)	(3)	(4)
1	Revenue Requirement	\$828,153			Schedule JP-6, page 2
	Service Charge:				
2	Present Rates			\$8,976.07	Appilcation Exhibit 8 at 10
3	Recommended Rates	<u>\$215,426</u>	24 Bills	\$8,976.07	No Change
	Revenues to be Recovered In				
4	Distribution Volumetric Rates	\$612,727			Line 1 - Line 3
5	Total Demand-Related Costs	\$659,936			Page 2
6	Revenue-to-Cost Ratio	92.8%			Line 4 ÷ Line 5
7	Shared Facilities Cost	\$159,073	[REDACTED] kW	[REDACTED]	Col. 1 ÷ Col. 2
	Local Facilities Cost:				
8	Feeder Costs	\$98,919	[REDACTED] kW	[REDACTED]	(Line 6 x Schedule JP-6, Line 12, Col. 6) ÷ Col. 2
9	Poles, Towers, & Fixtures	<u>\$110,250</u>	[REDACTED] kW	[REDACTED]	(Line 6 x Schedule JP-6, page 3, Line 5) ÷ Col. 2
10	Primary Substation Volumetric Rate	\$190,877			Col. 1 = Col. 2 x Col. 3 Col. 3 = Sum Lines 8:9
11	Primary Distribution Volumetric Rate	\$262,778	[REDACTED] kW	[REDACTED]	(Line 4 - Line 7 - Line 10) ÷ Col. 2

Sources:

- (1) Schedule JP-6, page 2 x Line 6.
- (2) Schedule JP-6, page 4.

Schedule JP-6 Update
Page 2 of 4

ENERGY+, Inc.
Large Use Class Revenue Requirement By Component
Based on TMMC's Revised Class Cost-of-Service Study

Line	Description	Total Large Use Class	Customer- Related Costs	Total Demand- Related Costs	Shared Facilities (Bulk Distribution) Costs	Local Facilities	
						All Other Costs	TMMC Feeder Costs
		(1)	(2)	(3)	(4)	(5)	(6)
1	Distribution Costs	\$98,795	\$32	\$98,763	\$30,757	\$68,006	
2	Customer-Related Costs	\$16,000	\$16,000	\$0	\$0	\$0	
3	General & Administrative	\$175,903	\$24,553	\$49,850	\$15,524	\$34,326	
4	Depreciation & Amortization	\$130,914	\$15,492	\$115,422	\$38,191	\$77,231	
5	PILS	\$16,560	\$1,219	\$15,341	\$4,565	\$10,776	
6	Interest Expense	\$93,792	\$6,903	\$86,889	\$25,858	\$61,031	
7	Total Expenses	\$531,963	\$64,197	\$366,265	\$114,895	\$251,370	\$0
8	Direct Allocation	\$91,933	\$0	\$91,933	\$0	\$0	\$91,933
9	Allocated Net Income	\$133,048	\$9,792	\$123,256	\$36,680	\$86,576	\$0
10	Miscellaneous Revenue	\$42,333	\$30,336	\$11,997	\$3,736	\$8,261	
11	Revenue Requirement at Cost	\$714,611	\$43,653	\$569,458	\$147,839	\$329,685	\$91,933
12	Rev. Req. at 1.15 RCR*	\$828,153	\$50,589	\$659,936	\$171,329	\$382,067	\$106,540

Source: Schedules JP-3 and JP-5.

* Revenue Requirement incl NI	\$756,944
Revenue-to-Cost Ratio (RCR)	1.15
Revenue Requirement	\$870,486
Less: Misc. Revenue	\$42,333
Target Rate Design Revenue	\$828,153

Schedule JP-6 Update
Page 3 of 4

ENERGY+, Inc.
Large Use Class:
Estimated Cost Primary Poles, Towers, and Fixtures
Based on TMMC's Revised Class Cost-of-Service Study

Line	Description	Amount	Reference
		(1)	(2)
1	Total Primary Distribution Costs	\$382,067	Schedule JP-6, Line 12, Col. 5
	Gross Plant Investment:		
2	Primary Poles, Towers, & Fixtures	\$18,839,131	Energy+ CCOSS
3	Total Primary Gross Plant Investment	\$60,615,861	Energy+ CCOSS
4	Gross Plant Ratio	31.08%	Line 2 ÷ Line 3
5	Poles, Towers, & Fixtures Costs	\$118,745	Line 1 x Line 4

Schedule JP-6
Page 4 of 4

ENERGY+, Inc.
Large Use Class Billing Demand
(Amounts in kW)

<u>Line</u>	<u>Description</u>	<u>Amount</u>	<u>Reference</u>
		(1)	(2)
1	Energy+ Projection	361,276	
2	Less: Energy+ LDG Adjustment		Schedule JP-1, Line 3, Col. 2 x 12
3	Supplementary Billing Demand		Line 1 + Line 2
4	Percent of Load at Primary Substation		Estimated
5	Primary Substation Billing Demand Supplemental		Line 3 x Line 4
6	Primary Distribution Billing Demand		Line 3 - Line 5
	<u>Primary Substation - Feeder</u>		
7	Base (Supplemental)		Line 5
8	Standby Contract Demand	55,200	4,600 kW
9	Total Primary Substation - Feeder Billing Demand		Sum Lines 7 - 8
	<u>Primary Substation - Poles</u>		
10	Base - Substation		Line 5
11	Standby Contract Demand	55,200	4,600 kW
12	Primary Distribution		Line 6
13	Total Primary Substation - Pole Billing Demand	386,032	Sum Lines 10 - 12

Schedule JP-8 Update
Page 1 of 1

ENERGY+, Inc.
Recommended Standby Service Rate Design

<u>Line</u>	<u>Description</u>	<u>Rate</u>	<u>Reference</u>
		(1)	(2)
1	Contract Volumetric Rate		Schedule JP-6, Page 1
	Daily Volumetric Rate:		
2	Local Facilities Unit Cost		Schedule JP-6, Page 1
3	No. of Weekdays Per Billing Month	20.9	
4	Daily Volumetric Rate		Line 2 ÷ Line 3
5	Monthly Maximum Standby Volumetric Rate		Sum Lines 1:2

Schedule JP-9 Update
Page 1 of 1

ENERGY+, Inc.
Revenues From Recommended Standby Service Rate

Line	Description	Rate	Billing Units	Revenues	Reference
		(1)	(2)	(3)	(4)
1	Contract Volumetric Rate		55,200 kW		Schedule JP-8
2	Daily Volumetric Rate	\$0.023			Schedules JP-7 & JP-8
3	Total Standby Service Revenues				Sum Lines 1:2

APPENDIX D-1

Critique of Energy+'s Class Cost-of-Service Study

1 **Q. WHAT ARE YOUR SPECIFIC CONCERNS ABOUT ENERGY+'S CLASS COST-OF-**
2 **SERVICE STUDY?**

3 **A.** Energy+'s CCOSS overstates the cost of serving the Large Use class for several reasons.
4 First, Energy+ has erroneously adjusted the Large Use class 12CP, 4NCP and 12NCP
5 demands that it uses to allocate demand-related costs in its CCOSS. These adjusted
6 demands do not reflect the load profile of the Large Use class; instead, they reflect a load
7 profile *adjusted for the assumed impact of TMMC's LDG facility*. Moreover, Energy+'s
8 LDG adjustments ignore the procedures that have been outlined by the Board for
9 recognizing LDG in a CCOSS, and they ignore diversity.

10 Second, Energy+ failed to recognize that the specific distribution infrastructure it
11 uses to serve TMMC is different from the infrastructure that it uses to serve the other Large
12 Use customer. Specifically, TMMC is served directly from two dedicated feeders that
13 extend from Hydro One's Preston TS to the TMMC plant. This type of distribution service
14 can be described as "Primary Substation" service. The cost of the two dedicated feeders
15 serving TMMC has been ascertained by Energy+ and, accordingly, should be directly
16 assigned to TMMC. The other Large Use customer, by contrast, takes Primary
17 Distribution service from an integrated primary distribution network.

18 Each of these flaws is discussed below.

19 **Q. WHAT IS THE LARGE USE CLASS?**

20 **A.** The Large Use class is a rate class comprised of two customers that each have peak
21 demands of at least 5 MW. The class is served entirely at primary voltage, although, as

Appendix D

1 previously stated and discussed in more detail below, the Energy+ infrastructure used to
2 serve these two Large Use customers differs.

3 **Load Displacement Generation Adjustments**

4 **Q. WHY DO YOU ASSERT THAT ENERGY+ HAS OVERSTATED THE LARGE USE**
5 **CLASS DEMAND ALLOCATION FACTORS?**

6 A. The demand allocation factors are overstated because they do not reflect the Large Use
7 class's *actual* load characteristics as derived from the load profile analysis. Instead, they
8 reflect unsupported assumptions about the timing, amount, and duration of the standby
9 delivery service provided during outages of TMMC's LDG.

10 **Q. WHAT DEMAND ALLOCATION FACTORS DOES ENERGY+ USE TO ALLOCATE**
11 **DISTRIBUTION COSTS TO THE LARGE USE CLASS?**

12 A. Energy+ uses the 12CP method to allocate Bulk Distribution costs and the 4NCP method
13 to allocate Primary Distribution costs.

14 **Q. DID ENERGY+ USE THE 12CP, 4NCP, AND 12NCP DEMANDS THAT WERE DERIVED**
15 **FROM ENERGY+'S LOAD PROFILE ANALYSIS?**

16 A. No. The 12CP, 4NCP, and 12NCP demands used in the Energy+'s CCROSS for the Large
17 Use class are not the same as the 12CP, 4NCP, and 12NCP demands derived in
18 Energy+'s load profile. Instead, Energy+ adjusted these load profile demands for the
19 assumed impact of TMMC's LDG. The specific LDG adjustments are shown on Table 1.

Table 1 Derivation of Adjusted 12CP, 4NCP and 12NCP Demands Large Use Class (kW)			
Description	12CP	4NCP	12NCP
Per Load Profile	259,575	102,987	286,587
Energy+ LDG Adjustments			
Per Updated CCROSS			
Source: 2019 EnergyPlus Load Profile Model 2006 Hydro One data for 2019_IRR_20180914; Cost Allocation Model Schedule I-18; Energy+ Response to IR-TMMC-4.			

1 Q. WHAT IS THE BASIS FOR ENERGY+'S LDG ADJUSTMENTS?

2 A. Energy+ observed that in calendar year 2017, TMMC reached an annual peak demand of
3 approximately [REDACTED] MW.⁷ The actual peak demand was [REDACTED] kW. This annual peak
4 demand occurred on Wednesday, November 8, 2017 at 8 am.

5 Q. HOW DID ENERGY+ DETERMINE THAT LDG WOULD INCREASE THE LARGE USE
6 CLASS'S TWELVE MONTH LOADS BY PRECISELY [REDACTED] KW?

7 A. The derivation of the Energy+ LDG adjustments is shown in **Schedule JP-1**. It shows
8 TMMC's monthly peak demands for calendar years 2016, 2017, and six months of 2018.
9 TMMC's annual peak demand is shown in column 1, and its average monthly peak
10 demand is shown in column 2. Column 3 shows the difference between columns 1 and 2.

11 For example, in 2017, TMMC's peak demand was [REDACTED] kW, while its average
12 monthly peak demand was [REDACTED] kW (line 2). This reflects a difference of [REDACTED] kW
13 (column 3, line 2). Energy+'s proposed [REDACTED] kW adjustment to both the 12CP and
14 12NCP demands is exactly the product of [REDACTED] kW and 12 (line 5).

⁷ Energy+ Response to IR-TMMC-9, Sub-Question vii.

1 Q. SCHEDULE JP-1 SHOWS THAT TMMC IMPOSED A NET PEAK DEMAND OF
2 APPROXIMATELY 28.8 MW IN 2016. DOESN'T ENERGY+ HAVE TO SIZE ITS
3 DISTRIBUTION FACILITIES TO SERVE LOADS OF AT LEAST 28.8 MW?

4 A. No, it does not. The dedicated distribution feeders that serve TMMC were energized long
5 before TMMC's LDG went into service on January 1, 2016.⁸ Prior to installing that facility,
6 TMMC's peak demand was as high as [REDACTED] MW.⁹ Accordingly, the dedicated distribution
7 feeders are already more than adequate to deliver TMMC's gross peak demand.

8 Q. ARE ENERGY+'S PROPOSED LDG ADJUSTMENTS REASONABLE?

9 A. No. The LDG adjustments shown in Table 1 above assume that an outage of TMMC's
10 LDG would occur simultaneously with the Large Use class's coincident and non-coincident
11 peak demands *in each and every month*. This assumption is not supported by any
12 analysis presented by Energy+ in its application. Accordingly, there is no basis for making
13 the same LDG adjustment to the 12CP demands as Energy+ is proposing to make to the
14 4NCP and 12NCP demands. To do so would assume that Standby Distribution service
15 has zero diversity.

16 Q. WHAT DO YOU MEAN BY DIVERSITY?

17 A. Diversity recognizes that individual customers experience their peak demands at different
18 times. It can be expressed in several ways, as shown in Table 2.

⁸ *Id.*

⁹ Information provided by TMMC.

Table 2 Example of Demand Diversity			
Description	Customer #1	Customer #2	Total Class
Demand Coincident With the System Peak	50	50	100
Demand Coincident With the Class Peak	60	75	135
Maximum Demand	75	85	160
Diversity: Class Peak To Coincident Peak	1.20	1.25	1.35
Diversity: Maximum To Class Peak	1.25	1.13	1.18

One measure of diversity is the ratio of each customer's contribution to the class peak to the coincident peak. The corresponding diversity factors are 1.20 and 1.25 times, respectively, for Customer 1 and Customer 2. Overall, the class diversity is 1.35 times.

A second measure is the ratio of each customer's maximum demand to class peak demand. The corresponding diversity factors are 1.25 and 1.13 times, respectively, for Customer 1 and Customer 2. Overall, the class diversity is 1.18 times.

Because of diversity, coincident demands are lower than class peak demands, and class peak demands are lower than the sum of each customer's maximum demand.

Q. IS THERE ANY DIVERSITY WITHIN THE LARGE USE CLASS?

A. Yes. Table 3 below measures Energy+'s Large Use class demand diversity. As shown in Table 3, the diversity between the Large Use class's 12NCP and its 12CP is 1.10, while the diversity between the Large Use class's billing demand and the 12NCP demand is 1.15. Therefore, even a class comprised of only two customers can exhibit diversity.

Table 3 Large Use Class Demand Diversity Excluding LDG Adjustments		
Description	Demand (kW)	Diversity
12CP	259,575	N/A
12NCP	286,587	1.10
Billing Demand		1.15
Sources: 2019 EnergyPlus Load Profile Model 2006 Hydro One data for 2019_IRR_20180914; Cost Allocation Model, Schedule 16.1 less 12NCP LDG adjustment; and Energy+ Response to IR-TMMC-19.		

1 **Q. DO THE LOAD PROFILES USED BY ENERGY+ INCLUDE LDG?**

2 A. No. Energy+ is using 2006 Hydro One data to project its 2019 load profile.¹⁰ As previously
 3 stated, TMMC did not begin operation of its LDG until January 1, 2016. Thus, the diversity
 4 shown in Table 3 excludes the impact of LDG.

5 **Q. HOW MIGHT LDG IMPACT DIVERSITY?**

6 A. As discussed later, forced outages of generators are random, short-duration occurrences.
 7 Similarly, planned outages can be scheduled in advance to occur at times when capacity
 8 is readily available such as during the non-summer months and off-peak hours. Based on
 9 these assumptions, the addition of LDG will increase the diversity within the Large Use
 10 class. As demonstrated below, the higher the diversity, the lower the distribution
 11 volumetric rate required to recover the cost of providing Standby Distribution service.

¹⁰ 2019 EnergyPlus Load profile model 2006 Hydro One data for 2019_IRR_20180914 provided in response to Staff IRs.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM ENERGY+'S PROPOSED LDG ADJUSTMENTS?

A. Energy+ failed to analyze the impact of LDG on the Large Use class's load characteristics. Absent such an analysis, it is impossible to precisely determine the amount of diversity associated with any Standby Distribution service that Energy+ provides to TMMC to replace its on-site generation.

Consistency With the Board's Directions

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT ENERGY+'S CLASS COST-OF-SERVICE STUDY?

A. Yes. Energy+'s LDG adjustments are contrary to the Board's directions on cost allocation. Specifically, with respect to LDG, the Board directed distributors to explain in its Filing Summary:

- What steps were taken to gather relevant data to assess the existence of diversity, and
- What steps were taken to reflect any diversity of generation in its filing.¹¹

As previously stated, Energy+ assumed zero diversity for TMMC's generator outages, and it provided no explanation or evidentiary support for this assumption.

Q. IS ENERGY+'S CLASS COST-OF-SERVICE STUDY CONSISTENT WITH THE PRINCIPLES ARTICULATED BY THE BOARD WITH RESPECT TO THE ALLOCATION OF COSTS TO LDG?

A. No, it is not. The Board states as follows:

¹¹ EB-2005-0317, Cost Allocation Review, *Board Directions on Cost Allocation Methodology for Electricity Distributors* at 23 (Sept. 29, 2006).

1 The total costs to be allocated to the LDG classification will consist of costs
2 associated with providing distribution service to the base load that is the
3 same as a standard distribution customer, along with the distribution costs
4 required to support the incremental load when the load displacement
5 generator is not operating.¹²

6 In other words, the first step is to determine a proper cost-based rate for providing
7 Supplementary distribution service to the class, irrespective of the impact of LDG.
8 Energy+ skipped this step because the CCOSS originally filed with its Application, as well
9 as the CCOSS updated and filed on September 14, 2018, include erroneous and
10 unsupported LDG adjustments to the Large Use class demand allocation factors. By
11 skipping this step, Energy+ failed to follow the Board's direction.

12 **Q. WHAT DO YOU MEAN BY SUPPLEMENTARY DISTRIBUTION SERVICE?**

13 A. Supplementary distribution service is the amount of delivery service normally provided to
14 a customer while its LDG is fully operational.

15 **Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE ADJUSTMENTS PROPOSED**
16 **BY ENERGY+?**

17 A. The LDG adjustments should be removed from the CCOSS.

18 **Direct Assignment**

19 **Q. SHOULD ANY OTHER CHANGES TO ENERGY+'S CLASS COST-OF-SERVICE**
20 **STUDY ALSO BE CONSIDERED?**

21 A. Yes. As discussed below, TMMC receives a different type of primary distribution service
22 than the other Large Use customer. Further, most of the costs of the Energy+ distribution

¹² *Id.* at 92.

1 infrastructure used to serve TMMC can be directly assigned. The facilities used to serve
2 TMMC are shown in **Schedule JP-2** attached to my original written evidence.

3 **Schedule JP-2** is an electric single-line diagram that shows the delivery facilities
4 that serve TMMC (page 1) and the other Large Use customer (page 2). Referring to
5 page 1, TMMC is served directly from Hydro One's Preston TS through two dedicated
6 27.6 KV feeders, M24 and M30. These are the only Energy+ facilities that serve TMMC.
7 Because of its direct connection to a Hydro One substation, TMMC is receiving Primary
8 Substation service.

9 This is in stark contrast to Large Use Customer 2 (page 2), which takes primary
10 distribution service through an integrated distribution system that serves other Energy+
11 customers. Hence, Customer 2 receives Primary Distribution service.

12 **Q. IS A DIRECT ASSIGNMENT OF THE COSTS OF THE FEEDERS DEDICATED TO**
13 **SERVING TMMC CONSISTENT WITH BOARD POLICY?**

14 A. Yes. The Board has recognized that it may be appropriate to directly assign costs where
15 there is evidence that a clearly identifiable and significant distribution facility can be
16 tracked directly to a single rate classification.¹⁵ The Board's directions on direct allocation
17 state:

18 When direct allocation is used, the distributor should consider whether it
19 needs to adjust the appropriate allocation factors so that the rate
20 classification to which costs for a specific function are directly allocated is
21 not allocated further costs related to that function, except where there are
22 joint costs that apply to the customer classification.¹⁶

¹⁵ EB-2005-0317, Cost Allocation Review, *Board Directions on Cost Allocation Methodology for Electricity Distributors* (September 29, 2006) at 31.

¹⁶ *Id.* at 32.

1 **Q. IF THE COSTS OF THE FEEDERS DEDICATED TO SERVING TMMC ARE DIRECTLY**
2 **ASSIGNED, HOW WOULD THIS CHANGE THE CLASS COST-OF-SERVICE STUDY?**

3 A. With one exception, TMMC's load should be removed from the factors used to allocate all
4 other primary distribution plant. The exception is with respect to Poles, Towers, and
5 Fixtures – Primary (USoA 1830-4). TMMC should be considered in the allocation of the
6 costs of these assets.

APPENDIX D-2

Critique of Energy+'s Proposed Standby Rate

1 Q. HOW IS ENERGY+ PROPOSING TO DESIGN A RATE FOR STANDBY
2 DISTRIBUTION SERVICE?

3 A. Energy+ proposes to charge for Standby Distribution service by applying the otherwise
4 applicable distribution volumetric rate to any portion of the LDG customer's Contract
5 Demand in excess of the LDG customer's actual monthly peak demand. For TMMC,
6 the otherwise applicable charge would be the Large Use Distribution Volumetric Rate.
7 Energy+ initially set TMMC's Contract Demand to 28.8 MW.²¹ It subsequently revised
8 this to [REDACTED] MW in response to an interrogatory from TMMC.²² The new lower Contract
9 Demand reflects TMMC's maximum demand during calendar year 2017.

10 In effect, the Energy+ proposal involves "topping up" the distribution charges
11 payable when the observed demand is less than the Contract Demand. The top-up
12 would not be based on any measure of the actual amount of delivered standby power
13 drawn. If, however, the LDG customer's actual peak demand in any month exceeds
14 its Contract Demand (in which case there would be no shortfall between actual
15 demand and Contract Demand), then the Distribution Volumetric rate would be applied
16 only to the actual monthly peak demand. Finally, under Energy+'s Standby
17 Distribution service rate design, an LDG customer's Contract Demand could be
18 adjusted from time to time, presumably at Energy+'s discretion.

²¹ Application, Exhibit 7 at 10.

²² Energy+ Response to IR-TMMC-4.

1 **Q. WHY IS ENERGY+ PROPOSING TO CHARGE THE SAME RATE FOR STANDBY**
2 **DISTRIBUTION SERVICE AS FOR SUPPLEMENTARY DISTRIBUTION SERVICE?**

3 A. Energy+ asserts that it has to reserve this capacity "...to ensure that the Energy+
4 infrastructure is in place at all times to provide the contracted peak load at any time."²³
5 Further, Energy+ asserts that establishing a [REDACTED] MW Contract Demand for TMMC is
6 necessary in order to keep it whole with respect to the recovery of costs associated
7 with peak demand.²⁴

8 **Q. DO YOU HAVE SPECIFIC CONCERNS WITH ENERGY+'S PROPOSED STANDBY**
9 **DISTRIBUTION SERVICE RATE DESIGN?**

10 A. Yes. First, as explained in more detail below, Energy+'s proposed Large Use Standby
11 Distribution service rate design does not reflect cost-causation principles, and thus,
12 would not result in a just and reasonable rate. Cost causation means recognizing how
13 Standby Distribution service has different usage characteristics than Supplementary
14 Distribution service because thermal LDGs, such as TMMC's LDG facility, are typically
15 both highly efficient and reliable. This means that Standby Distribution service is used
16 infrequently.

17 Second, Energy+ has provided no explanation for how it determined the
18 Standby Contract Demand for TMMC. Typically such a determination is made in
19 consultation with (rather than being imposed on) the LDG customer. Third, Energy+
20 ignored the reduction in the amount of capacity it has to reserve as a result of TMMC's

²³ Energy+ Response to IR-TMMC-1.

²⁴ Application, Exhibit 7 at 13.

1 LDG. With LDG reducing TMMC's net peak demand, more capacity is available to serve
2 Energy+'s other customers.

3 Finally, Energy+'s proposed Standby Distribution service rate design would send
4 the wrong price signals and discourage customers with LDG from scheduling outages in
5 advance at times when the distribution system is not as stressed.

6 **Cost Causation**

7 **Q. WHY DO YOU ASSERT THAT ENERGY+'S PROPOSED STANDBY RATE DESIGN IS** 8 **NOT CONSISTENT WITH COST CAUSATION?**

9 A. Energy+ used TMMC's maximum demand in 2017 to establish the Standby Contract
10 Demand. As previously stated, both Energy+'s and TMMC's Revised CCOSs allocated
11 Bulk distribution facilities on a 12CP basis and Primary distribution facilities on a 4NCP
12 and 12NCP (or class peak) basis. Thus, no distribution demand-related costs were
13 allocated on the basis of a customer's highest recorded peak demand. Accordingly, a
14 standby rate based solely on the highest recorded peak demand of one specific customer
15 is not consistent with how demand-related costs were allocated to the Large Use class in
16 either Energy+'s or TMMC's Revised CCOSs.

17 Therefore, Energy+'s proposed Standby Distribution service rate design is both
18 inconsistent with cost-causation principles and discriminatory as between an LDG
19 customer and a non-LDG customer in the same rate class.

20 **Standby Usage Characteristics**

21 **Q. SHOULD STANDBY DISTRIBUTION SERVICE BE PRICED THE SAME AS** 22 **SUPPLEMENTARY DISTRIBUTION SERVICE?**

23 A. No. Setting the same volumetric rate for both Standby and Supplementary distribution

1 service assumes that Standby Distribution service has precisely the same usage
2 characteristics as Supplementary Distribution service. The specific Energy+ proposed
3 LDG adjustments were not based on any analysis of TMMC's load characteristics as
4 would be necessary to estimate the expected amount of incremental load associated with
5 the Standby Distribution service required by TMMC. Thus, Energy+'s assumption about
6 TMMC's standby usage characteristics is simply unsupported.

7 **Q. ARE THERE DIFFERENT TYPES OF STANDBY SERVICE?**

8 A. Yes. Standby Distribution service consists of Backup service and Maintenance service.

9 **Q. HOW ARE BACKUP SERVICE AND MAINTENANCE SERVICE DEFINED?**

10 A. Backup service is the incremental delivery service required to provide electric energy or
11 capacity to replace the energy or capacity that is unavailable due to an unscheduled or
12 forced outage of the LDG. Thus, Backup service must be available at any time.
13 Maintenance service, by contrast, is the incremental delivery service required to deliver
14 electric energy or capacity supplied during a scheduled outage. Typically utilities will
15 require self-generating customers to request Maintenance service in advance when there
16 are adequate resources to accommodate a planned outage. This is often the
17 characteristic that differentiates Maintenance service from Backup service.

18 **Q. DO BACKUP SERVICE AND MAINTENANCE SERVICE HAVE THE SAME**
19 **CHARACTERISTICS AS SUPPLEMENTARY SERVICE?**

20 A. No. Backup service and Maintenance service are different from Supplementary service.
21 Table 6 illustrates the differences.

Table 6 Relationship Between Diversity Factor and Distribution Volumetric Rates					
Customer	Class Peak Demand (kW)	Billing Demand (kW)	Diversity Factor	Allocated Demand Costs	Cost-Based Volumetric Rate
	(1)	(2)	(3)	(4)	(5)
1	1,000	2,000	2.00	\$10,000	\$5.00
2	1,000	1,250	1.25	\$10,000	\$8.00
3	1,000	10,000	10.00	\$10,000	\$1.00
Assumptions:			Col 2 ÷ Col 1	\$30,000 allocated on Col 1	Col 4 ÷ Col 2

Table 6 shows the class peak and the billing demands of three customers. Each customer has the same class peak demand of 1,000 kW (column 1), but distinct billing demands of 2,000 kW, 1,250 kW, and 10,000 kW (column 2). Thus, there is substantial diversity within the class (column 3). Customers 1 and 2 purchase their full requirements; that is, they do not own LDG. Customer 3 owns LDG. The example further assumes that the utility has allocated \$30,000 of demand-related costs to the class. Thus each customer is responsible for \$10,000 of demand-related costs (column 4).

Because of varying diversity, the per-unit demand-related cost to serve each customer is different. Specifically, a cost-based volumetric rate would be \$5 for Customer 1, \$8 for Customer 2, and only \$1 for Customer 3. In other words, a cost-based volumetric rate would be inversely proportional to each customer's diversity factor.

Q. WHY WOULD YOU ASSUME THAT A CUSTOMER WITH LDG WOULD HAVE A HIGHER DIVERSITY FACTOR?

A. Thermal LDG is typically very reliable and efficient. It would not be atypical for LDG facilities to operate at very high capacity factors and experience very low outage rates.

1 Thus, forced outages can be few and far between. Any maintenance outages could be
2 planned well in advance because both the timing and duration of a maintenance outage
3 can be reasonably estimated based on the scope of maintenance work to be performed
4 on the LDG facility.

5 These characteristics mean that outages where replacement power is needed are
6 unlikely to occur coincident with either a class peak or the distributor's system peak
7 demands. In other words, customers with LDG facilities would more closely resemble
8 Customer 3 than either Customers 1 or 2 in Table 6 above.

9 For this reason, it is unreasonable to levy the same Volumetric Rate for Standby
10 Distribution service as for Supplementary Distribution service.

11 **Q. HAVE YOU REVIEWED TMMC'S USE OF STANDBY DISTRIBUTION SERVICE?**

12 A. Yes. **Schedule JP-7** provides an analysis of TMMC's use of Standby Distribution service
13 for the period January 1, 2016 through June 30, 2018. The amount of Standby Distribution
14 service used by TMMC is derived in column 3 and is the difference in the monthly
15 maximum demands during periods when the generators were fully operational (column 1)
16 and the maximum on-peak demands during periods when an outage occurred (column
17 2). Standby Distribution service only occurs when the customer sets a new monthly
18 maximum demand because of a generator outage during on-peak hours. The outage
19 duration is shown in column 4 and is measured using the number of on-peak days per
20 month. Several conclusions can be drawn from **Schedule JP-7**.

21 First, there were no outages during on-peak hours in several months. Second,
22 when outages occurred, they were of short duration. On average, TMMC experienced
23 only two days of outage per month. Third, on some occasions when an outage occurred,

1 it did not result in TMMC setting a new on-peak demand. On average, TMMC's on-peak
2 maximum demand was less than 1,500 kW higher due to generator outages.

3 These statistics demonstrate that, contrary to Energy+'s LDG adjustments,
4 Standby Distribution service did not impact peak demand equally in every month.

5 **Energy+'s Make Whole Assertion**

6 **Q. IS ENERGY+'S PROPOSED STANDBY DISTRIBUTION SERVICE RATE DESIGN**
7 **NECESSARY TO KEEP IT WHOLE WITH RESPECT TO THE COSTS ASSOCIATED**
8 **WITH SERVING PEAK DEMAND?**

9 A. No. In this proceeding, the Board will set rates for each customer class using a Board-
10 approved CCOSS and projected billing determinants. By definition, the rates derived from
11 a Board-approved CCOSS and billing determinants will fully recover Energy+'s revenue
12 requirement. There would be no trapped or unrecovered costs and, as a result, Energy+
13 would be made whole.

14 **Q. IF STANDBY DISTRIBUTION SERVICE IS PRICED SEPARATELY FROM**
15 **SUPPLEMENTARY DISTRIBUTION SERVICE, SHOULD ANY OTHER MAKE-WHOLE**
16 **ADJUSTMENT BE MADE?**

17 A. Yes. Assuming that Standby Distribution service is separately priced, it would be
18 appropriate to account for the incremental revenues in determining the revenues that need
19 to be recovered from the rates for Supplementary distribution service. This would ensure
20 that Energy+'s customers are kept whole.

Capacity Reservation

Q. WHAT CAPACITY DOES ENERGY+ PURPORTEDLY RESERVE FOR TMMC'S LDG?

A. As previously stated, Energy+ asserts that it must have infrastructure in place at all times in order to provide the Contract Demand at any time. However, the Energy+ infrastructure that serves TMMC consists of two 27.6 kV feeders. These feeders have more than enough capacity to serve TMMC's gross load, which, prior to placing its LDG in operation, was as high as [REDACTED] MW. Under my recommended Large Use rate design, the cost of these feeders are directly assigned and would be recovered in the Primary Substation Volumetric Rate applicable to TMMC. Thus, Energy+ would not incur any incremental primary distribution costs to serve TMMC.

Q. DOESN'T ENERGY+ ALSO HAVE TO RESERVE [REDACTED] MW OF CAPACITY IN THE PRESTON TS TO SERVE TMMC'S STANDBY NEEDS?

A. No. This statement assumes that both TMMC generators sustain simultaneous forced outages and that the impact of the simultaneous forced outage is a [REDACTED] MW increase in TMMC's load. However, Energy+ has provided no evidence that a simultaneous forced outage would immediately increase TMMC's load by [REDACTED] MW or that it would cause TMMC's peak demand to exceed what TMMC's maximum load was prior to installing its LDG facility.

Further, as can be seen in **Schedule JP-7**, the maximum amount of Standby Distribution service that has ever been taken by TMMC was [REDACTED] MW (line 23, column 3). This occurred during a rare simultaneous outage of both generators at 8 am on Wednesday, November 8, 2017. When this simultaneous outage occurred, however,

1 TMMC's maximum demand was [REDACTED] MW. Energy+'s system demand in that hour was
2 [REDACTED] MW. This is only 70% of Energy+'s 2017 system peak.²⁵

3 **Q. HOW MUCH CAPACITY DID ENERGY+ HAVE TO RESERVE ON THE PRESTON TS**
4 **PRIOR TO WHEN TMMC ADDED ITS LDG FACILITY?**

5 A. Energy+ would have had to reserve at least [REDACTED] MW to accommodate TMMC's maximum
6 demand prior to installing its LDG facility. This is nearly 10 MW higher than TMMC's
7 maximum net peak demand in 2017.

8 **Q. HAS ENERGY+ RECOGNIZED THE REDUCTION IN THE CAPACITY RESERVATION**
9 **TO SERVE TMMC IN DETERMINING A STANDBY CHARGE?**

10 A. No. Energy+ has provided no evidence that it considered the avoided costs resulting from
11 the lower capacity reservation in designing its proposed Standby Distribution Volumetric
12 Rates.

13 **Q. IS ENERGY+'S PROPOSAL TO PERIODICALLY REVIEW AND RESET THE**
14 **CONTRACTED CAPACITY RESERVE A REASONABLE APPROACH?**

15 A. No. Energy+ has no incentive to ever reduce the arbitrarily selected Contract Demand
16 value. Further, a customer would have no ability or leverage to negotiate a lower amount.

17 **Q. SHOULD THE BOARD PLACE ANY WEIGHT ON ENERGY+'S STATEMENT ABOUT**
18 **RESETTING THE CONTRACTED CAPACITY RESERVE VALUE?**

19 A. No.

²⁵ Derived from information provided in Energy+'s Response to TMMC-IR-14, Question 1.

1 **Wrong Price Signals**

2 **Q. IF THE STANDBY DISTRIBUTION VOLUMETRIC RATE IS APPLIED TO A FIXED**
3 **CONTRACTED CAPACITY RESERVE VALUE, IRRESPECTIVE OF THE**
4 **CUSTOMER'S ACTUAL DEMAND, DOES THE CUSTOMER HAVE ANY**
5 **INCENTIVE TO OPERATE MORE EFFICIENTLY?**

6 A. No. The Energy+ Standby Distribution rate design sends exactly the wrong price
7 signals. Requiring LDG customers to pay for a specified amount of capacity at a fixed
8 rate provides no incentive to either defer unplanned outages or schedule maintenance
9 outages from on-peak to off-peak hours.

10 **Q. HAS THE BOARD RECOGNIZED THE BENEFITS OF SHIFTING LOAD TO OFF-**
11 **PEAK HOURS, EVEN FOR A DISTRIBUTOR?**

12 A. Yes. The benefits of shifting load to off-peak hours were articulated in a 2015 OEB
13 Staff discussion paper, which stated:

14 While the size of system investment required is driven by the peak
15 demand, customers also consume power at other "off-peak" times.
16 Considered from the economic standpoint, off-peak demand is a co-
17 product of the primary product and can be 'sold' at reduced prices as
18 an additional source of revenue while peak capacity draws the primary
19 revenue. Lower off-peak prices will encourage customers to make
20 better use of existing distribution system assets and reduce the need
21 for new capacity expansion.²⁶

²⁶ EB-2015-0043, Staff Discussion Paper, *Rate Design for Commercial and Industrial Electricity Customers: Aligning the Interests of Customers and Distributors* at 6 (Mar. 31, 2016).

Developing a Cost-Based Rate for Standby Distribution Service

February 15, 2019

Standby Distribution Service

Applicable to Customers Who Own Load Displacement Generation (LDG) That is Located Behind the Customer's Meter

The Additional Delivery Service is Required When

- A Customer's LDG Sustains an Outage, AND
- There is a Net Increase in the Customer's Peak Demand As a Result of the Outage

Standby Distribution Service

Cost Basis

Types Of Distribution Facilities

- Shared Facilities are the “Highway”
- Local Facilities are the “Driveway”

Shared Distribution Facilities

- Provide Distribution Service to all Customers (*i.e.*, Bulk Distribution) or Multiple Customers
- CP or NCP Allocation

Local Distribution Facilities

- Provide Distribution Service To Specific Customers (*i.e.*, Primary & Secondary Overhead Lines & Conductors, Poles, Towers, & Fixtures, Underground Conduit, & Underground Conductors)
- Directly Assigned or NCP Allocation

Allocation of Shared Distribution Costs

Outages Rarely Occur Coincident With a System Peak

- Forced Outages are Random, Nonrecurring Events
- Scheduled Outages can be Planned, Sometimes Well in Advance (Controlled Diversity)

Thus, the Recovery of Shared Distribution Costs Should Recognize Diversity

That is, the More Standby Distribution Service is Used, the More Likely an Outage Will Coincide With a System Peak

- & the Higher the Cost to Serve

Allocation of Local Distribution Costs

Local Facilities are Electrically Closer to the Customer

- Less Diversity (Not Zero)
- Sized to Meet the Maximum Expected Demand
- Anytime

Local Distribution Costs Are Incurred Regardless of the Amount of Standby Distribution Service

Thus, the Recovery of Local Distribution Costs Should Recognize Expected Max Peak Demand

Cost-Based Rate For Distribution Standby Service

Contract Volumetric Rate

**Local Distribution
Costs**

**Standby Contract
Demand**

- Customer Determined

Annual Fixed Costs

- Not Affected By the Amount of
Service Actually Provided

Daily Volumetric Rate

Bulk Distribution Costs

Daily Demand

- Weekdays
- On-Peak Period

**Costs Vary With the
Amount of Service**

- Higher Coincidence
- Higher Costs

Example of a Distribution Standby Rate Design For a Hypothetical Customer Class

Description	Supplementary Service	Standby Service	
		Shared Costs	Local Costs
1. Target Rate Design Revenues	\$1,000,000		
2. Less: Service Charge Revenues	\$100,000		
3. Equals: Volumetric Rate Revenues	\$900,000	\$200,000	\$700,000
4. Billing Determinants (kW)	300,000		300,000
5. Volumetric Rate (\$/kW)	\$3.00		
6. Contract Volumetric Rate (\$/kW)			\$2.33
7. System Bulk Distribution Costs	Assumption	\$1,650,000	
8. System 12CP Demand (kW)		2,710,000	
9. Unit Cost (\$/kW)	L.7 ÷ L.8	\$0.609	
10. Loss Factor	Assumption	10%	
11. Unit Cost at Delivery Voltage	L.9 x (1+L.10)	\$0.670	
12. No. of Weekdays Per Billing Month		20.9	
13. Daily Volumetric Rate (\$/kW)	L.11 ÷ L.12	\$0.032	

Billing Example For a Hypothetical Customer

Description	No Outage	7-Day Outage	1 Month Outage
Supplementary Power Demand (kW)	50	50	50
Standby Contract Demand (kW)	100	100	100
On-Peak Monthly Peak Demand (kW)	50	150	150
Maximum Daily Demand (kW)	N/A	100	100
Volumetric Rate at \$3.00/kW	\$150.00	\$150.00	\$150.00
Contract Volumetric Rate at \$2.33/kW	\$233.00	\$233.00	\$233.00
Daily Volumetric Rate at \$0.032/kW-Day	\$0	\$22.40	\$67.00
Total Volumetric Charges	\$383.00	\$405.40	\$450.00

Questions?



Jeffry Pollock

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FORM A

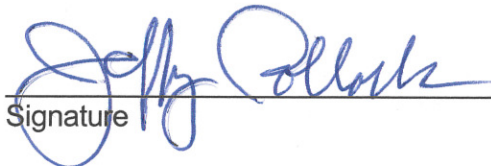
IN THE MATTER the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15 (Schedule B);

AND IN THE MATTER OF an application to the Ontario Energy Board by Energy+ Inc. pursuant to Section 78 of the *Ontario Energy Board Act* for approval of its proposed distribution rates and other charges effective January 1, 2019.

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Jeffry Pollock. I work in St. Louis, Missouri.
2. I have been engaged by or on behalf of Toyota Motor Manufacturing Canada Inc. to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.
3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
 - (a) provide opinion evidence that is fair, objective and non-partisan;
 - (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
 - (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.
4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date: 2/15, 2019.


Signature

2019 Cost Allocation Model

EB-2018-0028

**Sheet 01 Revenue to Cost Summary Worksheet - Two
Large Use Classes/Direct Assignment**

Class Revenue, Cost Analysis, and Return on Rate

Line	Description	Total	1 Residential	2 GS <50	3 GS> 50- 999 kW	5 GS> 1,000 - 4,999 kW	6 Large Use 1	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor Hydro One - CND
1	Distribution Revenue at Existing Rates	\$33,454,352	\$17,528,595	\$4,131,617	\$7,466,138	\$2,140,493	\$259,214	\$671,811	\$14,573	\$64,042	\$50,527
2	Miscellaneous Revenue (mi)	\$2,022,079	\$1,357,552	\$222,387	\$245,249	\$91,016	\$9,890	\$56,446	\$1,326	\$4,532	\$634
Miscellaneous Revenue Input equals Output											
3	Total Revenue at Existing Rates	\$35,476,431	\$18,886,147	\$4,354,004	\$7,711,387	\$2,231,509	\$269,104	\$728,257	\$15,899	\$68,574	\$51,160
4	Factor required to recover deficiency (1 + D)	1.0261									
5	Distribution Revenue at Status Quo Rates	\$34,327,788	\$17,986,236	\$4,239,487	\$7,661,066	\$2,196,378	\$265,982	\$689,351	\$14,953	\$65,714	\$51,846
6	Miscellaneous Revenue (mi)	\$2,022,079	\$1,357,552	\$222,387	\$245,249	\$91,016	\$9,890	\$56,446	\$1,326	\$4,532	\$634
7	Total Revenue at Status Quo Rates	\$36,349,867	\$19,343,789	\$4,461,874	\$7,906,315	\$2,287,394	\$275,872	\$745,797	\$16,279	\$70,246	\$52,479
Expenses											
8	Distribution Costs (di)	\$4,860,260	\$2,894,315	\$496,783	\$924,004	\$368,553	\$37,319	\$89,526	\$4,097	\$13,539	\$0
9	Customer Related Costs (cu)	\$4,893,912	\$3,864,374	\$637,539	\$290,367	\$88,328	\$3,679	\$1,531	\$181	\$1,388	\$2,419
10	General and Administration (ad)	\$8,577,377	\$5,835,791	\$983,930	\$1,078,442	\$404,670	\$36,581	\$82,040	\$3,850	\$13,384	\$6,040
11	Depreciation and Amortization (dep)	\$6,367,412	\$3,699,099	\$787,062	\$1,232,687	\$425,215	\$44,329	\$102,799	\$5,022	\$16,561	\$2,920
12	PILs (INPUT)	\$768,955	\$437,847	\$85,069	\$156,082	\$56,097	\$5,677	\$14,657	\$679	\$2,239	\$675
13	Interest	\$4,422,152	\$2,517,994	\$489,221	\$897,604	\$322,607	\$32,648	\$84,289	\$3,907	\$12,879	\$3,883
14	Total Expenses	\$29,890,069	\$19,249,420	\$3,479,606	\$4,579,187	\$1,665,469	\$160,234	\$374,841	\$17,736	\$59,991	\$15,937
15	Direct Allocation	\$251,148	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$22,095
16	Allocated Net Income (NI)	\$6,208,651	\$3,535,235	\$686,861	\$1,260,226	\$452,937	\$45,838	\$118,341	\$5,485	\$18,082	\$5,452
17	Revenue Requirement (includes NI)	\$36,349,867	\$22,784,655	\$4,166,467	\$5,839,413	\$2,118,406	\$206,072	\$493,182	\$23,221	\$78,073	\$43,484
Rate Base Calculation											
Net Assets											
18	Distribution Plant - Gross	\$197,935,948	\$113,846,096	\$22,412,562	\$39,822,590	\$14,301,697	\$1,473,989	\$3,760,150	\$172,865	\$569,415	\$21,826
19	General Plant - Gross	\$15,515,903	\$8,867,702	\$1,720,596	\$3,118,738	\$1,112,787	\$115,662	\$297,611	\$13,781	\$45,280	\$14,576
20	Accumulated Depreciation	(\$25,194,196)	(\$14,429,251)	(\$3,125,165)	(\$4,903,161)	(\$1,851,093)	(\$176,582)	(\$422,782)	(\$18,346)	(\$61,858)	(\$15,705)
21	Capital Contribution	(\$31,975,089)	(\$18,800,037)	(\$3,623,016)	(\$6,157,110)	(\$2,108,500)	(\$252,523)	(\$639,181)	(\$29,448)	(\$95,175)	(\$3,739)
22	Total Net Plant	\$156,282,566	\$89,484,511	\$17,384,978	\$31,881,057	\$11,454,891	\$1,160,546	\$2,995,798	\$138,852	\$457,663	\$16,959
23	Directly Allocated Net Fixed Assets	\$847,530	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$121,453
24	Working Capital	\$16,695,208	\$5,237,203.86	\$1,953,880	\$4,710,064	\$2,183,424	\$293,928	\$48,068	\$1,783	\$23,128	\$117,405
25	Total Rate Base	\$173,825,304	\$94,721,715	\$19,338,859	\$36,591,122	\$13,638,315	\$1,454,473	\$3,043,865	\$140,635	\$480,792	\$255,817
26	REVENUE TO EXPENSES STATUS QUO%	100.00%	84.90%	107.09%	135.40%	107.98%	133.87%	151.22%	70.11%	89.97%	120.69%

2019 Cost Allocation Model

EB-2018-0028

**Sheet 01 Revenue to Cost Summary Worksheet - Two
Large Use Classes/Direct Assignment**

Class Revenue, Cost Analysis, and Return on Rate

Line	Description	Total	12 Embedded Distributor Waterloo North Hydro - CND	13 Embedded Distributor Hydro One 1 - BCP	14 Embedded Distributor Brantford Power - BCP	15 Embedded Distributor Hydro One 2 - BCP	16 Large Use 2
1	Distribution Revenue at Existing Rates	\$33,454,352	\$221,287	\$115,168	\$5,388	\$4,655	\$780,844
2	Miscellaneous Revenue (mi)	\$2,022,079	\$1,666	\$351	\$201	\$224	\$30,605
	Mis						
3	Total Revenue at Existing Rates	\$35,476,431	\$222,954	\$115,519	\$5,589	\$4,879	\$811,450
4	Factor required to recover deficiency (1 + D)	1.0261					
5	Distribution Revenue at Status Quo Rates	\$34,327,788	\$227,064	\$118,174	\$5,529	\$4,777	\$801,231
6	Miscellaneous Revenue (mi)	\$2,022,079	\$1,666	\$351	\$201	\$224	\$30,605
7	Total Revenue at Status Quo Rates	\$36,349,867	\$228,731	\$118,525	\$5,730	\$5,000	\$831,836
	Expenses						
8	Distribution Costs (di)	\$4,860,260	\$0	\$0	\$0	\$0	\$32,125
9	Customer Related Costs (cu)	\$4,893,912	\$405	\$405	\$705	\$1,620	\$972
10	General and Administration (ad)	\$8,577,377	\$17,599	\$3,502	\$1,820	\$1,358	\$108,371
11	Depreciation and Amortization (dep)	\$6,367,412	\$4,560	\$835	\$602	\$0	\$45,719
12	PILs (INPUT)	\$768,955	\$2,683	\$492	\$199	\$0	\$6,559
13	Interest	\$4,422,152	\$15,430	\$2,827	\$1,143	\$0	\$37,718
14	Total Expenses	\$29,890,069	\$40,676	\$8,061	\$4,468	\$2,978	\$231,464
15	Direct Allocation	\$251,148	\$95,569	\$17,510	\$6,787	\$0	\$109,187
16	Allocated Net Income (NI)	\$6,208,651	\$21,663	\$3,969	\$1,604	\$0	\$52,956
17	Revenue Requirement (includes NI)	\$36,349,867	\$157,909	\$29,540	\$12,859	\$2,978	\$393,607
	Rate Base Calculation						
	Net Assets						
18	Distribution Plant - Gross	\$197,935,948	\$0	\$0	\$3,252	\$0	\$1,551,504
19	General Plant - Gross	\$15,515,903	\$57,769	\$10,584	\$4,284	\$0	\$136,531
20	Accumulated Depreciation	(\$25,194,196)	(\$33,205)	(\$6,084)	(\$3,554)	\$0	(\$147,411)
21	Capital Contribution	(\$31,975,089)	\$0	\$0	(\$557)	\$0	(\$265,803)
22	Total Net Plant	\$156,282,566	\$24,564	\$4,501	\$3,425	\$0	\$1,274,821
23	Directly Allocated Net Fixed Assets	\$847,530	\$525,336	\$96,250	\$37,305	\$0	\$67,185
24	Working Capital	\$16,695,208	\$539,518	\$113,175	\$3,505	\$399,953	\$1,070,174
25	Total Rate Base	\$173,825,304	\$1,089,418	\$213,926	\$44,235	\$399,953	\$2,412,180
26	REVENUE TO EXPENSES STATUS QUO%	100.00%	144.85%	401.24%	44.56%	167.91%	211.34%

ENERGY+, Inc.
4NCP and 12CP Allocation Factors With and Without TMMC

Line	Customer Class	With TMMC				Without TMMC			
		4NCP		12CP		4NCP		12CP	
		Amount	Percent	Amount	Percent	Amount	Percent	Amount	Percent
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	290,249	28.95%	919,944	32.99%	290,249	31.49%	919,944	35.62%
2	GS <50	102,988	10.27%	283,153	10.16%	102,988	11.17%	283,153	10.96%
3	GS> 50- 999 kW	331,610	33.08%	869,313	31.18%	331,610	35.98%	869,313	33.66%
4	GS> 1,000 - 4,999 kW	172,359	17.19%	446,445	16.01%	172,359	18.70%	446,445	17.29%
5	Large Use 1	22,131	2.21%	53,994	1.94%	22,131	2.40%	53,994	2.09%
6	Street Light	2,019	0.20%	6,541	0.23%	2,019	0.22%	6,541	0.25%
7	Sentinel	0	0.00%	219	0.01%	0	0.00%	219	0.01%
8	Unmetered Scattered Load	298	0.03%	3,107	0.11%	298	0.03%	3,107	0.12%
9	TMMC	80,855	8.07%	205,580	7.37%	0	0.00%	0	0.00%
10	Total	1,002,509	100.00%	2,788,296	100.00%	921,654	100.00%	2,582,715	100.00%

Source: Energy+ Response to TCQ TMMC IR-2(a).

ENERGY+, Inc.
TMMC Recommended Supplementary Distribution Service Rate Design

Line	Description	Cost	Billing Units	Rate	Reference
		(1)	(2)	(3)	(4)
1	Total Revenue Requirement	\$393,607			Schedule JP-11, Row 40
2	Revenue-to-Cost Ratio	<u>1.15</u>			Assumption
3	Target Revenue	\$452,649			Line 1 x Line 2
4	Less: Other Revenues	<u>\$30,605</u>			Schedule JP-11, Row 2
5	Target Rate Design Revenue	<u>\$422,043</u>			Line 3 - Line 4
6	Service Charge	<u><u>\$107,713</u></u>	12 Bills	\$8,976.07	
7	Revenues to be Recovered In Distribution Volumetric Rate	\$314,330			Line 5 - Line 6
8	Shared Facilities Cost	\$50,102			Line 14
9	Local Facilities Cost	\$264,229			Line 15
10	Distribution Volumetric Rate				Line 8 + Line 9

Revenue Requirement By Function:

11	Target Rate Design Revenue	\$422,043	
12	Less Service Charge Revenue	<u>\$107,713</u>	
13	Demand-Related Revenue Required	\$314,330	
14	Shared Facilities (Primary Poles)	<u>\$50,102</u>	JP-11, Sht O2.2
15	Local Facilities	\$264,229	

ENERGY+, Inc.
TMMC Class Billing Demand
(Amounts in kW)

<u>Line</u>	<u>Description</u>	<u>Amount</u>	<u>Reference</u>
		(1)	(2)
1	Energy+ Projection	300,496	Energy+ Response to TCQ TMMC IR-2(a)
2	Less: Energy+ LDG Adjustment		Schedule JP-1
3	Supplementary Billing Demand		Line 1 - Line 2
4	Standby Contract Demand	82,800	6,900 kW per Month
5	Total Primary Substation - Feeder Billing Demand		Line 3 + Line 4

ENERGY+, Inc.
TMMC Recommended Standby Distribution Service Rate Design

<u>Line</u>	<u>Description</u>	<u>Rate</u>	<u>Reference</u>
		(1)	(2)
1	Contract Volumetric Rate (Local Facilities)		Schedule JP-13, pg. 1, Line 12
	Daily Volumetric Rate:		
2	Shared Facilities Unit Cost		Schedule JP-13, pg. 1, Line 11
3	No. of Weekdays Per Billing Month	20.9	
4	Daily Volumetric Rate		Line 2 ÷ Line 3
5	Monthly Maximum Standby Volumetric Rate		Line 1 + Line 2

ENERGY+, Inc.
Recommended Standby Distribution Service Rate Design
Applicable to the GS 50 - 999 kW Customer Class

<u>Line</u>	<u>Description</u>	<u>Rate</u>	<u>Reference</u>
		(1)	(2)
	Contract Volumetric Rate:		
1	Local Distribution Costs	\$4,792,589	Schedule JP-15, pg. 2
2	Billing Demand	1,568,556	Schedule JP-11, Sht. I6.1
3	Contract Volumetric Rate	\$3.055	Line 1 ÷ Line 2
	Daily Volumetric Rate:		
4	Shared Distribution Costs	\$1,523,408	Schedule JP-15, pg. 3
5	Sum of 12CP Demand at Source	2,528,721	Schedule JP-11, Sht. I8
6	Unit Cost	\$0.602	Line 4 ÷ Line 5
7	Distribution Secondary Loss Factor	2.61%	Application Exhibit 8, Table 8-16
8	Unit Cost at Secondary Voltage	\$0.618	Line 6 x (1 + Line 7)
9	No. of Weekdays Per Billing Month	20.9	
10	Daily Volumetric Rate	\$0.030	Line 8 ÷ Line 9

ENERGY+, Inc.
Local Distribution Costs
GS 50 - 999 kW Customer Class

<u>Line</u>	<u>Description</u>	<u>Amount</u>
		(1)
1	Distribution Costs	\$1,059,213
2	General & Administrative	\$931,424
3	Depreciation & Amortization	\$1,007,207
4	PILS	\$135,874
5	Interest Expense	<u>\$781,389</u>
6	Total Expenses	\$3,915,106
7	Allocated Net Income	\$1,097,062
8	Total Revenue Requirement	\$5,012,168
8	Revenue-to-Cost Ratio	1.00
9	Miscellaneous Revenue	<u>\$219,579</u>
10	Revenue Requirement	<u><u>\$4,792,589</u></u>

ENERGY+, Inc.

**Shared Distribution Costs Based on
The Settlement Revenue Requirement**

<u>Line</u>	<u>Description</u>	<u>Amount</u>
		(1)
1	Distribution Costs	\$398,041
2	General & Administrative	\$350,020
3	Depreciation & Amortization	\$171,787
4	PILS	\$46,278
5	Interest Expense	<u>\$266,140</u>
6	Total Expenses	\$1,232,266
7	Allocated Net Income	\$373,658
8	Miscellaneous Revenue	<u>\$82,516</u>
9	Revenue Requirement	<u><u>\$1,523,408</u></u>

ENERGY+, Inc.
Revenues From TMMC Recommended
Standby Distributiion Service Rate

<u>Line</u>	<u>Description</u>	<u>Rate</u>	<u>Billing Units</u>	<u>Revenues</u>
		(1)	(2)	(3)
1	Contract Volumetric Rate		55,200 kW	
2	Daily Volumetric Rate	\$0.009		
3	Total Standby Service Revenues			

Col. References:

- (1) Schedule JP-14, page 1.
- (2) Assumed Standby Contract Demand; Schedule JP-7 Revised.
- (3) Col (1) x Col (2).