EB-2018-0028
REDACTED VERSION

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.

CONTAINS CONFIDENTIAL INFORMATION

Toyota Motor Manufacturing Canada Inc. ("TMMC")

Responses to Interrogatories

of

Vulnerable Energy Consumers Coalition ("VECC")

October 25, 2018

1.0 Reference: Written Evidence of Jeffry Pollock, page 8 (lines 4-10) and page 19 (Table 1)

Preamble: The written evidence states: “As a result of certain adjustments that Energy+ has erroneously made to the Large Use class demands and the corresponding demand allocation factors, the CCOSS overstates the cost of serving the Large Use class. The 12CP, 4NCP and 12NCP demands used to allocate costs to the Large Use class in the CCOSS do not reflect the load profile of the Large Use class; instead, they reflect a load profile adjusted for the assumed impact of TMMC’s LDG facility.”

Questions:

1.1 Please confirm that the "adjustments" Mr. Pollock is referring are those set out in Table 1 (page 19). If not, what are the adjustments that are being referred to?

1.2 The footnotes to Table 1indicate that the values in the last row were taken from Tab I-18 of Energy+'s updated CCOSS as referenced in interrogatories TMMC-4 and 1-Staff-2. Please confirm whether the correct reference is Tab I-8.

1.2.1 If yes, please confirm whether the values for the last row in Table 1 were taken directly from the CCOSS or whether any adjustments were made to them.

Responses:

1.1 Confirmed.

1.2 Confirmed. The correct references tab is I-8. The values in the last row of Table 1 were taken from the 12CP, 4NCP and 12NCP demands shown in Tab I-8 of the cost allocation model.

2.0 Reference: Written Evidence of Jeffry Pollock, page 8 (lines 10-14) and page 24 (line 16) to page 25 (line 8)

Preamble: Mr. Pollock's evidence references those sections of the Board's EB-2005-0317 Report (Board Directions on Cost Allocation Methodology for Electricity Distributors) that deal with Load Displacement Generation as a separate Rate Classification (i.e., Section 11.5.2).

Questions:

2.1 Please confirm that Energy + is not proposing a new and separate rate classification for customers with load displacement generation but rather is proposing that these customers remain part of the main customer classifications (i.e., Large Use, GS >1,000-4,999 and GS>50-999) per Energy + Schedule 7, page 14.

2.2 If confirmed, please explain why Mr. Pollock's evidence referenced and relied on Section 11.5.2 of the Board's EB-2005-0317 Report as opposed Section 11.5.3.

Responses:

2.1 Confirmed.

2.2 Cost allocation principles are the same regardless of whether LDG is consolidated with an existing rate classification or treated as a separate rate classification. Either way, the utility must have conducted a thorough analysis of the LDG's standby requirements in order to determine a proper cost allocation, assuming that it is appropriate to include LDG in the CCOSS.

3.0 Reference: Written Evidence of Jeffry Pollock, page 9 (lines 9-14); page 19 (Table 1) and page 21 (lines 5-11) Written Evidence of Melody Collis, page 7 (lines 105-108)

Preamble: The written evidence of Jeffry Pollock states (page 21): "The LDG adjustments shown in Table 1 above assume that an outage of TMMC's LDG would occur simultaneously with the Large Use class's coincident and non-coincident peak demands in each and every month."

The written evidence of Melody Collis state (page 7): "The CHP Facility comprises two gas-fired turbine generators, each with a nameplate capacity of 4.6 MW".

3.1 With respect to Mr. Pollock's written evidence please confirm (yes or no) whether with respect to Table 1:

3.1.1 The Energy+ LDG adjustment applicable to the 12CP value is 110,400 kW (i.e., 12 months x 4.6 MW x 2).

3.1.2 The Energy+ LDG adjustment applicable to the 12NCP values is 110,400 kW (i.e., 12 months x 4.6 MW x 2).

3.1.3 The Energy+ LDG adjustment applicable to the 4NCP values is 36,800 kW (i.e., 4 months x 4.6 MW x 2).

3.2 If not confirmed, please explain the basis for the referenced quote from page 21 of Mr. Pollock's written evidence.

Responses:

3.1. Not confirmed.

3.2 The Energy+ LDG adjustments are shown in Table 1 of Mr. Pollock's evidence. The Energy+ LDG adjustments were calculated based on the difference between TMMC's maximum peak demand during calendar year 2017 and its average monthly peak demand. It was not calculated based on the size of TMMC's LDG facility. The citation from Mr. Pollock's evidence is that Energy+'s LDG adjustments assume that an outage would occur simultaneously with the Large Use class's coincident and non-coincident peak demands. The fact that an outage may occur simultaneously does not mean that TMMC's load would increase by exactly 4.6 MW if one of TMMC's two generators were to be forced or scheduled out of service.

4.0 Reference: Written Evidence of Jeffry Pollock, page 24 (lines 5-12) Energy + Application, Schedule 7, pages 3-4 and Response to 7-Staff-84

Preamble: The written evidence of Mr. Pollock claims that Energy+ provided no explanation as to why it assumed no diversity for TMMC's generator outages.

4.1 Please confirm that at the above references Energy+ provided an explanation as to why it relied on the 2004 load profiles as opposed to the 2016 load profiles (which would have reflected the operation of TMMC's load displacement generation).

Responses:

4.1 Confirmed in part. Energy+ explained why it used the 2004 rather than the 2016 load profile. However, Energy+ did not explain its specific adjustments to the 2019 coincident peak (CP) and non-coincident (or class) peak (NCP) demands derived from the 2004 load profile to recognize LDG. These adjustments assume that TMMC's use of Standby service would be 100% coincident with the system monthly CP and with the Large Use class's 4NCP demands. Thus, diversity was ignored.

5.0 Reference: Written Evidence of Jeffry Pollock, page 25 (lines 11-14) and page 29 (lines 4-9)

5.1 Are there any other revisions to Energy+'s CCOSS that Mr. Pollock is recommending apart from the two set out on page 29?

5.1.1 If yes, what other revisions to the CCOSS is Mr. Pollock recommending?

5.2 Is it Mr. Pollock's view that, with these revisions, the cost allocated to the Large Use class will reflect the cost of providing both Supplementary Service (as defined on page 25 at lines 9-11) and Standby Service?

5.2.1 If yes, please explain why.

5.2.2 If not, what do the CCOSS results represent?

5.2.3 If not, what other adjustments would need to be made to the CCOSS in order that the results reflect the "costs" of both services?

Responses:

5.1 No.

5.2 No. As discussed in Mr. Pollock's evidence, the cost-based Supplementary service rates derived from TMMC's revised CCOSS form the basis for the recommended Standby Maximum and Daily Volumetric rates. No further adjustments to the CCOSS are needed. Our proposed approach ties the rates for Standby service to the costs of providing Supplementary service, rather than trying to estimate the costs of providing Standby service directly. This approach is adopted because it is difficult to measure the costs of providing Standby service. This difficulty reflects the fact that the Standby service is intermittent and observed load patterns in any particular time period are subject to considerable variability depending on the frequency, duration, and types of outage (*i.e.,* forced or planned maintenance). Thus, our approach avoids the complication and instability associated with creating a separate rate classification in the cost allocation model. It also provides a logical link between Standby service rates and Supplementary service rates.

6.0 Reference: Written Evidence of Jeffry Pollock, page 26 (lines 5-7) Written Evidence of Melody Collis, page 5 lines 72-74

Preamble: The Pollock evidence states: "TMMC is served directly from Hydro One's Preston TS through two dedicated 27.6 KV feeders, M24 and M30."

The Collis evidence also states: "The Cambridge Plant is connected to the electricity distribution system of Energy+ via two dedicated 27.6 kV feeder lines (M24 and M30) that are connected to Hydro One's Preston Transformer Station ("Preston TS")."

6.1 Does TMMC have any formal agreement or contract with Energy + whereby it is granted/guaranteed exclusive use of the two feeders or (conceivably) could Energy + connect other customers to these lines?

6.2 If a formal agreement/contract exists please provide a copy.

Responses:

6.1 &
6.2 The dedicated feeder lines were the subject of a Construction Cost Agreement or similar with Cambridge Hydro that was executed in approximately 1995. TMMC does not have access to a copy of this agreement at this time. The dedicated feeders are also the subject of an Operating Agreement between Cambridge and North Dumfries Hydro and TMMC dated December 9, 1999. Section 5.2 of that agreement states as follow:

> "CNDH owns and is responsible for the operation and maintenance of the dedicated 27.6Kv Feeders 21M24 and 21M30 from Preston TS up to and including the deadend insulators on the TMMC substation structure." [emphasis added]

The 1999 Operating Agreement was updated in December 2015 to incorporate TMMC's CHP Facility. The updated agreement states as follows:

> "TMMC's electricity is supplied from Cambridge and North Dumfries Hydro Inc.'s (CNDHI) distribution system through dedicated 27.6Kv Feeders 21M24 AND 21M30 coming from Hydro One's Preston Transformer Station (TS) "J" Bus." [emphasis added]

Finally, Energy+ in its response to TMMC-15(4), confirms that the 21M24 and 21M30 feeders are "dedicated exclusively to TMMC". [emphasis added]

Further, for technical reasons, the addition of other customers to this line is not practical because of protection equipment that has been installed In this protection scheme, the current is monitored between the TMMC bus and the Preston TS bus and it will send a trip signal if a difference in current flow is detected. This precludes the addition of other loads to the line.

7.0 Reference: Written Evidence of Jeffry Pollock, page 26 (lines 3-11) and Schedule JP-2.

7.1 Mr. Pollock’s evidence indicates that both Large Users receive their electricity service via 27.6 kV feeder(s) connected to a Hydro One owned transformer station. Given this similarity in the nature as to how they are served, please explain more fully Mr. Pollock’s view that there is “stark difference” in the service the two customers receive.

Responses:

7.1 As discussed in Mr. Pollock’s evidence, the two Large Use customers take different types of distribution service. TMMC is takes Primary Substation service through two dedicated 27.6 kV feeders that are directly connected to a Hydro-One substation. The other Large Use customer is served from the integrated primary distribution network. Hence, the two Large Use customers receive different types of distribution service.

8.0 Reference: Written Evidence of Jeffry Pollock, page 26 (line 19) to page 27 (line 10) and Schedule JP-3

Preamble: The written evidence states: "The methodology is essentially identical to the process used by Energy+ to quantify the total demand-related primary distribution costs in its CCOSS."

8.1 With respect to Schedule JP-3, please confirm that, in column 1, the gross plant investment value excludes investment in General Plant (per CCOSS Tab O1, row 47) whereas the accumulated depreciation value used includes General Plant (per CCOSS Tab O1, rows 47-49).

8.2 The footnote to Schedule JP-3 indicates that column 1 excludes Embedded Distributors. Please explain why this is the case, particularly since not all distribution plant costs attributed to the Embedded Distributors is directly allocated (per CCOSS Tab O1, row 47).

8.3 At page 27 (lines 6-9) the evidence notes that the gross and net plant ratios were used to determine the amount of each cost component that would be attributed to the dedicated feeders that serve TMMC. For each of the cost components please indicate whether it was the gross or net plant ratio that was used.

8.4 Please confirm that in the case of General and Administrative Expense the Board's CCOSS methodology does not use either the gross or net plant ratio to allocate these costs – but rather primarily uses an allocator based on O&M costs (see CCOSS Tab E4, rows 176-204).

8.4.1 If confirmed, why did Mr. Pollock not use a similar approach?

8.5 It is not clear from the explanation whether or not the costs attributed to the dedicated feeders include a portion of Energy+ General Plant costs. Please confirm whether or not provision for these costs has been included in the analysis.

8.5.1 If yes, please indicate/explain how this was done.

Responses:

8.1 Confirmed.

8.2 The only distribution plant that was allocated to the embedded distributors was meters. All of the demand-related distribution costs were directly assigned. The TMMC feeder costs are demand-related distribution facilities.

8.3 Please refer to the unredacted version of Schedule JP-3. It shows that the gross plant ratios were used to allocate Operation and Maintenance and General and Administrative expenses, and the net plant allocator was used to allocate interest and equity return and the payment in lieu of tax expense. Depreciation expense was directly assigned.

8.4 Not confirmed. General and Administrative expenses (Schedule JP-3, line 7) were allocated in the same manner as the previously allocated Operation and Maintenance expenses (Schedule JP-3, line 6).

8.5 The direct assigned feeder costs do not explicitly include a portion of general plant. However, none of the $1.1 million capital contribution made by the Large Use class, which is an offset to allocated plant in service, was attributed to the directly assigned feeders. The capital contribution more than exceeds the allocation of general plant to the Large Use class.

9.0 Reference: Written Evidence of Jeffry Pollock, page 27 (line 13) to page 28 (line 2); page 29 (lines 5-6)

9.1 The evidence references a Board statement regarding the direct assignment of cost to rate classifications. However, Mr. Pollock is proposing not only to directly assign the cost of the dedicated feeders to the Large Use rate class but to also charge the costs to only one of the customers in the class. Can Mr. Pollock point to any Board directions/reports that support the direct assignment of costs to individual customers within a customer class for purposes of the CCOSS and/or rate-setting?

Responses:

9.1 Mr. Pollock has not reviewed all of the Board's orders that address direct assignment. However, it would not be unusual to have a dedicated facility that only serves a specific customer within a specific rate classification. Further, the directly assigned feeder costs, in this instance, are designed to recognize the fact that TMMC receives primary substation service whereas the other Large Use customer receives primary distribution service.

10.0 Reference: Written Evidence of Jeffry Pollock, page 28 (lines 12-14) and Schedule JP-4

10.1 The evidence states that TMMC represents 81% of the Large Use class energy sales. Please indicate what year or years of usage this value is based on.

10.2 Schedule JP-4 indicates that the portion of Energy+ forecast 2019 sales attributable to Customer 1 was provided by Customer 1. Please explain how Customer 1 determined what portion of the forecast (prepared by Energy+) would be attributable to it.

10.3 For purposes of preparing JP-4 did Mr. Pollock assume that both Customer 1 and Customer 2 had the same load profile as the Large Use class overall?

10.3.1 If yes, what tests were performed to determine that this assumption was appropriate?

10.3.2 If no, what was the load profile used for each customer and how were they established?

Responses:

10.1 81% is the approximate portion of TMMC's annualized historical energy usage as a percentage of the total Large Use class energy usage. The historical period was January 2016 through June 2018.

10.2 Schedule JP-4 assumes that TMMC's historical annualized usage would be approximately the same as the Energy+ forecast 2019 usage.

10.3 Yes. The 81% is applied in the same manner as the scaling factor is used to derive the test year load profiles from the historical 2004 load profile. It makes no assumptions about the load profiles of specific customers within each rate classification.

11.0 Reference: Written Evidence of Jeffry Pollock, page 28 (line 6) to page 29 (line 2)

Preamble: Mr. Pollock is proposing that the TMMC load be removed from the factors used to allocate all other primary distribution plant with the exception of Poles, Towers and Fixtures-Primary (USoA 1830-4).

11.1 Please confirm that Mr. Pollock is recommending that the TMMC load be removed from the allocation factor for Underground Conduit-Primary (USoA 1840-4).

11.2 If this is the case, wouldn't the allocation factor used for the other customer classes for USoA 1830-4 also need to be adjusted to remove any loads served via Underground Conduit-Primary? Otherwise won't customers with these loads be inappropriately allocated a share of USoA 1830-4?

11.2.1 If not, please explain why.

Responses:

11.1 Confirmed.

11.2 No. All other primary distribution customers are served from an integrated network. Thus, it wold not be appropriate to remove any loads that are not served via underground conduit or conductors.

12.0 Reference: Written Evidence of Jeffry Pollock, page 30 (line 2) to page 31 (line 1); page 37 (lines 14-17) and Schedule JP-5 Energy+ 2019 CCOSS (Updated)

12.1 Please confirm that for the TMMC Revised CCOSS the only demand allocation factors that were changed in Tab I8 (from those used in the Energy+CCOSS) were those associated with the Large Use class.

12.1.1 If not confirmed please explain why.

12.2 Please confirm that in the Energy+ CCOSS not all distribution plant costs attributed to the Embedded Distributors are directly assigned and that some are allocated using the demand allocators.

12.2.1 If confirmed, please explain why the costs allocated to the various Embedded Distributors do not change under the TMMC Revised results.

12.3 Please confirm that the changes proposed by Mr. Pollock effectively reduce the primary distribution asset costs allocated to the Large Use class and, correspondingly, increase the costs to be allocated to other customer classes.

12.3.1 If not confirmed please explain why.

12.4 Please explain why (per Table 4) the TMMC Revised CCOSS increases the costs allocated to the Residential class while reducing the costs allocated to the GS<50; GS 50-999 and GS 1,000-4,999 classes. (Note: Based on the changes proposed one would have expected the costs allocated to all of these classes to increase and that the percentage increase would have been greater for those classes that make less use of Energy+'s secondary assets).

12.5 It is noted that in Schedule JP-5 the revenue at current rates (line 1) is the same as in the Energy + CCOSS. However, for the Energy+ CCOSS the 2019 Large Use load used to determine the revenue at current rates (i.e., 361,276 kW) include the LDG Adjustment (Note: This can be seen in the revised Load Forecast model, Rate Class Load Model Tab, Cell E11). Please confirm that the Large Use load (kW) used in the TMMC Revised CCOSS for purposes of determining revenue at current rates included the LDG adjustment.

12.5.1 If confirmed, please explain why this is appropriate given Mr. Pollock's proposal to remove the LDG adjustment from the allocators and from the loads used for purposes of rate design (page 37).

Responses:

12.1 Confirmed. See Schedule JP-5 Revised, which was revised to include the PLCC adjustment that was inadvertently removed from the originally filed Schedule JP-5.

12.2 Not confirmed. The only distribution plant allocated to the embedded distributors is the investment in meters, which is a customer-related cost. No demand-related distribution plant was allocated to the embedded distributors.

12.3 Confirmed. However, the embedded distributors are not affected by the exclusion of TMMC from the allocation of underground conductors and conduit.

12.4 Please see the revisions to Mr. Pollock's evidence and to Schedule JP-5. The revised Table 4 is as follows:

Table 4 Revised
TMMC's Revised CCOSS Results
Revenue Requirement
($000)

Rate Class	Energy+ Updated	TMMC Revised
Residential	$22,723.2	$22,901.3
GS < 50 kW	$4,118.2	$4,180.5
GS: 50 – 999 kW	$5,638.1	$5,825.6
GS: 1,000 – 4,999 kW	$2,013.2	$1,922.8
Large Use	$1,108.2	$769.2
Street Light	$494.6	$495.8
Sentinel	$23.4	$23.4
Unmetered Load	$78.3	$78.5
Hydro One 1 CND	$43.1	$43.1
Waterloo No. CND	$156.4	$156.4
Hydro One BCP	$30.2	$30.2
Brantford Power	$12.8	$12.8
Hydro One 2 BCP	$3.0	$3.0

Source: Energy+ 2019 Cost Allocation Model (Updated September 14, 2018), Worksheet O1 and **Schedule JP-5 Revised**, Row 40**.**

12.5 The revenues at current rates are stated prior to the implementation of any separate standby charges, which Energy+ is proposing in this case. Hence, there is no inconsistency.

13.0 Reference: Written Evidence of Jeffry Pollock, page 33 (lines 1-17) And Schedules JP-5 and JP-6

13.1 At page 3, line 1 the evidence states that the Revised CCOSS allocates $67,078 of customer-related costs to the Large Use class. However, at line 11 the evidence states that the Large Use customer-related costs are $6,181. Please reconcile.

13.2 Please provide a schedule (with references to Schedule JP-3 and JP-5 as required and in confidence if necessary) that shows how each element (lines 1-10) of the Total Large Use Class revenue requirement in Schedule JP-6 was broken down as between columns 2 through 6.

Responses:

13.1 In the filed evidence, $67,078 is the total amount of customer-related costs allocated to the Large Use class as shown in Schedule JP-6, page 2, line 11, column 2. This translates into a per-unit customer cost of $2,794.91 per month ($67,078 ÷ 24). The latter is $6,181 below the current Large Use service charge of $8,976.07.

In Schedule JP-6 Revised, the allocated customer-related costs is $61,495 (Schedule JP-6 Revised, page 2). This translates into a per-unit customer cost of $2,562.28 per month. The unit cost is $6,413.79 below the present Service Charge.

13.2 The workpapers to Schedule JP-6 Revised are confidential and are being provided to the appropriate parties *via* link: [redacted]

14.0 Reference: Written Evidence of Jeffry Pollock, page 34 (line 1) to page 38 (line 10) and page 46 (lines 14-16)

14.1 Please confirm that the rate in Table 5 for the "Feeder Costs" is only applied to TMMC?

14.1.1 If yes, why wouldn't it be more appropriate to recover these costs based on a fixed monthly charge of $7,132.67 (i.e., $85,592 divided by 12)?

14.2 Is the forecast billing demand used to determine the rate for Bulk Distribution in Table 5 the same as that used to determine the rate for Associated Poles?

14.2.1 If not, why not?

14.3 In accordance with page 37 (lines 16-17), please confirm that demands (kW) associated with the use of Standby Distribution service were removed from the billing demands used to calculate all of the rates in Table 5.

14.4 It is noted that the resulting rates in Table 5 have been redacted and are deemed to be confidential. If the Board were to adopt Mr. Pollock`s approach could the rate schedule for the Large Use class be made public or would it have to be confidential?

14.4.1 If the later, is Mr. Pollock or TMMC aware of any previous case where the OEB approved rates for distribution service but did not make them publically available?

Responses:

14.1 Confirmed. The dedicated feeders are demand-related costs. Only customer-related costs are included in a Service charge.

14.2 No. The billing demand for the Bulk Distribution Volumetric rate applies to the entire Large Use class and includes only Supplementary service. The billing demand for poles, towers and fixtures includes both Supplementary and Standby service. Specifically, a Standby Contract Demand of 55,200 kW was included in designing the Primary Substation Volumetric and the Maximum Volumetric rates.

14.3 Not confirmed. The Primary Substation Volumetric rate includes both Supplementary and Standby service billing determinants.

14.4 The rates shown in Table 5 were redacted because the billing determinants are deemed to be confidential. If the Board adopts TMMC's proposed Large Use class and Standby rate designs, the rates would not be confidential.

15.0 Reference: Written Evidence of Jeffry Pollock, page 41 (lines 2-4)

Preamble: The written evidence states: "Energy+ ignored the reduction in the amount of capacity it has to reserve as a result of TMMC's LDG".

15.1 Please explain what "capacity" the evidence is referring to and how TMMC`s LDG reduces the amount that has to be reserved.

Response:

15.1 The capacity referenced in the written evidence refers to Energy+'s asserted "capacity reservation" in the transformers at Hydro-One's Preston Substation on behalf of TMMC.

16.0 Reference: Written Evidence of Jeffry Pollock, page 41 (lines 10-20)

16.1 Please confirm that Energy+`s demand rates for basic distribution service to all of its demand billed customers are based on the highest recorded peak demand in each month.

16.1.1 If confirmed, please explain why applying such an approach to Standby distribution service is discriminatory as between an LDG and a non-LDG customer in the same class (or a different class).

Responses:

16.1 Confirmed. Applying the same approach to standby distribution service would fail to recognize the diversity between standby and supplementary services. Thus, Mr. Pollock proposed a standby rate that takes into account the different diversity between and LDG and a non-LDG customer. This principle would apply equally to all rate classifications.

17.0 Reference: Written Evidence of Jeffry Pollock, page 43 (line 4) to page 44 (line 2)

17.1 The example set out in the evidence in Table 3 assumes that Customer 3 owns LDG. Please confirm that the example could equally apply to three customers (with the prescribed load characteristics) where none of them owned LDG.

17.2 In such circumstances, please confirm that under the rate-setting practices used by Ontario distribution utilities in setting rates to be approved by the OEB, if all three customers were in the same rate class they would all face the same $/kW charge for their distribution service even though the per unit demand costs to serve are different.

Responses:

17.1 It is highly unlikely that Customer 3 would not have LDG. However, if that were the case, it would be incorrect to include all three customers in the same rate classification because they do not have the same load characteristics. In general, a rate classification should be comprised of customers with similar load characteristics.

17.2 See the response to 17.1.

18.0 Reference: Written Evidence of Jeffry Pollock, page 44 (line 11) to page 45 (lines 11)

Preamble: The evidence focuses on outages and new peak demands that occurred during the on-peak period.

18.1 What is Mr. Pollock`s definition of “on-peak”?

18.2 Has Mr. Pollock reviewed the load profile data provided by Energy+ (i.e., the 2019 Energy+ Load Profile Model – excel file) and confirmed that all of the Large Use class peaks occurred during the on-peak period”?

Responses:

18.1 Mr. Pollock’s definition of on-peak is weekdays, excluding public holidays, between the hours of 7 am to 7 pm. This coincides with the definition of Peak Demand Service in applying the rates for provincial network transmission service.

18.2 Yes. The results of Mr. Pollock’s review are summarized in the table below. As can be seen, the Large Use class generally peaks during off-peak hours.

Large Use Class Peak Demand

Month	Date	Hour Ending	Day Type*	Holiday	On or Off Peak Hours
Jan	1/23/2004	2	5	No	Off
Feb	2/5/2004	2	4	No	Off
Mar	3/24/2004	2	3	No	Off
Apr	4/14/2004	1	3	No	Off
May	5/13/2004	15	4	No	On
Jun	6/8/2004	23	2	No	Off
Jul	7/12/2004	23	1	No	Off
Aug	8/27/2004	12	5	No	On
Sep	9/3/2004	19	5	No	On
Oct	10/7/2004	20	4	No	Off
Nov	11/4/2004	2	4	No	Off
Dec	12/1/2004	24	3	No	Off

*1=Monday
2=Tuesday
3=Wednesday
4=Thursday
5=Friday
6=Saturday
7=Sunday

19.0 Reference: Written Evidence of Jeffry Pollock, page 46 (lines 4-7)

Preamble: The written evidence states: "Assuming that Standby distribution service is separately priced, it would be appropriate to account for the incremental revenues in determining the revenues that need to be recovered from the rates for Supplementary distribution service".

19.1 If there is no Standby distribution service taken over the course of a year will the rates set out in Table 5 fully recover the costs as set out in the table – assuming actual loads for basic distribution service are equivalent to the forecast referenced at page 37 (i.e., with the LDG adjustment removed)?

19.1.1 If not, how are the revenues from Standby distribution service considered to be "incremental?

19.2 How would these incremental revenues be accounted for (i.e., would they be used to reduce the rates for all customers in the same rate class as the LDG customer or for all customers overall)?

Responses:

19.1 Yes. The rate design shown in Table 5 assumes that TMMC will commit to a Standby Contract Capacity of 4,600 kW. These revenues are incremental to current revenues, which do not include any Standby charges. If no Standby distribution service is actually used, Energy+ would recover the same revenues from the Large Use class as reflected in Table 5.

19.2 Revenues that would be recovered in the Daily Volumetric rate during the test year would be used to reduce the rates for all customers.

20.0 Reference: Written Evidence of Jeffry Pollock, page 47 (lines 12-14)

20.1 Please explain what is meant by the term "net peak demand". In particular does this refer to the peak demand when standby service is not being provided?

Responses:

20.1 The term "net peak demand" refers to the amount of distribution service provided by Energy+. The 10 MW amount referred to on page 47, line 13 represents the difference between TMMC's maximum demand prior to installing its LDG facility and its highest peak demand in 2017, which occurred when Standby service was being provided.

21.0 Reference: Written Evidence of Jeffry Pollock, page 50 (lines 17-23); and page 44 (lines 5-10) and Schedule JP-8

21.1 It is noted that the Daily Volumetric Rate is derived by dividing the Large Use Bulk Distribution Volumetric Rate by the number of weekdays in a month. Would the Daily Volumetric Rate be applicable only if the outage occurred on a weekday?

21.2 If LDG is as reliable as Mr. Pollock suggests and provides system benefits accordingly, why should the rate derivation be based on the total number of weekdays in the month as opposed to a lower value?

21.3 If LDG is as reliable as Mr. Pollock suggests and provides system benefits accordingly, would it not be reasonable to put a limit on the number of days (either monthly or annually) that the Daily Rate would apply – after which the rate would equal the applicable Large Use rate?

Responses:

21.1 Yes.

21.2 Structuring the Standby rate with a Daily Volumetric charge recognizes the varying diversity of a LDG customer's need for Standby service. The expected diversity is high if little or no Standby service is actually used during a billing month. Accordingly, the Daily Volumetric charge is low or zero. If Standby service is used for several weeks or for the entire billing month, the expected diversity is much lower, and the Daily Volumetric charges are higher.

21.3 The Daily Volumetric rate recognizes the reliability of LDG. The more reliable the LDG, the less often Standby distribution service would be required and the lower the cost relative to a similarly sized non-LDG customer. Another way to recognize reliability would be to implement a performance reliability credit. As implemented in New York, the performance reliability credit would refund of all or a portion of the monthly Contract Standby charge, which recovers local distribution system costs, if no outages occur during the summer on-peak period.

22.0 Reference: Written Evidence of Jeffry Pollock, page 51 (lines 2-3 & 16-23) and page 52 (lines 7-14) Written Evidence of Melody Collis, page 12 (lines 251-253)

22.1 With respect to page 51 of Mr. Pollock, please clarify what is meant by "the previously established monthly peak demand" as used at line 11.

22.2 Given the seasonal nature of TMMC`s load, why is it appropriate to use the difference between the previously established monthly peak demand and the peak demand during the outage to determine the daily demand that the Daily Volumetric Rate would apply to?

22.3 Given that the Contract Demand will only be adjusted on a going forward basis (Pollock Evidence, page 51, lines 12-13), what is the incentive for a customer to initially establish a realistic Contract Demand as opposed to setting one that is too low?

Responses:

22.1 The phrase "previously established monthly peak demand" appears on page 52, line 11, of Mr. Pollock's written evidence. It refers to the peak demand established by the customer for its Supplementary power requirements (that is, when no Standby service is being taken). Previously established means the peak demand established *in the current billing month*.

22.2 As discussed in response to 22.1, the previously established monthly peak demand would be for the Supplementary service provided in the current billing month (*i.e.,* when no Standby service was provided). Standby service is incremental to Supplementary service. This is why the Standby billing demand is the difference between the peak demand for the month and the previously established peak demand during the billing month for Supplementary service.

22.3 The Standby Contract Demand would not be adjusted unless the customer's actual Standby demand exceeded the Contract Demand during a billing month. In that event, the customer would pay full Volumetric charges on the incremental demand for the month, and the Maximum Volumetric rate would apply to a higher Standby Contract Demand in subsequent months. This structure provides an incentive for the customer to stay within the specified Standby Contract Demand.

23.0 Reference: Written Evidence of Melody Collis, page 8 (lines 138-147)

Preamble: The evidence states: "Most of the CHP unit outages that occurred in the period January 2018 to June 2018 did not have the effect of increasing maximum monthly demands on the Energy+ system". (emphasis added)

23.1 The evidence suggests that during the January 2018 to June 2018 period some of CHP unit outages did have the effect of increasing the maximum monthly demands on the Energy+ system. Please confirm if this was the case.

23.1.1 If confirmed, please indicate in which months this occurred.

23.2 During the period January 2016 to December 2017 did any CHP outages have the effect of increasing TMMC`s maximum monthly demands on the Energy+ system?

23.2.1 If yes, in which months did this occur?

Responses:

23.1 &
23.2 There was a typographical error in the quotation highlighted. The sentence should have read instead:

> "Most of the CHP unit outages that occurred in the period January <u>2016</u> to June 2018 did not have the effect of increasing maximum monthly demands on the Energy+ system."

For its analysis, TMMC analyzed the full period for which operational data were available. During this period, CHP outages that increased TMMC maximum monthly demands occurred in each the following months:

For the year 2016: February, March, April, May, July, October
For the year 2017: January, February, April, May, October, November, December
For the first six months of 2018: January, February, March, April, June

It should be noted that the statement noted in TMMC evidence was not addressing the question of how many monthly demand peaks were set by an outage. It was instead making the point that most outages do not serve to increase demand. This can be true even if there is one outage within a month that does serve to increase maximum monthly demand. (This is a consequence of the fact that there can be more than one outage in any month.)

For its analysis, TMMC treated each hour in which at least one CHP unit was not operating at full or nearly full capacity as an individual "outage". This approach facilitated the scatter-plot analysis summarized in Figures 2 through 6 of TMMC's evidence. Outage hours included those hours in which TMMC shut down one or more CHP units to match reductions in underlying TMMC plant load (for example, during weekend periods). Figures 2 through 6 clearly show that most reductions in CHP output are accommodated within the demand envelope established when both CHP units are operating.