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EB-2018-0028

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.

CONFIDENTIAL

Written Evidence

of

Jeffry Pollock
(J. Pollock Incorporated)

on behalf of

Toyota Motor Manufacturing Canada Inc.

September 27, 2018

J. POLLOCK
INCORPORATED

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LIST OF SCHEDULES

GLOSSARY OF ACRONYMS

Term	Definition
4NCP	Four Non-Coincident Peak
12CP	Twelve Coincident Peak
12NCP	Twelve Non-Coincident Peak
CCOSS	Class Cost-of-Service Study
CP	Coincident Peak
Energy+	Energy+ Inc.
Hydro One	Hydro One Networks Inc.
kW	Kilowatt
kV	Kilovolt
LDG	Load Displacement Generation
MW	Megawatt
NCP	Non-Coincident Peak
OEB or Board	Ontario Energy Board
Preston TS	Preston Transmission Substation
TMMC	Toyota Motor Manufacturing Canada Inc.

Evidence of Jeffry Pollock

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. For over 40 years, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. My qualifications are documented in **Appendix A.** A partial list of my appearances in regulatory proceedings is provided in **Appendix B**.

Q HAVE YOU PREVIOUSLY SUBMITTED EVIDENCE BEFORE THE ONTARIO ENERGY BOARD?

A No. However, as demonstrated in **Appendix B**, I have provided evidence in hundreds of regulatory proceedings addressing the topics that are included in my evidence.

Q ON WHOSE BEHALF ARE YOU PROVIDING EVIDENCE IN THIS PROCEEDING?

A I am providing evidence on behalf of Toyota Motor Manufacturing Canada Inc. (TMMC) in connection with an application ("Application") by Energy+ Inc. (Energy+) filed with the Ontario Energy Board (Board or OEB) on April 30, 2018, for approval of electricity distribution rates effective January 1, 2019. TMMC purchases distribution service for its "base" (*i.e.*, supplementary, around-the-clock) load. TMMC also purchases additional delivery service during forced or planned outages of a [redacted] megawatt (MW) load displacement generation (LDG) facility that it owns and operates.

Q ON WHAT ISSUES ARE YOU PROVIDING EVIDENCE?

A My evidence addresses the following issues:

- **Class Cost-of-Service Study (CCOSS)**: I identify the specific flaws with Energy+'s CCOSS and present a revised CCOSS (TMMC's Revised CCOSS).
- **Large Use Class Rate Design:** Based on TMMC's Revised CCOSS, I present evidence on the appropriate rate structure to recover the costs allocated to the Large Use class for base distribution service; and
- **Standby Distribution Service Rate Design**: I propose an alternative rate for Standby distribution service based on TMMC's Revised CCOSS, the Large Use class rate design, and cost-causation principles.

Q WHAT INSTRUCTIONS WERE YOU PROVIDED IN RELATION TO THE ISSUES TO BE ADDRESSED IN YOUR EVIDENCE?

A I was retained by Dentons Canada LLP (on behalf of Toyota Motor Manufacturing Canada Inc.) to prepare a report that provides:

(i) My expert and independent opinion on a proposal by Energy+ to impose Standby distribution service charges on customers who have embedded load displacement generation facilities, such as TMMC, with regard to accepted rate design and cost allocation principles; and

(ii) in the event that I conclude that the Energy+'s proposed Standby charges are not just and reasonable, my expert and independent opinion as to how just and reasonable standby charges should be determined in accordance with accepted rate design and cost allocation principles.

I was also advised that TMMC may decide to submit my report to the Board as evidence in OEB Proceeding EB-2018-0028, convened to consider and decide Energy+'s Application. In that event, I would be required to respond to written interrogatories regarding my evidence and, should an oral hearing be convened, I would be required to appear at the hearing as a testifying, independent expert to answer questions on my report.

Q ARE YOU PROVIDING ANY SCHEDULES WITH YOUR EVIDENCE?

A Yes. Attached to this evidence are **Schedules JP-1** through **JP-10**. These schedules were prepared by me or under my supervision and direction.

Q DOES THE FACT THAT YOUR EVIDENCE DOES NOT ADDRESS OTHER ISSUES IN CONNECTION WITH THE APPLICATION MEAN THAT YOU HAVE ACCEPTED ENERGY+'S PROPOSALS ON THESE ISSUES?

A No. The fact that I do not address all issues presented in the Application should not be interpreted as an endorsement of Energy+'s proposals on issues not discussed in my evidence.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS

A My findings and recommendations can be summarized as follows:

Class Cost-of-Service Study[1]

- Energy+'s CCOSS is flawed in several ways:

- 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. This adjustment methodology ignores the principles articulated by the Board to the effect that the first step in allocating total costs to the LDG classification is to determine a proper cost-based rate for providing distribution service to the class, irrespective of the impact of LDG.[2]

- The adjustments to the Large Use class demand allocators also ignore the diversity within the Large Use class. Energy+ assumes zero diversity within the Large Use class (i.e., peak demands occurring at different times). This is unreasonable because, as I show below, notwithstanding the fact that the Large Use class has only two customers (at the current time), it still exhibits diversity. Moreover, as I also explain below, when TMMC's LDG facility went into service on

[1] As of the date of this report, Energy+ has filed two different Class Cost-of-Service Studies. The first is the CCOSS that was included in its Application. The second CCOSS was filed on September 14, 2018, in response to interrogatories from Ontario Energy Board Staff. This CCOSS was updated for 2017 actuals and replaces the CCOSS that was filed with the Application. All references to Energy+'s CCOSS in this evidence are to the study filed on September 14, 2018.

[2] EB-2005-0317, *Board Directions on Cost Allocation Methodology for Electricity Distributors* (September 29, 2006) at 23.

January 1, 2016, the degree of diversity within the Large Use class would have increased thereby decreasing the Distribution Volumetric Rate required to recover the cost of providing Standby distribution service.

- Further, the adjustments that Energy+ makes to the demand allocators for the Large Use class are not reasonable because they do not reflect the frequency, duration and timing of planned and unplanned outages, and, therefore, do not properly reflect the cost of providing Standby distribution service. Specifically, Energy+ assumes that an outage would occur simultaneously with the coincident and non-coincident peak demands of the Large Use class, in each and every month of the test year. Energy+ presents no analysis to support this assumption. In fact, TMMC's actual use of Standby distribution service is both intermittent and of short duration.

- Finally, the adjustments to the demand allocators for the Large Use class also erroneously assume that the cost of providing Standby distribution service is the same as the cost of providing Base (or Supplementary) distribution service.

- For the reasons described above, no LDG-related adjustments should be made to the Large Use class demand.

- Quite apart from the erroneous adjustments to the Large Use class demand allocators is the fact that the CCOSS also fails to recognize the lower cost of serving TMMC.

- TMMC is served via two dedicated feeders that extend from Hydro One Networks Inc.'s (Hydro One's) Preston Transmission Substation (Preston TS) to the TMMC plant (I refer to this as "Primary Substation service"), while the other customer in the Large Use class is served via Energy+'s integrated primary distribution network (I refer to this as "Primary Distribution service").

- The cost of the two dedicated feeders serving TMMC has been ascertained by Energy+ and, accordingly, should be directly assigned to TMMC.

- Although Energy+ has ascertained the cost of certain other assets, such as poles, towers and fixtures (USoA 1830-4), which are used to provide service to TMMC but that are also used to serve its other customers, further analysis is required to establish how the costs of these shared assets should be allocated. The Board should direct Energy+, in consultation with TMMC, to formulate an allocation methodology for these shared assets and file such methodology for Board approval within 90 days of its decision in this proceeding.

- TMMC's load should be removed from the factors that are used to allocate the costs of Primary distribution plant to the Large Use class, with the exception of the costs of assets in USoA 1830-4, which serve both TMMC and other Energy+ loads.

- To correct these flaws, I have revised the CCOSS by: (i) removing the LDG-related adjustments; and (ii) directly assigning the costs of the two dedicated feeders that serve TMMC would reduce the Large Use class revenue requirement by $448,659, from $1,108,105 to $659,446.

Large Use Class Rate Design

- Rate design is a continuation of the cost allocation process. Thus, a just and reasonable rate structure for the Large Use class should closely parallel the results of the CCOSS revised in accordance with my findings and recommendations, namely, the removal of the LDG-related adjustments made by Energy+ and the direct assignment of the cost of the dedicated feeders that serve TMMC (TMMC's Revised CCOSS).

- Based on TMMC's Revised CCOSS, the Large Use Service charge should be reduced by at least 50% in order to reflect cost causation principles.

- A properly designed Large Use class rate design should also recognize the different types of distribution costs incurred to serve this class. Thus, the Distribution Volumetric Rate should consist of three separate charges:

  - A Bulk Distribution Volumetric Rate that recovers the allocated costs of the bulk (or shared) distribution assets;

  - A Primary Substation Volumetric Rate that recovers the directly assigned feeder costs and an allocated share of the costs of poles, towers, and fixtures used to provide Primary Substation service; and

  - A Primary Distribution Volumetric Rate that recovers the cost to provide Primary Distribution service.

Standby Distribution Service Rate Design

- Energy+'s proposed Large Use Standby distribution service rate is not just and reasonable for various reasons. First, setting the Standby Volumetric Rate the same as the Large Use Distribution Volumetric Rate does not reflect cost-causation principles. Applying cost-causation principles means recognizing that Standby distribution service has different characteristics than Supplementary distribution service. This requires an in-depth analysis of TMMC's Standby distribution service requirements, something which Energy+ has failed to do.

- Second, Energy+'s proposed Large Use standby rate design fails to provide proper price signals to encourage planned maintenance outages during off-peak hours.

- Third, Energy+ is incorrect in its assertion that setting the Standby Distribution Volumetric Rate the same as the otherwise applicable rate for Supplementary distribution service is necessary in order to keep Energy+ whole. No incremental Energy+ facilities are required to provide Standby distribution service to TMMC because the existing distribution feeders (the costs of which are directly assigned to TMMC in TMMC's Revised CCOSS) have more than enough capacity to serve TMMC's gross load. Moreover, Energy+ does not need to reserve incremental capacity in the Preston TS because there is no evidence that a simultaneous forced outage of both of TMMC's generators would immediately increase TMMC's load by [redacted] MW or that it would cause TMMC's peak demand to exceed what was TMMC's maximum load, prior to January 1, 2016, when its LDG facility commenced service. In fact, since that time, TMMC's peak demand has been nearly 10 MW lower than before the LDG facility came into service. In other words, TMMC's LDG has freed-up approximately 10 MW of capacity which, in turn, allows Energy+ to use the capacity in the Preston TS to serve other loads. Energy+'s proposed Large Use Standby Distribution Volumetric Rate ignores these facts.

- A properly designed, cost-based standby rate would include:

  - (1) A Maximum Volumetric Rate derived from the applicable Supplementary Distribution Volumetric Rate. For TMMC, the Maximum Volumetric Rate would be based on the Primary Substation Volumetric Rate; and

  - (2) A Daily Volumetric Rate derived from the Bulk Distribution Volumetric Rate that would only apply when Standby distribution service is actually used.

- To properly incent LDG customers to schedule planned outages during off-peak hours, any generator outage that results in setting a peak demand during off-peak hours should be forgiven, and the Daily Volumetric Rate should apply only when outages occur on weekdays, excluding public holidays.

2. CLASS COST-OF-SERVICE STUDY

Q WHAT IS A CLASS COST-OF-SERVICE STUDY?

A A CCOSS is an analysis used to determine each class's responsibility for a utility's costs. Thus, it determines whether the revenues a class generates cover the class's cost of service. A CCOSS separates the utility's total costs into portions incurred on behalf of the various classes. Most of the utility's costs are incurred to jointly serve many customers. For purposes of class revenue allocation and rate design, customers are grouped into homogenous classes according to their usage patterns and service characteristics.

Q WHAT PROCEDURES ARE USED IN A CLASS COST-OF-SERVICE STUDY?

A The basic procedure for conducting a CCOSS is fairly simple. First, we identify the different types of costs (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Summing the individual pieces gives the total cost for each class.

Functionalization means separating the costs between the different operating functions of a utility in accordance with Board policies. In this case, Energy+'s distribution costs are functionalized to Bulk distribution, Primary distribution, and Secondary distribution.

Classification separates the functionalized costs between customer-related and demand-related costs. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (kWs). Customer-related costs vary with the number of customers and include meters, service laterals, billing, customer service, and a portion of the distribution network.

The distribution network consists of a utility's investments in poles, towers, fixtures, overhead and underground conductors and conduits, and line transformers. Classifying a portion of the distribution network as a customer-related cost recognizes that the central roles of a distribution network are to:

- Provide access to a delivery-ready power grid (*i.e*., a customer-related cost); and
- Meet customers' peak electrical power needs (*i.e*., a demand-related cost).

Each functionalized and classified cost must then be allocated to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total costs that should be paid by each class. The allocation factors should reflect cost causation; that is, the degree to which each class causes the utility to incur the cost.

Q HAS THE BOARD DEFINED WHAT ASSETS ARE TO BE CONSIDERED BULK DISTRIBUTION FACILITIES?

A Yes. The Board states:

> The test to determine if any bulk assets exist in a given distributor's system is to identify all facilities that were built to support the system peak of its distribution system. Note the test is to be applied in light of the function when the asset was built, not its present function, because use of the former will reflect the reason for the facility's initial sizing and provide a more stable cost allocation methodology.
>
> When applying the test, distributors should distinguish between assets that were built to support the distribution system's peak or the

> customer's peak. Only assets built to support the distribution system's peak will be treated as bulk assets for the cost allocation filings.[3]

Energy+ books the investment in Bulk distribution facilities to USoA Account Nos. 1805-1 (Land Station > 50 kV), 1806-1 (Land Rights Station > 50 kV), 1808-1 (Buildings and Fixtures > 50 kV), and 1815 (Transformer Station Equipment – Normally Primary above 50 kV).

Q DOES THE BOARD ALSO DEFINE PRIMARY DISTRIBUTION FACILITIES?

A Yes. The Board defines Primary distribution facilities as including:

> Assets built to support the customer's peak are primary or secondary assets; and the voltage based test provided should be applied to identify secondary assets.[4]
>
> The primary sub-accounts will cover all assets that are not identified as bulk assets (if applicable) or as secondary assets.[5]

Energy+ books the investments in Primary distribution facilities to USoA Account Nos. 1830-4 (Poles, Towers, and Fixtures), 1835-4 (Overhead Conductors and Devices), 1840-4 (Underground Conduit), and 1845-4 (Underground Conductors and Devices).

[3] EB-2005-0317, Cost Allocation Review, *Board Directions on Cost Allocation Methodology for Electricity Distributors* (Sept. 29, 2006) at 36.

[4] *Id.*

[5] *Id.* at 38.

Q DOES THE BOARD PRESCRIBE DIFFERENT ALLOCATION METHODS FOR BULK AND PRIMARY DISTRIBUTION FACILITIES?

A Yes. The Board states that:

> When working with the bulk test, it would be helpful to recall the overall steps in the cost allocation: bulk assets will be allocated using Coincident Peak, while primary and secondary assets will be allocated using Non-Coincident Peak.[6]

Q WHAT IS THE NON-COINCIDENT PEAK METHOD?

A The non-coincident (*i.e.,* NCP or Class Peak) method allocates costs based on the maximum diversified demand of each particular customer class.

Q IS THE NON-COINCIDENT PEAK METHOD THE SAME AS ALLOCATING DEMAND-RELATED COSTS BASED ON EACH INDIVIDUAL CUSTOMER'S MAXIMUM DEMAND?

A No.

Energy+'s CCOSS

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

A Energy+'s CCOSS overstates the cost of serving the Large Use class for several reasons. First, Energy+ has erroneously adjusted the Large Use class 12CP, 4NCP and 12NCP demands that it uses to allocate demand-related costs in its CCOSS. These adjusted demands do not reflect the load profile of the Large Use class; instead,

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6 *Id.* at 37

they reflect a load profile *adjusted for the assumed impact of TMMC's LDG facility*. Moreover, Energy+'s LDG adjustments ignore the procedures for recognizing LDG in conducting a CCOSS as outlined by the Board, and they ignore diversity.

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

Each of these flaws is discussed below.

Q WHAT IS THE LARGE USE CLASS?

A The Large Use class is a rate class comprised of two customers that each have peak demands of at least 5 MW. The class is served entirely at primary voltage, although, as previously stated and discussed in more detail below, the Energy+ infrastructure serving the two Large Use customers is different.

<u>Load Displacement Generation Adjustments</u>

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

A The demand allocation factors are overstated because they do not reflect the Large Use class's *actual* load characteristics as derived from the load profile analysis.

Instead, they reflect unsupported assumptions about the timing, amount, and duration of the standby delivery service provided during outages of TMMC's LDG. As discussed later in this evidence, Standby distribution service rates should be derived from the Large Use rate design.

Q WHAT DEMAND ALLOCATION FACTORS DOES ENERGY+ USE TO ALLOCATE DISTRIBUTION COST TO THE LARGE USE CLASS?

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

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

A No. The 12CP, 4NCP, and 12NCP demands used in the Energy+'s CCOSS for the Large Use class are not the same as the 12CP, 4NCP, and 12NCP demands derived in Energy+'s load profile. Instead, Energy+ adjusted these load profile demands for the 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	[redacted]	[redacted]	[redacted]
Per Updated CCOSS	[redacted]	[redacted]	[redacted]

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.

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

A Energy+ observed that in calendar year 2017, TMMC reached an annual peak demand of approximately 26.2 MW.[7] The actual peak demand was [redacted] kW. This annual peak demand occurred on Wednesday, November 8, 2017 at 8 am.

Q HOW DID ENERGY+ DETERMINE THAT LDG WOULD INCREASE THE LARGE USE CLASS'S TWELVE MONTH LOADS BY PRECISELY [redacted] kW?

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

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

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

A No, it does not. The dedicated distribution feeders that serve TMMC were energized long before TMMC's LDG went into service on January 1, 2016.[8] Prior to installing

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

[8] *Id.*

that facility, TMMC's peak demand was as high as [redacted] MW.[9] Accordingly, the dedicated distribution feeders are already more than adequate to deliver TMMC's gross peak demand.

Q ARE ENERGY+'S PROPOSED LDG ADJUSTMENTS REASONABLE?

A No. 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***. This assumption is not supported by any analysis presented by Energy+ in its application. Accordingly, there is no basis for making the same LDG adjustment to the 12CP demands as Energy+ is proposing to make to the 4NCP and 12NCP demands. To do so would assume that Standby distribution service has zero diversity.

Q WHAT DO YOU MEAN BY DIVERSITY?

A Diversity recognizes that individual customers experience their peak demands at different times. An example of diversity is shown in Table 2.

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

[9] Information provided by TMMC.

Diversity can be expressed in several ways.

One measure 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 measures Energy+'s Large Use class demand diversity. For purposes of the analysis, the demands shown in Table 3 exclude the LDG adjustments.

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	330,832	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.

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.

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

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

Q HOW MIGHT LDG IMPACT DIVERSITY?

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

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

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

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 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:

> The total costs to be allocated to the LDG classification will consist of costs associated with providing distribution service to the base load that is the same as a standard distribution customer, along with the

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

> distribution costs required to support the incremental load when the load displacement generator is not operating.[12]

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

Q WHAT DO YOU MEAN BY SUPPLEMENTARY DISTRIBUTION SERVICE?

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

Q WHAT DO YOU RECOMMEND WITH RESPECT TO THE ADJUSTMENTS PROPOSED BY ENERGY+?

A The LDG adjustments should be removed from the CCOSS.

Direct Assignment

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

A Yes. As discussed below, TMMC receives a different type of primary distribution service than the other Large Use customer. Further, most of the costs of the Energy+ distribution infrastructure used to serve TMMC can be directly assigned. The facilities

[12] *Id.* at 92.

used to serve TMMC are shown in **Schedule JP-2**.

Q PLEASE EXPLAIN SCHEDULE JP-2.

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

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

Q CAN THE COST OF PROVIDING PRIMARY SUBSTATION SERVICE BE READILY ASCERTAINED?

A Yes. Energy+ has estimated that the feeders serving TMMC have a net book value of $[redacted] and associated annual depreciation expense of $[redacted].[13] Using Energy+'s revenue requirement parameters, the all-in annual cost of the feeders is approximately $92,000. The derivation of the $92,000 all-in cost is shown in **Schedule JP-3.**

Q PLEASE EXPLAIN SCHEDULE JP-3.

A **Schedule JP-3** shows the individual cost components that comprise the Revenue Requirement of the dedicated 27.6 kV feeders that serve TMMC, as follows:

[13] Energy+ Conf. Response to IR-TMMC-11, Sub-Questions 1.

- Interest and equity return (line 8);
- Operation and maintenance expense (line 9);
- General and administrative expense (line 10);
- Depreciation expense (line 11); and
- Payment in lieu of income taxes (line 12);

I used the gross and net plant investment in the dedicated feeders (column 2, lines 1 and 5) to derive gross and net plant ratios (column 3, lines 1 and 5). I then used these ratios to determine each of the above-listed cost components of the dedicated feeder revenue requirement. The methodology is essentially identical to the process used by Energy+ to quantify the total demand-related primary distribution costs in its CCOSS.[14]

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

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

> When direct allocation is used, the distributor should consider whether it needs to adjust the appropriate allocation factors so that the rate classification to which costs for a specific function are directly allocated

[14] Energy+ Cost Allocation Model, Worksheet O2.2 Primary Cost PLCC Adj.

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

is not allocated further costs related to that function, except where there are joint costs that apply to the customer classification.[16]

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

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

Q HOW DO YOU PROPOSE TO REMOVE TMMC'S LOAD IN DETERMINING THE ALLOCATION FACTORS FOR ALL OTHER PRIMARY DISTRIBUTION PLANT?

A TMMC represents about 81% of the Large Use class energy sales. Accordingly, I have removed 81% of the Large Use class's 4NCP and 12NCP demands. The revised 4NCP and 12NCP demands are developed in **Schedule JP-4.**

Q WHY DID YOU MAKE AN EXCEPTION FOR PRIMARY POLES, TOWERS, AND FIXTURES?

A Although Energy+ estimated the costs of the poles used by the two dedicated 27.6 kV feeders, this entire cost would not be directly assigned to TMMC.[17] This is because the poles supporting the dedicated feeders also carry other feeders that provide

[16] *Id*. at 32.

[17] Energy+ Clarification to IR-TMMC-3.

distribution service to other customers. Accordingly, these costs should continue to be allocated to the Large Use class, including TMMC.

Q WHAT DO YOU RECOMMEND?

A Energy+'s CCOSS as follows should be further revised as follows:

- The cost of the dedicated feeders that serve TMMC should be directly assigned;
- TMMC loads should be removed from the demands used to allocate all other primary distribution plant and related expenses with the exception of USoA 1830-4: Poles, Towers, and Fixtures – Primary

The Board should also direct Energy+, in consultation with TMMC to determine an allocation methodology for determining the cost of those primary poles, towers, and fixtures that are used to serve TMMC and other customers and file such methodology for Board approval within 90 days of the Board decision and order in this proceeding. To the extent that the specific cost of those poles serving TMMC can be directly assigned, there would be no reason to include TMMC's loads in allocating USoA 1830-4 costs.

Q IN THE EVENT THAT THE BOARD DISAGREES WITH YOUR DIRECT ASSIGNMENT PROPOSAL, SHOULD ANY FURTHER CHANGES BE MADE TO ENERGY+'S CLASS COST-OF-SERVICE STUDY?

A Yes. There are no underground distribution facilities serving TMMC. Further, there is no indication of any underground distribution facilities serving the other Large Use customer. Accordingly, if the Board rejects my direct assignment proposal, no Underground Conduits or Conductors and Devices — Primary (USoA Account Nos.

1840-4 and 1845-4) should be allocated to the Large Use class.

TMMC's Revised CCOSS

Q HAVE YOU PREPARED A REVISED CLASS COST-OF-SERVICE STUDY?

A Yes. **Schedule JP-5** is a CCOSS, revised to reflect my findings and recommendations (TMMC's Revised CCOSS) as follows:

- The LDG adjustments made by Energy+ to the Large Use class's load profile were removed in deriving the 12CP, 4NCP, and 12NCP demands; and
- The costs of the dedicated distribution feeders serving TMMC were directly assigned to the Large Use class, and TMMC's loads were removed from the 4NCP and 12NCP demands used to allocate primary distribution plant and related expenses except for USoA 1830-4.

The results of TMMC's Revised CCOSS are summarized below in Table 4.

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

Rate Class	Energy+ Updated	TMMC Revised
Residential	$22,723.2	$23,698.4
GS < 50 kW	$4,118.2	$4,116.7
GS: 50 – 999 kW	$5,638.1	$5,312.0
GS: 1,000 – 4,999 kW	$2,013.2	$1,778.4
Large Use	$1,108.2	$659.1
Street Light	$494.6	$516.2
Sentinel	$23.4	$24.9
Unmetered Load	$78.3	$91.3
Hydro One 1 CND	$43.1	$43.1
Waterloo No. CND	$156.4	$156.4

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

Rate Class	Energy+ Updated	TMMC Revised
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**, Row 40**.**

3. LARGE USE CLASS RATE DESIGN

Q WHAT PRINCIPLES SHOULD BE USED TO DESIGN A COST-BASED RATE FOR THE LARGE USE CLASS?

A Designing a just and reasonable rate means applying the same cost-causation principles used to determine the allocation of costs by rate class to the design of the rates applicable to each class. Thus, for the Large Use class, the Service charge should recover the allocated customer-related costs and the Distribution Volumetric Rate should reflect the allocated demand-related costs.

Q HAVE YOU DEVELOPED A RATE DESIGN FOR THE LARGE USE CLASS BASED ON TMMC'S REVISED CCOSS THAT INCORPORATES THE COST-CAUSATION PRINCIPLES DISCUSSED EARLIER?

A Yes. **Schedule JP-6**, page 1 is my recommended Large Use rate design using TMMC's Revised CCOSS provided in **Schedule JP-5**. Support for my recommended Large Use rate design is provided in **Schedule JP-6**, pages 2 through 4. My recommended rate design is based on a revenue requirement of $625,952 ($659,076 less $33,125 of miscellaneous revenues) as shown in **Schedule JP-5**).

Q WHAT CHANGES TO ENERGY+'S PROPOSED LARGE USE CLASS RATE DESIGN ARE YOU RECOMMENDING?

A I am recommending changes in both the proposed Service charge and the Distribution Volumetric Rate.

Q HOW SHOULD THE SERVICE CHARGE BE DESIGNED?

A The Service charge should recover allocated customer-related costs. TMMC's

Revised CCOSS allocates $67,078 of customer-related costs to the Large Use class (**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).

Q HOW DID ENERGY+ DERIVE THE LARGE USE SERVICE CHARGE?

A The currently approved Service charge is $8,976.07.[18] Energy+ is proposing a Service charge of $9,388.05 per month, an increase of $411.98 per month or 4.6%.[19] Energy+'s proposal is premised on retaining the current split between the fixed and volumetric charges.[20]

Q IS ENERGY+'S PROPOSED INCREASE IN THE SERVICE CHARGE COST-BASED?

A No. The Large Use customer-related costs are $6,181 or 69% below the current Large Use Service charge. The proposed new Service charge would be more than three times the per unit customer cost. Accordingly, there is no cost justification for increasing the Service charge. If the Service charge is not set equal to the allocated customer-related costs, the Distribution Volumetric Rate would be understated, which would send the wrong price signals. Accordingly, the current Service charge ($8,976.07) should be reduced.

Q WHAT IS YOUR RECOMMENDED SERVICE CHARGE?

A I recommend that the current Service charge be reduced by *at least* 50%. This would

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18 Application, Exhibit 8 at 10.

19 Application, Exhibit 1 at 60.

20 Application, Exhibit 8 at 6.

provide reasonable movement toward a more cost-based rate.

Q WHAT CHANGES SHOULD BE MADE TO THE DISTRIBUTION VOLUMETRIC RATE?

A The Large Use class is served from two types of distribution facilities: Bulk and Primary. Bulk facilities are used by all customers (*i.e.*, shared facilities). Primary facilities serve only specific customers (*i.e.*, local facilities). Primary facilities can be further separated between Primary Substation and Primary Distribution. Primary Substation facilities serve a Large Use customer that is directly interconnected through dedicated feeder lines to a transmission substation (*i.e.,* TMMC). Primary distribution facilities serve a Large Use customer from the integrated primary distribution network. Accordingly, and consistent with how costs in the CCOSS are functionalized, I am proposing three separate Distribution Volumetric Rates:

- **Bulk Distribution Volumetric Rate**: to recover the allocated costs of Bulk distribution facilities;
- **Primary Substation Volumetric Rate**: to recover the allocated costs of Primary Substation facilities (*i.e.,* dedicated feeders and associated poles, towers, and fixtures); and
- **Primary Distribution Volumetric Rate**: to recover the allocated costs of the integrated Primary Distribution network.

Q ARE THERE OTHER REASONS FOR HAVING THREE SEPARATE DISTRIBUTION VOLUMETRIC RATES?

A Yes. In addition to more closely reflecting the methodology used in the CCOSS, having three separate Distribution Volumetric Rates would properly reflect the different types of distribution costs (*i.e.,* Bulk and Primary) as well as the different types of primary distribution service (*i.e.,* Primary Substation and Primary Distribution), all of which have different costs. This structure also supports a cost-based Standby distribution service rate, as discussed in Section 4.

Q HOW DID YOU DETERMINE THE DIFFERENT TYPES OF DEMAND-RELATED DISTRIBUTION COSTS ALLOCATED TO THE LARGE USE CLASS?

A The demand-related distribution costs presented in **Schedule JP-6**, page 2 were derived from TMMC's Revised CCOSS. In total, the Large Use class was allocated $558,873 of demand-related costs (**Schedule JP-6**, page 2, line 11, column 3). They are comprised of:

- Bulk Distribution (column 4),
- Primary Distribution (column 5), and
- The directly assigned feeder costs (column 6).

Bulk distribution costs include all costs that were allocated to customer classes on a coincident peak basis. Primary distribution costs include all costs that were allocated to customer classes on a non-coincident peak basis. The cost of the dedicated feeders (column 5) was previously derived in **Schedule JP-3**.

Q HOW SHOULD THE DISTRIBUTION VOLUMETRIC RATES BE DESIGNED?

A Using TMMC's Revised CCOSS, **Schedule JP-6,** page 1 shows the design of the Bulk, Primary Substation, and Primary Distribution Volumetric Rates. This analysis is based on the costs derived in **Schedule JP-6,** pages 2 and 3, and the billing demands derived in **Schedule JP-6,** page 4.

Starting with the Large Use class's revenue requirement of $625,952 (**Schedule JP-6**, page 1, line 1), I first subtracted the revenues derived from my recommended Service charge (line 3) to determine the remaining revenues to be recovered in the various Distribution Volumetric Rates (line 4). Because my recommended Service charge would recover $107,713 (line 3), which is substantially more than the $67,078 (**Schedule JP-6**, page 2, line 11, column 2) of allocated customer-related costs, it is necessary to adjust the revenues to be recovered in the Distribution Volumetric Rates below the allocated demand-related costs by the revenue-to-cost ratio (line 6).

As can be seen, the revenue-to-cost ratio is 92.7%. It is derived by dividing the remaining revenues to be recovered from the Large Use class of $518,239 (**Schedule JP-6**, page 1, line 4, column 1) by the total allocated demand-related costs of $558,873 (**Schedule JP-6**, page 1, line 5, column 1).

Applying the 92.7% revenue-to-cost ratio lowers the revenues that can be recovered in the three Distribution Volumetric Rates as summarized in Table 5.

Table 5
Recommended Large Use
Distribution Volumetric Rates

Rate	Allocated Cost	Target Revenues*	Rate ($/kW)	Schedule JP-6
	(1)	(2)	(3)	(4)
Total Demand-Related Costs	$558,873	$518,239		Page 1, Line 4
Bulk Distribution	$145,954	$135,342	$[redacted]	Page 1, Line 7
Total Primary Distribution	$320,986	$299,801		
Primary Substation:				
Feeder Costs	$91,933	$85,592	$[redacted]	Page 1, Line 8
Associated Poles	$99,761	$92,508	$[redacted]	Page 1, Line 9
Total Primary Substation	$191,694	$178,100	$[redacted]	Page 1, Line 10
Primary Distribution	$221,225	$204,797	$[redacted]	Page 1, Line 11

(1) Schedule JP-6, page 2.
(2) = (1) x 92.7%.

Q HOW DID YOU DETERMINE THE $92,508 OF COSTS OF THE POLES, TOWERS, AND FIXTURES ASSOCIATED WITH PRIMARY SUBSTATION SERVICE?

A **Schedule JP-6,** page 3 shows the derivation of the costs of poles, towers, and fixtures associated with Primary Substation service. The starting point was the total primary distribution costs allocated to the Large Use class of $320,986 (line 1). This amount is also shown in **Schedule JP-6,** page 2, line 11, column 5). I then assumed that the portion of this cost associated with poles, towers, and fixtures would be approximately 31% (line 4), which is the gross plant ratio of poles, towers, and fixtures (line 2) to total primary investment (line 3) for the Energy+ system overall. This results in allocated costs of $99,761 (line 5). Reducing the allocated costs by the 92.7% revenue-to-cost ratio (**Schedule JP-6,** page 1, line 6) results in the target revenues of $92,508.

Q HOW DID YOU DERIVE THE BILLING UNITS FOR THE PRIMARY SUBSTATION AND PRIMARY DISTRIBUTION VOLUMETRIC RATES?

A The Large Use class billing demands are derived in **Schedule JP-6,** page 4. Energy+ projected total billing demand of 361,276 kW including Standby distribution service (line 1). I removed the LDG adjustment (line 2) to derive the Large Use class Supplementary distribution service billing demand (line 3).

I then separated the Supplementary distribution service billing demands between Primary Substation and Primary Distribution. I did so based on an assumption that TMMC's loads comprise about [redacted]% of the Large Use class. Using this estimate resulted in Supplementary distribution service billing demands of [redacted] kW for Primary Substation service (**Schedule JP-6,** page 4, line 5 and [redacted] kW for Primary Distribution service (**Schedule JP-6,** page 4, line 6). As discussed later, I am recommending that the Large Use Primary Substation Volumetric Rate would also be the Maximum Volumetric Rate under my recommended Standby distribution service rate design. Hence, the Primary Substation billing determinants also include an estimated Standby Contract Demand of 4,600 kW per month or 55,200 kW per year (**Schedule JP-6,** page 4, line 8). The basis for my assumption and the design of a cost-based Standby distribution service rate next is discussed in Section 4.

The total Primary Substation Supplementary and Standby distribution service billing demand is [redacted] kW (**Schedule JP-6,** page 4, line 9). The total Large Use class Supplementary and Standby distribution service billing demands is 386,032 kW (**Schedule JP-6,** page 4, line 13).

4. STANDBY DISTRIBUTION SERVICE RATE DESIGN

Q WHAT IS STANDBY DISTRIBUTION SERVICE?

A Standby distribution service is provided when a customer requires additional delivery service to replace the power and energy normally supplied by the customer's LDG.

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

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

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

[21] Application, Exhibit 7 at 10.

[22] Energy+ Response to IR-TMMC-4.

adjusted from time to time, presumably at Energy+'s discretion.

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

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

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

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

Second, Energy+ has provided no explanation for how it determined the Standby Contract Demand for TMMC. Typically such a determination is made in consultation with (rather than being imposed on) the LDG customer.

[23] Energy+ Response to IR-TMMC-1.

[24] Application, Exhibit 7 at 13.

Third, Energy+ ignored the reduction in the amount of capacity it has to reserve as a result of TMMC's LDG. With LDG reducing TMMC's net peak demand, more capacity is available to serve Energy+'s other customers.

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

Cost Causation

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

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

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

Standby Usage Characteristics

Q SHOULD STANDBY DISTRIBUTION SERVICE BE PRICED THE SAME AS SUPPLEMENTARY DISTRIBUTION SERVICE?

A No. Setting the same volumetric rate for both Standby and Supplementary distribution service assumes that Standby distribution service has precisely the same usage characteristics as Supplementary distribution service. The specific Energy+ proposed LDG adjustments were not based on any analysis of TMMC's load characteristics to estimate the expected amount of incremental load associated with the Standby distribution service required by TMMC. Thus, Energy+'s assumption about TMMC's standby usage characteristics is simply unsupported.

Q ARE THERE DIFFERENT TYPES OF STANDBY SERVICE?

A Yes. Standby distribution service consists of Backup service and Maintenance service.

Q HOW ARE BACKUP SERVICE AND MAINTENANCE SERVICE DEFINED?

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

Q DO BACKUP SERVICE AND MAINTENANCE SERVICE HAVE THE SAME CHARACTERISTICS AS SUPPLEMENTARY SERVICE?

A No. Backup service and Maintenance service are different from Supplementary service. 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. Thus, forced outages would be few and far between. Any maintenance outages could be planned well in advance because both the timing and duration of a maintenance outage can be reasonably estimated based on the scope of maintenance work to be performed on the LDG facility.

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

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

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

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

First, there were no outages during on-peak hours in several months. Second, when outages occurred, they were of short duration. On average, TMMC experienced only two days of outage per month. Third, on some occasions when an outage occurred, it did not result in TMMC setting a new on-peak demand. On average, TMMC's on-peak maximum demand was less than 1,500 kW higher due to generator outages.

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

Energy+'s Make Whole Assertion

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

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

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

A Yes. 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. This would ensure 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 9.2 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 was TMMC's maximum load 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 22, 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, TMMC's maximum demand was [redacted] MW. Energy+'s system demand in that hour was [redacted] MW. This is only 70% of Energy+'s 2017 system peak.[25]

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

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

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

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

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

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

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

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

A No.

<u>Wrong Price Signals</u>

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

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

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

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

> While the size of system investment required is driven by the peak demand, customers also consume power at other "off-peak" times.

> Considered from the economic standpoint, off-peak demand is a co-product of the primary product and can be 'sold' at reduced prices as an additional source of revenue while peak capacity draws the primary revenue. Lower off-peak prices will encourage customers to make better use of existing distribution system assets and reduce the need for new capacity expansion.[26]

Cost-Based Standby Distribution Service Rate Design

Q HOW SHOULD A COST-BASED STANDBY SERVICE RATE BE DESIGNED?

A Using the cost-causation principles and characteristics of Backup and Maintenance service as previously described, a cost-based rate for Standby distribution service would consist of two separate charges:

- A Maximum Volumetric Rate to recover the cost of Primary distribution facilities; and
- A Daily Volumetric Rate to recover the cost of the Bulk distribution facilities.

The Maximum 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 that use 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 Maximum Demand and Daily Volumetric Rates

[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).

applied in any month would not exceed the Large Use class Distribution Volumetric Rates.

Q SHOULD THE MAXIMUM VOLUMETRIC FOR STANDBY DISTRIBUTION SERVICE BE THE SAME AS THE MAXIMUM VOLUMETRIC RATES APPLICABLE TO SUPPLEMENTARY DISTRIBUTION SERVICE?

A In general, no. First, the Maximum Volumetric Rate for Standby distribution service should recover only the costs of local facilities; that is, those facilities whose costs were either allocated on a non-coincident peak basis or directly assigned. The costs of shared (or Bulk distribution) facilities should be separately recovered, as discussed below.

Second, the Maximum Volumetric Rate should also recognize the diversity between Supplementary and Standby distribution service. As previously illustrated, a cost-based standby volumetric rate would vary inversely with diversity; that is, the greater the diversity between Standby and Supplementary distribution service, the lower the Standby volumetric rate.

Q HAVE YOU DESIGNED A SPECIFIC COST-BASED STANDBY RATE?

A Yes. A specific cost-based standby rate is derived in **Schedule JP-8**. Specifically, the Maximum Volumetric Rate of $0.505 per kW (line 1) is the same as my recommended Large Use Primary Substation Volumetric Rate. The Daily Volumetric Rate is derived from my recommended Large Use Bulk Distribution Volumetric Rate of $0.409 per kW (line 2). The latter is divided by 20.9, which is the number of weekdays excluding public holidays in a typical billing month. The resulting Daily Volumetric Rate is $0.020 per kW.

Q HOW WOULD THE MAXIMUM VOLUMETRIC RATE WORK?

A The Maximum Volumetric Rate would apply to the designated Standby Contract Demand each month irrespective of the amount of Standby distribution service.

Q WHY ARE YOU RECOMMENDING THAT THE MAXIMUM VOLUMETRIC RATE BE SET THE SAME AS THE LARGE USE PRIMARY SUBSTATION VOLUMETRIC RATE?

A Due to differences in diversity, a cost-based rate for Standby distribution service would be lower than a cost-based rate for Supplementary distribution service. This would require a more in-depth analysis of TMMC's Supplementary and Standby distribution services. However, as discussed previously, the Large Use Primary Substation Volumetric Rate included the billing demand from both Supplementary and Standby distribution services. Thus, whether the Maximum Volumetric Rate is set the same as or lower than the corresponding Primary Substation Volumetric Rate, would not impact the total revenues collected by Energy+.

Q HOW WOULD THE STANDBY CONTRACT DEMAND BE DETERMINED?

A The customer would establish a Contract Demand under a written agreement between the customer and Energy+. Under no circumstances would the customer be allowed to designate more Standby Contract Demand than the nameplate rating of the customer's LDG. The customer should have the ability to periodically adjust the amount of Standby Contract Demand (up or down) as circumstances warrant (*i.e.,* addition/reduction in the amount of LDG capacity; operational changes). However, as discussed below, the Contract Demand could be adjusted if the customer actually uses more Standby distribution service.

Q WHAT STANDBY CONTRACT DEMAND DID YOU ASSUME IN DESIGNING YOUR RECOMMENDED MAXIMUM VOLUMETRIC RATE?

A I assumed a 4,600 kW per month Contract Demand. This is the size of one of TMMC's generators. Because simultaneous forced outages rarely occur, it is reasonable to contract for standby capacity to replace one generator.

Q HOW WOULD THE DAILY VOLUMETRIC RATE WORK?

A The Daily Volumetric Rate would apply when the customer experiences an outage and as a result, establishes a higher monthly peak demand. The customer would have to notify Energy+ when an outage occurs and when the LDG has been fully restored. The daily demand would be the difference between the monthly peak demand established during an outage and the previously established monthly peak demand. If the daily demand exceeds the Contract Demand, the Contract Demand would be increased. This "ratchet" provision would provide an incentive for the customer to closely manage its operating load during generator outages.

Q ARE THERE ANY CIRCUMSTANCES WHEN THE RATCHET PROVISION SHOULD NOT APPLY?

A Yes. The ratchet should not apply If a generator outage is the result of a reliability issue on the Energy+ system. In this instance, the generator was fully capable of operating but for the problem on the Energy+ system.

Q WHAT TOTAL VOLUMETRIC RATES WOULD A CUSTOMER PAY FOR STANDBY DISTRIBUTION SERVICE?

A The customer would always pay the Maximum Volumetric Rate. When an outage occurs, the customer would also pay the Daily Volumetric Rate for each day that a generator is out of service. However, the sum of the Maximum and Daily Volumetric Rates incurred for a billing month (**Schedule JP-8**, line 5) would not exceed the sum of the applicable Large Use Primary Substation and Bulk Distribution Volumetric Rates for the designated Contract Demand.

Q CAN YOU ILLUSTRATE HOW THE STANDBY VOLUMETRIC RATES WOULD BE APPLIED?

A Yes. Table 7 shows how the Maximum and Daily Volumetric Rates would be applied.

Table 7
Application of Cost-Based Standby Volumetric Rates

Description	No Outage	7-Day Outage	1 Month Outage
Standby Contract Demand (kW)	4,600	4,600	4,600
Maximum Demand (kW)	4,600	4,600	4,600
Monthly Peak Demand (kW)	25,000	28,000	28,000
Daily Demand (kW)	N/A	3,000	3,000
Maximum Volumetric Rate at $0.565/kW	$2,599	$2,599	$2,599
Daily Volumetric Rate at $0.022/kW-Day	$0	$330	$1,386
Total Standby Volumetric Charges	$2,599	$2,929	$3,985

Q IS THERE ANY PRECEDENT FOR INCLUDING BOTH MAXIMUM AND DAILY VOLUMETRIC RATES IN DESIGNING A COST-BASED STANDBY RATE?

A Yes. The structure of my recommended standby rate closely parallels the rate designs approved by several state regulatory commissions in the United States. For example, the New York Public Service Commission has approved standby rates in which the costs of *shared facilities* are recovered through a daily demand charge while the costs of *local facilities* are recovered through a contract demand charge. In this instance, shared and local facilities are synonymous with Bulk and Primary Substation facilities.

I am also aware that the Florida Public Service Commission and the Public Utility Commission of Texas have also approved similar designs for standby rates.

Q ARE THERE ANY OTHER FACETS OF YOUR PROPOSED STANDBY RATE DESIGN?

A Yes. First, TMMC's proposed Standby volumetric rates would have a "demand forgiveness" provision. If a customer establishes a higher peak demand during off-peak hours, that higher demand would be ignored and would not result in resetting the Contract Demand or establishing a higher Daily Demand in the billing month. Second, the Daily Volumetric Rate would only apply during weekdays, excluding public holidays. These provisions would provide a price signal to encourage a customer to defer/schedule outages during the off-peak hours.

Q HOW SHOULD ANY REVENUES FROM STANDBY DISTRIBUTION SERVICE BE REFLECTED IN SETTING THE RATES FOR SUPPLEMENTARY DISTRIBUTION SERVICE?

A **Schedule JP-9** provides an estimate of the revenues that Energy+ would derive from applying the recommended Standby distribution service rate design as shown in **Schedule JP-8** and the billing determinants derived in **Schedule JP-7**. Any estimated revenues from the Daily Volumetric Rate should be used to offset Energy+'s test-year revenue requirement. As previously explained, the revenues from the Maximum Volumetric Rate were already accounted for in my recommended Large Use rate design.

5. CONCLUSION

Q BASED ON YOUR ANALYSIS AND RECOMMENDATIONS, WHAT FINDINGS SHOULD THE BOARD MAKE?

A The Board should make the following findings:

- Reject the Energy+ Class Cost-of-Service Study.
- Revise the Energy+ Class Cost-of-Service Study by removing the LDG adjustments from the 12CP, 4NCP, and 12NCP allocation factors; directly assigning primary distribution feeder costs to the Large Use class; and removing TMMC's loads from the 4NCP and 12NCP demands used to allocate all other distribution plant and related expenses except for primary Poles, Towers, and Fixtures (USoA 1830-4).
- Use the revised Class Cost-of-Service Study to determine class revenue allocation and rate design.
- Establish just and reasonable rates for the Large Use class by reducing the Service charge by at least 50% and establishing separate Bulk Distribution, Primary Substation, and Primary Distribution Volumetric Rates for the Large Use class to recover the costs to provide Bulk Distribution, Primary Substation, and Primary Distribution services.
- Reject the Energy+ Standby distribution service rate design because it is not just and reasonable.
- Implement a just and reasonable standby rate design for Large Use customers comprised of Maximum Demand and Daily Volumetric Rates, where the former is based on the Large Use Primary Substation Volumetric Rate applied to the customer-designated Contract Demand and the latter is based on the Large Use Bulk Distribution Volumetric Rate applied to the amount of daily Standby distribution service and

capped at the otherwise applicable Large Use Distribution Volumetric Rates.

- Define daily Standby distribution service as the incremental peak demand established during on-peak hours when an outage has occurred.

Q DOES THIS COMPLETE YOUR EVIDENCE?

A Yes.

APPENDIX A
Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. I have also completed a Utility Finance and Accounting course.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my tenure at both DBA and BAI, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, and conducting site evaluations. Recent engagements have included advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing requests for proposals (RFPs), evaluating RFP responses and contract negotiation. I was also responsible for developing and presenting seminars on electricity issues.

I have worked on various projects in over 20 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission and the state regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Ohio, Pennsylvania, Texas, Virginia, Washington, and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J Pollock is a registered Class I aggregator in the State of Texas.

Appendix B
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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE	SUBJECT	DATE
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	20134	Direct	MI	Investment Recovery Mechanism, Litigation surcharge, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	9/10/2018
KANSAS GAS AND ELECTRIC COMPANY	Occidental Chemical Corporation	18-KG&E-303-CON	Rebuttal	KS	Benefits of the Interruptible Load Provided in the Special Contract	8/29/2018
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	48401	Cross-Rebuttal	TX	4CP Moderation Adjustment	8/28/2018
ENTERGY TEXAS, INC.	Texas Indusrial Energy Consumers	48371	Cross-Rebuttal	TX	Class Cost-of-Service Study; Schedule FERC	8/16/2018
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	48401	Direct	TX	Tax Cuts and Jobs Act; Rider TCRF; 4CP Moderation Adjustment	8/13/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Surrebuttal	PA	Post Test-Year Adjustment; Tax Cuts and Jobs Act; Class Cost-of-Service Study; Distribution System	8/8/2018
ENTERGY TEXAS, INC.	Texas Indusrial Energy Consumers	48371	Direct	TX	Revenue Requirements; Tax Cuts and Jobs Act; Riders	8/1/2018
ENTERGY TEXAS, INC.	Texas Indusrial Energy Consumers	48371	Direct	TX	Class Cost-of-Service Study; Firm, Interruptible and Standby Rate Design	8/1/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation	7/24/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Indusrial Energy Consumers	48233	Cross-Rebuttal	TX	Allocation of TCJA reduction	7/19/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Indusrial Energy Consumers	48233	Direct	TX	Allocation of TCJA reduction	7/5/2018
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2018-3000164	Direct	PA	Post Test-Year Adjustment; Tax Cuts and Jobs Act; Class Cost-of-Service Study; Class Revenue Allocation	6/26/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Indusrial Energy Consumers	47527	Cross-Rebuttal	TX	Class Cost-of-Service Study; Revenue Allocation	5/22/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00255-UT	Rebuttal	NM	Class Cost-of-Service Study; Revenue Allocation	5/2/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Stipulation	AR	Support of Stipulation	4/27/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Indusrial Energy Consumers	47527	Direct	TX	Present Base Revenues Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	4/25/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Indusrial Energy Consumers	47527	Direct	TX	Tax Cuts and Jobs Act; SPP Transmission and Wheeling Costs; Depreciation Rate; LLPPAs; Imputed Capacity; Off-System Sales Margins	4/25/2018

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SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00255-UT	Direct	NM	Class Cost-of-Service Study; Revenue Requirements; Revenue Allocation	4/13/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Surrebuttal	AR	Certificate of Convenience and Necessity	4/6/2018
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY, PENNSYLVANIA POWER COMPANY AND WEST PENN POWER COMPANY	MEIUG, PICA and WPPII	2017-2637855 2017-2637857 2017-2637858 2017-2637866	Rebuttal	PA	Recovery of NITS Charges	3/22/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Indusrial Energy Consumers	46936	2nd Supplemental Direct	TX	Support of Stipulation	3/2/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	18424	Direct	MI	Class Cost of Service	2/28/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-041	Direct	AR	Certificate of Convenience and Necessity	2/23/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Indusrial Energy Consumers	47553	Direct	TX	Off-System Sales Margins; Renewable Energy Credits	2/20/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Indusrial Energy Consumers	47461	2nd Supplemental Direct	TX	Certificate of Convenience and Necessity	2/7/2018
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Indusrial Energy Consumers	47461	Supplemental Direct	TX	Certificate of Convenience and Necessity	1/4/2018
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	17-E-0459/G-0460	Rebuttal	NY	Electric and Gas Embedded Class Cost of Service; Class Revenue Allocation; Gas Rate Design; Revenue Decoupling Mechanism	12/18/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00044-UT	Supplemental Direct	NM	Support of Unanimous Comprehensive Stipulation	12/11/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Indusrial Energy Consumers	47461	Direct	TX	Certificate of Convenience and Necessity	12/4/2017
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	17-E-0459/G-0460	Direct	NY	Electric and Gas Embedded Class Cost of Service; Class Revenue Allocation; Customer Charges; Revenue Decoupling Mechanism; Carbon	11/21/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	17-00044-UT	Direct	NM	Certificate of Convenience and Necessity	10/24/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Indusrial Energy Consumers	46936	Cross-Rebuttal	TX	Certificate of Convenience and Necessity	10/23/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Indusrial Energy Consumers	46936	Supplemental Direct	TX	Certificate of Convenience and Necessity	10/6/2017
KENTUCKY POWER COMPANY	Kentucky League of Cities	2017-00179	Direct	KY	Class Cost-of-Service Study; Class Revenue Allocation	10/3/2017

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SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Indusrial Energy Consumers	46936	Direct	TX	Certificate of Convenience and Necessity	10/2/2017
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	17-E-0238 / 17-G-0239	Rebuttal	NY	Electric/Gas Embedded Class Cost of Service; Class Revenue Allocation; Electric/Gas Rate Design	9/15/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	18322	Rebuttal	MI	Class Cost-of-Service Study, Rate Design	9/7/2017
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Water Large Users Group	R-2017-2595853	Rebuttal	PA	Rate Design	8/31/2017
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	17-E-0238 / 17-G-0239	Direct	NY	Electric/Gas Embedded Class Cost of Service; Class Revenue Allocation; Electric/Gas Rate Design, Electric/Gas Rate Modifiers, AMI Cost Allocation	8/25/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	18322	Direct	MI	Revenue Requirement, Class Cost-of-Service Study, Rate Design	8/10/2017
FLORIDA POWER & LIGHT COMPANY, DUKE ENERGY FLORIDA, LLC, AND TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	170057	Direct	FL	Fuel Hedging Practices	8/10/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	46449	Cross-Rebuttal	TX	Class Revenue Allocation and Rate Design	5/19/2017
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	46449	Direct	TX	Revenue Requirement, class cost of service study, class revenue allocation and rate design	4/25/2017
KENTUCKY UTILITIES COMPANY	Kentucky League of Cities	2016-00370	Supplemental Direct	KY	Class Cost-of-Service Study; Class Revenue Allocation	4/14/2017
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	46416	Direct	TX	Certificate of Convenience and Necessity - Montgomery County Power	3/31/2017
SHARYLAND UTILITIES, L.P.	Texas Industrial Energy Consumers	45414	Cross-Rebuttal	TX	Cost Allocation Issues; Class Revenue Allocation	3/16/2017
ENTERGY LOUISIANA, LLC	Occidental Chemical Corporation	U-34283	Direct*	LA	Approval to Construct Lake Charles Power Station	3/13/2017
LOUISVILLE GAS AND ELECTRIC COMPANY	Louisville/Jefferson Metro Government	2016-00371	Direct	KY	Revenue Requirement Issues; Class Cost-of-Service Study Electric/Gas; Class Revenue Allocation Electric/Gas	3/3/2017
KENTUCKY UTILITIES COMPANY	Kentucky League of Cities	2016-00370	Direct	KY	Revenue Requirement Issues; Class Cost-of-Service Study; Class Revenue Allocation	3/3/2017

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SHARYLAND UTILITIES, L.P.	Texas Industrial Energy Consumers	45414	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; TCRF Allocation Factors; McAllen Division Deferrals	2/28/2017
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46025	Direct	TX	Long-Term Purchased Power Agreements	12/12/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Surrebuttal	MN	Settlement, Cost-of-Service Study, Class Revenue Allocation, Interruptible Rates, Renew-A-Source	10/18/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Rebutal	MN	Class Cost-of-Service Study, Class Revenue Allocation	9/23/2016
VICTORY ELECTRIC COOPERATION ASSOCIATION, INC.	Westerrn Kansas Industrial Electric Consumers	16-VICE-494-TAR	Surrebuttal	KS	Formula-Based Rate Plan	9/22/2016
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	16-G-0257	Rebuttal	NY	Embedded Class Cost of Service; Class Revenue Allocation; Rate Design	9/16/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Cross-Rebuttal	TX	Class Cost-of-Service Study;	9/7/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Surrebuttal	PA	Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	8/31/2016
VICTORY ELECTRIC COOPERATION ASSOCIATION, INC.	Westerrn Kansas Industrial Electric Consumers	16-VICE-494-TAR	Direct	KS	Formula-Based Rate Plan	8/30/2016
WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC.	Westerrn Kansas Industrial Electric Consumers	16-WSTE-496-TAR	Direct	KS	Formula-Based Rate Plan and Debt Service Payments	8/30/2016
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	16-G-0257	Direct	NY	Embedded Class Cost of Service; Class Revenue Allocation; Rate Design	8/26/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Rebuttal	PA	Class Cost-of-Service; Class Revenue Allocation	8/17/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Direct	TX	Revenue Requirement; Class Cost-of-Service; Revenue Allocation; Rate Design	8/16/2016

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METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Direct	PA	Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	7/22/2016
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	160021	DIrect	FL	Multi-Year Rate Plan, Construction Work in Progress; Cost of Capital; Class Revenue Allocation; Class Cost-of-Service Study; Rate Design	7/7/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Supplemental	AR	Support for Settlement Stipulation	7/1/2016
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2016-0001	Direct	IA	Application of Advanced Ratemaking Principles to Wind XI	6/21/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Direct	MN	Class Cost-of-Service Study, Class Revenue Allocation, Multi-Year Rate Plan, Rate Design	6/14/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Surrebuttal	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, LCS-1 Rate Design	6/7/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	15-00296-UT	Direct	NM	Support of Stipulation	5/13/2016
CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Cross	WY	Large Power Contract Service Tariff	4/15/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Direct	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, Act 725, Formula Rate Plan	4/14/2016
CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Direct	WY	Large Power Contract Service Tariff	3/18/2016
ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA	Occidental Chemical Corporation	U-33770	Cross-Answering	LA	Approval to Construct St. Charles Power Station	2/26/2016

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NORTHERN INDIANA PUBLIC SERVICE COMPANY	NLMK-Indiana	44688	Cross-Answering	IN	Cost-of-Service Study, Rider 775	2/16/2016
ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA	Occidental Chemical Corporation	U-33770	Direct	LA	Approval to Construct St. Charles Power Station	1/21/2016
EL PASO ELECTRIC COMPANY	Freeport-McMoRan Copper & Gold, Inc.	44941	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Rate Design	1/15/2016
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Supplemental	AR	Support for Settlement Stipulation	12/31/2015
EL PASO ELECTRIC COMPANY	Freeport-McMoRan Copper & Gold, Inc.	44941	Direct	TX	Class Cost-of-Service Study, Class Revenue Allocation; Rate Design	12/11/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Surrebuttal	AR	Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders;	11/24/2015
MID-KANSAS ELECTRIC COMPANY, LLC, PRAIRIE LAND ELECTRIC COOPERATIVE, INC., SOUTHERN PIONEER ELECTRIC COMPANY, THE VICTORY ELECTRIC COOPERATIVE ASSOCIATION, INC., AND WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-MKEE-023	Direct	KS	Formula Rate Plan for Distribution Utility	11/17/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	45084	Direct	TX	Transmission Cost Recovery Factor Revenue Increase.	11/17/2015
GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Assocation of Manufacturers	39638	Direct	GA	Natural Gas Price Assumptions, IFR Mechanism, Seasonal FCR-24 Rates, Imputed Capacity	11/4/2015
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Rebuttal	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation	10/13/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Direct	AR	Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan	9/29/2015
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Direct	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation, Electric Rate Design	9/15/2015
SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Cross-Rebuttal	TX	Transmission Cost Recovery Factor Class Allocation Factors.	9/8/2015

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE	SUBJECT	DATE
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	14-118	Surrebuttal	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	8/21/2015
SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Direct	TX	Transmission Cost Recovery Factor Class Allocation Factors	8/7/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Surrebuttal	PA	Class Cost-of-Service, Capacity Reservation Rider	8/4/2015
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	15-WSEE-115-RTS	Cross-Answering	KS	Class Cost-of-Service Study, Revenue Allocation	7/22/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Rebuttal	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider, Revenue Deoupling	7/21/2015
SOUTHWEST ERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	15-00083	Direct	NM	Long-Term Purchased Power Agreements	7/10/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-014	Surrebuttal	AR	Solar Power Purchase Agreement	7/10/2015
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	15-WSEE-115-RTS	Direct	KS	Class Cost-of-Service and Electric Distrbution Grid Resiliency Program	7/9/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	43958	Supplemental DIrect	TX	Certificiate of Need for Union Power Station Power Block 1	7/7/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	14-118	Direct	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	7/2/2015
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Direct	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider	6/23/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-014-U	Direct	AR	Solar Power Purchase Agreement	6/19/2015
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	150075	Direct	FL	Cedar Bay Power Purchase Agreement	6/8/2015
SOUTHWEST ERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Cross-Rebuttal	TX	Class Cost of Service Study; Class Revenue Allocation	6/8/2015
FLORIDA POWER AND LIGHT COMPANY, DUKE ENERGY FLORIDA, GULF POWER COMPANY, TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	140226	Surrebuttal	FL	Opt-Out Provision	5/20/2015
SOUTHWEST ERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Post-Test Year Adjustments; Weather Normalization	5/15/2015

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SOUTHWEST ERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Class Cost of Service Study; Class Revenue Allocation	5/15/2015
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	43958	Direct	TX	Certificiate of Need for Union Power Station Power Block 1	4/29/2015
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	42370	Cross-Rebuttal	TX	Allocation and recovery of Municipal Rate Case Expenses and the proposed Rate-Case-Expense Surcharge Tariff.	1/27/2015
WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
PUBLIC SERVICE COMPANY OF COLORADO	Colorado Healthcare Electric Coordinating Council	14AL-0660E	Cross	CO	Clean Air Clean Jobs Act Rider; Transmission Cost Adjustment	12/17/2014
WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014

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PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage	11/24/2014
CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	14-E-0318 / 14-G-0319	Direct	NY	Class Cost-of-Service Study; Class Revenue Allocation (Electric)	11/21/2014
PUBLIC SERVICE COMPANY OF COLORADO	Colorado Healthcare Electric Coordinating Council	14AL-0660E	Direct	CO	Clean Air Clean Jobs Act Rider; Electric Commodity Adjustment Incentive Mechanism	11/7/2014
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	140001-E	Direct	FL	Cost-Effectiveness and Policy Issues Surrounding the Investment in Working Gas Production Facilities	9/22/2014
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Surrebuttal	WY	Class Cost-of-Service, Rule 12 (Line Extension Policy)	9/19/2014
INDIANA MICHIGAN POWER COMPANY	I&M Industrial Group	44511	Direct	IN	Clean Energy Solar Pilot Project, Solar Power Rider and Green Power Rider	9/17/2014
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Cross	WY	Class Cost-of-Service Study; Rule 12 Line Extension	9/5/2014
VARIOUS UTILITIES	Florida Industrial Power Users Group	140002-EI	Direct	FL	Energy Efficiency Cost Recovery Opt-Out Provision	9/5/2014
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Surrebuttal	MN	Nuclear Depreciation Expense, Monticello EPU/LCM Project, Class Cost-of-Service Study, Class Revenue Allocation, Fuel Clause Rider Reform, Rate Design	8/4/2014
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Direct	WY	Class Cost-of-Service Study, Rule 12 Line Extension	7/25/2014
DUKE ENERGY FLORIDA	NRG Florida, LP	140111 and 140110	Direct	FL	Cost-Effectiveness of Proposed Self Build Generating Projects	7/14/2014
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Rebuttal	MN	Class Cost-of-Service Study, Class Revenue Allocation	7/7/2014
PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Rebuttal	PA	Energy Efficiency Cost Recovery	7/1/2014

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NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Direct	MN	Revenue Requirements, Fuel Clause Rider, Class Cost-of-Service Study, Rate Design and Revenue Allocation	6/5/2014
PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Direct	PA	Energy Efficiency Cost Recovery	5/23/2014
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	42042	Direct	TX	Transmission Cost Recovery Factor	4/24/2014
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41791	Cross	TX	Class Cost-of-Service Study and Rate Design	1/31/2014
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41791	Direct	TX	Revenue Requirements, Fuel Reconciliation; Cost Allocation Issues; Rate Design Issues	1/10/2014
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Supplemental Surrebuttal	PA	Class Cost-of-Sevice Study	12/13/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Surrebuttal	PA	Class Cost-of-Service Study; Cash Working Capital; Miscellaneous General Expense; Uncollectable Expense; Class Revenue Allocation	12/9/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Rebuttal	PA	Rate L Transmission Service; Class Revenue Allocation	11/26/2013
ENTERGY TEXAS, INC. ITC HOLDINGS CORP.	Texas Industrial Energy Consumers	41850	Direct	TX	Rate Mitigation Plan; Conditions re Transfer of Control of Ownership	11/6/2013
SHARYLAND UTILITIES	Texas Inustrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Cross-Rebuttal	TX	Customer Class Definitions; Class Revenue Allocation; Allocation of TTC costs	11/4/2013
MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Surrebuttal	IA	Class Cost-of-Service Study; Class Revenue Allocation; Depreciation Surplus	11/4/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Direct	PA	Class Cost-of-Service, Class Revenue Allocations	11/1/2013
PUBLIC SERVICE ENERGY AND GAS	New Jersey Large Energy Users Coalition	EO13020155 and GO13020156	Direct	NJ	Energy Strong	10/28/2013
GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Association of Manufacturers	36989	Direct	GA	Depreciation Expense, Alternate Rate Plan, Return on Equity, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013

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SHARYLAND UTILITIES	Texas Inustrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Direct	TX	Regulatory Asset Cost Recovery; Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013
MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Rebutal	IA	Class Cost-of-Service Study	10/1/2013
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	130007	Direct	FL	Environmental Cost Recovery Clause	9/13/2013
MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Direct	IA	Class Cost-of-Service Study, Class Revenue Allocation, Depreciation, Cost Recovery Clauses, Revenue Sharing, Revenue True-up	9/10/2013
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Rebuttal	NM	RPS Cost Rider	9/9/2013
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Cross-Answering	KS	Cost Allocation Methodology	9/5/2013
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Direct	NM	Class Cost-of-Service Study	8/22/2013
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Direct	KS	Class Revenue Allocation.	8/21/2013
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41437	Direct	TX	Avoided Cost; Standby Rate Design	8/14/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-699	Direct	KS	Class Revenue Allocation	8/12/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Testimony in Support of Settlement	8/9/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Modification Agreement	7/24/2013
TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	130040	Direct	FL	GSD-IS Consolidation, GSD and IS Rate Design, Class Cost-of-Service Study, Planned Outage Expense, Storm Damage Expense	7/15/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Supplemental	KS	Testimony in Support of Nonunanimous Settlement	6/28/2013
JERSEY CENTRAL POWER & LIGHT COMPANY	Gerdau Ameristeel Sayreville, Inc.	ER12111052	Direct	NJ	Cost of Service Study for GT-230 KV Customers; AREP Rider	6/14/2013

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MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Direct	KS	Wholesale Requirements Agreement; Process for Excemption From Regulation; Conditions Required for Public Interest Finding on CCN spin-down	5/14/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Cross	KS	Formula Rate Plan for Distribution Utility	5/10/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Direct	KS	Formula Rate Plan for Distribution Utility	5/3/2013
ENTERGY TEXAS, INC. ITC HOLDINGS CORP.	Texas Industrial Energy Consumers	41223	Direct	TX	Public Interest of Proposed Divestiture of ETI's Transmission Business to an ITC Holdings Subsidiary	4/30/2013
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Surrebuttal	MN	Depreciation; Used and Useful; Cost Allocation; Revenue Allocation	4/12/2013
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Rebuttal	MN	Class Revenue Allocation.	3/25/2013
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Direct	MN	Depreciation; Used and Useful; Property Tax; Cost Allocation; Revenue Allocation; Competitive Rate & Property Tax Riders	2/28/2013
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental Rebuttal	TX	Competitive Generation Service Tariff	2/1/2013
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental Direct	TX	Competitive Generation Service Tariff	1/11/2013
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Cross Rebuttal	TX	Cost Allocation and Rate Design	1/10/2013
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Direct	TX	Application of the Turk Plant Cost-Cap; Revenue Requirements; Class Cost-of-Service Study; Class Revenue Allocation; Industrial Rate Design	12/10/2012
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Rebuttal	FL	Support for Non-Unanimous Settlement	11/13/2012
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Direct	FL	Support for Non-Unanimous Settlement	11/13/2012
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Rebuttal	NY	Electric and Gas Class Cost-of-Service Studies.	9/25/2012
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Direct	NY	Electric and Gas Class Cost-of-Service Study; Revenue Allocation; Rate Design; Historic Demand	8/31/2012
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	12-MKEE-650-TAR	Direct	KS	Transmission Formula Rate Plan	7/31/2012
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	12-WSEE-651-TAR	Direct	KS	TDC Tariff	7/30/2012

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FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Direct	FL	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	7/2/2012
LONE STAR TRANSMISSION, LLC	Texas Industrial Energy Consumers	40020	Direct	TX	Revenue Requirement, Rider AVT	6/21/2012
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Cross	TX	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	4/13/2012
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Direct	TX	Revenue Requirements, Class Cost-of-Service Study, Revenue Allocation, and Rate Design	3/27/2012
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Supplemental Rebuttal	TX	Competitive Generation Service Issues	2/24/2012
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Supplemental Direct	TX	Competitive Generation Service Issues	2/10/2012
AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39722	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Tax Balances	11/4/2011
GULF POWER COMPANY	Florida Industrial Power Users Group	110138-EI	Direct	FL	Cost Allocation and Storm Reserve	10/14/2011
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39504	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Taxes	9/12/2011
AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39360	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
ONCOR ELECTRIC DELIVERY COMPANY, LLC	Texas Industrial Energy Consumers	39375	Direct	TX	Energy Efficiency Cost Recovery Factor	8/2/2011
ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	31653	Direct	AL	Renewable Purchased Power Agreement	7/28/2011
AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Direct	TX	Energy Efficiency Cost Recovery Factor	7/26/2011
AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	36360	Direct	TX	Energy Efficiency Cost Recovery Factor	7/20/2011
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39366	Direct	TX	Energy Efficiency Cost Recovery Factor	7/19/2011
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39363	Direct	TX	Energy Efficiency Cost Recovery Factor	7/15/2011
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Surrebuttal	MN	Depreciation; Non-Asset Margin Sharing; Step-In Increase; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	5/26/2011
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Rebuttal	MN	Classification of Wind Investment	5/4/2011
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Direct	MN	Surplus Depreciation Reserve, Incentive Compensation, Non-Asset Trading Margin Sharing, Cost Allocation, Class Revenue Allocation, Rate Design	4/5/2011
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-381-EA-10	Direct	WY	2010 Protocols	2/11/2011
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	38480	Direct	TX	Cost Allocation, TCRF	11/8/2010

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GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	31958	Direct	GA	Alternate Rate Plan, Return on Equity, Riders, Cost-of-Service Study, Revenue Allocation, Economic Development	10/22/2010
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Cross-Rebuttal	TX	Cost Allocation, Class Revenue Allocation	9/24/2010
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Direct	TX	Pension Expense, Surplus Depreciation Reserve, Cost Allocation, Rate Design, Riders	9/10/2010
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Rebuttal	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	8/6/2010
NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Direct	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	7/14/2010
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Cross Rebuttal	TX	Cost Allocation, Revenue Allocation, CGS Rate Design, Interruptible Service	6/30/2010
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Direct	TX	Class Cost of Service Study, Revenue Allocation, Rate Design, Competitive Generation Services, Line Extension Policy	6/9/2010
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37482	Cross Rebuttal	TX	Allocation of Purchased Power Capacity Costs	2/3/2010
GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	28945	Direct	GA	Fuel Cost Recovery	1/29/2010
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37482	Direct	TX	Purchased Power Capacity Cost Factor	1/22/2010
VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00081	Direct	VA	Allocation of DSM Costs	1/13/2010
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37580	Direct	TX	Fuel refund	12/4/2009
VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00019	Direct	VA	Standby rate design; dynamic pricing	11/9/2009
VIRGINIA ELECTRIC AND POWER COMPANY	MWV	PUE-2009-00019	Direct	VA	Base Rate Case	11/9/2009
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	37135	Direct	TX	Transmission cost recovery factor	10/22/2009
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	09-MKEE-969-RTS	Direct	KS	Revenue requirements, TIER, rate	10/19/2009
VARIOUS UTILITIES	Florida Industrial Power Users Group	090002-EG	Direct	FL	Interruptible Credits	10/2/2009
ONCOR ELECTRIC DELIVERY COMPANY	Texas Industrial Energy Consumers	36958	Cross Rebuttal	TX	2010 Energy efficiency cost recovery factor	8/18/2009
PROGRESS ENERGY FLORIDA	Florida Industrial Power Users Group	90079	Direct	FL	Cost-of-service study, revenue allocation, rate design, depreciation expense, capital structure	8/10/2009

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CENTERPOINT	Texas Industrial Energy Consumers	36918	Cross Rebuttal	TX	Allocation of System Restoration Costs	7/17/2009
FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	080677	Direct	FL	Depreciation; class revenue allocation; rate design; cost allocation; and capital structure	7/16/2009
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36956	Direct	TX	Approval to revise energy efficiency cost recovery factor	7/16/2009
VARIOUS UTILITIES	Florida Industrial Power Users Group	VARIOUS DOCKETS	Direct	FL	Conservation goals	7/6/2009
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36931	Direct	TX	System restoration costs under Senate Bill 769	6/30/2009
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	36966	Direct	TX	Authority to revise fixed fuel factors	6/18/2009
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Cross-Rebuttal	TX	Cost allocatiion, revenue allocation and rate design	6/10/2009
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Surrebuttal	MN	Cost allocation, revenue allocation, rate design	5/27/2009
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Direct	TX	Cost allocation, revenue allocation, rate design	5/27/2009
VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00018	Direct	VA	Transmission cost allocation and rate design	5/20/2009
NORTHERN INDIANA PUBLIC SERVICE COMPANY	Beta Steel Corporation	43526	Direct	IN	Cost allocation and rate design	5/8/2009
ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER008-1056	Rebuttal	FERC	Rough Production Cost Equalization payments	5/7/2009
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Rebuttal	MN	Class revenue allocation and the classification of renewable energy costs	5/5/2009
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Direct	MN	Cost-of-service study, class revenue allocation, and rate design	4/7/2009
ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER08-1056	Answer	FERC	Rough Production Cost Equalization payments	3/6/2009
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-333-ER-08	Direct	WY	Cost of service study; revenue allocation; inverted rates; revenue requirements	1/30/2009
ENTERGY SERVICES	Texas Industrial Energy Consumers	ER08-1056	Direct	FERC	Entergy's proposal seeking Commission approval to allocate Rough Production Cost Equalization payments	1/9/2009
ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	35717	Cross Rebuttal	TX	Retail transformation; cost allocation, demand ratchet waivers, transmission cost allocation factor	12/24/2008
GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Traditional Manufacturers Association	27800	Direct	GA	Cash Return on CWIP associated with the Plant Vogtle Expansion	12/19/2008

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TAMPA ELECTRIC COMPANY	The Florida Industrial Power Users Group and Mosaic Company	080317-EI	Direct	FL	Revenue Requirements, retail class cost of service study, class revenue allocation, firm and non firm rate design and the Transmission Base Rate Adjustment	11/26/2008
ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	35717	Direct	TX	Revenue Requirement, class cost of service study, class revenue allocation and rate design	11/26/2008
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Supplemental Direct	TX	Recovery of Energy Efficiency Costs	11/6/2008
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Cross-Rebuttal	TX	Cost Allocation, Demand Ratchet, Renewable Energy Certificates (REC)	10/28/2008
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Direct	TX	Revenue Requirements, Fuel Reconciliation Revenue Allocation, Cost-of-Service and Rate Design Issues	10/13/2008
ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	18148	Direct	AL	Energy Cost Recovery Rate (WITHDRAWN)	9/16/2008
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	35269	Direct	TX	Allocation of rough production costs equalization payments	7/9/2008
ENTERGY GULF STATES UTILITIES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Non-Unanimous Stipulation	6/11/2008
TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Supplemental Rebuttal	TX	Transmission Optimization and Ancillary Services Studies	6/3/2008
TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Supplemental Direct	TX	Transmission Optimization and Ancillary Services Studies	5/23/2008
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	33891	Supplemental Cross Rebuttal	TX	Certificate of Convenience and Necessity	5/21/2008
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	33891	Supplemental Direct	TX	Certificate of Convenience and	5/8/2008
ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Cross-Rebuttal	TX	Cost Allocation and Rate Design and Competitive Generation Service	4/18/2008
GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	26794	Direct	GA	Fuel Cost Recovery	4/15/2008
TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	35038	Rebuttal	TX	Over $5 Billion Compliance Filing	4/14/2008
ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Eligible Fuel Expense	4/11/2008
ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Competitive Generation Service Tariff	4/11/2008
ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Revenue Requirements	4/11/2008
ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Cost of Service study, revenue allocation, design of firm, interruptible and standby service tariffs; interconnection costs	4/11/2008
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	07-00319-UT	Rebuttal	NM	Revenue requirements, cost of service study, rate design	3/28/2008
AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	35105	Direct	TX	Over $5 Billion Compliance Filing	3/24/2008

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UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE	SUBJECT	DATE
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	32902	Direct	TX	Over $5 Billion Compliance Filing	3/20/2008
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	07-00319-UT	Direct	NM	Revenue requirements, cost of service study (COS); rate design	3/7/2008

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: 27 September, 2018.

Jeffry Pollock

Signature

ENERGY+, INC.
Derivation of LDG Adjustments (kW)
January 2016 to June 2018

Line	Period	TMMC Peak Demand	TMMC Average Monthly Demand	Difference
		(1)	(2)	(3)
1	CY 2016	[redacted]		
2	CY 2017			
3	CY 2018 (6 Months)			
4	Last 12 Months			
5	Energy+ LDG Adjustment (line 2 x 12)			[redacted]

Source: Information provided by TMMC.

CONTAINS CONFIDENTIAL MATERIAL

ENERGY+, INC.
TMMC'S Monthly Peak Demands
January 2016 to June 2018

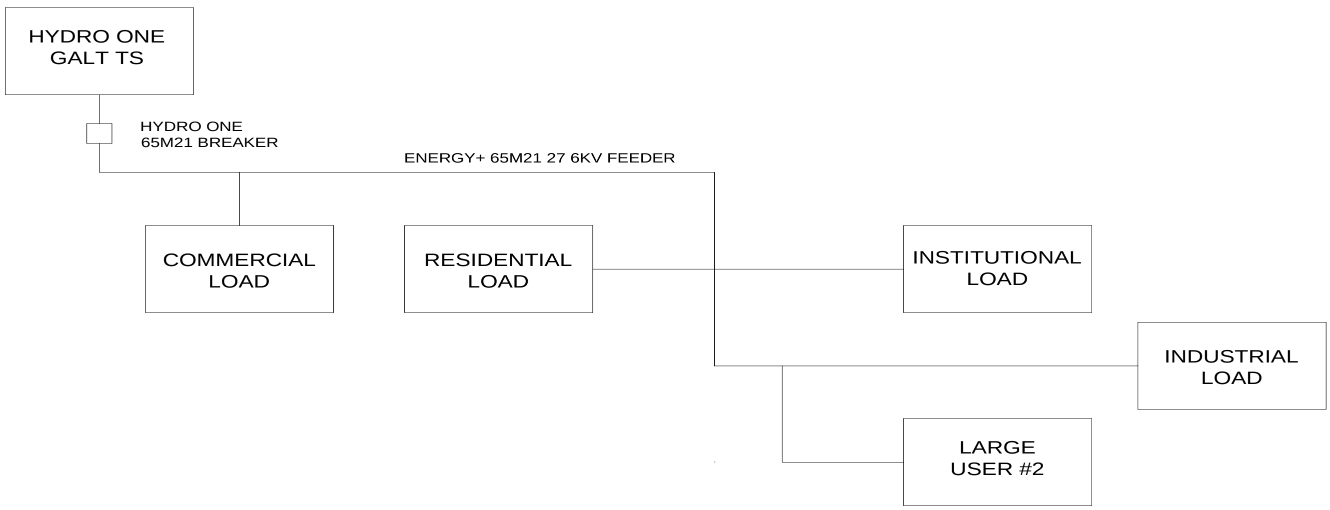
Line	Month	On-Peak Hours Amount	On-Peak Hours Date	On-Peak Hours Time	Off-Peak Hours Amount	Off-Peak Hours Date	Off-Peak Hours Time
		(1)	(2)	(3)	(4)	(5)	(6)
1	Jan-16	[redacted]					
2	Feb-16						
3	Mar-16						
4	Apr-16						
5	May-16						
6	Jun-16						
7	Jul-16						
8	Aug-16						
9	Sep-16						
10	Oct-16						
11	Nov-16						
12	Dec-16						
13	Jan-17						
14	Feb-17						
15	Mar-17						
16	Apr-17						
17	May-17						
18	Jun-17						
19	Jul-17						
20	Aug-17						
21	Sep-17						
22	Oct-17						
23	Nov-17						
24	Dec-17						
25	Jan-18						
26	Feb-18						
27	Mar-18						
28	Apr-18						
29	May-18						
30	Jun-18						

Source: Information provided by TMMC.

[redacted]

<u>One-Line Diagram – Supply to TMMC</u>

The other Large User customer on Energy+'s distribution system is supplied quite differently. This customer is supplied from the Hydro One owned Galt Transformer Station (TS) on the 27.6kV 65M21 feeder. The 65M21 feeder is shared with other residential, institutional, industrial and commercial customers. A high level one line diagram of the 65M21 feeder is shown below. A detailed diagram is very involved as it supplies 1,982 customers. Energy+ owns overhead and underground 27.6kV and secondary wires, distribution transformers, fused cutouts, lightning arresters, loadbreak switches, poles, brackets, insulators, clamps, bolts, guying/anchoring, lightning arresters and other distribution equipment along the 65M21 feeder.



<u>One-Line Diagram – Supply to Other Large User Customer</u>

The peak loading of the 65M21 feeder in 2017 was 11.9MVA.

ENERGY+, Inc.
Direct Assigned Feeder Costs

Line	Description	Total Direct Served Custs.	Feeders	Percent	Reference
		(1)	(2)	(3)	(4)
1	Gross Plant Investment	$195,290,405	[redacted]		IR-TMMC-11
2	Accumulated Depreciation	($25,232,813)	[redacted]		IR-TMMC-11
3	Contribution	($29,935,814)	[redacted]		Assumption
4	Total Fixed Assets	$140,121,777	[redacted]		Sum L1:L2
5	Interest & Equity Return	$10,532,240	[redacted]		Col 1 x Col 3
6	Operation & Maintenance	$9,841,641	[redacted]		Col 1 x Col 3
7	General & Administrative	$8,716,406	[redacted]		Col 1 x Col 3
8	Depreciation & Amortization	$6,360,737	[redacted]		IR-TMMC-11
9	PILS	$746,157	[redacted]		Col 1 x Col 3
10	Total Revenue Requirement	$36,197,181	$91,933		Sum L4:L9

Source: 2019 Cost Allocation Model (Updated), Worksheet 01 Revenue to cost|RR.
Direct Served Customers Exclude Embedded Distributors.

ENERGY+, Inc.
Adjusted 4NCP and 12NCP Demand Allocation Factors

		Per Energy+				Excluding Large Use Customer 1			
		4NCP		12NCP		4NCP		12NCP	
Line	Customer Class	Amount	Percent	Amount	Percent	Amount	Percent	Amount	Percent
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	384,132	35.34%	1,021,204	33.60%	384,132	38.26%	1,021,204	36.37%
2	GS <50	113,309	10.42%	321,272	10.57%	113,309	11.29%	321,272	11.44%
3	GS> 50- 999 kW	326,869	30.07%	954,919	31.42%	326,869	32.56%	954,919	34.01%
4	GS> 1,000 - 4,999 kW	155,783	14.33%	444,745	14.64%	155,783	15.52%	444,745	15.84%
5	Large Use	102,987	9.47%	286,587	9.43%	19,941	1.99%	55,490	1.98%
6	Street Light	2,672	0.25%	6,851	0.23%	2,672	0.27%	6,851	0.24%
7	Sentinel	89	0.01%	229	0.01%	89	0.01%	229	0.01%
8	Unmetered Scattered Load	1,096	0.10%	3,107	0.10%	1,096	0.11%	3,107	0.11%
9	Total	1,086,938	100.00%	3,038,913	100.00%	1,003,892	100.00%	2,807,816	100.00%

	Large User Class Usage (kWh)		
10	Total Class	145,141,006	Energy+ Load Profile
11	Customer 1	[redacted]	Supplied by Customer 1
12	Customer 2		Line 10 - Line 11
13	2004-2019 Factor	0.5848798	Energy+ Load Profile
14	Scaling Factor Excl. Cust. 1	[redacted]	Line 12 ÷ [redacted]
15	4NCP Excluding TMMC	19,941	Line 14 x Col 1, Line 5 ÷ Line 13
16	12NCP Excluding TMMC	55,490	Line 14 x Col 3, Line 5 ÷ Line 13

Source: Energy+ 2019 Load Profile.

Ontario Energy Board

2019 Cost Allocation Model

EB-2018-0028

Sheet O1 Revenue to Cost Summary Worksheet - Application

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	5	6	7	8
Line		**Total**	**Residential**	**GS <50**	**GS> 50- 999 kW**	**GS> 1,000 - 4,999 kW**	**Large Use**	**Street Light**	**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)	$1,870,459	$1,286,634	$203,810	$210,187	$71,937	$33,125	$55,882	$1,320
		Miscellaneous Revenue Input equals Output							
3	**Total Revenue at Existing Rates**	$35,328,679	$18,815,228	$4,335,428	$7,676,325	$2,212,431	$1,073,185	$727,693	$15,893
4	Factor required to recover deficiency (1 + D)	1.0333							
5	Distribution Revenue at Status Quo Rates	$34,572,250	$18,112,229	$4,269,184	$7,714,732	$2,211,764	$1,074,691	$694,180	$15,058
6	Miscellaneous Revenue (mi)	$1,870,459	$1,286,634	$203,810	$210,187	$71,937	$33,125	$55,882	$1,320
7	**Total Revenue at Status Quo Rates**	$36,442,709	$19,398,863	$4,472,995	$7,924,919	$2,283,701	$1,107,815	$750,062	$16,378
	Expenses								
8	Distribution Costs (di)	$4,953,255	$3,086,628	$495,003	$847,731	$311,353	$97,224	$94,751	$4,459
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)	$8,747,377	$6,119,348	$999,003	$1,027,015	$359,759	$102,737	$88,308	$4,251
11	Depreciation and Amortization (dep)	$6,369,992	$3,867,462	$771,613	$1,112,957	$351,481	$125,474	$107,077	$5,346
12	PILs (INPUT)	$750,049	$450,136	$81,156	$136,678	$45,120	$14,932	$14,874	$706
13	Interest	$4,377,475	$2,627,109	$473,649	$797,689	$263,333	$87,150	$86,807	$4,122
14	**Total Expenses**	$30,092,060	$20,007,427	$3,455,382	$4,211,378	$1,419,321	$443,517	$393,346	$19,065
15	**Direct Allocation**	$140,979	($35,672)	($10,522)	($30,914)	($14,467)	$91,933	($248)	($8)
16	Allocated Net Income (NI)	$6,209,670	$3,726,687	$671,895	$1,131,562	$373,551	$123,626	$123,139	$5,847
17	**Revenue Requirement (includes NI)**	$36,442,709	$23,698,442	$4,116,754	$5,312,026	$1,778,406	$659,076	$516,238	$24,904
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
18	Distribution Plant - Gross	$195,315,384	$118,165,079	$21,628,665	$35,309,409	$11,646,198	$3,846,031	$3,856,732	$181,631
19	General Plant - Gross	$15,819,244	$9,533,257	$1,716,530	$2,856,382	$936,506	$302,867	$315,672	$14,974
20	Accumulated Depreciation	($25,291,672)	($15,053,922)	($3,065,251)	($4,457,014)	($1,537,973)	($584,949)	($441,713)	($19,649)
21	Capital Contribution	($29,939,878)	($18,604,360)	($3,326,171)	($5,171,244)	($1,626,708)	($450,119)	($623,073)	($29,404)
22	**Total Net Plant**	$155,903,079	$94,040,054	$16,953,773	$28,537,533	$9,418,023	$3,113,830	$3,107,618	$147,553
23	**Directly Allocated Net Fixed Assets**	$764,856	($97,773)	($28,841)	($84,731)	($39,651)	$251,979	($680)	($23)
24	Cost of Power (COP)	$204,149,413	$57,234,905	$23,933,484	$60,508,046	$28,250,770	$17,875,854	$467,804	$15,640
25	OM&A Expenses	$18,594,544	$13,062,720	$2,128,964	$2,164,055	$759,387	$215,961	$184,589	$8,891
26	Directly Allocated Expenses	$28,814	($24,706)	($7,288)	($21,410)	($10,019)	$63,671	($172)	($6)
27	***Subtotal***	*$222,772,772*	*$70,272,920*	*$26,055,161*	*$62,650,691*	*$29,000,139*	*$18,155,485*	*$652,221*	*$24,525*
28	**Working Capital**	$16,707,958	$5,270,468.98	$1,954,137	$4,698,802	$2,175,010	$1,361,661	$48,917	$1,839
29	**Total Rate Base**	$173,375,892	$99,212,749	$18,879,069	$33,151,604	$11,553,382	$4,727,470	$3,155,855	$149,370
		Rate Base Input equals Output							
30	**Equity Component of Rate Base**	$69,350,357	$39,685,100	$7,551,628	$13,260,642	$4,621,353	$1,890,988	$1,262,342	$59,748
31	**Net Income on Allocated Assets**	$6,209,670	($572,892)	$1,028,135	$3,744,454	$878,846	$572,365	$356,964	($2,679)
32	**Net Income on Direct Allocation Assets**	$31,862	($4,073)	($1,201)	($3,530)	($1,652)	$10,497	($28)	($1)
33	**Net Income**	$6,241,532	($576,965)	$1,026,934	$3,740,925	$877,194	$582,862	$356,935	($2,680)
34	**RATIOS ANALYSIS**								
35	**REVENUE TO EXPENSES STATUS QUO%**	100.00%	81.86%	108.65%	149.19%	128.41%	168.09%	145.29%	65.77%
36	EXISTING REVENUE MINUS ALLOCATED COSTS	($1,114,029)	($4,883,213)	$218,673	$2,364,299	$434,025	$414,109	$211,456	($9,011)
		Deficiency Input equals Output							
37	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($4,299,579)	$356,240	$2,612,893	$505,295	$448,739	$233,824	($8,526)
38	RETURN ON EQUITY COMPONENT OF RATE BASE	9.00%	-1.45%	13.60%	28.21%	18.98%	30.82%	28.28%	-4.49%

Ontario Energy Board

2019 Cost Allocation Mode

EB-2018-0028

Sheet O1 Revenue to Cost Summary Worksheet - Application

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Line		Total	9 Unmetered Scattered Load	10 Embedded Distributor Hydro One - CND	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
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)	$1,870,459	$4,777	$562	$1,518	$328	$180	$199
		M						
3	**Total Revenue at Existing Rates**	$35,328,679	$68,819	$51,088	$222,805	$119,362	$5,568	$4,854
4	Factor required to recover deficiency (1 + D)	1.0333						
5	Distribution Revenue at Status Quo Rates	$34,572,250	$66,174	$52,209	$228,655	$122,997	$5,567	$4,810
6	Miscellaneous Revenue (mi)	$1,870,459	$4,777	$562	$1,518	$328	$180	$199
7	**Total Revenue at Status Quo Rates**	$36,442,709	$70,952	$52,770	$230,173	$123,325	$5,747	$5,009
	Expenses							
8	Distribution Costs (di)	$4,953,255	$16,106	$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)	$8,747,377	$15,985	$6,134	$17,923	$3,676	$1,852	$1,386
11	Depreciation and Amortization (dep)	$6,369,992	$19,327	$2,962	$4,774	$904	$616	$0
12	PILs (INPUT)	$750,049	$2,554	$648	$2,566	$486	$190	$0
13	Interest	$4,377,475	$14,908	$3,783	$14,978	$2,837	$1,111	$0
14	**Total Expenses**	$30,092,060	$70,269	$15,922	$40,647	$8,309	$4,471	$3,006
15	**Direct Allocation**	$140,979	($102)	$21,851	$94,513	$17,904	$6,712	$0
16	Allocated Net Income (NI)	$6,209,670	$21,147	$5,366	$21,247	$4,025	$1,577	$0
17	**Revenue Requirement (includes NI)**	$36,442,709	$91,315	$43,139	$156,407	$30,237	$12,759	$3,006
		Revenue Re						
	Rate Base Calculation							
	Net Assets							
18	Distribution Plant - Gross	$195,315,384	$656,660	$21,740	$0	$0	$3,239	$0
19	General Plant - Gross	$15,819,244	$54,030	$14,837	$58,711	$11,122	$4,357	$0
20	Accumulated Depreciation	($25,291,672)	($72,343)	($15,665)	($33,328)	($6,313)	($3,553)	$0
21	Capital Contribution	($29,939,878)	($104,736)	($3,537)	$0	$0	($527)	$0
22	**Total Net Plant**	$155,903,079	$533,611	$17,375	$25,383	$4,808	$3,517	$0
23	**Directly Allocated Net Fixed Assets**	$764,856	($279)	$118,547	$512,764	$97,133	$36,413	$0
24	Cost of Power (COP)	$204,149,413	$280,069	$1,552,477	$7,156,251	$1,501,556	$42,830	$5,329,726
25	OM&A Expenses	$18,594,544	$33,480	$8,529	$18,328	$4,081	$2,553	$3,006
26	Directly Allocated Expenses	$28,814	($71)	$4,466	$19,317	$3,659	$1,372	$0
27	***Subtotal***	*$222,772,772*	*$313,478*	*$1,565,472*	*$7,193,896*	*$1,509,297*	*$46,755*	*$5,332,732*
28	**Working Capital**	$16,707,958	$23,511	$117,410	$539,542	$113,197	$3,507	$399,955
29	**Total Rate Base**	$173,375,892	$556,843	$253,332	$1,077,689	$215,138	$43,436	$399,955
		Rate						
30	**Equity Component of Rate Base**	$69,350,357	$222,737	$101,333	$431,076	$86,055	$17,374	$159,982
31	**Net Income on Allocated Assets**	$6,209,670	$784	$14,998	$95,013	$97,112	($5,435)	$2,003
32	**Net Income on Direct Allocation Assets**	$31,862	($12)	$4,938	$21,361	$4,046	$1,517	$0
33	**Net Income**	$6,241,532	$772	$19,936	$116,374	$101,159	($3,918)	$2,003
34	**RATIOS ANALYSIS**							
35	**REVENUE TO EXPENSES STATUS QUO%**	100.00%	77.70%	122.33%	147.16%	407.86%	45.04%	166.64%
36	EXISTING REVENUE MINUS ALLOCATED COSTS	($1,114,029)	($22,496)	$7,949	$66,398	$89,124	($7,191)	$1,848
		Defici						
37	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($20,363)	$9,632	$73,766	$93,087	($7,012)	$2,003
38	RETURN ON EQUITY COMPONENT OF RATE BASE	9.00%	0.35%	19.67%	27.00%	117.55%	-22.55%	1.25%

ENERGY+, Inc.

Recommended Large Use Class Rate Design

Line	Description	Cost	Billing Units		Rate	Reference
		(1)	(2)		(3)	(4)
1	**Revenue Requirement**	$625,952				Schedule JP-6, page 2
	Service Charge:					
2	Present Rates				$8,976.07	Appilcation Exhibit 8 at 10
3	Recommended Rates	$107,713	24	Bills	$4,488.04	50% Decrease
4	**Revenues to be Recovered In Distribution Volumetric Rates**	$518,239				Line 1 - Line 3
5	**Total Demand-Related Costs**	$558,873				Page 2
6	**Revenue-to-Cost Ratio**	92.7%				Line 4 ÷ Line 5
7	**Bulk Distribution Volumetric Rate**	$135,342	[redacted]	kW	[redacted]	Col. 1 ÷ Col. 2
	Primary Substation Volumetric Rate:					
8	Feeder Costs	$85,592	[redacted]	kW	[redacted]	(Line 6 x Schedule JP-3, Line 10, Col. 2) ÷ Col. 2
9	Poles, Towers, & Fixtures	$92,508		kW		(Line 6 x Schedule JP-6, page 3, Line 7) ÷ Col. 2
10	Total Prim. Sub. Volumetric Rate	$178,099			$0.505	Sum Lines 8:9
11	**Primary Distribution Volumetric Rate**	$204,797	[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.

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	Demand-Related Costs	Bulk Distribution Costs	Primary Distribution Costs Excluding Feeder Costs	Feeder Costs
		(1)	(2)	(3)	(4)	(5)	(6)
1	Distribution Costs	$97,224	$33	$97,191	$41,012	$56,179	
2	Customer-Related Costs	$16,000	$16,000	$0	$0	$0	
3	General & Administrative	$102,737	$14,548	$88,189	$37,213	$50,976	
4	Depreciation & Amortization	$125,474	$28,755	$96,719	$58,871	$37,848	
5	PILS	$14,932	$608	$14,324	$1,690	$12,635	
6	Interest Expense	$87,150	$3,551	$83,599	$9,861	$73,738	
7	Total Expenses	$443,517	$63,494	$380,023	$148,647	$231,375	
8	Direct Allocation	$91,933	$0	$91,933	$0	$0	
9	Allocated Net Income	$123,626	$5,037	$118,590	$13,988	$104,601	
10	Miscellaneous Revenue	$33,125	$1,453	$31,672	$16,681	$14,991	
11	Revenue Requirement	$625,952	$67,078	$558,873	$145,954	$320,986	$91,933

Source: Schedules JP-3 and JP-5.

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	$320,986	Schedule JP-6, Line 10, 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	$99,761	Line 1 x Line 4

ENERGY+, Inc.

Large Use Class Billing Demand
(Amounts in kW)

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

ENERGY+, INC.
TMMC Standby Service Requirements
January 2016 Through July 2018

Line	Month-Year	Monthly Maximum Demand No Outage (kW)	Monthly Maximum On-Peak Demand Outage (kW)	Standby Service Demand (kW)	Outage Duration (No. of On-Peak Days)	Daily Demand Charge Billing Units Col. 3 x Col. 4
		(1)	(2)	(3)	(4)	(5)
1	Jan-16	[redacted]				
2	Feb-16					
3	Mar-16					
4	Apr-16					
5	May-16					
6	Jun-16					
7	Jul-16					
8	Aug-16					
9	Sep-16					
10	Oct-16					
11	Nov-16					
12	Dec-16					
13	Jan-17					
14	Feb-17					
15	Mar-17					
16	Apr-17					
17	May-17					
18	Jun-17					
19	Jul-17					
20	Aug-17					
21	Sep-17					
22	Oct-17					
23	Nov-17					
24	Dec-17					
25	Jan-18					
26	Feb-18					
27	Mar-18					
28	Apr-18					
29	May-18					
30	Jun-18					
31	Annualized					

On-Peak Hours are: Monday-Friday 7am-7pm, Except for Public Holidays.

Source: Information provided by TMMC.

ENERGY+, Inc.

Recommended Standby Service Rate Design

Line	Description	Rate	Reference
		(1)	(2)
1	**Maximum Volumetric Rate**	$0.505	Schedule JP-6, Page 1
	Daily Volumetric Rate:		
2	Large Use Bulk Distribution Volumetric Rate	$0.409	Schedule JP-6, Page 1
3	No. of Weekdays Per Billing Month	20.9	
4	Daily Volumetric Rate	$0.020	Line 2 ÷ Line 3
5	**Monthly Maximum Standby Volumetric Rate**	$0.915	Sum Lines 1:2

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EB-2018-0028
Schedule JP-9

ENERGY+, Inc.

Revenues From Recommended Standby Service Rate

Line	Description	Rate	Billing Units		Revenues	Reference
		(1)	(2)		(3)	(4)
1	**Maximum Volumetric Rate**	$0.505	55,200	kW	$27,902	Schedule JP-8
2	**Daily Volumetric Rate**	$0.020	[redacted]	kW	$929	Schedules JP-7 & JP-8
3	**Total Standby Service Revenues**				$28,828	Sum Lines 1:2

Schedule JP-10

The documents upon which I relied in preparing my evidence are listed below and are also referenced in footnotes throughout my evidence. Factual assumptions that underpin my analysis and conclusions are set out in my evidence itself. Source documents that underpin the data in the various schedules to my evidence are set out below and/or indicated in footnotes to the schedules.

Document	Public/ Confidential	Source	Date Received
A. **EB-2018-0028 Proceeding Exhibits**			
1. Energy+ Inc., Application for Approval of 2019 Electricity Distribution Rates (April 30, 2018)	Public	OEB-Web-Drawer Download	N/A
2. Energy+ Inc., Responses to Interrogatories from OEB Staff (September 14, 2018)	Public	OEB-Web-Drawer Download	9-14-18
3. Energy+ Inc., Responses to Interrogatories from TMMC (September 14, 2018)	Public & Confidential	OEB-Web-Drawer Download	9-14-18
4. Energy+ Inc., Responses to Interrogatories Schools Energy Coalition (September 14, 2018)	Public	OEB-Web-Drawer Download	9-14-18
5. Energy+ Inc., Responses to Interrogatories from Consumers Council of Canada (September 14, 2018)	Public	OEB-Web-Drawer Download	9-14-18
6. Energy+ Inc., Responses to Interrogatories from Vulnerable Energy Consumers Coalition (September 14, 2018)	Public	OEB-Web-Drawer Download	9-14-18
7. Energy+ Inc., Updated Class Cost of Service Study (included in #2)		OEB-Web-Drawer Download	9-17-18
8. Energy+ Inc., Updated Load Profile (included in #2)		OEB-Web-Drawer Download	9-17-18

Document	Public/ Confidential	Source	Date Received
B. **OEB Decisions, Guidelines & Reports**			
1. EB-2005-0317, Cost Allocation Review, *Board Directions on Cost Allocation Methodology for Electricity Distributors* (Sept. 29, 2006)	Public	https://www.oeb.ca/documents/cases/EB-2005-0317/report_directions_290906.pdf	N/A
2. EB-2015-0043, Staff Discussion Paper, *Rate Design for Commercial and Industrial Electricity Customers: Aligning the Interests of Customers and Distributors* (Mar. 31, 2016)	Public	https://www.oeb.ca/oeb/_Documents/EB-2015-0043/Staff_Discussion_Paper_RDCI_20160331.pdf	N/A
C. **Confidential Information Provided by TMMC**			
1. TMMC Highest Monthly Peak 2013, 2014, 2015	Confidential	Email	9-19-18
2. TMMC 2018 Main Plant Bills	Confidential	Email	9-6-18
3. TMMC 2017 Main Plant Bills	Confidential	Email	9-6-18
4. TMMC 2016 Main Plant Bills	Confidential	Email	9-5-18
5. DemandStudy_2016 Monthly Scatter Plots.xlsx	Confidential	Email download link	8-22-18
6. DemandStudy_2017 Monthly Scatter Plots.xlsx	Confidential	Email download link	8-22-18
7. DemandStudy_2018 Monthly Scatter Plots.xlsx	Confidential	Email download link	8-22-18
8. On and Off Peak Max Demand 2016 - 2018.xlsx	Confidential	Email	8-14-18