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SOAH DOCKET NO. 473-22-2695
PUC DOCKET NO. 53601

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| APPLICATION OF ONCOR ELECTRIC DELIVERY COMPANY LLC FOR AUTHORITY TO CHANGE RATES | §<br>§<br>§ | BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS |

Direct Testimony and Exhibits

of

**JEFFRY POLLOCK**

On Behalf of

**Texas Industrial Energy Consumers**

August 26, 2022

J. POLLOCK
INCORPORATED

SOAH DOCKET NO. 473-22-2695
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## TABLE OF CONTENTS

**SOAH DOCKET NO. 473-22-2695**
**PUC DOCKET NO. 53601**

| | | |
|---|---|---|
| **APPLICATION OF ONCOR ELECTRIC DELIVERY COMPANY LLC FOR AUTHORITY TO CHANGE RATES** | §<br>§<br>§ | **BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS** |

## AFFIDAVIT OF JEFFRY POLLOCK

**State of Missouri** )
) **SS**
**County of St. Louis** )

Jeffry Pollock, being first duly sworn, on his oath states:

1. My name is Jeffry Pollock. I am President of J. Pollock, Incorporated, 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141. We have been retained by Texas Industrial Energy Consumers to testify in this proceeding on its behalf;

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony, Exhibits, and Appendices A, B and C, which have been prepared in written form for introduction into evidence in SOAH Docket No. 473-22-2695 and Public Utility Commission of Texas Docket No. 53601; and,

3. I hereby swear and affirm that my answers contained in the testimony are true and correct.

Jeffry Pollock

*Subscribed and sworn to* before me this 26th day of August 2022.

KITTY TURNER
Notary Public - Notary Seal
State of Missouri
Commissioned for Lincoln County
My Commission Expires: April 25, 2023
Commission Number: 15390610

Kitty Turner, Notary Public
Commission #: 15390610

My Commission expires on April 25, 2023.

# GLOSSARY OF ACRONYMS

| Term | Definition |
|---|---|
| **4CP** | Four Coincident Peak |
| **AEP** | AEP Texas |
| **A362** | Capacitors Booked to FERC Account No. 362 (Station Equipment) |
| **A368** | Capacitors Booked to FERC Account No. 368 (Line Transformers) |
| **AMI** | Advanced Metering Infrastructure |
| **CCOSS** | Class Cost-of-Service Study |
| **CIAC** | Contribution in Aid of Construction |
| **DCRF** | Distribution Cost Recovery Factor |
| **DSC** | Distribution System Charge |
| **ESI** | Electric Service Identifier |
| **kVA / KVAR** | Kilovolt Amperes / Kilovolt Ampere Reactive |
| **kW** | Kilowatt |
| **MW** | Megawatts |
| **NCP** | Non-Coincident Peak |
| **Oncor** | Oncor Electric Delivery Company LLC |
| **TCOS** | Transmission Cost of Service |
| **TCRF** | Transmission Cost Recovery Factor |
| **TIEC** | Texas Industrial Energy Consumers |
| **TNMP** | Texas-New Mexico Power Company |

# EXHIBIT LIST

| Exhibit | Description |
|---|---|
| **JP-1** | TIEC's Revised Class Cost-of-Service Study |
| **JP-2** | Proposed Delivery Rate Increases |
| **JP-3** | Recommended 4CP Rate Moderation Plan |
| **JP-4** | Summary of Facilities Charge Rate for Distribution Substation Investment |
| **JP-5** | Revised Tariff Language |
| **JP-6** | Interconnection Timelines |

# DIRECT TESTIMONY 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 Arts degree in electrical engineering and a Master's in Business Administration from Washington University. Since graduation, 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. I have participated in numerous regulatory proceedings before the Public Utility Commission of Texas, including rate cases and rulemaking cases. My qualifications are documented in **Appendix A**. A list of my appearances is provided in **Appendix B** to this testimony.

**Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A I am testifying on behalf of Texas Industrial Energy Consumers (TIEC). TIEC members take delivery service under Oncor Electric Delivery Company LLC's (Oncor's) Large (over 10 kW), Secondary, Primary Line, Primary Substation and Transmission service rates.

**Q WHAT ISSUES ARE YOU ADDRESSING IN YOUR DIRECT TESTIMONY?**

A I addressing cost allocation and rate design issue, including:

- The derivation of the four coincident peak (4CP) demand allocation factors used to allocate wholesale transmission costs and to design the updated Transmission Cost Recovery Factor (TCRF);
- The allocation of distribution capacitors;
- The allocation of costs associated with mobile generators;
- Class revenue allocation issues, including the treatment of power factor revenues and rate moderation;
- Rate design, including test-year billing determinants and the design of the Secondary > 10 kW rate schedule; and
- Other tariff terms and conditions.

**Q ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?**

A Yes. I am sponsoring **Exhibits JP-1** through **JP-6**. These exhibits were prepared either by me or under my direction.

**Q SHOULD THE FACT THAT YOU ARE NOT ADDRESSING OTHER ISSUES BE INTERPRETED AS AN ENDORSEMENT OF ONCOR'S PROPOSALS?**

A No.

## Summary

**Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.**

A My findings and recommendation are as follows:

*4CP Allocation Factors*

- Oncor is proposing significant changes to the 4CP allocation factors. The proposed changes would range from an 11.2% decrease to an 84.7% increase. Absent any rate moderation, the significant changes in the 4CP allocation factors would cause delivery rates to increase by up to 87%.
- The sum of the class 4CPs as determined by Oncor are 373 megawatts (MW) to 642 MW below the 4CP as determined by ERCOT. These differences are material. Because of the significance of the change in the 4CP allocation factors, Oncor should investigate the reasons for the differences between the sum of the class 4CPs and ERCOT reported 4CPs.

*Allocation of Distribution Capacitors*

- Oncor is proposing to allocate the distribution capacitors installed along distribution feeders, which are booked to FERC Account No. 368 (A368 Capacitors) to all classes, including Primary Substation and Transmission.
- Although A368 distribution capacitors benefit all customers, the benefits to Primary Substation and Transmission are imperceptible and unquantifiable. The flaw with Oncor's proposal is that it ignores the reality that A368 Capacitors are required by the reactive loading imposed on the system by distribution customers located downstream of the demarcation between transmission and distribution.
- Oncor concedes that A368 Capacitors are not intended to provide reactive power upstream to Transmission or Primary Substation customers. Any reactive power needs by these customers are provided by the capacitors installed in substations, which are booked to FERC Account No. 362 (A362 Capacitors). The A362 Capacitors are part of Oncor's transmission cost of service (TCOS) that is paid for by all customers.
- No other Texas transmission-distribution utility allocates distribution capacitors to Transmission customers.
- Thus, A368 Capacitors are not caused by loads taking either primary substation or transmission service. Thus, no A368 Capacitor costs should be allocated to either Primary Substation or Transmission customers.
- If the Commission determines that A368 Capacitors should be allocated to all classes, it should reject the NCP-All allocation method and require Oncor to quantify the reactive power requirements by delivery class.

*Mobile Generator Cost Allocation*

- Oncor is proposing various allocations of mobile generator costs that would have the result of requiring Transmission and Primary Substation customers to pay for some portion of these costs.
- Pursuant to PURA § 39.918(b)(1), mobile generators provide temporary emergency electric energy to aid in restoring power *to the utility's distribution customers* during a widespread power outage. Mobile generators specifically cannot be used to serve customers that take Transmission service (and Primary Substation customers, who are essentially the same as Transmission service except for the fact that Oncor owns their dedicated transformation facilities).
- Because mobile generation facilities are for the utility's distribution customers, none of the costs should be allocated to Transmission and Primary Substation customers.

*Power Factor Adjustment to Revenues*

- During the test year, Oncor collected $29.9 million of additional Distribution System Charges (DSCs) when customers taking service on demand-metered delivery service rate schedules (*i.e.,* Secondary > 10 kW, Primary > 10 kW, Primary Substation, and Transmission) fail to maintain a 95% power factor. Thus, power factor revenues are specifically associated with these classes.
- Oncor removed all power factor revenues from base delivery rates. However, $14.3 million of these revenues were treated as "other" revenues and allocated to all delivery rate classes, including classes that are not subject to power factor charges.
- Oncor asserts that the remaining $15.6 million of test-year power factor revenues (and the associated billing determinants) that was excluded from test-year sales and revenues reflects power factor improvements by customers.
- Oncor has not demonstrated that the power factor improvement was the result of specific actions taken by customers (*i.e.*, to install capacitors) to raise their power factors during the test year. Hence, it does not qualify as known and measurable. The power factor improvement adjustment should be rejected.
- Delivery revenues (and the associated billing determinants) by rate class at present rates should be restated to reflect (1) the $14.3 million of power factor revenues that Oncor treated as other revenues and (2) the $15.6 million of power factor revenues that were removed from test-year revenues that reflect the power factor charges paid by customers in the affected delivery rate classes.

*Rate Moderation*

- Resetting the 4CP allocation factors would result in TCRF charges that would account for between -8.6% and 196% of the overall electric delivery revenue increase by rate class. It is the primary reason why some (Primary Substation and Transmission) delivery rate classes would experience huge delivery rate increases under Oncor's filed case.
- It is both reasonable and consistent with past Commission practice to apply gradualism to mitigate substantial rate impacts which, in this specific instance, can be directly attributed to resetting the 4CP allocation factors.
- The 4CP allocation factors should be phased in over at least two steps. The first step should be to set new 4CP allocation factors that would result in moving 50% of the distance from the current 4CPs to Oncor's proposed 4CP allocation factors. The second step would be to reset the 4CP allocation factors to move the remainder of the way to cost *based on the most recent 4 CP demands*.

*Rate Design*

- Test-year billing determinants should be restated to reverse Oncor's power factor improvement adjustment.
- Oncor is proposing to replace the current load-factor structure of the Secondary > 10 kW DSC with a flat DSC. Further, Oncor also proposes eliminating the 80% demand ratchet for customers not subject to the load-factor based DSC.
- Oncor has not demonstrated that the proposed changes in the Secondary > 10 kW DSC are cost-based. Removing the 80% demand ratchet is not consistent with cost causation, and it would be contrary to the standard rate design approved by the Commission in Docket No. 22344.
- Both AEP Texas (AEP) and Texas New-Mexico Power Company (TNMP) have an 80% demand ratchet in applying the DSCs in their respective retail tariffs.
- The Commission should retain the current Secondary > 10 kW DSC and the 80% ratchet.

*Tariff Terms and Conditions*

- The Commission should reject Oncor's proposal to codify a six-month minimum before a customer can switch to a different rate. Rate switching is a normal operating risk. With full deployment of advanced metering infrastructure (AMI) supported by a more modern billing system, it should not be costly or time-consuming to allow customers to switch to a different rate provided that the applicability requirements are met.
- A six-month minimum is also unreasonable because it would fail to timely accommodate a customer's changing needs. Customers should not be prevented from choosing the most economic and efficient rate that will create opportunities to better manage electricity costs and reliability.
- The Commission should reject Oncor's proposal to limit the eligibility for Primary Substation service to new loads because it be unfair to customers who, through no fault of their own, may currently be receiving service at a single premise or location through multiple meters due to facility expansions and load growth. It would prevent customers from implementing effective load and cost management and improving service reliability.
- Rate design should empower customers to better manage their loads and costs. This means creating opportunities to allow a customer to consolidate the loads at an existing premise or location to save money, regardless of the delivery rate that currently applies to the separate loads.

- Allowing Primary Substation customers to consolidate load at other delivery points should not result in stranded investment because Oncor will always be compensated for all of its delivery costs, regardless if some facilities are idled by changes in the delivery service provided to specific retail customers. Even if consolidating a customer's load behind a single primary substation delivery point would idle some facilities, some equipment may be utilized as spare parts, serve other customers, replace worn-out or older equipment, or sold as scrap.
- Oncor should implement a Facility Charge tariff so that customers can lease the equipment necessary to qualify for a higher voltage service. The Facility Charge would be a percentage of the investment in the leased facilities.
- Oncor has provided no justification for designating 345 kV as a non-standard service for retail customers. Not only would this not be consistent with past Commission practice, it is inconsistent with Oncor's proposal to retain 345 kV voltage in its Standard Transmission and Distribution Voltages, subject to meeting safety and reliability concerns.
- Oncor's proposed changes to the non-utilization clause (Retail Tariff Section 6.3.1, Article II) could penalize a customer at the end of the second year of service if the load fails to achieve the projected load ramp. Although Oncor should have a realistic expectation that it will recover costs attributable to extended delivery facilities, the timeframe may be too short and there may be extenuating circumstances causing delays, such as supply chain issues, labor shortages, or market conditions.
- If a customer is already funding the portion of a facility extension that the customer was projected to use, it should not matter to Oncor that the customer failed to achieve the projected load.
- If the purpose of Oncor's proposed change is to make capacity available to serve other customers, Oncor should reimburse the customer that originally paid a contribution in aid of construction (CIAC) for those facilities.
- Oncor should adopt a more proactive process with the customer to stay abreast of changing circumstances that could impact the build-out or utilization of extended facilities. If Oncor determines that any of the extended facilities originally funded by a customer will not be fully utilized and, therefore, can be used to serve other customers within 10 years after the facilities are energized, it should reimburse the customer who paid the CIAC a pro-rata share of the capacity used to serve new/additional customers.
- Oncor's proposed new language in Retail Tariff Section 6.3.1, Article III should be rejected because it is contrary to Oncor's obligation to provide delivery service, and a customer should not have to secure rights-of-way because (unlike Oncor) they do not have eminent domain rights.

- Oncor's proposal to require customers to pay both the unamortized capital costs and removal costs for facilities that may be idled (Retail Tariff Section Nos. 6.1.2.2.9, 6.1.3.2.9 and 6.1.4.2.9.) should be rejected because (1) no timeframe (for when a facility is determined to be idle) was specified, (2) the cost of removal is already included in setting depreciation rates, and (3) it assumes that any idled equipment, in all circumstances, would no longer be used and useful.
- TIEC members continue to experience interconnection delays for new or expanded facilities. In some areas this is driven by both the lack of transmission infrastructure in the region and by challenges for Oncor and others in handling the speed and magnitude of interconnection and upgrade requests.
- With respect to the oil and gas industry in particular, the Commission spearheaded a collaborative effort in 2019 to better define the interconnection process and establish timelines to ensure that service requests are completed in a more timely manner. The parties to the collaboration reached an agreement that was intended to be a framework for interconnection called the Distribution Service Request Process.
- Despite working with customers to develop the process, it is my understanding that the utilities have not been able to meet the specified timelines and, perhaps more importantly, they often have provided little or no explanation as to the reason for the delay, or an updated timeline.
- Oncor should make a more deliberate effort to comply with the Distribution Service Request Process for all industrial and manufacturing customers. Non-compliance should be the exception, not the rule. Although some exceptions are to be expected, it is vital that Oncor be more proactive in managing the process. At a minimum, Oncor should be required to provide a written explanation and an updated timing estimate, which would improve accountability and customer transparency. This would allow the parties to adjust their expectations and plan accordingly.

## 2. CLASS COST-OF-SERVICE STUDY

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

A A cost-of-service study is an analysis used to determine each class's responsibility for the utility's costs. The study determines whether the revenues a class generates cover the class's cost-of-service. A class cost-of-service study separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For purposes of rate design and revenue allocation, customers are grouped into homogeneous classes according to their usage patterns and service characteristics. The procedures used in a cost-of-service study are described in more detail in **Appendix C.**

**Q HAVE YOU REVIEWED THE CLASS COST-OF-SERVICE STUDY FILED BY ONCOR IN THIS PROCEEDING?**

A Yes.

**Q DOES ONCOR'S CLASS COST-OF-SERVICE STUDY GENERALLY COMPORT WITH ACCEPTED INDUSTRY PRACTICES?**

A Yes. With some notable exceptions, Oncor's CCOSS generally recognizes the different types of costs as well as the different ways that delivery services are provided to customers.

**Q ARE THERE ANY SPECIFIC FLAWS WITH ONCOR'S CLASS COST-OF-SERVICE STUDY?**

A Yes. First, the total 4CP demand used by Oncor deviates from ERCOT's calculation. Oncor is proposing to use the 4CP method to allocate wholesale transmission costs to its retail classes and to reset the allocation factors in its TCRF. While the 4CP method is consistent with PUC Subst. Rule 25.192, I have observed that the sum of the class 4CP demands is between 373 MW and 642 MW below the 4CP that ERCOT reported for Oncor in the wholesale TCOS payment matrix finalized in Docket No. 52989. The differences, which are not insignificant, need to be further investigated and potentially reconciled.

The second flaw with Oncor's CCOSS is its proposal to allocate A368 Capacitors to all rate classes. This is in addition to the A362 Capacitors, some of which are also allocated to all customer classes. Oncor's proposed allocation of A368 Capacitors is contrary to cost causation because these capacitors serve a distribution function and do not serve transmission-connected customers. The principle of cost causation means that the costs caused by distribution customers should not be allocable to retail transmission customers. Every regulated electric utility in Texas (except Oncor) recognizes this fundamental concept for A368 Capacitors.

Capacitors normally increase the system power factor, which lowers current flow and losses on the delivery system. However, they must be installed in close proximity to the reactive loads they are intended to serve. Some distribution capacitors (found only in FERC Account A362) may provide reactive power and mitigate voltage drop caused by upstream customers, such as transmission and primary substation loads, but A368 Capacitors do not. It is, therefore, improper to allocate A368 Capacitors to the Transmission and Primary Substation classes. The A368 Capacitors do not serve transmission reactive power requirements or regulate transmission voltage. Thus, transmission and primary substation loads should be excluded from the allocation of A368 Capacitor costs.

A third flaw is that Oncor proposes to allocate power factor revenues to all customer classes based on allocated distribution plant. However, power factor revenues are unique to each customer class and should be directly assigned similar to other class-specific revenues and costs. In the event that direct assignment is rejected, power factor revenues should be allocated in the same manner as transmission and distribution capacitors, which better reflects the contribution of retail transmission customers.

The fourth flaw in Oncor's CCOSS is its proposal to allocate costs associated with mobile generators to all customer classes. By law, mobile generators may only be installed at the distribution level and deployed to restore electricity service to distribution level customers. As a result, there is no justification for allocating any of these mobile generator costs to retail Transmission or Primary Substation customers.

**<u>4CP Allocation Factors</u>**

**Q IS ONCOR PROPOSING TO RESET THE FOUR COINCIDENT PEAK ALLOCATION FACTORS IN THIS CASE?**

A Yes. The 4CP allocation factors currently in effect were established in Oncor's last rate case, Docket No. 46957, based on actual 4CP demands and adjusted for losses for the period June through September 2016. In this case, Oncor is proposing to reset the 4CP allocation factors based on actual loss-adjusted 4CP demands for the period June through September 2021.

**Q DOES ONCOR'S PROPOSAL CAUSE SIGNIFICANT CHANGES IN THE FOUR COINCIDENT PEAK ALLOCATION FACTORS BY RATE CLASS?**

A Yes. Table 1 summarizes both the current and proposed 4CP allocation factors.

**Table 1**
**Current Versus Proposed**
**4CP Allocation Factors**

| Rate Class | Current | Proposed | Percent Increase |
|---|---|---|---|
| Residential | 47.0021% | 45.8807% | -2.4% |
| Secondary ≤ 10 kW | 1.2704% | 1.2824% | 1.0% |
| Secondary > 10 kW | 37.5709% | 33.3536% | -11.2% |
| Primary ≤ 10 kW | 0.0115% | 0.0133% | 15.2% |
| Primary > 10 kW | 6.4653% | 8.3854% | 29.7% |
| Primary Substation | 1.4872% | 2.7463% | 84.7% |
| Transmission | 6.1926% | 8.3383% | 34.6% |

**Source:** Current & Proposed Tariff for Retail Delivery Service, Sheet 6.1.1.6.1

As Table 1 demonstrates, the proposed changes to the 4CP allocation factors would range from an 11.2% decrease to an 84.7% increase.

**Q DO THE SIGNIFICANT CHANGES IN THE 4CP ALLOCATION FACTORS RAISE ANY CONCERNS?**

A Yes. As discussed later, absent any rate moderation, the significant changes in the 4CP allocation factors would cause delivery rates to increase by up to 87% for the Primary Substation class.

**Q HOW DID ONCOR DEVELOP THE FOUR COINCIDENT PEAK ALLOCATION FACTORS FOR THIS CASE?**

A Oncor states that it has fully deployed its AMI. As a result, the 4CP demands purportedly reflect 100% actual metered data for each rate class.

**Q DO YOU HAVE ANY CONCERNS WITH THE FOUR COINCIDENT PEAK ALLOCATION FACTORS DERIVED BY ONCOR?**

A Yes. There is a significant difference between the sum of the class 4CP demands and the total Oncor 4CP demands as reported by ERCOT. These differences are shown in Table 2.

**Table 2**
**Sum of Class and Total Oncor 4CP Demands**
**(MW)**

| Description | June | July | August | September |
|---|---|---|---|---|
| **Sum of Rate Class** | 24,026 | 25,897 | 25,699 | 26,183 |
| **Oncor ERCOT 4CP** | 24,668 | 26,270 | 26,160 | 26,682 |
| **Difference** | 642 | 373 | 461 | 499 |

**Sources:** Schedule IV-J-7 and WP IV-J-7.1.

These differences are not, as Oncor asserts, "rather small."[1]

**Q WHAT DO YOU RECOMMEND?**

A Because resetting the 4CP allocation factors is a major driver of the proposed delivery rate increases as discussed below, Oncor should be required to investigate the reasons for the differences revealed in Table 2 between the calculated and reported 4CPs. In particular, it is essential to ensure that these differences are not the result of any errors or omissions. TIEC has asked discovery on this issue but Oncor's supplemental response did not fully explain the discrepancies or allow TIEC to make an alternative proposal for each class's 4CP demand values.

[1] Oncor Response to TIEC 2-7.

## Distribution Capacitors

### ***Background***

**Q WHAT ARE CAPACITORS?**

A Capacitors are electrical devices that provide reactive power to the loads on an electrical system. Capacitors produce "capacitive" reactive power, which is consumed by "inductive" loads (*e.g.,* motors, transformers, lamp ballasts). Reactive power flows lower the system power factor, causing more current to flow, using additional equipment capacity, and increasing losses.[2] Capacitors are also needed to offset the reactive losses, which occur in distribution lines and transformers.

**Q WHY ARE CAPACITORS NECESSARY?**

A Capacitors allow the system to operate at a higher power factor. Higher power factor means lower current flows, which results in lower losses and less voltage drop on the delivery system, while requiring less physical capacity to serve load.

**Q WHAT ARE DISTRIBUTION CAPACITORS?**

A Distribution capacitors are the capacitors that are connected at distribution voltage levels. The investment is booked to FERC Account Nos. 362 and 368.

**Q WHERE ARE CAPACITORS TYPICALLY INSTALLED?**

A Capacitors are installed at different points on the power system, usually as closely as possible to the reactive load they serve. This typically means that capacitors are

[2] Reactive power causes voltage and current to be out of phase with one another, requiring higher current flows (more kVa) for the same amount of useful energy (kW). At 100% power factor, reactive power flow is zero, and the kVa load equals the kW load). At 90% power factor, the kVa load is approximately 10% higher than the kW load.

installed on distribution feeders in close proximity to areas of heavy reactive load requirements. Capacitors are also installed near the ends of long distribution feeders to mitigate voltage drop on distribution lines. The A362 Capacitors are installed within substations. The A368 Capacitors are installed along distribution feeders.

**Q IF CAPACITORS ARE INSTALLED ONLY ON THE DISTRIBUTION SYSTEM, DOES THAT MEAN THAT ONLY DISTRIBUTION LOADS ARE RESPONSIBLE FOR THE COSTS OF CAPACITORS?**

A No. It is more economical to install capacitors on the distribution system than on the transmission system. Some of the A362 Capacitors that are installed in distribution substations may be used to supply reactive power and support voltage for the upstream transmission system, and thus are properly allocated to both transmission and distribution loads.

**Q HOW ARE THE CAPACITORS THAT SUPPORT POWER FACTOR AND VOLTAGE ON THE TRANSMISSION SYSTEM FUNCTIONALIZED AND ALLOCATED?**

A Pursuant to this Commission's Rules, these capacitors are functionalized to transmission and included in Oncor's TCOS if they meet three criteria. Specifically:

> (D) capacitors and other reactive devices that are operated at a voltage below 60 kilovolts, if they are located in a distribution substation, the load at the substation has a power factor in excess of 0.95 as measured or calculated at the distribution voltage level without the reactive devices, and the reactive devices are controlled by an operator or automatically switched in response to transmission voltage.[3]

Thus, these specific capacitors comprise a portion of Oncor's TCOS, which is then included in the ERCOT-wide wholesale transmission costs that are allocated to all

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[3] PUC SUBST. R. 25.192(c)(1)(D).

ERCOT loads on a 4CP basis. This means that all of Oncor's customers, including Transmission and Primary Substation customers, pay for the capacitors required to provide reactive power and mitigate voltage drop for the transmission system through the TCOS and TCRF charges.

**Q HAS ONCOR INCLUDED CAPACITORS THAT MEET THE THREE CRITERIA IN ITS TRANSMISSION COST OF SERVICE?**

A Yes. In a prior rate case, Oncor witness, R. Keith Pruett, stated that:

> Additionally, in accordance with the Commission's Order No. 14 in Docket No. 15840, low-voltage capacitor banks have been included as transmission equipment by meeting the Commission's three prong test: (1) not required by the distribution loads to comply with the 95 percent power factor requirements in Substantive Rule 25.192(c)(1)(D); (2) physically located within the substation boundary; and (3) actively controlled in response to changes in transmission voltages rather than distribution voltages.[4]

Based on the three prong test, some A362 Capacitors are functionalized to transmission.

***<u>Allocation to Transmission and Primary Substation Customers</u>***

**Q DO YOU TAKE ISSUE WITH HOW ONCOR HAS ALLOCATED THE CAPACITORS THAT MEET THE THREE CRITERIA LISTED ABOVE?**

A No, I agree that capacitors that meet the above criteria (which are all booked as A362 Capacitors) should be allocated as Oncor has proposed. I do, however, disagree with how Oncor proposes to allocate A368 Capacitors.

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[4] *Application of Oncor Electric Delivery Company LLC for Authority to Change Rates,* Docket No. 38929, Direct Testimony of R. Keith Pruett at 88 (Jan. 7, 2011).

**Q HOW IS ONCOR PROPOSING TO ALLOCATE A368 CAPACITORS?**

A Oncor is proposing to allocate A368 Capacitors to all delivery classes using the Non-Coincident Peak (NCP) method — specifically, the "NCP-All" factor, which includes Primary Substation and Transmission customers who do not cause Oncor to install A368 capacitors.[5]

**Q WHAT IS THE BASIS FOR ONCOR'S PROPOSAL TO ALLOCATE A368 CAPACITORS TO TRANSMISSION LOADS?**

A Oncor asserts that A368 Capacitors provide benefits to all delivery customers, including Primary Substation and Transmission customers, because:

> Distribution capacitors provide voltage support, improved power factor, and increased efficiency to the entire transmission network, thereby providing benefits to the transmission network itself and all distribution customer classes.[6]

Oncor also cited past orders to support its proposed allocation.[7]

**Q DO YOU AGREE THAT A368 CAPACITORS PROVIDE A BENEFIT TO THE SYSTEM AS A WHOLE, INCLUDING TRANSMISSION SYSTEM CUSTOMERS?**

A Yes, but that benefit is imperceptible and unquantifiable. It does not justify Primary Substation and Transmission customers paying for capacitors that are used solely to offset the negative effects of reactive power from distribution load.

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[5] NCP measures each class's peak demand, irrespective of when it occurs. This is in contrast to coincident peak, which measures the demand of each class on the same date and time.

[6] Oncor Response to TIEC 2-2. *See also*, Oncor Response to TIEC 2-1.

[7] *Id.*

**Q PLEASE EXPLAIN.**

A A368 Capacitors *may* cause incidental positive effects on the upstream transmission system, but that is not why they are installed. Rather, the positive effects of A368 Capacitors at transmission voltage are simply a result of offsetting the negative effects of distribution-level issues, such as increased losses and voltage drop resulting from supplying the reactive loads of customers on the distribution system. The flaw with Oncor's proposal is that it ignores the reality that additional A368 Capacitors are required when additional low power factor loads are added to the *distribution* system. The need for additional A368 Capacitors is not caused by either primary substation or transmission loads.

Many A368 Capacitors are specifically located on distribution lines, at a considerable distance from the distribution substation, for the specific purpose of raising distribution voltage. When properly located and sized, A368 Capacitors can actually mitigate almost all the voltage drop which occurs on long distribution feeders. However, because the transmission grid operates at much higher voltages than distribution lines, any voltage improvement on a distribution line does not translate to a corresponding improvement on the transmission grid. Thus, any upstream benefits from A368 Capacitors to Transmission and Primary Substation customers are incidental and imperceptible, at best, and are not the impetus for the investment.

**Q DO THE A368 CAPACITORS PROVIDE REACTIVE POWER TO TRANSMISSION AND PRIMARY SUBSTATION CUSTOMERS?**

A No. Oncor states that A368 Capacitors are not intended to provide reactive power upstream to Transmission or Primary Substation customers.[8] For there to be reactive

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[8] Oncor Response to TIEC 2-4.

flow from A368 Capacitors to Transmission or Primary Substation Customers the power factor at the high voltage side of the substation transformer would have to be corrected past 100%, resulting in leading power factor, which is unlikely. Because the A362 Capacitors address power factor concerns for Primary Substation and Transmission customers, none of the costs of the A368 Capacitors should be allocated to Primary Substation and Transmission customers.

**Q ARE YOU FAMILIAR WITH THE ORDERS THAT ONCOR RELIES ON TO ALLOCATE A368 CAPACITOR COSTS TO ALL CLASSES?**

A Yes. I was a witness in both Docket Nos. 22350 and 35717, which Oncor references. I have read the orders and am familiar with the arguments.

**Q DOES THE EVIDENCE IN THIS CASE SUPPORT THE SAME DECISION THAT WAS MADE IN THOSE CASES?**

A No. As discussed below, the A368 Capacitors at issue are required by the reactive loading imposed on the system by *distribution* customers located downstream of the demarcation between transmission and distribution, not by the reactive loading imposed by Primary Substation and Transmission customers. The A362 Capacitors are used to support voltage and supply reactive power upstream to the transmission system. To qualify as providing reactive power to upstream customers, A362 Capacitors must meet the three prong test that I discussed previously. Any A362 Capacitors that do not meet the test simply supply the reactive power needs of downstream distribution customers, as do A368 Capacitors. A362 Capacitors are allocated, in part, on a 4CP basis (because some of these costs are functionalized to transmission) and on a Class NCP basis. Thus, Primary Substation and Transmission customers are already paying for the costs of these capacitors. It is unnecessary (and would overstate the cost to serve Primary Substation and Transmission customers) to also allocate A368 Capacitors to these loads.

**Q IN YOUR EXPERIENCE, ARE A368 CAPACITORS TYPICALLY ALLOCATED TO LOADS THAT TAKE SERVICE AT TRANSMISSION VOLTAGES?**

A No. This would clearly violate a fundamental construct of a cost-of-service study, which is that distribution-related costs should not be allocated to transmission level customers. A transmission customer already owns all of the lower voltage equipment required to distribute power from the utility transmission system throughout the customer's facilities. This may also include distribution capacitors that are necessary to achieve a 95% power factor and avoid substantial penalties, as discussed later.

**Q IS THIS CONSTRUCT ACCEPTED BY OTHER REGULATED UTILITIES IN THIS STATE?**

A Yes. I have participated in rate cases and reviewed cost-of-service studies conducted by the other regulated electric utilities in Texas. Not a single utility – other than Oncor – allocates A368 Capacitor costs to transmission-level customers.

**Q SHOULD A368 CAPACITORS BE ALLOCATED TO TRANSMISSION CUSTOMERS?**

A For all of the above reasons, it would not be appropriate to allocate A368 Capacitors to Transmission customers. The loads of these customers should be removed in determining the allocation of A368 Capacitors and related costs.

**Q SHOULD A368 CAPACITORS BE ALLOCATED TO PRIMARY SUBSTATION CUSTOMERS?**

A No. Primary Substation customers are essentially the same as Transmission customers. The only difference is that the former require Oncor to install step-down transformers and related facilities. The Primary Substation customer invests in distribution facilities to provide delivery from the substation to the customer's electrical loads, including capacitors. Importantly, Primary Substation customers are not served from distribution feeders. As previously stated, A368 Capacitors are installed along distribution feeders either at reactive load centers or at the ends of long lines to provide voltage support. Further, any reactive power needs of Primary Substation customers are provided from the A362 Capacitors, which are installed in distribution substations. For all of the above reasons, A368 Capacitors should not be allocated to Primary Substation customers.

**Q ARE THERE ANY OTHER REASONS WHY TRANSMISSION AND PRIMARY SUBSTATION CUSTOMERS SHOULD NOT BE ALLOCATED COSTS FROM A368 CAPACITORS?**

A Yes. Since June 2004, when Oncor began enforcing the power factor provision of its Tariff for Retail Delivery Service, many customers have installed capacitors to raise their power factor to the minimum 95% level. Because Transmission and Primary Substation customers either self-provide or are served from A362 Capacitors, they should not be required to also pay for the costs of A368 Capacitors that are not required to serve them.

**Q IF THE COMMISSION NEVERTHELESS DECIDES TO ALLOCATE A368 CAPACITORS TO ALL CLASSES, IS ONCOR'S PROPOSED METHOD OF ALLOCATION REASONABLE?**

A No. The Commission should reject the NCP-All allocator if it approves allocating A368 Capacitors to all classes. The NCP-All allocator measures the "real power" (*i.e.,* kW) load of all customers. However, capacitors are needed to serve "reactive power" (*i.e., KVAR*) load. Real power and reactive power loads are not equal. In fact, the majority of customers in the customer classes that are subject to power factor penalties typically require no additional reactive power because they have already installed their own capacitors to maintain at least a 95% lagging power factor. These customers typically do not consume as much reactive power as customers not subject to power factor penalties, nor do they require Oncor to install A368 Capacitors. Thus, at most, the costs of A368 Capacitors should be allocated based on reactive load, not real power load, and not allocated to customers who already provide their own reactive power sources.

**Q HAVE YOU PREPARED AN ANALYSIS OF EACH CLASS'S REACTIVE POWER REQUIREMENTS?**

A No, I do not have all the necessary information. However, Oncor tracks power factor by an Electric Service Identifier (ESI) ID, so it should have the necessary information to quantify the reactive power requirements for demand-metered classes. Reactive power requirements for other customer classes can be estimated with data from the metering devices installed on each distribution feeder.

**Q PLEASE SUMMARIZE YOUR RECOMMENDATION.**

A For all of the reasons identified, A368 Capacitors should not be allocated to the Transmission or Primary Substation classes. Should the Commission determine that A368 Capacitors should be allocated to all classes, it should reject the NCP-All allocation method and require Oncor to quantify the reactive power requirements by delivery class.

## Mobile Generators

**Q WHY ARE MOBILE GENERATORS AT ISSUE IN THIS PROCEEDING?**

A PURA § 39.918(b)(1) allows a transmission and distribution utility to:

> (1) lease and operate facilities that provide temporary emergency electric energy to aid in restoring power *to the utility's distribution customers* during a widespread power outage in which:
>
> (A) the independent system operator has ordered the utility to shed load; or
>
> (B) *the utility's distribution facilities are not being fully served by the bulk power system* under normal operations[9]

Further, utilities are allowed to recover the reasonable and necessary costs of procuring, owning and operating the facilities, including any costs previously deferred.[10]

**Q IS ONCOR PROPOSING TO RECOVER COSTS ASSOCIATED WITH MOBILE GENERATORS IN THIS PROCEEDING?**

A Yes. Oncor is proposing to recover $769,171 of costs associated with mobile generators. These costs are included in various FERC accounts.[11]

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[9] PURA § 39.918; emphasis added.

[10] *Id.*

[11] Oncor Response to Staff 10-1, Attachment 1.

**Q HOW IS ONCOR PROPOSING TO ALLOCATE THE COSTS OF MOBILE GENERATORS?**

A Oncor is proposing to allocate mobile generator costs based on the previously allocated plant in service. Thus, all customer classes, including those served directly from the power system or from a specific substation, would pay a portion of the mobile generator costs.

**Q DO YOU AGREE WITH ONCOR'S PROPOSED ALLOCATION OF MOBILE GENERATORS?**

A No. Per the emphasized language from PURA § 39.918(b)(1), the mobile generation facilities are for the utility's "distribution customers." Further, the generators can only be used in a manner that is isolated from the transmission system, as subsection (d) specifically states:

> (d) Facilities described by Subsection (b)(1):
> (1) must be operated in isolation from the bulk power system;...[12]

In other words, mobile generators specifically cannot be used to serve customers that take transmission service. I would also exclude Primary Substation service, which is essentially the same as Transmission service except for the fact that Oncor owns the customer's dedicated transformation facilities. These customers are not served by Oncor's looped distribution system and would not be able to receive service from a mobile generator connected to Oncor's general purpose distribution feeders.

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[12] PURA § 39.918.

Q **WHAT DO YOU RECOMMEND?**

A I recommend that mobile generator costs be allocated to customer classes taking Secondary and Primary Line delivery service. These are the customers who can potentially benefit from the use of mobile generators to restore service during a major disruption.

## Revised Class Cost-of-Service Study

Q **HAVE YOU REVISED ONCOR'S CLASS COST-OF-SERVICE STUDY TO INCORPORATE YOUR RECOMMENDED ALLOCATION OF CAPACITORS, POWER FACTOR REVENUES AND MOBILE GENERATORS?**

A Yes. My revised CCOSS is provided in **Exhibit JP-1**. In this study, (1) A368 Capacitors were allocated to delivery rate classes taking Secondary and Primary Line service; (2) all power factor revenues were assigned to the specific delivery rate classes that paid them during the test year; and (3) no mobile generator costs were allocated to the Primary Substation and Transmission classes.

## 3. CLASS REVENUE ALLOCATION

**Q HOW IS ONCOR PROPOSING TO ALLOCATE THE PROPOSED DELIVERY REVENUE INCREASE?**

A Oncor is proposing to use the revenue requirements derived in its CCOSS to determine the proposed increase and rate design for each delivery rate class. **Exhibit JP-2** shows Oncor's current and proposed delivery revenues and the proposed increases by rate class.

### <u>Power Factor Adjustment to Revenues</u>

**Q REFERRING TO EXHIBIT JP-2, YOU SHOW TOTAL PRESENT RETAIL ELECTRIC DELIVERY REVENUES OF $4.023 BILLION (LINE 9) FOR THE TEST YEAR, WHEREAS ONCOR'S EXHIBIT 1 SHOWS $3.982 BILLION. WHAT ACCOUNTS FOR THE DIFFERENCE?**

A Present revenues (column 1) and proposed revenues (column 2) in **Exhibit JP-2** reflect two adjustments that I believe are necessary. First, Oncor moved all revenues associated with power factor charges from base rates to other revenues. I have reversed this adjustment and assigned power factor revenues to the classes that paid them. The affected classes are:

- Secondary > 10 kW;
- Primary > 10 kW Line;
- Primary Substation; and
- Transmission.

**Q HOW ARE CUSTOMERS IN THESE DELIVERY RATE CLASSES CHARGED FOR LOW POWER FACTORS?**

A Pursuant to Section 5.5.5 of Oncor's Tariff for Retail Delivery Service, when a customer has a power factor below 95% lagging, the billing demand is adjusted upward to approximate usage at a 95% power factor.

For example, if a customer has an actual monthly NCP demand of 1,000 kW and a 90% power factor, the customer's adjusted billing demand would be 1,056 kW (1,000 kW x 95% ÷ 90%).

**Q WHAT IS THE SECOND ADJUSTMENT TO ONCOR'S PROPOSED POWER FACTOR REVENUES?**

A During the test year, Oncor collected $29.9 million of power-factor related revenues. However, Oncor is including only $14.3 million ($17.6 million) of power factor revenues in its adjusted test year revenues at present (proposed) rates. Thus, $15.6 million of power factor revenues was removed from present revenues. This adjustment purportedly reflects Oncor's estimate of the extent in which customers improved their power factors during the test year.

**Q WHAT IS THE IMPACT OF ONCOR'S PROPOSED $15.6 MILLION POWER FACTOR IMPROVEMENT ADJUSTMENT?**

A Table 3 shows the impact on test-year billing demand and electric distribution revenue for each of the affected rate classes. As Table 3 demonstrates, Oncor's proposed power factor improvement adjustment eliminates nearly 4.8 million kW of actual test-year billing demand and $15.6 million of test-year electric distribution revenues.

| Table 3<br>Oncor's Proposed Adjustment<br>for Power Factor Improvement | | | |
|---|---|---|---|
| **Rate Class** | **Meter Type** | **Reduction in Billing Demand (kW)** | **Distribution Revenue* ($000)** |
| Secondary > 10 kW | Non-IDR | 923,578 | $4,607 |
| | IDR | 1,230,339 | $6,137 |
| Primary > 10 kW | Non-IDR | 145,154 | $580 |
| | IDR | 957,117 | $3,824 |
| Primary Substation | IDR | 134,424 | $71 |
| Transmission | IDR | 1,388,082 | $360 |
| Total Reduction | | 4,778,695 | $15,579 |

* Distribution System Charge + DCRF.
**Source:** WP_IV-J-5.

By understating billing demand, Oncor's proposed delivery rates would result in higher revenues at proposed rates than is shown in Oncor's Exhibit 1.

**Q SHOULD ONCOR'S PROPOSED POWER FACTOR IMPROVEMENT ADJUSTMENT BE ADOPTED?**

A No. The proposed adjustment is based on a generic, theoretical analysis that purports to show some improvement in the rate classes' overall power factors during the test year. However, this analysis is lacking because it only showed general trends by customer class, and it did not clearly demonstrate that the power factor improvements were the result of specific actions taken by customers (*i.e.*, installation of capacitors) to raise their power factors during the test year. When asked to provide documentation about specific customers that have installed capacitors to raise their power factor, Oncor indicated that it had not conducted any analysis.[13] Given how specious the underlying data is to support this adjustment, it does not qualify as "known and measurable" and should be rejected.

## Rate Moderation

**Q WHY ARE THE PROPOSED DELIVERY RATE INCREASES SO DISPARATE AMONG THE VARIOUS RATE CLASSES?**

A As previously stated, the test year 4CP is being used to reset the TCRF allocation factors for each class, which determines their respective TCRF increases. This is a substantial driver underlying the proposed electric delivery rate increases, as demonstrated in Table 4.

**Table 4**
**Oncor's Proposed**
**TCRF and Non-TCRF Electric Delivery Increases**

| Rate Class | Proposed Increase | TCRF Increase | Non-TCRF Increase |
|---|---|---|---|
| Residential | 11.2% | -8.6% | 12.1% |
| Secondary ≤ 10 kW | -7.9% | -2.6% | -8.1% |
| Secondary > 10 kW | -4.5% | 103.0% | 0.1% |
| Primary ≤ 10 kW | 31.4% | 7.5% | 29.0% |
| Primary > 10 kW | 5.8% | 195.9% | -5.6% |
| Primary Substation | 87.8% | 74.6% | 22.3% |
| Transmission | 42.8% | 71.9% | 12.0% |
| Lighting | 1.6% | 0.0% | 1.6% |

**Source:** Oncor's Exhibit 1 and Derived from RFP Schedule IV-J-7.

[13] Oncor Response to TIEC 2-15.

For example, the TCRF would account for between -8.6% and 196% of the overall electric delivery revenue increase by rate class. Removing the TCRF impact, the retail electric delivery revenue increases would range from an 8.1% decrease to a 29% increase.

Therefore, to a large degree, resetting the 4CP allocation factors is the primary reason why some (Primary Substation and Transmission) classes would experience huge delivery rate increases under Oncor's filed case.

**Q WHY ARE THE TCRF INCREASES SO LARGE FOR SOME DELIVERY RATE CLASSES?**

A Between rate cases, the TCRF allocates wholesale transmission costs to each customer class based on their share of the 4CP f*rom the utility's last delivery rate case*. However, the TCRF charges are calculated using actual (*i.e.*, updated) billing determinants. As a result, a class that experiences substantial load growth will be allocated the same portion of wholesale transmission costs, but the TCRF charge will be smaller because the costs are spread over a growing amount of billing determinants. TIEC expressed concerns about this feature of the rule when it was adopted and advocated to regularly update the allocation factors in each TCRF update. The consequences of this mismatch have been even more pronounced than anticipated for certain utilities, including Oncor, and it has created significant rate shock when the allocation factors are finally updated in a base rate case.

**Q SHOULD GRADUALISM BE APPLIED TO MITIGATE THE EXTREME DELIVERY RATE INCREASES THAT ARE DIRECTLY RELATED TO RESETTING THE FOUR COINCIDENT PEAK ALLOCATION FACTORS?**

A Yes. It is both reasonable and consistent with past Commission practice to apply gradualism to mitigate substantial rate impacts which, in this specific instance, can be directly attributed to resetting the 4CP allocation factors.

**Q HOW WOULD YOU APPLY GRADUALISM TO MODERATE THE IMPACTS TO THE CLASSES MOST IMPACTED BY RESETTING THE FOUR COINCIDENT PEAK ALLOCATION FACTORS?**

A In addition to the Commission requiring Oncor to reconcile the discrepancy between the sum of the 4CPs as provided in this case and those reported by ERCOT, I recommend that the 4CP allocation factors be phased in over at least two steps. The first step should be to set new 4CP allocation factors that would result in moving 50% of the distance from the current 4CPs to Oncor's proposed 4CP allocation factors. The second step would be to reset the 4CP allocation factors to move the remainder of the way to cost based on the subsequently determined 4CP demands. **Exhibit JP-3** illustrates my recommended 4CP moderation plan.

**Q HAS RATE MODERATION BEEN USED IN PRIOR DELIVERY RATE CASES?**

A Yes. The same problem arose in the most recent TNMP and AEP delivery rate cases. Specifically, in the TNMP case, the parties agreed to phase in the 4CP allocation factors.[14] Similarly, in the most recent AEP delivery rate case, the North Division

[14] *Application of Texas-New Mexico Power Company to Change Rates,* Docket No. 48401, Order at 12-13 (Dec. 20, 2018).

Transmission class received a $300,000 per year credit in its TCRF charge for two years.[15] While those cases were settled and are not necessarily precedential, I believe the approach is reasonable and a similar resolution should be applied here. Ultimately, the goal should be to get all classes to cost, but given the extreme impacts of updating the allocation factors through a single adjustment, a phased in approach is justified.

[15] Application of AEP Texas Inc. for Authority to Change Rates, Docket No. 49494, Order at 26 (Apr. 3, 2020).

## 4. RATE DESIGN

**Q WHAT RATE DESIGN ISSUES ARE YOU ADDRESSING?**

A I address the test-year billing determinants that should be used to design the proposed retail demand-metered delivery rates and the design of the Secondary > 10 kW rate schedule.

**Q WHAT CHANGES ARE YOU RECOMMENDING?**

A As previously stated, Oncor's proposed power factor improvement adjustment should be rejected. Thus the test-year billing demands for the Secondary > 10 kW, Primary > 10 kW Line, Primary Substation and Transmission rate classes should be restated. The affected billing determinants were summarized in Table 3 above. I also recommend retaining the status quo on the design the Secondary > 10 kW DSC.

**Q HOW IS ONCOR PROPOSING TO CHANGE THE DESIGN OF THE DISTRIBUTION SYSTEM CHARGE IN THE SECONDARY > 10 KW RATE SCHEDULE?**

A Oncor is proposing two significant changes. First, Oncor currently sets different DSCs based on customers' annual load factors, but is proposing to eliminate this approach. This load factor structure applies to customers with peak demands above 20 kW with annual load factors up to 25%. Second, Oncor is also proposing to remove the 80% demand ratchet. This applies to customers with loads above 20 kW and annual load factors greater than 25%.

**Q PLEASE EXPLAIN THE CURRENT LOAD FACTOR STRUCTURE.**

A The current load factor structure sets different DSCs as a function of a customer's annual load factor. This is shown in Table 5.

<table>
<tr><th colspan="5">Table 5<br>Secondary > 10 kW<br>Distribution System Charge</th></tr>
<tr><th>NCP kW</th><th>Annual Load Factor</th><th>Current Rate</th><th>Proposed Rate</th><th>Percent Increase</th></tr>
<tr><td>Less than or equal to 20 kW</td><td>All</td><td>$4.497330</td><td rowspan="6">$5.95168</td><td>32.3%</td></tr>
<tr><td rowspan="5">Greater than 20 kW</td><td>0% - 10%</td><td>$6.275746</td><td>-5.2%</td></tr>
<tr><td>11% - 15%</td><td>$5.557887</td><td>6.7%</td></tr>
<tr><td>16% - 20%</td><td>$5.227174</td><td>13.9%</td></tr>
<tr><td>21% - 25%</td><td>$5.053968</td><td>17.8%</td></tr>
<tr><td>≥ 26%</td><td>$4.497330</td><td>32.3%</td></tr>
<tr><td colspan="5">Source: Oncor Tariff for Retail Delivery Service, Sheet 1.3, page 1 Revision Ten and Eleven.</td></tr>
</table>

Under the current load factor structure, the DSC declines as a customer's annual load factor increases.

**Q WHEN WAS THE CURRENT LOAD FACTOR STRUCTURE IMPLEMENTED?**

A The current load factor structure was implemented in Docket No. 38929. The rates approved in that docket became effective on September 25, 2011.[16]

**Q WHAT WERE THE CIRCUMSTANCES SURROUNDING THE IMPLEMENTATION OF THE CURRENT LOAD FACTOR STRUCTURE IN THE SECONDARY > 10 KW RATE?**

A The load-factor structure was Oncor's response to concerns about the 80% demand ratchet. This was addressed in the testimony filed by Oncor's rate design witness,

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[16] Docket No. 38929, *Order* at 8, 9 and 13 (Aug. 26, 2011). See also, *Stipulation* at 4 and 71 (May 11, 2011) and *Direct Testimony of J. Michael Sherburne* at 23 (Jan. 7, 2011).

J. Michael Sherburne, in Docket No. 38929. Specifically:

> In the last two legislative sessions there have been bills filed that would grant certain types of customers an exemption from the demand ratchet provision. Oncor believes that the demand ratchet provision is an appropriate rate design mechanism that appropriately tracks cost causation. Oncor understands, however, that the Texas Legislature's concerns about the impact of that rate design mechanism may outweigh the strict adherence to cost causation principles. Therefore, with this proposed change, ***Oncor has attempted to remain true to cost causation principles*** and at the same time remove the demand ratchet provision for all [original emphasis omitted] low load factor customers. ***By making the kW charge revenue neutral with the amount that would have been received under the ratchet provision, other loads do not subsidize these low load factor customers***.[17] (emphasis added)

**Q IS THE LOAD FACTOR STRUCTURE UNIQUE TO ONCOR?**

A No. TNMP has a similar load factor provision. Specifically, TNMP charges a higher DSC for customers with annual load factors of 25% or lower.

**Q DOES ONCOR ALLEGE THAT THE CURRENT LOAD FACTOR STRUCTURE IS NOT COST-BASED?**

A No.

**Q WOULD ELIMINATING THE CURRENT LOAD FACTOR STRUCTURE BE CONSISTENT WITH COST CAUSATION?**

A No. In its CCOSS, Oncor allocates the costs of distribution substations, poles, lines and conductors to customer classes based on class peak demand. Class peak demand is the highest demand of each rate class, irrespective of when it occurs. This reflects cost causation because distribution facilities must be sized to meet the expected peak demand imposed on them. These facilities are electrically closer to

[17] Docket No. 38929, *Direct Testimony of J. Michael Sherburne* at 25-26 (Jan. 7, 2011).

customers served at secondary voltages. Thus, diversity is not as significant a factor in providing service at secondary voltage as it is for primary and higher voltages. Therefore, a customer's peak demand will be the primary factor in determining that customer's distribution cost to serve. The more steady a customer's peak demand from month-to-month, the lower the per-unit cost and vice versa.

Therefore, a cost-based DSC should charge more per kW for lower load factor customers than higher load factor customers. This cost relationship is the basis for the current load factor structure.

**Q WOULD ELIMINATING THE CURRENT LOAD FACTOR STRUCTURE BE CONSISTENT WITH THE STANDARD RATE DESIGN PREVIOUSLY APPROVED BY THE COMMISSION?**

A No. In Docket No. 22344, the Commission issued Order No. 40 establishing, among other things, a standard rate design for transmission and distribution utilities to be used in developing retail delivery system rates. In that Order, the Commission specifically approved an 80% demand ratchet. The Order states:

> The Commission finds that an 80% ratchet is appropriate for recovery of distribution costs from demand-metered customers. The Commission holds that although a 100% ratchet properly reflects the fixed nature of distribution costs, the 80% level more appropriately recognizes load diversity on the distribution system.[18]

As previously stated, the load-factor structure was implemented in lieu of applying the 80% demand ratchet.

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[18] *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39201 and Public Utility Commission Substantive Rule § 25.344*, Docket No. 22344, Order No. 40 – Interim Order Establishing Generic Customer Classification and Rate Design at 8 (Nov. 22, 2000).

**Q HOW IS ORDER NO. 40 ISSUED IN DOCKET NO. 22344 RELEVANT IN THIS PROCEEDING?**

A The 80% load factor authorized in Order No. 40 does not apply to customers with annual load factors at or below 25%. Thus, in the absence of an 80% ratchet, it follows that to properly reflect the fixed nature of distribution costs, the DSC should vary inversely with load factor, as is currently the case. To do otherwise would be to shift costs from low load factor to high load factor customers within the Secondary > 10 kW class.

**Q SHOULD THE 80% DEMAND RATCHET BE ELIMINATED?**

A No. As is evident from Order No. 40, the Commission approved an 80% demand ratchet to properly reflect cost causation. In fact, Oncor is proposing to retain the same 80% demand ratchet in all of its other demand-metered rates, including Primary > 10 kW Lines, Primary Substation and Transmission.

**Q IS AN 80% RATCHET A COMMON PRACTICE OF THE OTHER TRANSMISSION AND DISTRIBUTION UTILITIES IN TEXAS?**

A Yes. Both AEP and TNMP have an 80% demand ratchet in applying the DSCs in their respective retail tariffs.

**Q WHAT DO YOU RECOMMEND?**

A I recommend that the current DSC structure be retained. This means retaining both the load factor structure (which is an alternative to an 80% demand ratchet) and the 80% demand ratchet. Both provisions are essential to ensuring that delivery rates are cost based across a wide range of load sizes and load factors within the Secondary > 10 kW class.

## 5. TARIFF TERMS AND CONDITIONS

**Q ONCOR IS PROPOSING CHANGES TO SOME OF ITS TARIFF TERMS AND CONDITIONS. WHICH SPECIFIC CHANGES ARE YOU ADDRESSING?**

A I address the following tariff terms and conditions:

- Six-month minimum time period before changing to a different rate;
- Limiting Primary Substation service to new loads;
- Designating 345 kV service as a non-standard voltage;
- Proposed changes to the non-utilization clause;
- Recovery of stranded costs associated with the removal and relocation of utility facilities; and
- Interconnection timelines.

**<u>Six-Month Minimum Term for Switching Rates</u>**

**Q WHY IS ONCOR PROPOSING A SIX-MONTH MINIMUM PERIOD REQUIREMENT BEFORE A CUSTOMER CAN SWITCH TO A DIFFERENT RATE?**

A Oncor asserts that this is a long-standing business practice and, further, it would eliminate alleged arbitrage opportunities and limit additional administrative expenses.[19]

**Q DO YOU AGREE WITH THIS PROPOSAL?**

A No. First, it is irrelevant that Oncor has adopted an informal practice of restricting customers from switching classes within six months minimum, as this has not been reviewed or approved by the Commission. As previously stated, Oncor has fully deployed its AMI for all of its customers. AMI deployment requires Oncor to maintain

[19] Direct Testimony of Matthew A. Troxle at 33.

a modern, real-time billing system to accommodate multiple transactions. Such a modern billing system should be readily programmable to allow customers to change rates in an upcoming billing cycle. As such, it should not be costly to allow a customer to switch to a different rate, provided that the applicability requirements are met. Further, if rates are properly designed and cost-based, there should not be any stranded costs or other cost-shifting opportunities in allowing customers to switch between classes.

**Q IS A SIX-MONTH MINIMUM PERIOD REASONABLE?**

A No. A customer that continues to add load as it expands its infrastructure should have the opportunity to switch to the most appropriate rate without delay. As a customer grows, it will be more economic to switch to a higher rate class because the ongoing rates will be sufficiently lower to offset an upfront infrastructure investment that is required for the customer to qualify for the class of service. To prevent a customer from choosing the most economic and efficient rate based solely on an informal business practice is both punitive to the customer and unnecessarily enriches Oncor.

**Q WHY ELSE SHOULD CUSTOMERS BE ALLOWED TO SWITCH RATES PRIOR TO THE NEXT BILLING CYCLE?**

A In addition to better accommodating customers' changing needs, rate switching should be encouraged so that customers have an opportunity to better manage their electricity costs and reliability. Rate switching is a normal operating risk. Therefore, allowing customers to switch rates on a more frequent basis when their needs change should not have an undue impact on Oncor.

**Primary Substation Service**

**Q WHAT CHANGES IS ONCOR PROPOSING TO LIMIT PRIMARY SUBSTATION SERVICE?**

A Oncor is proposing to limit eligibility to new loads. This means that an existing Primary Substation customer may add load, or create a new primary substation delivery point, but an existing Primary Substation customer would not be allowed to consolidate its existing loads currently served under a different rate with a primary substation load.

**Q IS THIS A REASONABLE LIMITATION?**

A No. Limiting eligibility of Primary Substation service to new loads would be unfair to customers who, through no fault of their own, may currently receive service at a single premise or location through multiple meters due to phased facility expansions and load growth. In other words, although the customer's service has evolved, Oncor insists that it must maintain the status quo, even if it is no longer the most economic or efficient way to serve the customer.

**Q ARE THERE ANY ADVERSE EFFECTS OF LIMITING PRIMARY SUBSTATION SERVICE ELIGIBILITY TO NEW LOADS?**

A Yes. First, a customer with two different meters that would otherwise consolidate load behind a single Primary Substation meter will continue to pay two separate DSCs based on the 15-minute maximum demand at each meter, regardless of when it occurs. This does not allow the customer to benefit from diversity—*i.e.*, it does not recognize that the combined peak load of the premise or location may be lower than the sum of the individual peak demands at each delivery point.

Second, in addition to ignoring diversity, requiring the customer to maintain two separate delivery points limits the customer's ability and incentive to manage its total site load. This is contrary to good policy. Oncor's proposed limitation to the Primary Substation rate would prevent more effective load management.

**Q SHOULD UTILITIES IMPLEMENT POLICIES THAT PREVENT CUSTOMERS FROM MORE EFFECTIVELY MANAGING THEIR ELECTRICITY COSTS?**

A No. Rate design should empower customers to better manage their loads and costs. This means creating opportunities to allow a customer to consolidate the loads at an existing premise or location to save money, regardless of the delivery rate that currently applies to the separate loads. Consolidating load will improve a customer's ability to implement effective load management strategies and should be encouraged when efficient. This should also help reduce total system costs for the utility.

**Q WHY ELSE WOULD THE PROPOSED LIMITATION TO NEW LOADS BE AN UNREASONABLE POLICY?**

A Customers should also have the opportunity to upgrade to a higher delivery service to minimize costs and improve reliability. The higher the voltage of service, the lower the probability of reliability issues occurring due to reduced use of the utility's system. Imposing artificial constraints that prevent customers from taking service under a more suitable rate would effectively limit the customer's ability to obtain delivery service that is both more economical and more reliable.

**Q MR. TROXLE ASSERTS THAT LIMITING PRIMARY SUBSTATION SERVICE TO NEW LOADS WOULD AVOID CREATING WHAT IT CHARACTERIZES AS "DE-FACTO STRANDED INVESTMENT."[20] DO YOU AGREE?**

A No. There should not be any stranded investment. Oncor will always be compensated for all of its delivery costs, regardless if some facilities are idled by changes in the delivery service provided to specific retail customers. Even if consolidating a customer's load behind a single primary substation delivery point would idle some facilities, some of the idled equipment may be utilized as spare parts, serve other customers, replace worn-out or older equipment, or be sold as scrap. In the latter instance, any cost of removal would be offset by the resale value. Therefore, it would never be appropriate to charge the customer the full removal cost.

**Q SHOULD CUSTOMERS BE ALLOWED TO UPGRADE THEIR DELIVERY SERVICE?**

A Yes, customers should have an opportunity to upgrade to a higher voltage delivery service by either purchasing or leasing Oncor-owned facilities as needed to qualify for the rate. For example, a Primary > 10 kW customer could qualify for Primary Substation service by purchasing or leasing any dedicated Oncor distribution facilities from the current point of interconnection to the substation. Similarly, a Primary Substation customer could qualify for Transmission service by purchasing or leasing the transformation equipment, other related substation facilities and dedicated feeders serving that customer.

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[20] *Id.* at 32-33.

**Q DOES ONCOR CURRENTLY HAVE A RATE THAT ALLOWS CUSTOMERS TO PURCHASE OR LEASE DEDICATED DISTRIBUTION FACILITIES?**

A No.

**Q WHAT DO YOU RECOMMEND?**

A Oncor should implement a Facility Charge tariff. A Facility Charge tariff would allow customers to lease the equipment necessary to qualify for a higher voltage service. The Facility Charge would be a percentage of the investment in the leased facilities. The percentage would reflect the levelized capital carrying costs using the parameters established in setting delivery rates.

**Q HAVE YOU QUANTIFIED THE LEVELIZED CAPITAL CARRYING CHARGE ASSOCIATED WITH ONCOR'S DISTRIBUTION FACILITIES?**

A Yes. **Exhibit JP-4** shows the derivation of the levelized capital carrying charge based on Oncor's proposed capital structure, rate of return, depreciation, operation and maintenance expense, and property insurance and tax rates applicable to distribution substations. As can be seen, the levelized capital carrying charge would be 1.16% per month. Similar charges can be developed for other distribution facilities.

**Q IF ONCOR WERE TO IMPLEMENT A FACILITY CHARGE AS YOU HAVE DISCUSSED, WOULD THERE BY ANY REASON TO LIMIT THE SERVICE PROVIDED UNDER THE PRIMARY SUBSTATION RATE AS IT IS CURRENTLY PROPOSING?**

A No.

**345 kV Non-Standard Voltage**

**Q HAS ONCOR PROVIDED ANY EXPLANATION FOR ELIMINATING 345 KV AS A STANDARD VOLTAGE IN SECTION 6.2.2 OF ITS RETAIL TARIFF?**

A No. In fact, Oncor is proposing to retain 345 kV voltage in Section 4.3.1.2 of its Standard Transmission and Distribution Voltages. The only apparent constraint to 345 kV service is that it would be limited due to safety and reliability concerns.[21]

**Q IS IT A CONSISTENT PRACTICE TO DESIGNATE 345 KV A NON-STANDARD SERVICE?**

A No. AEP and TNMP do not designate 345 kV as a non-standard voltage.

**Q SHOULD 345 KV BE DESIGNATED AS A NON-STANDARD VOLTAGE FOR ONCOR?**

A No. Customers should have an opportunity to choose from a range of voltage levels based on economic as well as safety and reliability considerations.

**Q WHAT DO YOU RECOMMEND?**

A Oncor has provided no explanation for designating 345 kV as a non-standard voltage for retail service. Therefore, the Commission should reject this proposal.

**Non-Utilization Clause**

**Q WHAT IS THE NON-UTILIZATION CLAUSE?**

A The non-utilization clause appears in Article II, Section 6.3.1 (Facilities Extension Agreement) of Oncor's Retail Tariff. It specifies, among other things, the amount of any CIAC to be paid by the customer based on estimated contract demand.

[21] *Id.* at 47.

**Q HOW DOES THE NON-UTILIZATION CLAUSE CURRENTLY WORK?**

A Currently, Oncor conducts a review to determine the customer's actual load four years after completing a facilities extension. If the customer's estimated load does not match the level used to calculate the CIAC, Oncor recalculates the CIAC and surcharges imposed on the customer based on an actual maximum kW billing demand. This is meant to balance the costs attributable to extending facilities to the customer against the revenues the customer will provide to help pay for those facilities, so if demand is lower the CIAC is adjusted upward to reflect the reduced revenues the customer is expected to provide.

**Q HOW IS ONCOR PROPOSING TO CHANGE THE NON-UTILIZATION CLAUSE?**

A Oncor is proposing several options that it would exercise at its sole discretion to adjust the customer's load on a shorter timeframe, although the consequences of this adjustment are still unclear. The options would include (1) continue the current practice; (2) extend the four-year time frame for completing a review; or (3) reset the contract demand contained in a customer's Facilities Extension Agreement on a shorter timeframe. This latter change is addressed in Article II as follows:

> Customer will, prior to or contemporaneous with signing this Agreement, or as soon thereafter as reasonably possible, supply a load profile or load ramp document in support of the Contract kW set out above. If (a) Customer fails to provide a load ramp or load profile by the end of the second year after Company completes the extension of Delivery System facilities ("second year of service"), or (2) Customer provides a load ramp or load profile and the actual kW billing demand for the second year of service is below that set out in the load profile or load ramp document; then at the end of the second year of service the Contract kW shall be set equal to the highest billing demand reached during the second year of service and shall be reset every year thereafter to equal Customer's highest kW billing demand during the prior two years, but in no event higher than the then-existing Contract kW amount, unless Customer and Company reach a new agreement on a new contracted kW.[22]

[22] Oncor's Tariff for Retail Delivery Service, Section 6.3 Agreements and Forms, Article II (c) as proposed in current matter.

This new process for updating the customers' Contract kW is not explicitly tied to the CIAC calculation, so it is not clear whether Oncor intends to update the CIAC calculation on a shorter timeframe and, if so, how this would be done. A customer could potentially be penalized at the end of the second year of service if the load fails to achieve the projected load ramp. Two years may not a reasonable timeframe to expect a customer to meet full contract demand.

**Q ARE THE PROPOSED CHANGES TO THE NON-UTILIZATION CHARGE REASONABLE?**

A No. Although the proposed changes would provide more flexibility for Oncor, the provisions are one-sided and would place the customer solely at risk for providing an overly optimistic load forecast.

**Q ARE THERE ANY LEGITIMATE REASONS WHY A CUSTOMER'S LOAD MAY NOT MEET A PROJECTED LOAD RAMP?**

A Yes. A customer may not have met the projected load ramp for various reasons that may be beyond the customer's direct control, such as supply chain issues, labor shortages, or market conditions. However, rather than penalize the customer for being optimistic, Oncor has a responsibility to remain aware of changing load forecasts that could impact the build-out of new Delivery System facilities.

**Q DO YOU HAVE ANY OTHER CONCERNS WITH THE PROPOSED NON-UTILIZATION CLAUSE?**

A Yes, it also appears that part of the motivation behind this interim update to a customer's Contract kW is to make capacity available for other customers. If Oncor unilaterally decided to serve other customers from the extended facilities, it could prevent the customer who funded the extension from achieving its maximum potential load or, as a result of excess loading, it could reduce the customer's quality of service.

**Q WHAT DO YOU RECOMMEND?**

A First, Oncor should adopt a more proactive process with the customer to stay abreast of changing circumstances that could impact the build-out or utilization of extended facilities. Being more proactive means having periodic meetings with the customer, at least annually, but as often as necessary. At a minimum, Oncor should send a request for an update on load expansion plans to the customer.

Second, if the customer is already funding the portion of a facility extension that the customer was projected to use, it should not matter to Oncor that the customer failed to achieve the projected load within the existing four-year timeframe — and certainly not within the proposed two-year timeframe.

Third, if Oncor determines that any of the extended facilities originally funded by a customer will not be fully utilized and, therefore, can be used to serve other customers within ten years of the facilities being energized, it should reimburse the customer that paid a CIAC for those facilities. The amount of compensation should be based on a pro-rata share of the capacity funded by the original customer that would be subsequently used to serve new customers.

**Q HAVE YOU DRAFTED PROPOSED LANGUAGE CONSISTENT WITH YOUR RECOMMENDATION?**

A Yes. My proposed language is provided in **Exhibit JP-5**. Specifically, I have revised Article II to incorporate each of the three changes described above. The revised terms would be more balanced and fair.

**Q DO YOU HAVE ANY ADDITIONAL CONCERNS WITH SECTION 6.3.1 OF ONCOR'S RETAIL TARIFF?**

A Yes. Oncor is proposing new language in Article III that states:

> Once Customer has granted or secured for the Company, any rights-of-way or easements, regardless of the passage of time and the level of activity, the Company never intends to abandon any rights-of-way or easements unless the Company specifically states, in writing, the intention to do so, and the Company then takes additional specific affirmative action to effectuate the abandonment.[23]

This language suggests that customers would, at least in some instances, be required to secure rights-of-way from third parties for a facilities extension. While customers may voluntarily do this for various reasons in some circumstances, it should not be a requirement. This would be contrary to Oncor's obligation to provide delivery service within its service territory.

**Q HOW IS THE PROPOSED LANGUAGE PROBLEMATIC?**

A Customers do not have eminent domain rights. This means, as a practical matter, the customer does not have any leverage to negotiate rights-of-way with third-party landowners, and certainly not in a timely manner. More importantly, negotiating and obtaining rights-of-way is Oncor's responsibility.

**Q WHAT DO YOU RECOMMEND?**

A The Commission should reject Oncor's proposed new language in Article III indicating that customers must secure rights-of-way from third parties. This change is reflected in **Exhibit JP-5**.

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[23] *Id.*, Article III.

**Removal and Relocation of Company Facilities**

**Q IS ONCOR PROPOSING ANY NEW PROVISIONS APPLICABLE TO THE REMOVAL AND RELOCATION OF COMPANY FACILITIES?**

A Yes. Oncor is proposing the following additional language:

> If Retail Customer moves its load to a different Point of Delivery (or ESI ID) and causes Company facilities to become idled, Retail Customer shall reimburse the Company for the cost of removal of the idled facilities.
>
> If Retail Customer removes its load resulting in Company facilities becoming stranded, not used and useful, or in any way unrecoverable, Retail Customer shall reimburse the Company a sum equal to the estimated present worth of the unamortized original cost (or book) value (if any) for all remaining facilities plus removal costs for all remaining facilities.[24]

Similar language would be added to Section 6.1.3.2.9 and 6.1.4.2.9.

**Q IS THE PROPOSED ADDITIONAL LANGUAGE REASONABLE?**

A No. Neither addition is appropriate. First, the provision does not specify a timeframe for determining when facilities have become idled. Second, the cost of removal is already included in setting the depreciation rate applicable to the utility's capital investments. Charging the customer for removal costs, thus, would result in a double recovery.

Third, the provision assumes that idled equipment cannot be used to serve other customer's loads, to provide spare parts to replace other facilities that are either damaged or at the end of their lifespans, or sold as scrap. The customer should not be responsible for compensating Oncor for costs it is already recovering and for facilities that continue to be used and useful. As previously stated, in no event should the customer be charged the full removal cost if the equipment is either reused or sold as scrap.

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[24] *Id.*, 6.1.2 Discretionary Charges, 6.1.2.2.9. Removal and Relocation of Company's Facilities.

**Q DO YOU HAVE ANY OTHER CONCERNS ABOUT THE PROPOSED LANGUAGE?**

A Yes. Lost or idled load is a normal operating risk for an electric utility. A customer cannot be held responsible for changes in circumstances that may require a reduction or complete shutdown that results in idled equipment. This is a normal operating risk.

I would also note that under its proposal, unless Oncor were to remove the investment from its rate base, or treat the removal costs paid by the customer as an offset to its rate base (because it is capital supplied by the customer rather than the shareholders), Oncor would be overcompensated.

**Q WHAT DO YOU RECOMMEND?**

A The Commission should reject the proposed language in Section Nos. 6.1.2.2.9, 6.1.3.2.9 and 6.1.4.2.9.

## <u>Interconnection Timelines</u>

**Q DO TIEC MEMBERS HAVE CONCERNS ABOUT THE TIMELINESS OF OBTAINING DELIVERY SERVICE FOR NEW FACILITIES?**

A Yes. TIEC members have been working with the Commission and Oncor for several years in an effort to improve interconnection timelines. The focus historically has been on oil and gas development in West Texas, but I understand that these timing concerns also extend to other types of facilities. Interconnection delays have been driven, in part, by both the lack of transmission infrastructure in certain regions and by challenges for Oncor and others in handling the speed and magnitude of interconnection and upgrade requests. This is particularly true for the oil and gas industry, but it is also true for other manufacturing customers. In the oil and gas context, these delays have historically resulted in a significant number of "drilled but uncompleted" wells that are unable to obtain timely electric service, and long lead times for interconnecting new fields and processing facilities.

**Q IS THIS A NEW ISSUE?**

A No. Interconnection delays have been an ongoing problem for at least the last decade and have been the subject of numerous ERCOT and PUC planning meetings. The delays have been particularly heightened over the past five years or so.

**Q HAVE THERE BEEN ATTEMPTS TO RESOLVE THE INTERCONNECTION DELAYS EXPERIENCED IN THE RECENT PAST?**

A Yes. In 2019, this Commission spearheaded a collaborative effort between the petroleum industry and the utilities to define both the process and timelines to ensure that service requests are completed in a more timely manner. One outcome of these discussions was the Delaware Basin Load Integration Study, which was conducted by ERCOT in 2019. The purpose of the Study was to identify cost-effective bulk power system upgrades that may be necessary if load in the Delaware Basin continues to increase at a rapid pace through 2024. The Study acknowledged the challenges to ensure the transmission improvements are in place in time to serve the load.

In addition to the Delaware Basin Load Integration Study, the parties to the collaboration reached an agreement that was intended to be a framework for interconnection called the Distribution Service Request Process. The process, which is dated September 11, 2018, is outlined in **Exhibit JP-6**. It consists of a very detailed standardized electric load requirements form (pages 1 through 4) and seven specific milestones along with timelines for accomplishing them (page 5).

**Q HAVE THE UTILITIES BEEN ABLE TO MEET THE SPECIFIC TIMELINES IN THE DISTRIBUTION SERVICE REQUEST PROCESS?**

A Not consistently. Despite working with customers to develop the process, it is my understanding that the utilities have not been able to meet the specified timelines and, perhaps more importantly, they often have provided little or no explanation as to the reason(s) for the delay, or an updated timeline. This uncertainty prevents customers from making business decisions that are based on when their processes will be interconnected and, therefore, the utilities are also foregoing an opportunity to earn a return on their investments.

**Q WHAT DO YOU RECOMMEND?**

A The utilities should make a more concerted effort to comply with the Distribution Service Request Process and the timelines as outlined in **Exhibit JP-6**. I am aware that there are additional requirements being developed at ERCOT around interconnecting large loads, which will be finalized over the next few months and may impact Oncor's interconnection timelines. My recommendation should apply to all industrial and manufacturing customers with the understanding that the interconnections will, of course, be subject to any additional requirements ERCOT imposes, which may delay interconnection in some scenarios. Non-compliance should be the exception, not the rule. Although some exceptions are to be expected, it is vital that Oncor be more proactive in managing the interconnection process. This means engaging in regular communications with the affected customers.

It would be atypical to have firm deadlines for a utility, or any financial consequences around failing to meet timelines, and TIEC understands that utilities have to manage competing priorities and allocate their resources reasonably.

However, TIEC believes that accountability for delays could be improved through tariff changes. Specifically, the Commission should require Oncor to provide a reasonable written explanation for missing any timeline and provide revised set of timelines. TIEC understands that in some instances Oncor has been resource constrained and may not always be able to meet the timelines that were developed in the 2019 discussions, but customers are unable to make decisions about investments and operations without better information on the sources of these delays, when they might be resolved, and when facilities may be energized. A requirement to provide a written explanation and revised timeline would improve accountability and customer transparency. This would allow the parties to adjust their expectations and plan accordingly.

**Q DO YOU HAVE ANY SUGGESTED LANGUAGE THAT WOULD FURTHER CODIFY YOUR RECOMMENDATION?**

A Yes. The suggested language is provided in **Exhibit JP-5**, specifically in Article IV of Oncor's Facilities Extension Agreement. Additionally, the interconnection guidelines provided in **Exhibit JP-6** would be appended to that Agreement.

# 6. CONCLUSION

**Q WHAT FINDINGS SHOULD THE COMMISSION MAKE TO ADDRESS THE ISSUES RAISED IN YOUR DIRECT TESTIMONY?**

A The Commission should make the following findings:

- Require Oncor to investigate the reasons for the differences between the sum of the class 4CPs and ERCOT reported 4CPs for Oncor.
- Consistent with cost causation and the practices of other utilities, allocate distribution A368 Capacitors to only customers taking Primary Line or Secondary service.
- Consistent with PURA § 39.918(b)(1), allocate the costs of mobile generators to only customers taking Primary Line or Secondary service.
- Reject Oncor's proposal to reclassify power factor revenues from base rates to other revenues and require Oncor to directly assign power factor revenues to the delivery rate classes that are subject to power factor charges.
- Reject Oncor's proposed power factor improvement adjustment and adjust both base delivery revenues and billing determinants accordingly.
- Consistent with the accepted practice of gradualism, require that the reset of the 4CP allocation factors be phased in over at least two steps to prevent rate shock.
- Reject Oncor's proposed restructuring of the Distribution System Charge in the Secondary > 10 kW rate schedule and retain the 80% demand ratchet.
- Reject Oncor's proposed six-month minimum before allowing a customer to switch to a different (but otherwise applicable) rate schedule.
- Reject Oncor's proposal to limit the eligibility for Primary Substation service to new loads and require Oncor to allow customers to consolidate the loads at an existing premise or location to provide more effective load and cost management and to improve service reliability.
- Require Oncor to implement a Facility Charge tariff to allow customers to lease the equipment necessary to upgrade delivery service to a higher voltage.
- Reject Oncor's proposal to designate 345 kV as a non-standard service for retail customers.
- Reject Oncor's proposed changes to the non-utilization clause and require Oncor to be more proactive in being aware of changing load forecasts that could impact the build-out of new Delivery System facilities.

- Require Oncor to compensate customers who initially funded extended Delivery System Facilities if Oncor makes capacity available from these facilities to other customers within ten years of the facility being energized.
- Reject Oncor's proposal to require retail customers to obtain rights-of-way.
- Reject Oncor's proposal to require customers to pay both the unamortized capital costs and removal costs for facilities that may be idled.
- Require Oncor to more closely adhere to the Distribution Service Request Process developed as a result of the 2019 collaborative and require Oncor to provide a written explanation for any delays in adhering to the timelines specified in the process and provide updated timelines for the interconnection of new industrial and manufacturing load.

**Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

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 career, 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, tariff review and analysis, conducting site evaluations, 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 and developing and presenting seminars on electricity issues.

I have worked on various projects in 28 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission, the Ontario Energy Board, 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, South Carolina, 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 broker and Class I aggregator in the State of Texas.

# APPENDIX B
# Testimony Filed in Regulatory Proceedings
# by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 53034 | Cross-Rebuttal | TX | Energy Loss Factors; Allocation of Eligible Fuel Expense; Allocation of Off-System Sales Margins | 8/5/2022 |
| MIDAMERICAN ENERGY COMPANY | Tech Customers | RPU-2022-0001 | Direct | IA | Application of Advanced Ratemaking Principles to Wind Prime | 7/29/2022 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 53034 | Direct | TX | Allocation of Eligible Fuel Expense; Allocation of Winter Storm Uri | 7/6/2022 |
| AUSTIN ENERGY | Texas Industrial Energy Consumers | None | Cross-Rebuttal | TX | Allocation of Production Plant Costs; Energy Efficiency Fee Allocation | 7/1/2022 |
| AUSTIN ENERGY | Texas Industrial Energy Consumers | None | Direct | TX | Revenue Requirement; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design | 6/22/2022 |
| DTE ELECTRIC COMPANY | Gerdau MacSteel, Inc. | U-20836 | Direct | MI | Interruptible Supply Rider No. 10 | 5/19/2022 |
| GEORGIA POWER COMPANY | Georgia Association of Manufacturers | 44160 | Direct | GA | CARES Program; Capacity Expansion Plan; Cost Recovery of Retired Plant; Additional Sum | 5/6/2022 |
| EL PASO ELECTRIC COMPANY | Freeport-McMoRan, Inc. | 52195 | Cross-Rebuttal | TX | Rate 38; Class Cost-of-Service Study; Revenue Allocation | 11/19/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 20-00238-UT | Supplemental | NM | Responding to Seventh Bench Request Order (Amended testimony filed on 11/15) | 11/12/2021 |
| EL PASO ELECTRIC COMPANY | Freeport-McMoRan, Inc. | 52195 | Direct | TX | Class Cost-of-Service Study; Class Revenue Allocation; Rate 15 Design | 10/22/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 51802 | Cross-Rebuttal | TX | Cost Allocation; Production Tax Credits; Radial Lines; Load Dispatching Expenses; Uncollectible Expense; Class Revenue Allocation; LGS-T Rate Design | 9/14/2021 |
| GEORGIA POWER COMPANY | Georgia Association of Manufacturers | 43838 | Direct | GA | Vogtle Unit 3 Rate Increase | 9/9/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 21-00172-UT | Direct | NM | RPS Financial Incentive | 9/3/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 51802 | Direct | TX | Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design | 8/13/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 51802 | Direct | TX | Schedule 11 Expenses; Jurisdictional Cost Allocation; Abandoned Generation Assets | 8/13/2021 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 51997 | Direct | TX | Storm Restoration Cost Allocation and Rate Design | 8/6/2021 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | R-2021-3024601 | Surrebuttal | PA | Class Cost-of-Service Study; Revenue Allocation | 8/5/2021 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | R-2021-3024601 | Rebuttal | PA | Class Cost-of-Service Study; Revenue Allocation; Universal Service Costs | 7/22/2021 |

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|---|---|---|---|---|---|---|
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 20-00238-UT | Supplemental | NM | Settlement Support of Class Cost-of-Service Study; Rate Desgin; Revenue Requirement. | 7/1/2021 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | R-2021-3024601 | Direct | PA | Class Cost-of-Service Study; Revenue Allocation | 6/28/2021 |
| DTE GAS COMPANY | Association of Businesses Advocating Tariff Equity | U-20940 | Rebuttal | MI | Allocation of Uncollectible Expense | 6/23/2021 |
| FLORIDA POWER & LIGHT COMPANY | Florida Industrial Power Users Group | 20210015-EI | Direct | FL | Four-Year Rate Plan; Reserve Surplus; Solar Base Rate Adjustments; Class Cost-of-Service Study; Class Revenue Allocation; CILC/CDR Credits | 6/21/2021 |
| ENTERGY ARKANSAS, LLC | Arkansas Electric Energy Consumers, Inc. | 20-067-U | Surrebuttal | AR | Certificate of Environmental Compatibility and Public Need | 6/17/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 20-00238-UT | Rebuttal | NM | Rate Design | 6/9/2021 |
| DTE GAS COMPANY | Association of Businesses Advocating Tariff Equity | U-20940 | Direct | MI | Class Cost-of-Service Study; Rate Design | 6/3/2021 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 51415 | Supplemental Direct | TX | Retail Behind-The-Meter-Generation; Class Cost of Service Study; Class Revenue Allocation; LGS-T Rate Design; Time-of-Use Fuel Rate | 5/17/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 20-00238-UT | Direct | NM | Class Cost-of-Service Study; Class Revenue Allocation, LGS-T Rate Design, TOU Fuel Charge | 5/17/2021 |
| ENTERGY ARKANSAS, LLC | Arkansas Electric Energy Consumers, Inc. | 20-067-U | Direct | AR | Certificate of Environmental Compatibility and Public Need | 5/6/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 51625 | Direct | TX | Fuel Factor Formula; Time Differentiated Costs; Time-of-Use Fuel Factor | 4/5/2021 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 51415 | Direct | TX | ATC Tracker, Behind-The-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; Large Lighting and Power Rate Design; Synchronous Self-Generation Load Charge | 3/31/2021 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 51215 | Direct | TX | Certificate of Convenience and Necessity for the Liberty County Solar Facility | 3/5/2021 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 50997 | Cross Rebuttal | TX | Rate Case Expenses | 1/28/2021 |
| PPL ELECTRIC UTILITIES CORPORATION | PPL Industrial Customer Alliance | M-2020-3020824 | Supplemental | PA | Energy Efficiency and Conservation Plan | 1/27/2021 |
| CENTRAL HUDSON GAS & ELECTRIC | Multiple Intervenors | 20-E-0428 / 20-G-0429 | Rebuttal | NY | Distribution cost classification; revised Electric Embedded Cost-of-Service Study; revised Distribution Mains Study | 1/22/2020 |
| MIDAMERICAN ENERGY COMPANY | Tech Customers | EPB-2020-0156 | Reply | IA | Emissions Plan | 1/21/2021 |

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|---|---|---|---|---|---|---|
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 50997 | Direct | TX | Disallowance of Unreasonable Mine Development Costs; Amortization of Mine Closure Costs; Imputed Capacity | 1/7/2021 |
| CENTRAL HUDSON GAS & ELECTRIC | Multiple Intervenors | 20-E-0428 / 20-G-0429 | Direct | NY | Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Revenue Decoupling Mechanism | 12/22/2020 |
| NIAGARA MOHAWK POWER CORP. | Multiple Intervenors | 20-E-0380 / 20-G-0381 | Rebuttal | NY | AMI Cost Allocation Framework | 12/16/2020 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 51381 | Direct | TX | Generation Cost Recovery Rider | 12/8/2020 |
| NIAGARA MOHAWK POWER CORP. | Multiple Intervenors | 20-E-0380 / 20-G-0381 | Direct | NY | Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Earnings Adjustment Mechanism; Advanced Metering Infrastructure Cost Allocation | 11/25/2020 |
| LUBBOCK POWER & LIGHT | Texas Industrial Energy Consumers | 51100 | Direct | TX | Test Year; Wholesale Transmission Cost of Service and Rate Design | 11/6/2020 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20889 | Direct | MI | Scheduled Lives, Cost Allocation and Rate Design of Securitization Bonds | 10/30/2020 |
| CHEYENNE LIGHT, FUEL AND POWER COMPANY | HollyFrontier Cheyenne Refining LLC | 20003-194-EM-20 | Cross-Answer | WY | PCA Tariff | 10/16/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 20-00143 | Direct | NM | RPS Incentives; Reassignment of non-jurisdictional PPAs | 9/11/2020 |
| ROCKY MOUNTAIN POWER | Wyoming Industrial Energy Consumers | 20000-578-ER-20 | Cross | WY | Time-of-Use period definitions; ECAM Tracking of Large Customer Pilot Programs | 9/11/2020 |
| ROCKY MOUNTAIN POWER | Wyoming Industrial Energy Consumers | 20000-578-ER-20 | Direct | WY | Class Cost-of-Service Study; Time-of-Use period definitions; Interruptible Service and Real-Time Day Ahead Pricing pilot programs | 8/7/2020 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 50790 | Direct | TX | Hardin Facility Acquisition | 7/27/2020 |
| PHILADELPHIA GAS WORKS | Philadelphia Industrial and Commercial Gas Users Group | 2020-3017206 | Surrebuttal | PA | Interruptible transportation tariff; Allocation of Distribution Mains; Universal Service and Energy Conservations; Gradualism | 7/24/2020 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20697 | Rebuttal | MI | Energy Weighting, Treatment of Interruptible Load; Allocation of Distribution Capacity Costs; Allocation of CVR Costs | 7/14/2020 |
| PHILADELPHIA GAS WORKS | Philadelphia Industrial and Commercial Gas Users Group | 2020-3017206 | Rebuttal | PA | Distribution Main Allocation; Design Day Demand; Class Revenue Allocation; Balancing Provisions | 7/13/2020 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | 2020-3019290 | Rebuttal | PA | Network Integration Transmission Service Costs | 7/9/2020 |

# APPENDIX B
# Testimony Filed in Regulatory Proceedings
# by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20697 | Direct | MI | Class Cost-of-Service Study;Financial Compensation Method; General Interruptible Service Credit | 6/24/2020 |
| PHILADELPHIA GAS WORKS | Philadelphia Industrial and Commercial Gas Users Group | 2020-3017206 | Direct | PA | Class Cost-of-Service Study; Class Revenue Allocation; Rate Design | 6/15/2020 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20650 | Rebuttal | MI | Distribution Mains Classification and Allocation | 5/5/2020 |
| GEORGIA POWER COMPANY | Georgia Association of Manufacturers and Georgia Industrial Group | 43011 | Direct | GA | Fuel Cost Recovery Natural Gas Price Assumptions | 5/1/2020 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20650 | Direct | MI | Class Cost-of-Service Study; Transportation Rate Design; Gas Demand Response Pilot Program; Industry Association Dues | 4/14/2020 |
| ROCKY MOUNTAIN POWER | Wyoming Industrial Energy Consumers | 90000-144-XI-19 | Direct | WY | Coal Retirement Studies and IRP Scenarios | 4/1/2020 |
| DTE GAS COMPANY | Association of Businesses Advocating Tariff Equity | U-20642 | Direct | MI | Class Cost-of-Service Study; Class Revenue Allocation; Infrastructure Recovery Mechanism; Industry Association Dues | 3/24/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 49831 | Cross | TX | Radial Transmission Lines; Allocation of Transmission Costs; SPP Administrative Fees; Load Dispatching Expenses; Uncollectible Expense | 3/10/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 19-00315-UT | Direct | NM | Time-Differentiated Fuel Factor | 3/6/2020 |
| SOUTHERN PIONEER ELECTRIC COMPANY | Western Kansas Industrial Electric Consumers | 20-SPEE-169-RTS | Direct | KS | Class Revenue Allocation | 3/2/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 49831 | Direct | TX | Schedule 11 Expenses; Depreciation Expense (Rev. Req. Phase Testimony) | 2/10/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 49831 | Direct | TX | Class-Cost-of-Service Study; Class Revenue Allocation; Rate Design (Rate Design Phase Testimony) | 2/10/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 19-00134-UT | Direct | NM | Renewable Portfolio Standard Rider | 2/5/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 19-00170-UT | Settlement | NM | Settlement Support of Rate Design, Cost Allocation and Revenue Requirement | 1/20/2020 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 49737 | Direct | TX | Certificate of Convenience and Necessity | 1/14/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 19-00170-UT | Rebuttal | NM | Class Cost-of-Service Study; Class Revenue Allocation | 12/20/2019 |
| ALABAMA POWER COMPANY | Alabama Industrial Energy Consumers | 32953 | Direct | AL | Certificate of Convenience and Necessity | 12/4/2019 |

# APPENDIX B
# Testimony Filed in Regulatory Proceedings
# by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 19-00170-UT | Direct | NM | Class Cost-of-Service Study; Class Revenue Allocation; Rate Design | 11/22/2019 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 49616 | Cross | TX | Contest proposed changes in the Fuel Factor Formula | 10/17/2019 |
| GEORGIA POWER COMPANY | Georgia Association of Manufacturers and Georgia Industrial Group | 42516 | Direct | GA | Return on Equity; Capital Structure; Coal Combustion Residuals Recovery; Class Revenue Allocation; Rate Design | 10/17/2019 |
| NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION | Multiple Intervenors | 19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381 | Rebuttal | NY | Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design | 10/15/2019 |
| NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION | Multiple Intervenors | 19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381 | Direct | NY | Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Amortization of Regulatory Liabilties; AMI Cost Allocation | 9/20/2019 |
| AEP TEXAS INC. | Texas Industrial Energy Consumers | 49494 | Cross-Rebuttal | TX | ERCOT 4CPs; Class Revenue Allocation; Customer Support Costs | 8/13/2019 |
| AEP TEXAS INC. | Texas Industrial Energy Consumers | 49494 | Direct | TX | Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Transmission Line Extensions | 7/25/2019 |
| CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC | Texas Industrial Energy Consumers | 49421 | Cross-Rebuttal | TX | Class Cost-of-Service Study | 6/19/2019 |
| CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC | Texas Industrial Energy Consumers | 49421 | Direct | TX | Class Cost-of-Service Study; Rate Design; Transmission Service Facilities Extensions | 6/6/2019 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 48973 | Direct | TX | Prudence of Solar PPAs, Imputed Capacity, treatment of margins from Off-System Sales | 5/21/2019 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20322 | Rebuttal | MI | Classification of Distribution Mains; Allocation of Working Gas in Storage and Storage | 4/29/2019 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20322 | Direct | MI | Class Cost-of-Service Study; Transportation Rate Design | 4/5/2019 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 49042 | Cross-Rebuttal | TX | Transmsision Cost Recovery Factor | 3/21/2019 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 49057 | Direct | TX | Transmsision Cost Recovery Factor | 3/18/2019 |
| DUKE ENERGY PROGRESS, LLC | Nucor Steel - South Carolina | 2018-318-E | Direct | SC | Class Cost-of-Service Study, Class Revenue Allocation, LGS Rate Design, Depreciation Expense | 3/4/2019 |
| ENTERGY ARKANSAS, LLC | Arkansas Electric Energy Consumers, Inc. | 18-037 | Settlement | AR | Testimony in Support of Settlement | 3/1/2019 |
| ENERGY+ INC. | Toyota Motor Manufacturing Canada | EB-2018-0028 | Updated Evidence | ON | Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design | 2/15/2019 |
| ENTERGY ARKANSAS, LLC | Arkansas Electric Energy Consumers, Inc. | 18-037 | Surrebuttal | AR | Solar Energy Purchase Option Tariff | 2/14/2019 |

# APPENDIX B
# Testimony Filed in Regulatory Proceedings
# by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 48847 | Direct | TX | Fuel Factor Formulas | 1/11/2019 |
| ENTERGY ARKANSAS, LLC | Arkansas Electric Energy Consumers, Inc. | 18-037 | Direct | AR | Solar Energy Purchase Option Tariff | 1/10/2019 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20165 | Direct | MI | Integrated Resources Plan; Projected Rate Impact, Risk Assessment; Early Retirement of Coal Units; Financial Compensation Mechanism | 10/15/2018 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20134 | Rebuttal | MI | Class Cost-of-Service Study; Average Historical Profile; Distribution Cost Classification and Allocation; Rate Design | 10/1/2018 |
| ENERGY+ INC. | Toyota Motor Manufacturing Canada | EB-2018-0028 | Initial Evidence | ON | Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design | 9/27/2018 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-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 Industrial 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 Improvement Charge | 8/8/2018 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 48371 | Direct | TX | Revenue Requirements; Tax Cuts and Jobs Act; Riders | 8/1/2018 |
| ENTERGY TEXAS, INC. | Texas Industrial 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 Industrial Energy Consumers | 48233 | Cross-Rebuttal | TX | Allocation of TCJA reduction | 7/19/2018 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial 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 Industrial 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 |

# APPENDIX B
# Testimony Filed in Regulatory Proceedings
# by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 17-041 | Stipulation | AR | Support of Stipulation | 4/27/2018 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 47527 | Direct | TX | Present Base Revenues<br>Class Cost-of-Service Study; Class Revenue Allocation; Rate Design | 4/25/2018 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial 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 |
| 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<br>2017-2637857<br>2017-2637858<br>2017-2637866 | Rebuttal | PA | Recovery of NITS Charges | 3/22/2018 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 46936 | 2nd Supplemental Direct | TX | Support of Stipulation | 3/2/2018 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-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 Industrial Energy Consumers | 47553 | Direct | TX | Off-System Sales Margins; Renewable Energy Credits | 2/20/2018 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 47461 | 2nd Supplemental Direct | TX | Certificate of Convenience and Necessity | 2/7/2018 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial 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 Industrial 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 Program and EAM | 11/21/2017 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 17-00044-UT | Direct | NM | Certificate of Convenience and Necessity | 10/24/2017 |

# APPENDIX B
# Testimony Filed in Regulatory Proceedings
# by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 46936 | Cross-Rebuttal | TX | Certificate of Convenience and Necessity | 10/23/2017 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial 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 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial 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 | U-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 | U-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 Station | 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 |

# APPENDIX B
# Testimony Filed in Regulatory Proceedings
# by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| 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 | Rebuttal | MN | Class Cost-of-Service Study, Class Revenue Allocation | 9/23/2016 |
| VICTORY ELECTRIC COOPERATION ASSOCIATION, INC. | Western 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<br>2016-2537352<br>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. | Western Kansas Industrial Electric Consumers | 16-VICE-494-TAR | Direct | KS | Formula-Based Rate Plan | 8/30/2016 |
| WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC. | Western 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<br>2016-2537352<br>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 |
| METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER | MEIUG, PICA and WPPII | 2016-2537349<br>2016-2537352<br>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 |

# APPENDIX B
# Testimony Filed in Regulatory Proceedings
# by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| 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 POWER, LLC | Occidental Chemical Corporation | U-33770 | Cross-Answering | LA | Approval to Construct St. Charles Power Station | 2/26/2016 |
| 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 POWER, LLC | 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; Formula Rate Plan | 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 Association 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<br>15-G-0284<br>15-E-0285<br>15-G-0286 | Rebuttal | NY | Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation | 10/13/2015 |

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# Testimony Filed in Regulatory Proceedings
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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| 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<br>15-G-0284<br>15-E-0285<br>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 |
| 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 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian 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 |
| SOUTHWESTERN 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 |

# APPENDIX B
# Testimony Filed in Regulatory Proceedings
# by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 43695 | Direct | TX | Post-Test Year Adjustments; Weather Normalization | 5/15/2015 |
| SOUTHWESTERN 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 |
| 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 |

# APPENDIX B
# Testimony Filed in Regulatory Proceedings
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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| 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 Rider | 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 |
| 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 |

# APPENDIX B
# Testimony Filed in Regulatory Proceedings
# by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| 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.<br>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 Industrial 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<br>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 |
| SHARYLAND UTILITIES | Texas Industrial 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 | Rebuttal | 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<br>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<br>KANSAS GAS & ELECTRIC CO. | Occidental Chemical Corporation | 13-WSEE-629-RTS | Direct | KS | Class Revenue Allocation. | 8/21/2013 |

# APPENDIX B
# Testimony Filed in Regulatory Proceedings
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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| 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 |
| 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.<br>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 | TX | Competitive Generation Service Tariff | 2/1/2013 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 38951 | Second Supplemental | 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 |

# APPENDIX B
# Testimony Filed in Regulatory Proceedings
# by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| 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 |
| 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 |

# APPENDIX B
# Testimony Filed in Regulatory Proceedings
# by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| 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 |

## APPENDIX C

## Procedure for Conducting a Class Cost-of-Service Study

**Q WHAT PROCEDURES ARE USED IN A 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). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by FERC.

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as classification. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (kW). This includes production, transmission, and some distribution investment and related fixed Operation and Maintenance (O&M) expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy, which is measured in kilowatt-hours (kWh). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers and include expenses such as meters, service drops, billing, and customer service.

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 cost that should be paid by each class. The allocation factors should reflect cost-causation; that is, the degree to which each class caused the utility to incur the cost.

**Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?**

A A properly conducted CCOSS recognizes two key cost-causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost-causation is also related to how electricity is used, both the timing and rate of energy consumption (*i.e.*, demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand, including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities.

**Q WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER AMONG CUSTOMER CLASSES?**

A Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating (load factor), whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, the amount of electricity that a customer uses, and the quality of service (*e.g.,* firm or non-firm). In general, industrial consumers are less costly to serve on a per-unit basis because they:

- operate at higher load factors;
- take service at higher delivery voltages; and
- use more electricity per customer.

Further, non-firm service is a lower quality of service than firm service. Thus, non-firm service is less costly per unit than firm service for customers that otherwise have the same characteristics. This explains why some customers pay lower average rates than others.

For example, the difference in the losses incurred to deliver electricity at the various delivery voltages is a reason why the per-unit energy cost to serve is not the same for all customers. More losses occur to deliver electricity at distribution voltage (either primary or secondary) than at transmission voltage, which is generally the level at which industrial customers take service. This means that the cost per kWh is lower for a transmission customer than a distribution customer. The cost to deliver a kWh at primary distribution, though higher than the per-unit cost at transmission, is lower than the delivered cost at secondary distribution.

In addition to lower losses, transmission customers do not use the distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers who do not use that system. Distribution customers, by contrast, require substantial investments in these lower voltage facilities to provide service. Secondary distribution customers require more investment than primary distribution customers. This results in a different cost to serve each type of customer.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis.

Efficiency can be measured in terms of load factor. Load factor is the ratio of average demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Said differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

# ONCOR ELECTRIC DELIVERY COMPANY LLC
## TIEC's Revised Class Cost-of-Service Study
## Test Year Ended December 31, 2021

| Line | Description | Total TX | Residential | Secondary <=10kW | Secondary >10kW | Primary DL <=10kW | Primary DL >10kW |
|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) |
| 1 | O&M and A&G Expense | 896,152,762 | 483,314,807 | 25,585,179 | 293,210,586 | 708,952 | 58,494,545 |
| 2 | Wholesale Transmission Costs (Acct 565) | 1,652,522,021 | 758,188,213 | 21,192,617 | 551,175,464 | 219,196 | 138,570,540 |
| 3 | RateCaseExpense A928 | 1,646,626 | 824,746 | 33,961 | 560,216 | 623 | 114,082 |
| 4 | **Total O&M and A&G Expenses** | **2,550,321,409** | **1,242,327,766** | **46,811,757** | **844,946,266** | **928,771** | **197,179,167** |
| 5 | Depreciation, Amortization, & Other Exp | 546,347,840 | 294,030,717 | 17,905,266 | 175,405,843 | 385,688 | 29,498,378 |
| 6 | Taxes Other Than FIT | 460,498,199 | 210,801,912 | 8,644,205 | 178,719,926 | 71,578 | 28,672,443 |
| 7 | **Subtotal** | **3,557,167,447** | **1,747,160,394** | **73,361,227** | **1,199,072,035** | **1,386,037** | **255,349,988** |
| 8 | Cost-Based Return on Rate Base | 683,000,124 | 380,305,597 | 15,312,475 | 238,300,134 | 245,376 | 38,429,485 |
| 9 | Cost-Based Federal Income Tax | 82,404,583 | 45,908,328 | 1,772,312 | 28,825,708 | 25,557 | 4,615,206 |
| 10 | **COST OF SERVICE** | **4,322,572,155** | **2,173,374,320** | **90,446,014** | **1,466,197,877** | **1,656,970** | **298,394,679** |
| 11 | Minus: Other Revenues | 39,440,850 | 27,022,573 | 2,087,305 | 8,303,783 | 35,507 | 1,472,027 |
| 12 | **REVENUE REQUIREMENT** | **4,283,131,305** | **2,146,351,747** | **88,358,709** | **1,457,894,094** | **1,621,463** | **296,922,652** |
| 13 | **PROPOSED REVENUE** | **4,283,131,305** | **2,146,351,747** | **88,358,709** | **1,457,894,094** | **1,621,463** | **296,922,652** |
| 14 | **TOTAL PRESENT REVENUES (Incl PF)** | **4,026,088,618** | **1,921,088,302** | **95,557,181** | **1,518,612,724** | **1,232,285** | **279,608,449** |
| 15 | **COST-BASED REVENUE REQUIREMENT** | **4,283,131,305** | **2,146,351,747** | **88,358,709** | **1,457,894,094** | **1,621,463** | **296,922,652** |
| 16 | Revenue Deficiency (Sufficiency) | 257,042,687 | 225,263,445 | (7,198,472) | (60,718,630) | 389,178 | 17,314,203 |
| 17 | Change from Present Revenues | 6.38% | 11.73% | -7.53% | -4.00% | 31.58% | 6.19% |

# ONCOR ELECTRIC DELIVERY COMPANY LLC
## TIEC's Revised Class Cost-of-Service Study
## Test Year Ended December 31, 2021

| Line | Description | Total TX | Residential | Secondary <=10kW | Secondary >10kW | Primary DL <=10kW | Primary DL >10kW |
|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) |
| 1 | RATE BASE | | | | | | |
| 2 | Gross Plant In Service | 16,393,872,127 | 8,949,799,574 | 431,102,603 | 5,486,813,593 | 5,781,977 | 844,889,129 |
| 3 | General Plant | 534,959,372 | 298,154,560 | 23,714,562 | 170,655,904 | 804,464 | 33,755,580 |
| 4 | Communication Equipment | 108,581,709 | 60,524,300 | 5,196,684 | 34,146,078 | 183,708 | 6,986,232 |
| 5 | Total Plant | **17,037,413,208** | **9,308,478,434** | **460,013,849** | **5,691,615,575** | **6,770,150** | **885,630,940** |
| 6 | Minus: Accumulated Depreciation | 6,571,378,311 | 3,475,315,320 | 224,356,468 | 2,056,715,309 | 3,203,647 | 305,146,828 |
| 7 | Net Plant In Service | 10,466,034,897 | 5,833,163,114 | 235,657,381 | 3,634,900,266 | 3,566,503 | 580,484,112 |
| 8 | **Other Rate Base Items:** | | | | | | |
| 9 | CWIP | - | - | - | - | - | - |
| 10 | Plant Held for Future Use | 1,745,979 | 918,949 | 22,441 | 591,686 | 335 | 141,579 |
| 11 | Accumulated Provisions ex ADFIT | - | - | - | - | - | - |
| 12 | Materials & Supplies | 74,796,188 | 40,797,078 | 1,655,471 | 25,413,001 | 9,186 | 3,729,353 |
| 13 | Cash Working Capital | (16,280,094) | (7,626,072) | (184,154) | (5,475,669) | (1,016) | (1,327,584) |
| 14 | Prepayments | 104,576,673 | 41,996,472 | 1,500,195 | 43,969,879 | 759 | 7,070,030 |
| 15 | Misc Other Rate Base | (3,102,162) | (1,489,321) | (36,370) | (958,933) | (542) | (229,454) |
| 16 | Regulatory Assets | 314,699,496 | 172,346,774 | 14,058,781 | 98,910,449 | 494,253 | 21,140,751 |
| 17 | Acuumulated Deferred Income Taxes | (1,254,525,959) | (685,701,357) | (35,475,520) | (417,206,929) | (588,973) | (65,909,710) |
| 18 | **Subtotal: Other Rate Base** | **(778,089,879)** | **(438,757,477)** | **(18,459,155)** | **(254,756,516)** | **(85,999)** | **(35,385,034)** |
| 19 | **TOTAL RATE BASE** | **9,687,945,019** | **5,394,405,636** | **217,198,226** | **3,380,143,750** | **3,480,504** | **545,099,078** |
| 28 | PRESENT REVENUE | | | | | | |
| 29 | TCRF (incl Power Factor) | 1,641,672,523 | 771,619,863 | 20,855,235 | 616,792,422 | 189,054 | 106,138,547 |
| 30 | Distribution (incl Power Factor) | 2,114,206,354 | 1,015,748,505 | 45,038,287 | 803,927,047 | 123,349 | 169,027,361 |
| 31 | Customer | 68,856,145 | 35,189,456 | 7,488,978 | 22,598,269 | 231,459 | 1,337,400 |
| 32 | Meter | 201,353,596 | 98,530,478 | 22,174,681 | 75,294,986 | 688,423 | 3,105,141 |
| 33 | **Total Electric Delivery Revenues** | **4,026,088,618** | **1,921,088,302** | **95,557,181** | **1,518,612,724** | **1,232,285** | **279,608,449** |
| 34 | Discretionary Service Revenues | 22,468,503 | 9,915,351 | 9,403,069 | 2,617,581 | 31,456 | 181,995 |
| 35 | Other Revenue | 16,972,346 | 8,191,462 | 532,349 | 6,426,646 | 7,434 | 1,236,199 |
| 36 | **Total Present Revenues** | **4,065,529,468** | **1,939,195,115** | **105,492,599** | **1,527,656,951** | **1,271,175** | **281,026,643** |

## ONCOR ELECTRIC DELIVERY COMPANY LLC
## TIEC's Revised Class Cost-of-Service Study
## Test Year Ended December 31, 2021

| Line | Description | Primary Substation | Transmission | Lighting | Wholesale Substation | Wholesale DLS |
|---|---|---|---|---|---|---|
| | | (7) | (8) | (9) | (10) | (11) |
| 1 | O&M and A&G Expense | 4,429,550 | 1,130,578 | 26,178,750 | 519,215 | 2,580,599 |
| 2 | Wholesale Transmission Costs (Acct 565) | 45,384,309 | 137,791,683 | - | - | - |
| 3 | RateCaseExpense A928 | 22,961 | 63,197 | 23,633 | 605 | 2,602 |
| 4 | **Total O&M and A&G Expenses** | **49,836,821** | **138,985,458** | **26,202,382** | **519,820** | **2,583,201** |
| 5 | Depreciation, Amortization, & Other Exp | 1,843,492 | 515,974 | 25,253,969 | 219,894 | 1,288,619 |
| 6 | Taxes Other Than FIT | 3,806,679 | 22,649,811 | 5,994,594 | 324,779 | 812,272 |
| 7 | **Subtotal** | **55,486,993** | **162,151,243** | **57,450,945** | **1,064,493** | **4,684,092** |
| 8 | Cost-Based Return on Rate Base | 3,418,758 | 741,671 | 3,925,743 | 408,062 | 1,912,823 |
| 9 | Cost-Based Federal Income Tax | 417,238 | 83,457 | 473,836 | 49,665 | 233,276 |
| 10 | **COST OF SERVICE** | **59,322,989** | **162,976,372** | **61,850,523** | **1,522,219** | **6,830,191** |
| 11 | Minus: Other Revenues | 48,076 | 41,314 | 373,630 | 3,356 | 53,279 |
| 12 | **REVENUE REQUIREMENT** | **59,274,914** | **162,935,058** | **61,476,893** | **1,518,864** | **6,776,912** |
| 13 | **PROPOSED REVENUE** | **59,274,914** | **162,935,058** | **61,476,893** | **1,518,864** | **6,776,912** |
| 14 | **TOTAL PRESENT REVENUES (Incl PF)** | **31,757,894** | **115,088,693** | **60,374,542** | **608,356** | **2,160,192** |
| 15 | **COST-BASED REVENUE REQUIREMENT** | **59,274,914** | **162,935,058** | **61,476,893** | **1,518,864** | **6,776,912** |
| 16 | Revenue Deficiency (Sufficiency) | 27,517,020 | 47,846,365 | 1,102,351 | 910,508 | 4,616,720 |
| 17 | Change from Present Revenues | 86.65% | 41.57% | 1.83% | 149.67% | 213.72% |

# ONCOR ELECTRIC DELIVERY COMPANY LLC
## TIEC's Revised Class Cost-of-Service Study
## Test Year Ended December 31, 2021

| Line | Description | Primary Substation | Transmission | Lighting | Wholesale Substation | Wholesale DLS |
|---|---|---|---|---|---|---|
| | | (7) | (8) | (9) | (10) | (11) |
| 1 | **RATE BASE** | | | | | |
| 2 | Gross Plant In Service | 68,017,630 | 6,181,675 | 551,028,931 | 8,139,641 | 42,117,373 |
| 3 | General Plant | 2,204,354 | 1,183,356 | 3,109,481 | 261,775 | 1,115,337 |
| 4 | Communication Equipment | 433,982 | 273,019 | 572,444 | 51,455 | 213,807 |
| 5 | Total Plant | **70,655,967** | **7,638,050** | **554,710,856** | **8,452,870** | **43,446,517** |
| 6 | Minus: Accumulated Depreciation | 19,479,898 | 4,053,892 | 466,672,575 | 2,326,461 | 14,107,914 |
| 7 | Net Plant In Service | 51,176,069 | 3,584,158 | 88,038,282 | 6,126,410 | 29,338,603 |
| 8 | **Other Rate Base Items:** | | | | | |
| 9 | CWIP | - | - | - | - | - |
| 10 | Plant Held for Future Use | 51,200 | - | 5,968 | 6,137 | 7,685 |
| 11 | Accumulated Provisions ex ADFIT | - | - | - | - | - |
| 12 | Materials & Supplies | 319,409 | 611 | 2,631,727 | 38,282 | 202,069 |
| 13 | Cash Working Capital | (399,111) | (1,166,548) | (88,781) | (1,692) | (9,467) |
| 14 | Prepayments | 1,112,422 | 8,332,812 | 382,811 | 84,880 | 126,412 |
| 15 | Misc Other Rate Base | (82,813) | (272,677) | (9,672) | (9,926) | (12,455) |
| 16 | Regulatory Assets | 1,477,754 | 749,239 | 4,731,735 | 161,256 | 628,505 |
| 17 | Acuumulated Deferred Income Taxes | (5,161,905) | (707,439) | (40,007,776) | (617,233) | (3,149,116) |
| 18 | **Subtotal: Other Rate Base** | **(2,683,044)** | **6,935,998** | **(32,353,989)** | **(338,296)** | **(2,206,366)** |
| 19 | **TOTAL RATE BASE** | **48,493,024** | **10,520,156** | **55,684,292** | **5,788,114** | **27,132,237** |
| 28 | **PRESENT REVENUE** | | | | | |
| 29 | TCRF (incl Power Factor) | 24,415,314 | 101,662,088 | 0 | 0 | 0 |
| 30 | Distribution (incl Power Factor) | 6,718,985 | 12,003,885 | 59,091,425 | 544,013 | 1,983,497 |
| 31 | Customer | 235,825 | 550,491 | 1,158,944 | 18,966 | 46,357 |
| 32 | Meter | 387,770 | 872,229 | 124,173 | 45,377 | 130,338 |
| 33 | **Total Electric Delivery Revenues** | **31,757,894** | **115,088,693** | **60,374,542** | **608,356** | **2,160,192** |
| 34 | Discretionary Service Revenues | 2,247 | 4,494 | 312,312 | 0 | 0 |
| 35 | Other Revenue | 52,325 | 95,682 | 430,247 | 0 | 0 |
| 36 | **Total Present Revenues** | **31,812,466** | **115,188,869** | **61,117,102** | **608,356** | **2,160,192** |

# ONCOR ELECTRIC DELIVERY COMPANY LLC

## Summary of Proposed Electric Delivery Revenue Increase By Rate Class
## Test Year Ended December 31, 2021
## (Dollar Amounts in Thousands)

| Line | Rate Class | Present Revenues* | Proposed Revenues* | Proposed Increase Amount | Proposed Increase Percent |
|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) |
| 1 | Residential | $1,921,088 | $2,146,347 | $225,258 | 11.7% |
| 2 | Secondary <= 10 kW | $95,557 | $88,359 | ($7,199) | -7.5% |
| 3 | Secondary > 10 kW | $1,518,613 | $1,470,808 | ($47,805) | -3.1% |
| 4 | Primary DL <= 10 kW | $1,232 | $1,621 | $389 | 31.6% |
| 5 | Primary > 10 kW Dist. Line | $279,608 | $300,677 | $21,069 | 7.5% |
| 6 | Primary > 10 kW Substation | $31,758 | $59,435 | $27,677 | 87.2% |
| 7 | Transmission | $115,089 | $163,728 | $48,639 | 42.3% |
| 8 | Lighting | $60,375 | $61,477 | $1,102 | 1.8% |
| 9 | Retail Electric Delivery Revenues | $4,023,320 | $4,292,452 | $269,128 | 6.7% |
| 10 | Wholesale Substation | $608 | $1,573 | $965 | 158.6% |
| 11 | Wholesale DLS | $2,160 | $6,768 | $4,608 | 213.3% |
| 12 | Total Electric Delivery Revenues | $4,026,089 | $4,300,793 | $274,701 | 6.8% |
| 13 | Other Revenue | $39,441 | $39,441 | $0 | 0.0% |
| 14 | Total Delivery Revenues | $4,065,529 | $4,340,234 | $274,701 | 6.8% |

* Includes Power Factor Revenues.

## ONCOR ELECTRIC DELIVERY COMPANY LLC

## Recommended 4CP Rate Moderation Plan

| Line | Rate Class | Step 1 | | | Step 2 | | |
|---|---|---|---|---|---|---|---|
| | | Present | Proposed | Moderated | Present | Actual | Reset |
| | | (1) | (2) | (3) | (4) | (5) | (6) |
| 1 | Residential | 47.0021% | 45.8807% | 46.4414% | 46.4414% | 45.8807% | 45.8807% |
| 2 | Secondary <= 10 kW | 1.2704% | 1.2824% | 1.2764% | 1.2764% | 1.2824% | 1.2824% |
| 3 | Secondary > 10 kW | 37.5710% | 33.3536% | 35.4623% | 35.4623% | 33.3536% | 33.3536% |
| 4 | Primary DL <= 10 kW | 0.0115% | 0.0133% | 0.0124% | 0.0124% | 0.0133% | 0.0133% |
| 5 | Primary > 10 kW Dist. Line | 6.4653% | 8.3854% | 7.4253% | 7.4253% | 8.3854% | 8.3854% |
| 6 | Primary > 10 kW Substation | 1.4872% | 2.7464% | 2.1168% | 2.1168% | 2.7464% | 2.7464% |
| 7 | Transmission | 6.1926% | 8.3383% | 7.2654% | 7.2654% | 8.3383% | 8.3383% |
| 8 | Lighting | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| 9 | Total Retail | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% | 100.0000% |

# ONCOR ELECTRIC DELIVERY COMPANY LLC
## Summary of Facilities Charge Rate
## For Distribution Substation Investment
## Year Ended December 31, 2021

| Line | Component | Monthly % |
|---|---|---|
| 1 | Return on Investment | 0.49% |
| 2 | Depreciation | 0.17% |
| 3 | O&M Expenses | 0.39% |
| 4 | Property Insurance & Taxes | 0.10% |
| 5 | Total Ongoing Charge | 0.66% |
| 6 | Total Charge | 1.16% |

# 6.3 Agreements and Forms

## 6.3.1 Facilities Extension Agreement

Project Number ______________________________
WR Number ______________________________
Region/District ______________________________

This Agreement is made between ____________________________ hereinafter called "Customer" and ______________________, a Delaware limited liability company, hereinafter called "Company" for the extension of Company Delivery System facilities, as hereinafter described, to the following location ___________________________________________________________________________.

The Company has received a request for the extension of: (check all that apply)

☐ **STANDARD DELIVERY SYSTEM FACILITIES TO NON-RESIDENTIAL DEVELOPMENT**

Company shall extend standard Delivery System facilities necessary to serve Customer's estimated maximum demand requirement of ________ kW ("Contract kW"). The Delivery System facilities installed hereunder will be of the character commonly described as _________________ volt, _________________ phase, at 60 hertz, with reasonable variation to be allowed.

☐ **STANDARD DELIVERY SYSTEM FACILITIES TO NON-RESIDENTIAL DEVELOPMENT**

Company shall extend standard Delivery System facilities necessary to serve:

______________ All-electric residential lot(s)/apartment units, or
(Number of lots/units)

______________ Electric and gas residential lot(s)/apartment units.
(Number of lots/units)

The Delivery System facilities installed hereunder will be of the character commonly described as ____________________ volt, ____________________ phase, at 60 hertz, with reasonable variation to be allowed.

☐ **NON-STANDARD DELIVERY SYSTEM FACILITIES**

Company shall extend/install the following non-standard facilities:

________________________________________________________________________________
________________________________________________________________________________
________________________________________________________________________________
________________________________________________________________________________

**ARTICLE I - PAYMENT BY CUSTOMER**

At the time of acceptance of this Agreement by Customer, Customer will pay to Company ______________________________ Dollars ($ ______________________) as payment for the Customer's portion of the cost of the extension of Company facilities, in accordance with Company's Facilities Extension Policy, such payment to be and remain the property of the Company.

**ARTICLE II - NON-UTILIZATION CLAUSE FOR STANDARD DELIVERY SYSTEM FACILITIES**

This Article II applies only to the installation of standard Delivery System facilities.

a. The amount of Contribution in Aid of Construction ("CIAC") to be paid by Customer under Article I above is calculated based on the amount of the Customer's estimated ~~data~~ load (i.e., Contract kW or load based on the number and type of lots/units) supplied by Customer and specified above as a percentage of the total capacity of the extended Delivery System facilities. Company and Customer will conduct ~~a~~ reviews as specified in paragraph c. of the actual load or number and type of lots/units at the designated location to determine the accuracy of the estimated data supplied by Customer. If, within four (4) years after Company completes the extension of Delivery System facilities, the Customer's estimated load as measured by actual maximum kW billing demand at said location has not materialized or the estimated number and type of dwelling units/lots at said location have not been substantially completed such that the Customer is not currently using or is not reasonably projected to use the percentage of the total capacity as estimated in the following two (2) years, Company shall ~~may, at its sole discretion,~~ re-calculate the CIAC based on the original estimated percentage of total capacity and the actual cost of the extended Delivery System facilities~~actual maximum kW billing demand realized or the number and type of substantially completed dwelling units/lots, or extend the four (4) year time frame~~. For purposes of this Agreement, a dwelling unit/lot shall be deemed substantially completed upon the installation of a meter. The installation of a meter in connection with Temporary Delivery Service does not constitute substantial completion. In the event that any portion(s) of the extended Delivery System facilities for which Customer paid a CIAC are used to serve other customers within ten years after the facilities are energized, the Customer that paid the CIAC shall be entitled to receive a prorated refund of the CIAC upon the commencement of the service to new customer(s).

b. Payments or refunds made pursuant to Article II ~~Customer will pay to Company a "non-utilization charge" in an amount equal to the difference between the re-calculated CIAC amount and the amount paid by Customer under Article I, above. Company's invoice to Customer for such "non-utilization charge" is~~ are due and payable within fifteen (15) days after the date of the invoice (for payments) and the commencement of service by new customers (for refunds).

c. Customer will, prior to or contemporaneous with signing this Agreement, or as soon thereafter as reasonably possible, supply a load profile or load ramp document in support of the Contract kW set out above. ~~If (a) Customer fails to provide a load ramp or load profile by the end of the second year after Company completes the extension of Delivery System facilities ("second year of service"), or (2) Customer provides a load ramp or load profile and the actual kW billing demand for the second year of service is below that set out in the load profile or load ramp document; then at the end of the second year of service the Contract kW shall be set equal to the highest billing demand reached during the second year of service and shall be reset every year thereafter to equal Customer's highest kW billing demand during the prior two years, but in no event higher than the then-existing Contract kW amount, unless Customer and Company~~ Customer and Company shall meet at least annually, or more frequently as necessary, to address any changes in the original load ramp.

**ARTICLE III - TITLE AND OWNERSHIP**

Company at all times shall have title to and complete ownership and control over the Delivery System facilities extended under this Agreement.

Once Customer has granted ~~or secured for the Company~~, any rights-of-way or easements for the use of its property, regardless of the passage of time and the level of activity, the Company never intends to abandon any rights-of-way or easements unless the Company specifically states, in writing, the intention to do so, and the Company then takes additional specific affirmative action to effectuate the abandonment.

**ARTICLE IV - GENERAL CONDITIONS**

Delivery service is not provided under this Agreement. However, Customer understands that, as a result of the installation provided for in this Agreement, the Delivery of Electric Power and Energy by Company to the specified location will be provided in accordance with Rate Schedule ________________________, which may from time to time be amended or succeeded.

The facilities covered by this Agreement will be interconnected consistent with the deadlines provided below. [Thirty (30)] days prior to each deadline, Company will provide a status update on whether it expects to meet the deadline. In the event that Company must deviate from these deadlines, Company will provide Customer with a written explanation and modified deadlines as soon as practicable.

This Agreement supersedes all previous agreements or representations, either written or oral, between Company and Customer made with respect to the matters herein contained, and when duly executed constitutes the agreement between the parties hereto and is not binding upon Company unless and until signed by one of its duly authorized representatives.

**ARTICLE V - DISCLOSURE**

Customer has disclosed to Company all underground facilities owned by Customer or any other party that is not a public utility or governmental entity, that are located within real property owned by Customer. In the event that Customer has failed to do so, or in the event of the existence of such facilities of which Customer has no knowledge, Company, its agents and contractors, shall have no liability, of any nature whatsoever, to Customer, or Customer's agents or assignees, for any actual or consequential damages resulting directly or indirectly from damage to such undisclosed or unknown facilities

**ARTICLE VI - PROHIBITION ON AGREEMENTS WITH CERTAIN FOREIGN-OWNED COMPANIES IN CONNECTION WITH CRITICAL INFRASTRUCTURE**

Customer represents and warrants that it does not meet any of the ownership, control, or headquarters criteria listed in Lone Star Infrastructure Protection Act, Chapter 113 of the Texas Business and Commerce Code, as added by Act of June 18, 2021, 87th Leg., R.S., Ch. 975 (S.B. 2116) (relating to China, Iran, North Korea, Russia, and any other country designated by the Texas governor as a threat to critical infrastructure).

**ARTICLE VII - OTHER SPECIAL CONDITIONS**

______________________________________________________________________
______________________________________________________________________
______________________________________________________________________
______________________________________________________________________
______________________________________________________________________

| ACCEPTED BY COMPANY: | ACCEPTED BY CUSTOMER: |
|---|---|
| ______________________________ | ______________________________ |
| Signature | Signature |
| ______________________________ | ______________________________ |
| Title | Title |
| ______________________________ | ______________________________ |
| Date Signed | Date Signed |

# Petroleum Industry - Electric Load Requirements Form

**LOAD SHEET**
**Customer:** ____________________
**Project:** ____________________

This Information is required when requesting the extension of Electric Utility Facilities to provide service to new or added customer electric loads. Please submit a separate load sheet for each metered point of delivery. If there is not enough space on pages 1-3, note that you may provide more information on page 4.

In order to begin the process to provide electrical service to the project, complete in full, sign and return to Utility. Provide construction diagrams and utility instructions for electrification as they become available.

## Project Location

**Customer and Project Name:** ____________________

**ESI ID/Premise #, if applicable:** ____________________ ____________________

☐ **Check here to request Utility to issue new ESI ID** ☐ **Check here to request Utility to issue Rate Code assignment**

**911 Street Address and/or GPS (lat/long) if outside city limits:** ____________________

**Nearest Town/County:** ____________________

**In rural areas, please provide detailed directions (for example, nearest cross roads, Section/Block #, and GPS coordinates). Attach map if available:**

☐ **Check box if additional information is included on page 4.**

## Contact Information (as applicable)

| | **Company Name** | **Contact Name** | **Cell Phone No.** | **E-mail Address** |
|---|---|---|---|---|
| **Customer:** | | | | |
| **GC:** | | | | |
| **Electrician:** | | | | |
| **Other:** | | | | |

**Customer mailing address for billing correspondence (such as contracts and CIAC invoices):**

## SME-PME Requirements

**A separate Load Requirements Form will be required for each Point of Delivery with a different Voltage/Phase requirement.**

Will the load represented on this form be added to an existing energized electric service (existing active meter)?

**Yes** (include existing meter number or ESI ID) ____________________

**Change SME to PME** **Upgrade Existing PME** ***Clear Selection*** ◉

◉ **No** (a new Premise ID will be required before service is energized.

**PME Requested** **SME Requested** ***Clear Selection*** ◉

What size is the largest fuse behind the meter? ________ Will there be a reclosing device at the PME? YES ☑ NO

What size is the largest transformer behind the meter?____________________

Please explain recloser coordination needs: ____________________

*(If needed, more space is available on page 4.)*

## Substation Service Requirements

**Requested Service Phase/Voltage** (select only one):

Single Phase 120/240 Three Phase 120/208 Three Phase 277/480 Other ________ (specify)

Single Phase 240/480 Three Phase 120/240 Three Phase 480 ◉

Depending on system configuration, Partial Service may not be available prior to Full Service, but we will make every effort to accommodate your schedule. If Partial Service is requested sooner than Full Service, a separate Itemized Load List will be required – See instructions on page 3.

Customer's # of conductors: ______ Request service type: **OVERHEAD** ◉ **UNDERGROUND** ○ **Meter Only** ○

Specify wire size at point of common coupling: ____________

Address for transocket delivery: ____________________

LOAD SHEET
Customer:____________________
Project:____________________

# Petroleum Industry – Electric Load Requirements Form

Customer and Project Name (as stated on first page):

______________________________________________

**If requesting power for Initial or Partial load (testing, ramp up operations, etc.), and full power at a later date, fill out Itemized Electric Load Requirements list for the power needed for each date. Provide a spreadsheet of the forecasted load if the load list cannot be put in the form. DO NOT DUPLICATE LOADS ON BOTH LISTS. Copy/complete additional sheets as needed. Provide additional Schedules and load forecasts as appropriate.**

**Load Requirements for New Service and Additions to Existing Service**

**ITEMIZED ELECTRIC LOAD REQUIREMENTS LIST.**

## Motor Load Information

| | Load Type (ESP, SWD, TB, Rod Pump, Compressor) (one type of load per line) | Target Service Date | Secondary Voltage (240/480) (120/240) or (4160) | Single Phase or Three Phase | Nameplate HP | Quantity of Same Size Motors | kW/MW Load Diversity (if known) | Motor Starting Type (VFD, Soft Start, Across the Line) |
|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | |
| 2 | | | | | | | | |
| 3 | | | | | | | | |
| 4 | | | | | | | | |
| 5 | | | | | | | | |
| 6 | | | | | | | | |
| 7 | | | | | | | | |
| 8 | | | | | | | | |
| 9 | | | | | | | | |
| 10 | | | | | | | | |

**Utility Notes to Customer**

**It is the expectation of the Utility and Customer that the load sheet will be processed consistent with the timelines in the flowchart attached on page 4 of the load sheet. In the event that the Utility deviates from the timelines, the Utility will provide customer with an explanation as soon as practicable and a modified timeline as soon as it can be determined.**

**Utility will provide least-cost design to Customer once the standard allowance has been factored into the construction charges.**
**Utility will provide estimated scope, estimated design/construction window, and preliminary CIAC figure within 20 business days from receipt of complete service request.**

**Utility acknowledges that receipt of the complete load form starts the initial service request process which will be considered day 0.**
**Utility agrees to keep Customer informed of the status of the service request consistent with the flowchart attached on page 4 of the load sheet. If Customer needs to provide easement, ROW or other documents, Utility will notify Customer within 5 business days of receipt of complete load sheet.**

LOAD SHEET
Customer:__________________________
Project:____________________________

# Petroleum Industry – Electric Load Requirements Form

## Temporary Power

**Will temporary power for construction be required prior to installation of permanent service?** YES ◯ NO ◉

If yes, specify: Phase/Voltage: ___________ , Load in KW:___________, Date Requested:_______________

Provide map or sketch of proposed temporary power location, including address, and GPS Coordinates. Temporary construction power may not be available in all locations. There will be a cost charged for the installation and removal of facilities required to provide Temporary construction power. Please designate party that will be responsible for Temporary Service Charges:

Customer ◉ General Contractor ◯ Electrical Contractor ◯ Other ____________

## Easement, Agreement and Payment

**Service Agreements:**
In addition to this Electric Load Requirements Form, a Facilities Extension Agreement (FEA), Discretionary Services Agreement (DSA), or Letter of Agreement (LOA) will be required prior to construction scheduling.

<u>All Service Agreements must be signed by the end use customer or developer.</u>

**Easements:**
Facilities that must be placed on private property (on-site or off-site) to serve customer facilities will require an easement. On-site easements require platted easements for the facility placement or easement by separate instrument, in which case customer is required to provide a metes & bounds survey and copy of the warranty deed. <u>Utility will notify customer to specify the necessary documents required to schedule construction.</u> Off-site easements from third parties will need to be obtained at customer's expense. Easements will be obtained pursuant to Utility's tariff. All required easements must be secured prior to construction scheduling.

**Right of Way (ROW):**
Customer is responsible for providing a clear ROW in which to place proposed facilities on customer-owned facilities and property.

**Contribution in Aid of Construction (CIAC):**
Should providing the requested services result in costs to the customer, payment must be received prior to construction scheduling. The following Service Requests will typically result in a CIAC:

- **Non-Standard Facilities** (e.g., Two-Way Feed, Vault Service, Underground Off-Site Work)
- **Standard Service where cost to serve exceeds the Standard Allowance**
- **Excess Facilities** (e.g., customer requests facilities in excess of minimum required to provide service)
- **Temporary Service** (e.g., facilities which, in the opinion of the Company, will be used for less than 60 months)

Please designate the party that will be responsible for payment of potential costs associated with providing permanent electrical service to this project. Please select only one:

Customer ◉ General Contractor ◯ Electrical Contractor ◯ Other ____________

## Scheduling

Project Authorization Date: The project must be authorized before material is ordered and construction is scheduled. Prior to Authorization, all applicable payments, easements and agreements must be executed and received.
**Construction Ready Date:** The date that utility can physically begin construction to bring electric service up to customer's facilities. If construction is required on customer's property, customer is required to clear necessary ROW within easements, have pole locations staked, and underground lines located, upon utility request.
**Requested Service Date:** The date that customer has requested utility to provide permanent electric service. The length of time required between each of the dates is determined based on material lead time requirements and scope of the work required by utility to complete construction. Customer will be contacted as soon as a construction start date is determined. The Construction Ready Date will be a mutually agreed upon date and will be established once customer has approved the preliminary design. Customer will contact utility to apply for a new meter installation and obtain an Electric Service ID number (ESI-ID). Customer also will contact a Retail Electric Provider (REP) and request a meter installation. Customer should request the install date to follow the estimated completions of construction and any city or county electrical inspection, if required.

## Acknowledgement

Signing and returning this document obligates the Customer and/or Contractor to Terms & Conditions expressed herein:

| | | |
|---|---|---|
| Signature | Printed Name | Title/Company |
| Best Contact Phone Number | E-mail Address | Date Signed |

Company Use ONLY: WR#: Date Completed Form Received by Utility

**LOAD SHEET**
**Customer:**__________________________
**Project:**____________________________

## OPTIONAL COMMENTS PAGE

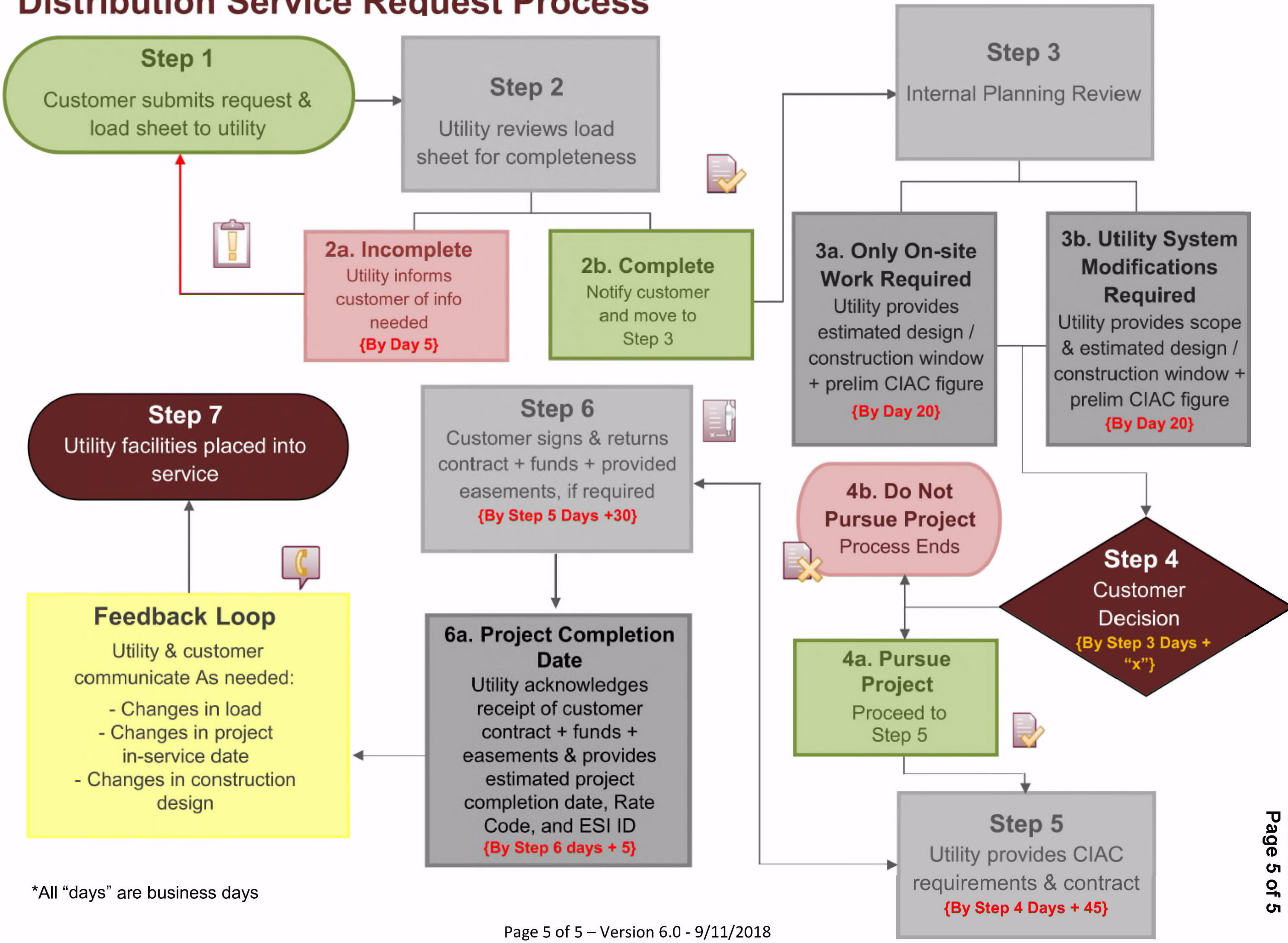
Customer and Project Name (as stated on first page):

________________________________________

Please enter your additional comments below:

**LOAD SHEET**
**Customer:** ____________________
**Project:** ____________________

# Distribution Service Request Process




*All "days" are business days