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ENTERGY TEXAS, INC'S STATEMENT OF INTENT AND APPLICATION FOR AUTHORITY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

Direct Testimony and Exhibits

of

JEFFRY POLLOCK

On Behalf of

Texas Industrial Energy Consumers

October 26, 2022

J. POLLOCK
INCORPORATED

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Table of Contents

LIST OF EXHIBITS

GLOSSARY OF ACRONYMS

Term	Definition
AED-4CP	Average and Excess Four Coincident Peak
AFC	Additional Facilities Charge
Big Cajun 2	Big Cajun 2 Unit No. 3
CCGT	Combined Cycle Gas Turbine
CCN	Certificate of Convenience and Necessity
CCOSS	Class Cost-of-Service Study
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
ETI	Entergy Texas, Inc.
FERC	Federal Energy Regulatory Commission
GCRR	Generation Cost Recovery Rider
IS	Interruptible Service
kV	Kilovolt
kW/kWh	Kilowatt, Kilowatt-Hours
LMR	Load Modifying Resources
MCPS	Montgomery County Power Station
MGRT	Miscellaneous Gross Receipts Taxes
MISO	Midcontinent Independent System Operator
MW/MWh	Megawatt, Megawatt-Hour
Nelson 6	Roy S. Nelson Unit No. 6
OCAPS	Orange County Advanced Power Station
O&M	Operation and Maintenance
SMS	Standby and Maintenance Service
SWEPCO	Southwestern Electric Power Company
TIEC	Texas Industrial Energy Consumers

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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, which have been prepared in written form for introduction into evidence in SOAH Docket No. 473-22-04394 and Public Utility Commission of Texas Docket No. 53719; 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 October 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.

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 Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. Since graduation in 1975, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. My qualifications are documented in **Appendix A.** A partial list of my appearances 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 are customers of Entergy Texas, Inc. (ETI), and they purchase electricity under various rate schedules.

Q WHAT ISSUES ARE YOU ADDRESSING?

A My testimony addresses:

- Depreciation Expense;
- HEB Backup Generators;
- Winter Storm Uri;
- Class Cost-of-Service Study;
- Schedule IS; and
- Schedule SMS.

Q ARE YOU SPONSORING ANY EXHIBITS TO YOUR DIRECT TESTIMONY?

A Yes. I am sponsoring **Exhibits JP-1** through **JP-4** and **Appendix C**. These exhibits were prepared under my supervision and direction. **Appendix C** discusses the procedures for conducting a CCOSS.

Q ARE YOU ADDRESSING ALL OF THE ISSUES IDENTIFIED BY THE COMMISSION IN THIS PROCEEDING?

A No. However, the fact that I am not addressing every issue should not be interpreted as an endorsement of ETI's proposals in this proceeding.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS.

A My findings and recommendations are as follows:

Depreciation Expense

- Higher annual depreciation expense accounts for nearly $109 million of the proposed $131 million net base revenue increase. Three proposed changes include reducing the lifespan for the Montgomery County Power Station (MCPS) from 38 years to 30 years; accelerating the depreciation of its coal units: Roy S. Nelson 6 (Nelson 6) and Big Cajun 2 Unit No. 3 (Big Cajun 2); and increasing depreciation expense for Sabine 4 to include new investment, which along with the existing investment, would be fully recovered by 2026.

- ETI's proposed 30-year lifespan for MCPS is based on a single technical report and reflects the practices of other Entergy affiliates for newly commissioned combined cycle gas turbine (CCGT) units. However, it is a common practice in the industry for depreciation rates for CCGTs to be based on a 40-year lifespan.

- The Commission has previously approved a 40-year lifespan for the Lamar Stall plant owned by Southwestern Electric Power Company (SWEPCO).

- The Commission should reduce the depreciation rate for MCPS to reflect a 40-year lifespan.

- Accelerating the depreciation of Nelson 6 and Big Cajun 2 is the result of deactivation studies that purport to justify drastic reductions in the remaining lives of these units. However, establishing a deactivation date for a specific generating unit is not a formal retirement decision.

- The studies that informed ETI's revised deactivation dates are not full retirement analyses that compare the cost and benefits of early retiring these plants to alternative courses of action, and are otherwise problematic. Further, the projected benefits of deactivation were less than [redacted] of the costs associated with continued operations. This difference is insignificant and well within the margin of error of the projections. Importantly, ETI's studies do not measure the benefits and costs of continuing to operate Nelson 6 and Big Cajun 2 for their entire 60-year lifespans.

- Although a specific retirement date for Big Cajun 2 has not yet been decided, the majority owners have committed to retiring the unit no later than December 31, 2032.

- The Commission should reject ETI's proposed changes to the assumed useful lives of both Nelson 6 and Big Cajun 2. The assumed useful life of Nelson 6 should not be changed. It would reasonable to approve revised depreciation rates for Big Cajun 2 that recognize a December 31, 2032 retirement date.

- ETI currently assumes that Sabine 4 will be retired and removed from service in 2026. However, this assumption is based on two contingencies that have yet to occur: (1) ETI receives a Certificate of Convenience and Necessity (CCN) for the Orange County Advanced Power Station (OCAPS) and places OCAPS in service in 2026 and (2) ETI receives approval from MISO to retire Sabine 4 in 2026.

- The Commission should retain the current depreciation rate for Sabine 4.

HEB Backup Generators

- ETI is proposing to include all the costs associated with backup generators installed at two separate HEB grocery stores. The backup generators would supply these stores when ETI is unable to do so because of outages. Thus, the backup generators would virtually guarantee an uninterruptible power supply to the two HEB stores.

- The full cost of the backup generators that would be included in base rates would be only partially offset by the payments received from HEB.

- ETI did not quantify the benefits of the backup generators to ETI's captive customers. Based on the size and characteristics of the backup generators and current capacity market prices in the Midcontinent Independent System Operator (MISO), the potential benefits to ETI's captive customers are insignificant.

- Therefore, ETI's captive customers are subsidizing HEB's backup generators. This is contrary to the Commission's long-standing policy to set rates that reflect the cost to provide service.

- Backup generation is not a natural monopoly. ETI can offer to help customers install backup generators provided that the costs are not subsidized by captive customers.

- The Commission should not charge captive ratepayers for the costs of HEB's backup generators.

Winter Storm Uri

- The test year was impacted by Winter Storm Uri. Although the extreme and catastrophic nature of the storm and the power supply disruptions that it caused were unprecedented, they are not recurring. Accordingly, it is essential to normalize the test year in setting rates in this case.

- ETI estimated that it sold 44,290 fewer megawatt hours (MWh) as a direct result of Winter Storm Uri. However, energy sales in February (as billed in March) were 10% to 14% lower than the energy sales in the two prior winter months.

- Failure to restore the sales lost due to Winter Storm Uri results in understating test-year revenues and billing determinants, which means that ETI's test-year revenue deficiency and tariff charges are overstated.

- Based on ETI's estimated lost sales, test-year base revenues are understated by approximately $2.3 million.

- The Commission should increase ETI's test-year base revenues by at least $2.3 million. Further, ETI should quantify the lost sales by rate schedule.

Class Cost-of-Service Study

- With two notable exceptions, ETI's class cost-of-service (CCOSS) properly recognizes the different types of costs, as well as the different ways electricity is used by various customers. Further, the methodologies used in the study comport with accepted industry practice and Commission precedent.

- ETI's proposed allocation of miscellaneous gross receipts taxes (MGRT) is not consistent with cost causation because it allocates the taxes to all customer classes, irrespective of whether the revenues are from customers located within or outside of municipalities. MGRT are caused by the revenues collected from customers located *within* municipalities—they are not caused by outside-city customers.

- The demand loss factors in ETI's CCOSS are based on an average of the peak demand losses over twelve months. However, ETI uses the Average and Excess Four Coincident Peak (AED-4CP) method to allocate generation and transmission plant and related expenses to customer classes. The 4CPs used in formulating the AED-4CP allocation factors are the coincident demands during the summer months, June through September. Thus, the loss factors used to restate the 4CP demands should reflect the summer peak losses, not the average of the twelve-month peak demand losses.

- The CCOSS should be revised to allocate MGRT expenses on in-city revenues and to use the summer peak demand losses to derive the 4CPs used in formulating the AED-4CP demand allocation factors. With these two revisions, ETI's CCOSS should be used to set base rates in this proceeding.

Schedule IS

- ETI is proposing to remove the off-peak provision. This provision allows an interruptible customer to increase the amount of Firm Contract Power when the customer is operating at higher loads during off-peak hours. It does not change a customer's obligation to curtail load down to the customer's Firm Contract Power, and the customer would still have to curtail the same amount of interruptible load.

- Eliminating this provision would force a customer to curtail firm load or increase the amount of Firm Contract Power in order to maintain the same level of reliability. Either option would force the customer to incur significant additional costs.

- The Commission should reject ETI's proposal because it is unnecessary to impose additional costs/risks on interruptible customers, and ETI provided no explanation for this proposed change. Further, ETI should be capable of offering the appropriate amount of load modifying resources (LMRs) into MISO to avoid incurring any non-compliance penalties.

<u>*Schedule SMS*</u>

- ETI is proposing to limit Maintenance Service to not more than six outages or 90 days per Contract Year, whichever is reached first.

- MISO does not limit maintenance outages to 90 days per generating station per planning year.

- Like ETI, customers may, in some years, potentially require more than 90 days for major maintenance outages or to maintain multiple generators. They may not be able to properly maintain their generators if there are unnecessary constraints on the number and duration of outages.

- Schedule SMS assumes that some amount of standby power is provided throughout the year.

- The Commission should reject ETI's proposal because it is unduly discriminatory, and ETI has failed to explain why these specific limitations (*i.e., only* six times or 90 days per Contract Year) are necessary.

2. DEPRECIATION EXPENSE

Q WHAT DEPRECIATION-RELATED ISSUES ARE YOU ADDRESSING?

A I address ETI's proposal to establish a 30-year lifespan for the MCPS; to accelerate depreciation of its coal units: Nelson 6 and Big Cajun 2; and to increase its depreciation rates to fully recover its investment in Sabine 4, including new capital expenditures, by 2026. Together ETI's proposals would increase annual depreciation expense by $[redacted] million.

<u>Montgomery County Power Station</u>

Q IS ETI CURRENTLY RECOVERING ITS INVESTMENT IN THE MONTGOMERY COUNTY POWER STATION?

A Yes. ETI is currently recovering depreciation on the MCPS investment through its Generation Cost Recovery Rider (GCRR). The MCPS GCRR was implemented in Docket No. 51381.[1]

Q WHAT LIFESPAN WAS ASSUMED IN SETTING THE DEPRECIATION EXPENSE?

A Pursuant to a settlement agreement, the depreciation expense is based on a 38-year lifespan.

Q WHAT WOULD BE THE IMPACT OF SHORTENING THE LIFESPAN FROM 38 TO 30 YEARS?

A Shortening the lifespan of MCPS from 38 to 30 years would increase annual

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[1] *Application of Entergy Texas, Inc. to Establish a Generation Cost Recovery Rider Related to the Montgomery County Power Station*, Docket No. 51381, Unopposed Stipulation and Settlement Agreement at 2 (Dec. 16, 2020). *See also*, Docket No. 51381, *Order* at 4 (Jan. 14, 2022).

depreciation expense by about $[redacted] million.

Q WHY IS ETI PROPOSING TO SHORTEN THE LIFESPAN TO 30 YEARS?

A ETI cites information provided by the MCPS equipment manufacturer, Mitsubishi, and a technology summary report published by the Electric Power Research Institute (EPRI) for a CCGT with a 2x1 configuration and technology similar to MCPS. According to the EPRI report, the expected unit life is 30 years.[2]

Q DID ETI ANALYZE WHETHER A 30-YEAR LIFESPAN WAS CONSISTENT WITH INDUSTRY PRACTICE?

A No. ETI did not conduct any industry assessments of the expected lifespans of CCGTs, other than noting that the four CCGTs constructed by the Entergy Operating Companies all assumed 30-year lifespans.[3]

Q ARE YOU AWARE OF ANY DECISIONS BY STATE REGULATORY COMMISSIONS REGARDING THE LIFESPANS OF COMBINED CYCLE GAS TURBINE UNITS FOR RATEMAKING PURPOSES?

A Yes. For example, this Commission approved a 40-year useful life for the Stall CCGT, which is operated by SWEPCO. Specifically, in its last rate case, SWEPCO filed a depreciation study which assumes that the Stall plant would have a 40-year useful life.[4] This assumption was incorporated in determining the approved base revenue requirement.

[2] ETI Response to TIEC 2-2.

[3] ETI Response to TIEC 2-3.

[4] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 51415, Direct Testimony of Jason A. Cash, Exhibit JAC-2 at 24 (Oct. 14, 2020).

Additionally, in the GCRR case I compiled a list of CCGT units operated by utilities with authorized 40-year lifespans for ratemaking purposes. These specific CCGTs are listed in **Exhibit JP-1**. The list includes CCGT's placed in commercial operation through 2016.

Q IS THE USE OF A 40-YEAR LIFESPAN FOR COMBINED CYCLE GAS TURBINES CONSISTENT WITH THE PLANNING ASSUMPTIONS USED BY OTHER UTILITIES AND ADOPTED BY REGULATORY COMMISSIONS?

A Yes. Based on my involvement in resource planning cases for various utilities, I am aware that a 40-year useful life for CCGTs is a common practice.[5]

Further, the Energy Information Administration (EIA) also assumes a 40-year useful life for advanced CCGTs in comparing the levelized busbar costs of different generation technologies. **Exhibit JP-2** provides an excerpt from EIA's 2020 Capital Cost Study published with the 2020 Annual Energy Outlook report.

Q HAVE YOU UPDATED YOUR ANALYSIS OF THE COMBINED CYCLE GAS TURBINE LIFESPAN FOR UNITS THAT WERE PLACED IN SERVICE AFTER 2016?

A Yes. **Exhibit JP-3** lists CCGTs that were placed in service after 2016 for which information about the lifespans used for determining the annual book depreciation expense was readily available. Although there can be exceptions, I believe that 40 years is a more common practice than 30 years.

[5] For example, it is a common practice for PacifiCorp, Southern Company, XCEL Energy and Duke Energy Progress.

Q WHAT DO YOU RECOMMEND?

A The Commission should approve a 40-year lifespan for MCPS.

Nelson 6 and Big Cajun 2

Q WHAT LIFESPANS IS ETI PROPOSING FOR NELSON 6 AND BIG CAJUN 2?

A ETI is proposing to dramatically reduce the remaining lives for Nelson 6 and Big Cajun 2. Specifically, the remaining life of Nelson 6 would be reduced from [redacted] years to [redacted] years, while the remaining life of Big Cajun 2 would be reduced from [redacted] years to [redacted] years. The much shorter lifespans will significantly increase the annual depreciation expense for these units.

Q WHAT IS ETI'S OWNERSHIP SHARE OF NELSON 6 AND BIG CAJUN 2?

A ETI has partial ownership of the Nelson 6 and Big Cajun 2 coal units. Specifically, ETI owns 29.75% (approx. 156 megawatts) of Nelson 6 and 17.85% (approx. 100 megawatts) of Big Cajun 2.[6] Together, Nelson 6 and Big Cajun 2 account for approximately $[redacted] million of undepreciated investment.

Q WHO ARE THE OTHER OWNERS OF NELSON 6 AND BIG CAJUN 2?

A Nelson 6 is jointly owned by Sam Rayburn G&T, Inc. (10%), East Texas Electric Cooperative, Inc. (9.1%), Entergy Louisiana, LLC (40.25%) and EAM Nelson Holding LLC (10.9%).[7] Thus, ETI and its affiliates own approximately 80.9% of Nelson 6.[8]

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[6] Direct Testimony of Beverly Gale at 7-8.

[7] *Id.* at 7.

[8] Direct Testimony of Anastasia R. Meyer at 13.

The other co-owners of Big Cajun 2 are Louisiana Generation, LLC (58%) and Entergy Louisiana, LLC (24.15%)[9]. Collectively ETI and its affiliate own 42% of Big Cajun 2.[10]

Q WHY IS ETI PROPOSING TO ACCELERATE DEPRECIATION OF NELSON 6 AND BIG CAJUN 2?

A In ETI's last rate case, depreciation rates were set assuming that Nelson 6 would remain in operation until [redacted] while Big Cajun 2 would remain in operation until [redacted] However, since the last rate case, ETI changed its planning assumptions. Specifically, ETI is proposing deactivation dates of [redacted] for Nelson 6 and [redacted] for Big Cajun 2.[12] Thus, when these units are retired, they will have been in service for approximately [redacted] years and [redacted] years, respectively, rather than the 60-year lifespan used in the depreciation study filed in ETI's last rate case. Accordingly, shortening the lifespans by [redacted] years and [redacted] years, respectively, would increase annual depreciation expense by [redacted] million per year (Nelson 6) and [redacted] million per year (Big Cajun 2Th). ETI's new assumed deactivation dates are consistent with Entergy's publicly announced commitment to cease burning coal by the end of 2030 as part of its 2050 net-zero carbon commitment.[13]

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[9] *Id*. at 15-16.

[10] *Id*.

[11] *Id*. at 12 (Highly Sensitive).

[12] *Id.*

[13] ETI's Response to TIEC 4-9; see also *https://cdn.entergy.com/userfiles/content/environment/docs/ClimateReportAddendum_2020.pdf*

Q DOES ESTABLISHING A DEACTIVATION DATE FOR A SPECIFIC GENERATING UNIT MEAN THAT THE UNIT WILL BE RETIRED ON THE INDICATED DEACTIVATION DATE?

A No. Establishing a deactivation date for a specific generating unit is not a formal retirement decision. It merely reflects ETI's current expectation of the useful life of a generating unit.[14] ETI admits that a decommissioning date has not been established for either Nelson 6 or Big Cajun 2.[15] Thus it remains uncertain when these plants would actually be retired. The new deactivation assumptions merely represent ETI's current expectation of when retirement will occur.

Q HAVE YOU REVIEWED THE DEACTIVATION STUDIES THAT INFORMED ETI'S REVISED DEACTIVATION DATES?

A Yes. The studies that informed ETI's revised deactivation do not establish that it is economic for these resources to be retired at the new assumed deactivation dates. As an initial matter, the projected benefits of deactivation for these plants were less than 1% of the costs associated with continued operations. This difference is insignificant and well within the margin of error of the projections.

Moreover, ETI's deactivation analyses are not full retirement studies. Instead, they are limited deactivation assessments based on ETI's preconceived notions of when these plants should be retired. For example, ETI did not evaluate the costs and benefits of operating Nelson Unit 6 through its previously assumed useful life compared to the costs and benefits over that horizon of early retiring that plant and

[14] Direct Testimony of Anastasia R. Meyer at 8.

[15] ETI's Responses to TIEC 4-4 and 4-8.

replacing it with an alternative source of power. Instead, it conducted a limited assessment of whether Nelson Unit 6 should be retired in 2026 or 2030, comparing it only to [redacted] over that time frame. Similarly, ETI's deactivation assessment of Big Cajun 2 was limited to reviewing whether it would be economic to deactivate that unit by [redacted]

These analyses fail to demonstrate that the going forward costs of operating a generating unit through its useful life are exceeded by the benefits of retiring and replacing the capacity provided by the unit.[16] Both Nelson 6 and Big Cajun 2 have been depreciated based on assumed useful lives of 60 years, which was a common practice for coal units. Hence, any decision to retire the units or to dramatically increase costs on ratepayers by assuming new, earlier retirement dates should examine the costs and benefits of early retirement over those 60-year lifespans. ETI has not demonstrated that heaping costs upon ratepayers to dramatically change the assumed deactivation dates for ratemaking purposes for units that have been in

[16] I note that these deactivation assessments raise other questions. For example, during the limited period covered by the assessment, they assume future gas prices that are [redacted] the average closing price of NYMEX gas future contracts traded through September 30, 2022. All other things being equal, [redacted] the projections ETI used in its deactivation assessments going forward, this would impact ETI's analysis of whether actually retiring the plants at the new assumed deactivation dates is economic. Market conditions fluctuate, and ETI will have to undertake a full analysis based on the best information available at the time the actual retirement decision is made. In the meantime, ETI's limited deactivation assessments do not support a major increase in its depreciation rates (and corresponding increase in charges to ratepayers).

service for only [redacted] years and [redacted] years, respectively, would be reasonable.

Q PLEASE DESCRIBE ETI'S ROLE IN MANAGING NELSON 6 AND BIG CAJUN 2, RESPECTIVELY.

A ETI and its affiliates are majority owners in Nelson 6. Thus, ETI can play a major role in determining the retirement date of Nelson 6. ETI and its affiliates are minority owners of Big Cajun 2, which is operated by CLECO. However, ETI is on the Management Advisory Committee for the plant and has input on planning decisions.[17]

Q HAS ETI ADVOCATED FOR THE RETIREMENT OF EITHER PLANT?

A When asked whether it has advocated for the retirement of these plants to other entities that own a share of them, ETI responded that, other than its corporate commitment to cease burning coal by 2030, it has not made any public announcements about the retirement of Nelson 6 or its share of the relevant Big Cajun 2 unit.[18]

Q HAVE THE MAJORITY OWNERS OF BIG CAJUN 2 MADE ANY ANNOUNCEMENTS ABOUT RETIRING THE UNIT?

A Yes. Although a specific retirement date has not yet been decided, the majority owners have committed to retiring the unit no later than December 31, 2032.[19]

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[17] ETI's Response to TIEC 4-2, TP-53719-00TIE004-X002-00001 HSPM Big Cajun II 3 JOPOA at TIEC 4-2 LC2251.

[18] ETI's Response to TIEC 4-9.

[19] Direct Testimony of Anastasia R. Meyer at 16.

Q HAS THE COMMISSION RECENTLY CONSIDERED ISSUES REGARDING AN EARLY RETIRED COAL PLANT?

A Yes. In Docket No. 51415, the Commission was faced with the question of how to handle SWEPCO's decision to retire the Dolet Hills plant in December 2021, when the previously approved assumed lifespan was until 2046.[20] Of interest here, the Commission ordered that the remaining undepreciated investment in the plant would be recovered based on a useful life of 2046,[21] notwithstanding that it also found the decision to retire the plant in 2021 was prudent.[22] The Commission found that this treatment "equitably balances the interests of SWEPCO and both its current and future customers."[23]

Similarly, in Docket No. 40443 (a proceeding filed in 2012), the Commission determined that Welsh Unit 2 should continue to be depreciated based on a 2040 assumed useful life even though SWEPCO had entered into a federal consent decree agreeing to retire it in 2016.[24]

Q WHAT CONCLUSIONS DO YOU DRAW FROM THIS PRECEDENT?

A I conclude that the Commission will carefully evaluate the impact on ratepayers of a

[20] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 51415, Final Order at FOFs 45, 48 (Jan. 14, 2022).

[21] *Id.* at FoFs 61, 63.

[22] *Id.* at FoF 50.

[23] FoF 63.

[24] *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443 PFD at 176-77, adopted by Order on Rehearing at FoFs 198-99 (Mar. 6, 2014). The Commission also found that SWEPCO had failed to justify its decision to retire Welsh Unit 2 more than 20 years early with thorough analysis, and that it would be appropriate to evaluate the prudence of retiring that plant once the retirement had occurred. Order On Rehearing at FoF 119 and 125A. As discussed above, ETI has likewise failed to justify its new deactivation assumptions, which do not even rise to the level of retirement decisions, with thorough analysis.

utility's decision to retire a plant earlier than expected. Changing an assumed deactivation date dramatically can result in significant cost burdens on the utility's current ratepayers. The Commission has recognized that in these two recent cases and mitigated the impact, even where the retirement is practically certain to occur. In this case, the impacts to ratepayers from ETI's are also significant, and ETI itself states that no formal decisions regarding retirement of either plant at issue has been made.

Q WHAT DO YOU RECOMMEND?

A The Commission should reject ETI's proposed new deactivation dates for both Nelson 6 and Big Cajun 2. However, because the majority owners have committed to retiring Big Cajun 2 by no later than December 31, 2032, it would be reasonable to reduce the lifespan for that unit by 10 years in determining the appropriate depreciation expense. However, there should be no change in the lifespan of Nelson 6. The proposed departure from the existing retirement date would substantially increase costs on ratepayers. Further, ETI has not conducted a full retirement study, and MISO has not made a determination as to whether the plant will be needed to maintain reliability after the proposed retirement date.

<u>Sabine 4</u>

Q WHAT IS DRIVING THE INCREASE IN THE ANNUAL DEPRECIATION EXPENSE FOR SABINE 4?

A There have been recent capital additions, and the [redacted] million in the annual depreciation expense of Sabine 4 is driven by ETI's assumption that the unit, including those new additions, will be retired and removed from service in 2026.[25]

Q WHAT IS THE BASIS FOR ETI'S ASSUMPTION THAT SABINE UNIT NO. 4 WILL BE RETIRED IN 2026?

A The 2026 retirement date assumes that ETI completes and places OCAPS in commercial operation by that time. ETI is currently seeking a CCN for OCAPS.[26] As of the filing date of this testimony, the CCN application is still pending.

Q IS THE OPERATIONAL DATE OF THE ORANGE COUNTY ADVANCED POWER STATION KNOWN?

A No. Although ETI plans to place OCAPS in service in 2026, it is not clear that it can do so, even if the Commission approves the CCN. Additionally, even if OCAPS is placed in service as scheduled, it is unclear that ETI will be able to retire Sabine 4 without further approval from MISO. Thus, the retirement of Sabine 4 is contingent upon the receipt of a CCN for OCAPS, placing OCAPS into commercial operation in 2026, and MISO approval to retire the unit in 2026.

Q WHAT DO YOU RECOMMEND?

A Given that the retirement decision for Sabine 4 is contingent, and the contingencies are as yet unresolved, the current depreciation rate should remain in effect.

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[25] *Application of Entergy Texas, Inc. to Amend its Certificate of Convenience and Necessity to Construct Orange County Power Station*; Docket No. 52487, Direct Testimony of Abigail B. Weaver at 18 (Sept. 16, 2021).

[26] *Application of Entergy Texas, Inc. to Amend its Certificate of Convenience and Necessity to Construct Orange County Power Station*; Docket No. 52487.

3. HEB BACKUP GENERATORS

Q DOES ETI'S APPLICATION INCLUDE ANY CAPITAL ADDITIONS THAT ARE SITED ON CUSTOMER PREMISES?

A Yes. The Company's application includes the costs associated with backup generators installed at two separate HEB grocery stores. The first of these generators, identified as C6PPWS1337, was commissioned in 2019 at a store located in The Woodlands. The second generator, C6PPTX004, was commissioned in 2021 for a store located in Beaumont. Each of these projects includes three 400 kW natural gas generators, totaling 1.2 MW at each location. Together, the installed cost of these backup generators is $2,504,234.[27] ETI has described the backup generators as "experimental programs."[28]

Q ARE THESE BACKUP GENERATORS CONNECTED TO ETI'S SYSTEM?

A Yes. I understand that both generators are located adjacent to the HEB stores and are connected to the distribution system on ETI's side of the meter. Thus, the backup generators are similar in concept to the mobile generators leased by various ERCOT utilities to facilitate power restoration during a major outage event.

Q HOW DOES ETI INTEND TO OPERATE THE BACKUP GENERATORS?

A During normal operating conditions, the Company states that the backup generators would be available for dispatch or to provide ancillary services. During outages, such as those caused by widespread generator failures or damages to delivery lines as

[27] Direct Testimony of Stuart Barrett at 27.

[28] *Id.*

experienced during Winter Storm Uri or Hurricane Laura, the generators would supply backup power to the affected HEB sites.

Q HOW DOES ETI PROPOSE TO RECOVER THE COSTS OF THE BACKUP GENERATORS?

A ETI proposes to include the investment in the backup generators in rate base. The corresponding operating expenses would be included in test-year operation and maintenance expense. The fuel costs to operate the backup generators would be considered eligible fuel expense. Offsetting these costs are the revenues charged to HEB under ETI's Additional Facilities Charge (Schedule AFC) rider, which are included in other operating revenues.[29] As discussed later, HEB is paying for only a fraction of the costs for the backup generators that primarily benefit HEB. Thus, ETI's captive customers would pay the majority of costs for HEB's backup generators.

Q HAS ETI QUANTIFIED THE SPECIFIC COSTS TO HEB AND ITS OTHER CUSTOMERS ASSOCIATED WITH THE HEB BACKUP GENERATORS?

A No, ETI has only stated that it has included the costs associated with the HEB backup generators in rate base without isolating the specific impacts of these resources.[30]

Q WHAT IS THE BASIS FOR YOUR ASSERTION THAT HEB IS PAYING FOR ONLY A FRACTION OF THE COSTS OF THE BACKUP GENERATORS?

A The annual revenue requirement associated with a $2.5 million investment is approximately $334,000 per year. This assumes annual fixed costs of 13.32% under

[29] ETI Response to TIEC 1-24.

[30] ETI Response to TIEC 2-10.

Option A of the Schedule AFC.[31] This is a conservative estimate of the annual revenue requirement of the two HEB generators because it assumes that investment is recovered on a levelized basis. The reality is the annual revenue requirement of a new investment is higher in the early years because it is undepreciated.

Of the $334,000 per year levelized annual cost, HEB is being charged [redacted] per month for backup service at The Woodlands location and [redacted] per month at the Beaumont location.[32] Thus, HEB is paying [redacted] per year for having dedicated backup generators. The remaining [redacted] per year would be paid by ETI's captive customers.

Q DO THE HEB BACKUP GENERATORS OFFER SIGNIFICANT CAPACITY BENEFITS TO ETI'S CAPTIVE CUSTOMERS?

A No, and ETI did not site the generators based on system-reliability concerns (*i.e.,* in transmission-constrained areas or areas requiring voltage support). Further, the auction clearing price from MISO's 2022/2023 Planning Resource Auction for Local Resource Zone 9, which includes parts of the state of Texas, was just $2.88 per MW-day. At this rate, the combined 2.4 MW of the HEB backup generators results in a benefit of just $2,523 annually.[33] Thus, ETI's proposal would require captive ETI customers to pay roughly 100 times more in base rates than they would pay through the Planning Resource Auction. This cost recovery method would result in HEB receiving a significant subsidy from ETI's captive customers for capacity for which it

[31] 1.11% (Schedule AFC Option A monthly charge) x 12 =13.32%.

[32] ETI Response to TIEC 2-9; Addendum No. 1 (HSPM).

[33] $2.88 per MW-day x 2.4 MW x 365 days = $2,522.88.

would primarily, if not exclusively, receive the benefits.

Q IS IT REASONABLE FOR ETI'S CAPTIVE CUSTOMERS TO PAY FOR THE COSTS OF THE BACKUP GENERATORS IN THE MANNER ETI PROPOSES?

A No. The backup generators are sited specifically at the HEB locations, and HEB has first call on the power generated from the backup generators when ETI is unable to supply power from its system. During outages caused by major storm events, widespread damage to delivery infrastructure is common. When the distribution system is compromised in these events, the backup generators will be unable to supply energy to other customers, and HEB would be the exclusive beneficiary of the generators in these instances. Further, if the gas supply is compromised, or the facilities are damaged during a storm, their ability to provide backup power would be compromised.

Q DO YOU HAVE ANY OTHER CONCERNS ABOUT THE HEB BACKUP GENERATORS?

A Yes. ETI is providing backup generation service to HEB at only a fraction of the cost to HEB by subsidizing HEB through its other customers. This is contrary to the Commission's long-standing policy, and ETI's overarching proposal in this case, to set rates to recover the actual cost to serve. Backup generation is not a natural monopoly. As such, it is not a service that ETI needs to offer. However, if ETI chooses to subsidize backup generation, it should not do so at the expense of its captive customers.

Q IS ETI PROPOSING TO EXPAND THE INSTALLATION DEDICATED OF BACKUP GENERATORS THROUGHOUT ITS SERVICE TERRITORY?

A Yes. Last August, ETI refiled its Power Through program with the goal of deploying [redacted] MW of backup generators throughout its service territory.[34] The structure of the proposed Power Through program is very similar to the structure of the agreements with the two HEB stores. A third party would supply the generation equipment that ETI would own, and ETI would oversee the installation, which would be located at the premises of hosting customers and installed on ETI's side of the electric meter. The entire cost of the backup generators would be included in ETI's revenue requirement, and ETI would charge the backup customers for approximately one-third of the non-fuel cost. In addition, the backup customers would receive a credit for the margins received by ETI when the generators are dispatched by MISO.[35] If approved and assuming full deployment, the subsidies that ETI's captive customers are paying for the backup generation would increase more than 30-fold.

Q WHAT DO YOU RECOMMEND?

A Backup generation is not a service that ETI should provide through its regulated operations. The amount of capacity and the corresponding benefits to ETI's customers are insignificant compared with the costs. Thus, the costs and revenues from the backup generators that primarily benefit HEB should be removed from ETI's test-year revenue requirement. If ETI chooses to supply this service, it should do so through an

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[34] ETI Response to Cities 1-12 (HSPM).

[35] *Entergy Texas, Inc.'s Statement of Intent and Application for Approval of Rate Schedule UODG (Utility-Owned Distributed Generation)*, Direct Testimony of David E. Hunt, Exhibit DEH-1 (Aug. 31, 2022).

unregulated affiliate, and captive customers other than the host customer should not be charged for it.

4. WINTER STORM URI

Q DOES 2021 REPRESENT A TYPICAL TEST YEAR?

A No. In early 2021, ETI and many other Texas utilities were impacted by the ice, snowfall and historically low temperatures of Winter Storm Uri, which led to fuel supply shortages, generator failures, and ultimately, widespread blackouts. ETI was directly impacted by the storm from February 14 to February 20, with impacts lingering through March 1.[36] This extreme event and the catastrophic results are hardly commonplace, and do not represent conditions that would be expected to recur on an annual basis.

Q WERE ETI'S CUSTOMERS AFFECTED BY WINTER STORM URI?

A Yes. The effects of Winter Storm Uri were felt throughout the various power regions in the south including ERCOT, the Southwest Power Pool and MISO. The effects included significant electrical outages. ETI estimates that because of Winter Storm Uri, energy sales were 44,290 MWh lower than in the previous period.[37]

Q HAS ETI MADE ANY ADJUSTMENTS TO ITS TEST-YEAR SALES AS A RESULT OF WINTER STORM URI?

A No. Although ETI used a standard weather normalization process, it made no specific adjustment to reflect the lost sales due to Winter Storm Uri.

Q WHY WOULD A STANDARD WEATHER NORMALIZATION PROCESS FAIL TO RECOGNIZE LOST SALES DUE TO WINTER STORM URI?

A Weather normalization adjusts the recorded kWh sales for the periods affected by

[36] ETI Response to TIEC 1-39.

[37] ETI Response to TIEC 1-40.

unusual weather.[38] For example, in a warmer than average year, customers might be expected to increase consumption in summer months as they utilize more cooling appliances. Conversely, in cooler than average years, customers would increase consumption in winter months as they turn on their heating appliances. However, it cannot adjust for kWh sales that never happened because of the widespread outages that occurred during Winter Storm Uri. This adjustment would not account for the Winter Storm Uri-related generation failures and blackouts.

Q IS THERE EVIDENCE THAT ETI EXPERIENCED HIGHER LOST SALES DUE TO WINTER STORM URI THAN IT ESTIMATED?

A Yes. Table 1 shows ETI's unadjusted kWh sales for the months January through March 2021. These sales represent kWh billed rather than kWh consumed in a given month, and there is consequently an approximate one-month lag in the data. In other words, the kWh sales shown in March were actually consumed in prior months, including January and February. Because Winter Storm Uri affected ETI's service area in February, the impacts would be observed in the kWh sales billed in March.

Table 1
Billed Energy Sales
(MWh)

Month	Sales	Difference from March
January 2021	1,561,639	219,444
February 2021	1,489,284	147,088
March 2021	1,342,195	-

Source: Schedule O-1.2.

[38] ETI Response to TIEC 1-41.

As Table 1 demonstrates, the energy billed in March for February usage was 10% to 14% below the energy billed in January and February for usage in December and January. While not all of the difference is due to Winter Storm Uri, it clearly demonstrates how Winter Storm Uri had a significant impact on test-year sales, which, in turn, resulted in lower test-year revenues.

Q ARE ETI'S TEST-YEAR SALES AND REVENUES REASONABLE ABSENT ADJUSTING FOR LOST SALES DUE TO WINTER STORM URI?

A No. Without an explicit adjustment made for these lost sales in the test year, the adjusted base revenues and billing determinants are understated. Consequently, ETI's revenue deficiency would be overstated, and, because less energy was sold, the billing determinants used to design the proposed rates are understated.

Q HAVE YOU QUANTIFIED THE IMPACT OF WINTER STORM URI ON ETI'S TEST-YEAR PRESENT BASE REVENUES?

A ETI's unadjusted present base, DCRF, TCRF, and GCRR revenues excluding customer charges is approximately $1,017 million.[39] Based on the test-year adjusted sales of 19,283,712 MWh, ETI's average rates for the 2021 test year are $52.74.[40] Thus, adjusting for lost sales due to Winter Storm Uri would have increased ETI's present base revenues by approximately $2.3 million.

Q WHAT DO YOU RECOMMEND?

A Because the events and aftermath of Winter Storm Uri are not expected to recur on

[39] Schedule Q-7.

[40] Schedule O-1.1.

an annual basis, ETI's present test-year revenues should be adjusted to reflect the revenues lost as a result of Winter Storm Uri. Further, the test-year billing determinants should be adjusted to reflect the higher kWh sales. ETI should quantify the lost sales by rate schedule.

5. CLASS COST-OF-SERVICE STUDY

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

A With one exception, yes. ETI's CCOSS recognizes the different types of costs as well as the different ways electricity is used by various customers.

In particular, ETI is proposing to use the AED-4CP method to allocate production and transmission plant and related expenses as well as wholesale transmission costs and revenue credits. AED-4CP has been adopted by this Commission in rate cases since prior to Docket No. 16705 (in 1996).[41]

Q DO YOU AGREE WITH ALL OF ETI'S PROPOSED ALLOCATION METHODS?

A No. First, ETI's proposed allocation of MGRT is not consistent with cost causation because it allocates the taxes to all customer classes, irrespective of whether the revenues are from customers located within or outside of municipalities. MGRT are caused by the revenues collected from customers located *within* municipalities — they are not caused by outside-city customers.

Second, ETI is using the wrong loss factors to adjust the demands from the meter to the generation level. Specifically, the peak demand loss factors are based on the average peak demand losses over twelve months. This is inconsistent with the use of the AED-4CP method, which places emphasis on peak demands during the four summer months (June through September). However, even after replacing the

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[41] *Application of Entergy Texas for Approval of its Transition to Competition Plan and the Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to set Revised Fuel Factors, and to Recover a Surcharge for Under-Recovered Fuel Costs*, Docket No. 16705, Second Order on Rehearing at FoF No. 221 (Oct. 14, 1998).

12CP loss factors with the 4CP peak demand loss factors, the peak demand losses for transmission-level voltages are higher than the corresponding energy losses. As explained later, consistent with the laws of physics, peak demand losses must be higher than the corresponding energy losses.

Background

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

A A CCOSS is an analysis used to determine each class's responsibility for the utility's costs. Thus, it determines whether the revenues generated by a class cover the class's cost of service. A CCOSS 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 for conducting a CCOSS are discussed in **Appendix C**.

Miscellaneous Gross Receipts Tax

Q WHAT ARE MISCELLANEOUS GROSS RECEIPTS TAXES?

A MGRT are state taxes imposed on each utility company's taxable gross receipts derived from sales in an incorporated city or town having a population of more than 1,000 according to the last federal census preceding the filing of the report.[42] Thus, MGRT are levied only on inside-city sales.

[42] Tex. Tax. Code § 182.022.

Q HOW IS ETI PROPOSING TO ALLOCATE MISCELLANEOUS GROSS RECEIPTS TAXES IN THIS PROCEEDING?

A ETI is proposing to allocate MGRT to all retail customer classes based on total base revenues. Total base revenues include sales from customers that are located both within and outside of incorporated municipalities.

Q IS ETI'S APPROACH CONSISTENT WITH COST CAUSATION?

A No. MGRT are not caused by total revenues. MGRT are caused by taxable receipts (*i.e.,* revenues) from business done inside incorporated municipalities.

Q IS ETI'S PROPOSED ALLOCATION OF MISCELLANEOUS GROSS RECEIPTS TAXES CONSISTENT WITH COMMISSION PRECEDENT?

A No. In the 2013 SWEPCO rate case, the Commission found:

> 278. Miscellaneous gross receipts taxes are caused by taxable receipts from business done within incorporated municipalities. The cost of miscellaneous gross receipts taxes should be directly allocated to customer classes based on inside-city revenues.[43]

Further, in Docket No. 46449, the Commission approved a CCOSS that allocated MGRT on inside-city revenues, consistent with the Commission's prior order. The Commission also approved a CCOSS in Southwestern Public Service Company's most recent litigated rate case (Docket No. 43695) that allocated MGRT on inside-city revenues.

[43] *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Order on Rehearing, FoF No. 278 (Mar. 6, 2014).

Q HOW SHOULD MISCELLANEOUS GROSS RECEIPTS TAXES BE ALLOCATED?

A MGRT should be allocated relative to inside-city revenues.

Loss Factors

Q HOW ARE THE LOSS FACTORS DERIVED?

A The loss factors used in a CCOSS are derived from a loss study. A loss study determines the fixed and variable losses that occur when an electric utility generates and delivers electricity to retail customers. As explained in **Appendix C**, not all customers take service at the same delivery voltage. A utility incurs more losses to serve customers at lower delivery voltages. Thus, in order to allocate costs equitably to the various classes of service on an electric power system, all of the customer sales volumes, both peak (demand) and annual energy measured at the meter, must be adjusted to one common voltage level; normally the generation level. In that way, customers that take power and energy at various voltage levels are only responsible for the losses that they cause the system to incur. For example, if demand and energy allocation factors of all classes of service are adjusted to a common level, customers that take power at the transmission levels are not allocated costs associated with losses that are incurred on the primary or secondary distribution levels. The output of a loss study consists of the peak (demand) and energy loss factors.

Q HAVE YOU REVIEWED THE LOSS STUDY USED BY ETI TO DERIVE THE DEMAND AND ALLOCATION FACTORS?

A Yes. ETI's loss study consisted of seven separate EXCEL workbooks. A summary of ETI's peak demand and energy losses is provided in Table 2.

Table 2
Summary of ETI's Loss Study

Delivery Voltage	Demand	Energy
Secondary	7.832%	7.680%
Primary	5.722%	4.799%
Transmission < 230 kV	1.098%	1.640%
Transmission ≥ 230 kV	0.2464%	0.4137%

Source: Schedule P-7.2.

As Table 2 demonstrates, the demand loss factors are higher than the energy loss factors except for delivery at transmission voltages.

Q DO YOU HAVE ANY CONCERNS WITH THE LOSS STUDY?

A Yes. There appears to be a fundamental problem with the loss factors used by ETI in its CCOSS. Losses are a function of electrical current, and current is highest during peak periods. Accordingly, the peak demand losses *should* be higher than energy losses. Despite the physics behind the variable losses incurred by electric utilities, the energy loss factors used by ETI in this proceeding (which measure the average losses incurred over all 8,760 hours) are higher than the corresponding peak demand loss factors for power delivered at transmission voltages.

Q DOES IT MAKE SENSE THAT THE DEMAND LOSS FACTORS WOULD EVER BE LOWER THAN THE CORRESPONDING ENERGY LOSS FACTORS FOR THE SERVICE PROVIDED AT TRANSMISSION VOLTAGE?

A No. At the time of peak demand on the power grid, the overall current passing through the system is at its highest level during the year. Since power loss varies exponentially with the current, the percentage loss at the time of the highest demand on the system should be significantly greater than the average energy percentage loss experienced throughout the year.

Q IS ETI USING THE CORRECT DEMAND LOSS FACTORS?

A No. Based on a review of the workpapers underlying the loss factors used in ETI's CCOSS, it appears that the demand loss factors were understated. This is because the demand loss factors were derived from load flow analysis during the peak hours in each of the twelve months of the year.[44] ETI, however, used the AED-4CP method to allocate production and transmission plant and related expenses. The 4CPs used in the AED-4CP are derived from the demands coincident with ETI's system peaks in the summer months, June through September. Thus, the use of 12CP demand loss factors is inconsistent with the AED-4CP method, which reflects summer peak demands.

Q HAVE YOU DEVELOPED THE LOSSES USING THE 4CP PEAK LOAD FLOWS?

A Yes. Table 3 summarizes the demand losses using the 4CP rather than the 12CP peak load flows.

Table 3
Demand Losses

Delivery Voltage	4CP	12CP
Secondary	8.329%	7.832%
Primary	6.357%	5.722%
Transmission < 230 kV	1.255%	1.098%
Transmission ≥ 230 kV	0.3271%	0.2464%

As Table 3 demonstrates, the demand losses are higher using the 4CP rather than the

[44] Direct Testimony of Khamsune Vongkamchanh at 90.

12CP peak load flows.

Q HAVE YOU DEVELOPED REVISED ALLOCATION FACTORS USING THE 4CP DEMAND LOSSES?

A Yes. The revised AED-4CP allocation factors are shown in **Exhibit JP-4**. The use of the 4CP rather than the 12 CP loss factors better reflects the conditions that occur in each of the summer months used in defining the average and excess demands. As a result of these changes, the Residential, Small General, General, and Large General Service classes experience a minor increase in the AED-4CP allocators relative to ETI's proposed factors improperly derived using the 12CP loss factors. Conversely, the Large Industrial Power Service and Lighting classes would decrease as a result of using the 4CP loss factors.

Q WOULD USING THE 4CP LOSSES ADDRESS YOUR CONCERNS WITH ETI'S LOSS STUDY?

A Partially. Although the 4CP demand losses compare more favorably to the corresponding energy losses, the energy losses for the transmission voltages are still higher. As previously stated, this result is implausible and requires further justification.

Q WHAT DO YOU RECOMMEND?

A The 4CP demand losses and the resultant allocation factors derived in **Exhibit JP-4** should be used in the CCOSS.

6. SCHEDULE IS

Q WHAT IS SCHEDULE IS?

A Schedule IS is a rider to Schedules LIPS and LIPS-TOD for Interruptible Service. It provides a service option under which a customer can designate a certain portion of load as interruptible. Further, Schedule IS allows customers to opt for either no notice interruptions or 5-minute notice interruptions. In return for agreeing to curtail interruptible load, the customer receives a credit for the amount of interruptible power provided. The current Schedule IS credits are:

(a) No notice requirement: $4.88 per billing kW per month.
(b) Five (5) minute notice requirement: $3.75 per billing kW per month.

Q UNDER WHAT CIRCUMSTANCES CAN ETI CALL AN INTERRUPTION?

A Schedule IS states:

> Interruption shall be requested by Company ***at the discretion of the Company*** as the Company deems necessary for any reason including, but not limited to, maintaining service to firm loads, avoiding establishment of a new system peak, maintaining service integrity in the area or other situations when reduction in load on the Company's system is required.[45] (emphasis added.)

Q WHAT IS THE CUSTOMER'S OBLIGATION WHEN AN INTERRUPTION IS CALLED?

A A customer is obligated to curtail all interruptible load. This effectively limits the customer to operating at the customer's Firm Contract Power. Schedule IS defines Firm Contract Power as:

> Firm Contract Power – the amount of Kilowatts (kW) Customer intends to exclude from interruptions as defined herein…Firm Contract Power will be the

[45] Entergy Texas, Inc., Section III Rate Schedules, Schedule IS, Sheet No. 29, Section V.

> amount of Kilowatts (kW) contracted for under this rider schedule or subsequently established per Section III above.[46]

Q DOES THE SCHEDULE ALSO DEFINE THE MAXIMUM AMOUNT OF POWER THAT IS SUBJECT TO INTERRUPTION?

A Yes. Schedule IS defines Interruptible Contract Power as:

> The maximum amount of Kilowatts (kW) Customer has designated as subject to interruptions. ***This amount of Kilowatts is subject to interruptions in both on-peak and off-peak periods***.[47] (emphasis added.)

Q IS ETI PROPOSING ANY CHANGES TO THE TERMS AND CONDITIONS THAT WILL AFFECT HOW SCHEDULE IS CUSTOMERS ARE REQUIRED TO OPERATE?

A Yes. Although ETI is not proposing to change the requirement that compliance with the terms of an interruption means that the customer must reduce to the Firm Contract Power, ETI is proposing to change how the amount of Firm Contract Power is calculated if an interruption were to occur during off-peak hours. Specifically, ETI is proposing that the Firm Contract Power would no longer be subject to the off-peak provision of the firm rate. This change would require the customer to curtail more than the amount of power designated by the customer as subject to interruption during off-peak hours.

Q HAS ETI PROVIDED ANY EXPLANATION SUPPORTING THIS CHANGE?

A No. This specific change is not discussed in the testimony of ETI's rate design witness, Ms. Crystal K. Elbe.

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[46] *Id.*, Section VI B.

[47] *Id.*, Section VI A.

Q HOW WILL THIS CHANGE AFFECT THE WAY THAT SCHEDULE IS CUSTOMERS OPERATE?

A ETI's proposal will not affect how a customer operates except during off-peak hours. For example, Table 4 shows how the Interruptible Power Billing Load would be calculated assuming that a Schedule IS customer has the same peak operating demand in both on-peak and off-peak hours.

Table 4
Schedule IS Interruptible Billing Demand

Description	Demand (kW)	Tariff Section
1. Firm Contract Power	10,000	VI.B. (Assumption)
2. Interruptible Contract Power	10,000	VI.A. (Assumption)
3. Total Contract Power	20,000	VI.C. (1. + 2.)
4. Minimum Billing Demand	12,000	III. (1. + 20% x 2.)
5. Peak Operating Demand	20,000	Assumption
6. Interruptible Power Billing Load (*i.e.,* IS Credit)	10,000	III. (5. – 1.)

As can be seen, the customer has specified a 10,000 kW Firm Contract Power and 10,000 kW Interruptible Contract Power. Based on the terms of Schedule IS, the Interruptible Power Billing Load, which is the amount of load that determines the credit payment, is the difference between the customer's peak operating demand and Firm Contract Power. Assuming a 20,000 kW peak operating demand, the customer would receive a credit for 10,000 kW of Interruptible Power.

Q WHAT IS THE OFF-PEAK PROVISION THAT ETI WANTS TO CHANGE?

A The off-peak provision allows a customer to increase its operating load during off-peak hours without incurring an additional demand charge. For interruptible customers, the off-peak provision provides:

> In case the monthly maximum measured 30-minute demand occurs during an off-peak period and is greater than Contract Power, such monthly maximum kW load will be reduced by 33-1/3% but will not be thereby reduced to a smaller number of kW than Contract Power, nor less than stipulated in §§ VI (C) [2,500 kW].[48]

Under this provision, Schedule IS provides that:

> If at any time the maximum demand in a month exceeds Total Contract Power, which shall be the sum of Firm Contract Power and Interruptible Contact Power, the increment shall serve to increase Firm Contract Power.[49]

In other words, if an interruptible customer responds to the price signals by increasing load during off-peak periods, such that the customer's total load exceeds its Total Contract Power, the amount of the customer's Firm Contract Power would increase.

Q CAN YOU PROVIDE AN EXAMPLE SHOWING THE INTERACTION BETWEEN THE AMOUNT OF FIRM CONTACT POWER AND THE OFF-PEAK PROVISION?

A Yes. Table 5 below demonstrates how the amount of Firm Contract Power is affected by the off-peak provision. It uses the same example as in Table 4 above, except that the customer's peak operating demand is 25,000 kW, and it occurs during off-peak hours. In this example, the customer's peak operating demand increases from 20,000 kW to 25,000 kW and the latter occurs during off-peak hours.

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[48] Entergy Texas, Inc., Section III Rate Schedules, Schedule LIPS, Sheet No. 26, Section V.

[49] Entergy Texas, Inc., Section III Rate Schedules, Schedule IS, Sheet No. 28, Section III Billing Amounts.

Table 5
Illustration of Off-Peak Provision
In Schedule IS

Description	Peak	Off Peak	Tariff Section
1. Firm Contract Power	10,000	15,000	VI.B. & III. (Assumption)
2. Interruptible Contract Power	10,000		VI.A. (Assumption)
3. Total Contract Power	20,000		VI.C. (1. + 2.)
4. Minimum Billing Demand	12,000		III. (1. + 20% x 2.)
5. Peak Operating Demand	20,000	25,000	Assumption
6. Interruptible Power Billing Load (*i.e.,* IS Credit)	10,000	10,000	III. (5. – 1.)

As Table 5 demonstrates, applying the off-peak provision of Schedule IS results in a similar increase in the customer's Firm Contract Power from 10,000 kW to 15,000 kW.

The bottom line is that the off-peak provision ensures that a customer does not have to curtail more load than the customer's Interruptible Contract Power.

Q HOW WOULD THIS CHANGE UNDER ETI'S PROPOSAL THAT WOULD ELIMINATE THE OFF-PEAK PROVISION?

A Under ETI's proposal, if a curtailment was called during off-peak hours when the customer was operating at 25,000 kW, the customer would be obligated to curtail 15,000 kW. This would exceed the customer's Interruptible Contract Power.

Q WOULD THE CUSTOMER BE IN COMPLIANCE WITH THE TERMS OF THE CURRENTLY EFFECTIVE SCHEDULE IS IF THE CUSTOMER CURTAILED LOAD FROM 25,000 KW TO 15,000 KW?

A Yes. Schedule IS requires a customer to curtail load down to the Firm Contract Power amount. Based on the above examples, the customer would be required to curtail load down to 10,000 kW during on-peak hours and 15,000 kW during off-peak hours. In both instances, the customer curtailed the same amount of Interruptible Power Billing Load: 10,000 kW. Thus, the customer would have fully complied with the terms and conditions under the current Schedule IS.

Q WOULD ETI'S PROPOSAL IMPOSE ADDITIONAL COSTS ON A SCHEDULE IS CUSTOMER?

A Yes. Requiring a customer to curtail more load than its Interruptible Contract Demand (irrespective of the customer's peak operating demand) could jeopardize the reliability of the customer's manufacturing operations and/or reduce the customer's revenues. Further, if the customer was required to increase the amount of Firm Contract Power in order to maintain the same level of reliability, the customer would incur significant additional costs. In a competitive environment, such increases in cost cannot be easily recovered.

Q CAN ETI EXERT SOME CONTROL TO PREVENT INCURRING ADDITIONAL COSTS FROM MISO DUE TO THE OFF-PEAK PROVISION?

A Yes. ETI submits offers to MISO for a specific amount of LMRs that are subject to curtailment as ordered by MISO. If the offers specify a lower amount of LMRs during off-peak periods that reflect the off-peak provision, it would not be necessary to force Schedule IS customers to curtail more interruptible load than the amount of their Interruptible Contract Demand to avoid extra costs and other penalties or fees that MISO may impose.

Q WHAT DO YOU RECOMMEND?

A The Commission should reject ETI's proposal to delete the off-peak provision in Schedule IS.

7. SCHEDULE SMS

Q WHAT IS SCHEDULE SMS?

A Schedule SMS (Standby and Maintenance Service) is applicable to customers that use self-generation to supply a portion of their electricity requirements. These customers contract for either Standby and/or Maintenance Service from ETI to replace capacity or energy normally generated by the customer's on-site generation.

Q WHAT IS STANDBY POWER?

A Standby (or Back-up) power is defined in the Commission's Substantive Rules as follows:

> Electric energy or capacity supplied to replace energy or capacity ordinarily generated by a qualifying facility's own generation equipment during an unscheduled outage of the qualifying facility.[50]

Thus, Back-up power is available at any time.

Q WHAT IS MAINTENANCE POWER?

A Maintenance power is electric energy or capacity supplied during a scheduled outage of the qualifying facility.[51]

Q ARE BACK-UP AND MAINTENANCE POWER THE SAME?

A No. Unlike Back-up power, Maintenance Service must be arranged in advance (currently with a 24-hour prior notice) only during such times as determined by ETI in its sole discretion. Schedule SMS states:

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[50] 16 T.A.C. § 25-242(c)(2).

[51] *Id.,* at (c)(7).

> ***Maintenance Service will be available on 24-hour prior notice only during such times and at such locations that, in Company's sole opinion, will not result in affecting adversely or jeopardizing firm service to other Customers, prior commitments for Maintenance Service to other Customers, or commitments to other utilities.*** Arrangements and scheduling of Maintenance Service will be agreed in writing in advance of use or confirmed in writing if arranged verbally. Where there are applications from more than one Customer, or Service applied for is more than Company has available, Company will allocate and schedule available service, in its final judgment, and curtail or cancel application. Where Maintenance Service stands requested, agreed and scheduled, but not taken, Customer will be obligated to pay for such service same as scheduled, if Company has refused to supply some other Customer similar service in order to limit total Maintenance Service to that which Company considers available. Maintenance Service will be scheduled for a continuous period of not less than one day.[52] (emphasis added.)

In other words, the availability of Maintenance Service is totally at ETI's discretion. ETI can choose to offer Maintenance Service and it can also decide to cancel such service if it would result in adversely affecting or jeopardizing firm service to other customers and/or prior commitments.

Thus, Maintenance Service is of a lower quality than Back-up or Standby service. Because ETI can limit the amount of Maintenance Service, it is more likely that customers will schedule Maintenance Service during the non-summer months.

Q IS ETI PROPOSING ANY CHANGES TO SCHEDULE SMS?

A Yes. ETI is proposing several changes. First, it would require a customer to provide five days advance notice to schedule Maintenance Service. Second, ETI is also proposing to limit the duration of Maintenance Service to six times or 90 days per Contract Year, whichever is reached first. Third, ETI is proposing that a customer be

[52] Entergy Texas, Inc., Section III Rate Schedules, Schedule SMS, Sheet No. 58, Section III B.

billed without a contract for firm service on the General Service rate schedule and sign a contract for firm service.[53]

Q DO ETI'S PROPOSED CHANGES RAISE ANY CONCERNS?

A Yes. ETI's proposed changes are neither necessary nor reasonable. Further, limiting the frequency and duration of Maintenance Service is improper and unduly discriminatory.

Q HOW DOES ETI JUSTIFY INCREASING THE ADVANCE NOTICE REQUIREMENT FOR MAINTENANCE SERVICE FROM 24 HOURS TO FIVE DAYS?

A ETI states that:

> The proposed change to the prior notification requirement in Schedule SMS is consistent with a customer's planning for a co-generation unit outage because a customer will need to know the schedule for any planned work in advance and be required to schedule crews and material for the co-generation unit's maintenance outage.[54]

Q DOES ETI'S JUSTIFICATION SUPPORT INCREASING THE ADVANCE NOTICE REQUIREMENT?

A No. First, not all maintenance outages have to be planned in advance. For example, if the customer sees a developing problem that could jeopardize the reliability and/or performance of its generating unit, the customer may want to take a maintenance outage sooner rather than wait for five days. This would be better than waiting until the unit sustains a forced outage. Second, the present 24-hour notice will not impose a burden because, as previously stated, ETI is not obligated to provide Maintenance

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[53] Direct Testimony of Crystal K. Elbe at 48.

[54] ETI Response to TIEC 3-6(b).

Power unless ETI has sufficient available capacity.

Q WHY DOES ETI PROPOSE TO LIMIT THE DURATION OF MAINTENANCE SERVICE TO NO MORE THAN SIX TIMES PER CALENDAR YEAR OR 90 CALENDAR DAYS PER CONTRACT YEAR, WHICHEVER IS REACHED FIRST?

A ETI asserts that the proposal is necessary to prevent an SMS customer from relying on Maintenance Service throughout the year instead of paying for firm service.[55]

Q DO SMS CUSTOMERS HAVE ANY INCENTIVE TO MISUSE MAINTENANCE SERVICE IN THE MANNER ETI ASSERTS?

A No. Behind-the-meter generation is typically an integral part of a customer's production processes. SMS customers, thus, have a strong incentive to maximize production by minimizing generator outages, including for maintenance.

Q DOES MISO IMPOSE THE SAME LIMITATIONS ON THE DURATION OF MAINTENANCE OUTAGES BY ETI'S GENERATING UNITS AS ETI IS PROPOSING FOR SCHEDULE SMS?

A No. MISO does not impose the same limitations on ETI's generating units. According to MISO's Business Practices Manual, BPM-11, ETI would not be penalized ***unless a generating unit were to sustain a full or partial outages that are planned and/or scheduled and reasonably expected to encompass ninety or more of the first 120 calendar days in the Planning Year***.[56] (emphasis added)

[55] ETI Response to TIEC 3-6(c).

[56] ETI Response to TIEC 3-7.

Q UNDER WHAT CIRCUMSTANCES WOULD MISO'S BPM-11 APPLY TO BEHIND-THE-METER GENERATION?

A BPM-11 would apply if ETI purchases firm capacity from a customer's behind-the-meter generation.

Q DO THESE CIRCUMSTANCES APPLY TO ALL SMS CUSTOMERS?

A No. Even in the rare circumstance that an SMS customer were to sell firm capacity to ETI, which would be accredited by MISO, it is highly likely that MISO BPM-11 would be incorporated in a purchased power agreement to prevent MISO from penalizing ETI. Otherwise, the requirements under the current Schedule SMS are more than sufficient.

Q WHY ELSE WOULD THE PROPOSED LIMITATIONS ON MAINTENANCE SERVICE BE UNREASONABLE?

A Customers are periodically required to perform extensive maintenance on major equipment such as rebuilding a boiler or turbine generator. Such major turn downs typically occur every 3-5 years depending upon the manufacturers. Further, such turn downs could require up to 90 days to complete, per generator. Similarly, if customers have multiple generating units to maintain, it may not be feasible to perform the necessary maintenance on all generators if Maintenance Service is limited to only six times per Contract Year.

Q WOULD USING MAINTENANCE SERVICE AT VARIOUS TIMES OF THE YEAR REPRESENT A MISUSE OF THIS SERVICE?

A No. First, as previously stated, Maintenance Service is typically provided during off-peak hours. This is when capacity is generally more readily available. For ETI, the off-peak hours occur in over 270 days per calendar year. Maintenance Service is also less costly during off-peak hours.

Second, some customers operate multiple generating units. They cannot absorb the risks of performing maintenance on generating units in a single outage and, thus, the outages of each generating unit could be staggered throughout the year.

Q HAS ETI OFFERED ANY COST JUSTIFICATION FOR LIMITING MAINTENANCE SERVICE?

A No. For example, in Docket No. 48371, ETI designed Schedule SMS on the assumption that about 8% of standby service occurs coincident with ETI's system peak.[57] Thus, the SMS Demand charges already account for some level of Back-up and/or Maintenance Service occurring throughout a Contract Year. Further, the Schedule SMS Energy charges are time differentiated. Specially, the on-peak Energy charge is nearly ten times the corresponding off-peak Energy charge. This provides a substantial price signal for customers to avoid any type of standby service during on-peak hours. It also means that customers that are unable to avoid such outage will pay a proper cost-based rate.

Q WHAT DO YOU RECOMMEND?

A The Commission should reject ETI's proposal to impose any limits on the frequency and duration of Maintenance Service per Contract Year.

[57] *Entergy Texas Inc's Statement of Intent and Application for Authority to Change Rates,* Docket No. 48371, ETI Rate Filing Package, Schedule Q-7/WP, page 16.

8. CONCLUSION

Q WHAT FINDINGS SHOULD THE COMMISSION MAKE BASED ON YOUR RECOMMENDATIONS?

A I recommend that the Commission make the following findings:

- Reject ETI's proposed changes in depreciation rates for Montgomery County, Nelson 6, Big Cajun 2, and Sabine 4.
- Approve a 40-year lifespan in setting the depreciation rate for Montgomery County Power Station and an eleven-year remaining life for resetting the depreciation rate Big Cajun 2.
- Reject ETI's proposal to include the cost of two backup generators in its test-year revenue requirement.
- Adjust present base revenues by $2.3 million and adjust the billing determinants to reflect the lost sales due to Winter Storm Uri.
- Approve ETI's CCOSS with the exception of the allocation of MGRT and the demand losses.
- Allocate MGRT to rate classes using the proportion of base revenues recovered from customers located inside-cities.
- Reject ETI's use of the 12CP demand losses and adopt the 4CP demand losses.
- Reject ETI's proposed change to Schedule IS that would eliminate the off-peak provision in determining the amount of Firm Contract Power during a curtailment.
- Reject ETI's proposal to limit the frequency and duration of Maintenance Service provided under Schedule SMS to only six times and/or 90 days per Contract Year.

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

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

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
GEORGIA POWER COMPANY	Georgia Association of Manufacturers	44280	Direct	GA	Alternate Rate Plan, Cost Recovery of Major Assets; Class Revenue Allocation; Other Tariff Terms and Conditions	10/20/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Rebuttal	NY		10/18/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00155-UT	Direct	NM	Capacity Reservation Charge; Backup Power Charge; Maintenance Power; Distribution Capacity Costs	10/17/2022
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-21-630	Direct	MN	Class Cost-of-Service Study; Class Revenue Allocation; Multi-Year Rate Plan; Interim Rates; TOU Rate Design	10/3/2022
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320	Direct	NY	Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Rate Design	9/26/2022
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	22-00177-UT	Direct	NM	Renewable Portfolio Standard Incentive	9/26/2022
CENTERPOINT HOUSTON ELECTRIC LLC	Texas Industrial Energy Consumers	53442	Direct	TX	Mobile Generators	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Distribution Energy Storage Resource	9/16/2022
ONCOR ELECTRIC DELIVERY COMPANY LLC	Texas Industrial Energy Consumers	53601	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Tariff Terms and Conditions	8/26/2022
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
AUST N ENERGY	Texas Industrial Energy Consumers	None	Cross-Rebuttal	TX	Allocation of Production Plant Costs; Energy Efficiency Fee Allocation	7/1/2022
AUST N 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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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
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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

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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
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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

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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
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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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
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 NC.	Texas Industrial Energy Consumers	49494	Cross-Rebuttal	TX	ERCOT 4CPs; Class Revenue Allocation; Customer Support Costs	8/13/2019

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
AEP TEXAS NC.	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
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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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
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 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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY, PENNSYLVANIA POWER COMPANY AND WEST PENN POWER COMPANY	MEIUG, PICA and WPPII	2017-2637855 2017-2637857 2017-2637858 2017-2637866	Rebuttal	PA	Recovery of NITS Charges	3/22/2018
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas 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
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

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-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 UTILIT ES, 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
SHARYLAND UTILIT ES, 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, NC.	Western Kansas Industrial Electric Consumers	16-VICE-494-TAR	Surrebuttal	KS	Formula-Based Rate Plan	9/22/2016

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	16-G-0257	Rebuttal	NY	Embedded Class Cost of Service; Class Revenue Allocation; Rate Design	9/16/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Cross-Rebuttal	TX	Class Cost-of-Service Study;	9/7/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Surrebuttal	PA	Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	8/31/2016
VICTORY ELECTRIC COOPERATION ASSOCIATION, NC.	Western Kansas Industrial Electric Consumers	16-VICE-494-TAR	Direct	KS	Formula-Based Rate Plan	8/30/2016
WESTERN COOPERATIVE ELECTRIC ASSOCIATION, NC.	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 2016-2537352 2016-2537359	Rebuttal	PA	Class Cost-of-Service; Class Revenue Allocation	8/17/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Direct	TX	Revenue Requirement; Class Cost-of-Service; Revenue Allocation; Rate Design	8/16/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Direct	PA	Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	7/22/2016
FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	160021	DIrect	FL	Multi-Year Rate Plan, Construction Work in Progress; Cost of Capital; Class Revenue Allocation; Class Cost-of-Service Study; Rate Design	7/7/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Supplemental	AR	Support for Settlement Stipulation	7/1/2016
MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2016-0001	Direct	IA	Application of Advanced Ratemaking Principles to Wind XI	6/21/2016
NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Direct	MN	Class Cost-of-Service Study, Class Revenue Allocation, Multi-Year Rate Plan, Rate Design	6/14/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Surrebuttal	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, LCS-1 Rate Design	6/7/2016
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	15-00296-UT	Direct	NM	Support of Stipulation	5/13/2016
CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Cross	WY	Large Power Contract Service Tariff	4/15/2016
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Direct	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, Act 725, Formula Rate Plan	4/14/2016
CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Direct	WY	Large Power Contract Service Tariff	3/18/2016

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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, PRAIR E LAND ELECTRIC COOPERATIVE, NC., SOUTHERN PIONEER ELECTRIC COMPANY, THE VICTORY ELECTRIC COOPERATIVE ASSOCIATION, INC., AND WESTERN COOPERATIVE ELECTRIC ASSOCIATION, NC.	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, FR Mechanism, Seasonal FCR-24 Rates, Imputed Capacity	11/4/2015
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Rebuttal	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation	10/13/2015
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Direct	AR	Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan	9/29/2015
NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Direct	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation, Electric Rate Design	9/15/2015
SHARYLAND UTILIT ES	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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SHARYLAND UTILIT ES	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
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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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
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

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Surrebuttal	WY	Class Cost-of-Service, Rule 12 (Line Extension Policy)	9/19/2014
NDIANA 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
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41791	Direct	TX	Revenue Requirements, Fuel Reconciliation; Cost Allocation Issues; Rate Design Issues	1/10/2014
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Supplemental Surrebuttal	PA	Class Cost-of-Sevice Study	12/13/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Surrebuttal	PA	Class Cost-of-Service Study; Cash Working Capital; Miscellaneous General Expense; Uncollectable Expense; Class Revenue Allocation	12/9/2013
DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Rebuttal	PA	Rate L Transmission Service; Class Revenue Allocation	11/26/2013
ENTERGY TEXAS, INC. ITC HOLDINGS CORP.	Texas Industrial Energy Consumers	41850	Direct	TX	Rate Mitigation Plan; Conditions re Transfer of Control of Ownership	11/6/2013

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SHARYLAND UTILIT ES	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 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 UTILIT ES	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 KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Cross-Answering	KS	Cost Allocation Methodology	9/5/2013
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Direct	NM	Class Cost-of-Service Study	8/22/2013
WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Direct	KS	Class Revenue Allocation.	8/21/2013
ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41437	Direct	TX	Avoided Cost; Standby Rate Design	8/14/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-699	Direct	KS	Class Revenue Allocation	8/12/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Testimony in Support of Settlement	8/9/2013
MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Modification Agreement	7/24/2013
TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	130040	Direct	FL	GSD-IS Consolidation, GSD and IS Rate Design, Class Cost-of-Service Study, Planned Outage Expense, Storm Damage Expense	7/15/2013

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
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. 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
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

APPENDIX C

Procedures 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 by function (production, transmission, etc.). To a large extent, this is done in accordance with the Uniform System of Accounts developed by the Federal Energy Regulatory Commission (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 (or 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 (or 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.

Thus, a properly conducted CCOSS will recognize 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 HOW ARE COSTS ALLOCATED TO CUSTOMER CLASSES?

A Costs should be allocated to customer classes consistent with cost-causation principles. Some costs, such as metering, customer accounting and billing are caused by the number of customers weighted by the relative costs of metering. Other costs, such as production, transmission and a portion of distribution plant investment and related expenses, are caused by the demands imposed by customers coincident with peak demands. Finally, fuel and variable operating and maintenance costs are caused by the amount of energy purchased, adjusted for losses at the generation level.

Q WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER BETWEEN 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, and the amount of electricity that a customer uses. In general, industrial consumers are less costly to serve on a per unit basis because they:

(1) Operate at higher load factors;
(2) Take service at higher delivery voltages; and
(3) Use more electricity per customer.

These three factors explain why some customers pay higher 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. 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 also 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 do 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 those for a low load factor customer.

Exhibit JP-1

ENTERGY TEXAS, INC.
Combined Cycle Gas Turbine Power Plants
With 40-Year Lifespans

Line	Plant	Utility	Nameplate Capacity (MW)	In-Service Year	Retirement Year	Lifespan
		(1)	(2)	(3)	(4)	(5)
1	Martin Units 3 and 4	Florida Power & Light Company	612	1994	2034	40
2	Ft. Myers Unit 2	Florida Power & Light Company	1,721	2002	2043	41
3	Sanford Unit 5	Florida Power & Light Company	1,189	2002	2042	40
4	Sanford Unit 4	Florida Power & Light Company	1,189	2003	2043	40
5	Manatee Unit 3	Florida Power & Light Company	1,225	2005	2045	40
6	Martin Unit 8	Florida Power & Light Company	1,225	2005	2045	40
7	McIntosh Unit 10	Georgia Power Company	688	2005	2050	45
8	McIntosh Unit 11	Georgia Power Company	688	2005	2050	45
9	Mankato Energy Center	Xcel Energy	762	2006	2046	40
10	Turkey Point Unit 5	Florida Power & Light Company	1,225	2007	2047	40
11	High Bridge	Xcel Energy	606	2008	2048	40
12	Riverside	Xcel Energy	508	2009	2049	40
13	West County Units 1 and 2	Florida Power & Light Company	1,367	2009	2049	40
14	J. Lamar Stall	Southwestern Electric Power Company	569	2010	2050	40
15	McDonough Unit 4	Georgia Power Company	840	2011	2057	46
16	West County Unit 3	Florida Power & Light Company	1,367	2011	2051	40
17	McDonough Unit 5	Georgia Power Company	840	2012	2057	45
18	McDonough Unit 6	Georgia Power Company	840	2012	2058	46
19	Cape Canaveral Unit 3	Florida Power & Light Company	1,295	2013	2053	40
20	Riviera Beach Unit 5	Florida Power & Light Company	1,295	2014	2054	40
21	Port Everglades Next Generation Clean Energy Center	Florida Power & Light Company	1,338	2016	2056	40

Sources: S&P Global Market Intelligence.

FPL Ten Year Power Plant Site Plan 2019-2028, Submitted to the FPSC April 2019, Schedule 1, Existing Generating Facilities; FPL 2017 Depreciation Study Submitted to the FPSC, Docket No. 160021-EI.

Xcel Energy Upper Midwest Integrated Resource Plan 2020-2034, Docket No. E002/RP-19-368, Appendix F6: Resource Options, Table 3: Existing Natural Gas and Oil Resources.

PUCT Docket No. 46449, SWEPCO Rate Filing, Schedule D-6 (Retirement Data for all Generating Units).

Georgia Power Company's 2019 Rate Case, Docket No. 42516, Workpapers, Depreciation Study Summary, Current and Proposed Generating Unit Retirement Dates.

Independent Statistics & Analysis
U.S. Energy Information Administration

Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies

February 2020

Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies

To accurately reflect the changing cost of new electric power generators for AEO2020, EIA commissioned Sargent & Lundy (S&L) to evaluate the overnight capital cost and performance characteristics for 25 electric generator types. The following report represents S&L's findings. A separate EIA report, "Addendum: Updated Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity Generating Plants in the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS)," details subsequent updates to the EMM module.

The following report was accepted by EIA in fulfillment of contract number 89303019-CEI00022. All views expressed in this report are solely those of the contractor and acceptance of the report in fulfillment of contractual obligations does not imply agreement with nor endorsement of the findings contained therein. Responsibility for accuracy of the information contained in this report lies with the contractor. Although intended to be used to inform the updating of EIA's EMM module of NEMS, EIA is not obligated to modify any of its models or data in accordance with the findings of this report.

Sargent & Lundy

Capital Cost Study

Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies

Prepared for
U.S. Energy Information Administration,
an agency of the U.S. Department of Energy

Independent Statistics & Analysis
U.S. Energy Information Administration

FINAL REPORT | DECEMBER 2019

Contract No. 89303019CEI00022
SL-014940 | Project No. 13651.005

CASE 7. COMBUSTION TURBINE H CLASS, 1100-MW COMBINED CYCLE

7.1 CASE DESCRIPTION

This case is comprised of one block of a CC power generation unit in a 2x2x1 configuration. The plant includes two industrial frame Model H "advanced technology" CTs and one STG. Case 7 is based on natural gas firing of the CTs, although dual fuel capability is provided. Main plant cooling is accomplished with a wet cooling tower system. Output power voltage is stepped up for transmission to the external grid through an onsite switchyard.

7.1.1 Mechanical Equipment & Systems

Case 7 is comprised of a pair of Model H, dual fuel CTs in a 2x2x1 CC configuration (two CTs, two heat recovery steam generators [HRSGs], and one steam turbine) with a nominal output for the CC plant of 1114.7-MW gross. Each CT generates 385.2 MW gross; the STG generates 344.3 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 1083.3 MW. Refer to Figure 7-1 for a diagram of the Case 7 configuration.

Each CT's inlet air duct has an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT and plant output. Each CT is also equipped with burners designed to reduce NO_X emissions. Included in the Case 7 configuration are SCR units for further NO_X emissions reduction and CO catalysts for further CO emissions reduction.

The CTs are Model H industrial frame type CTs with an advanced technology design, since they incorporate the following features:

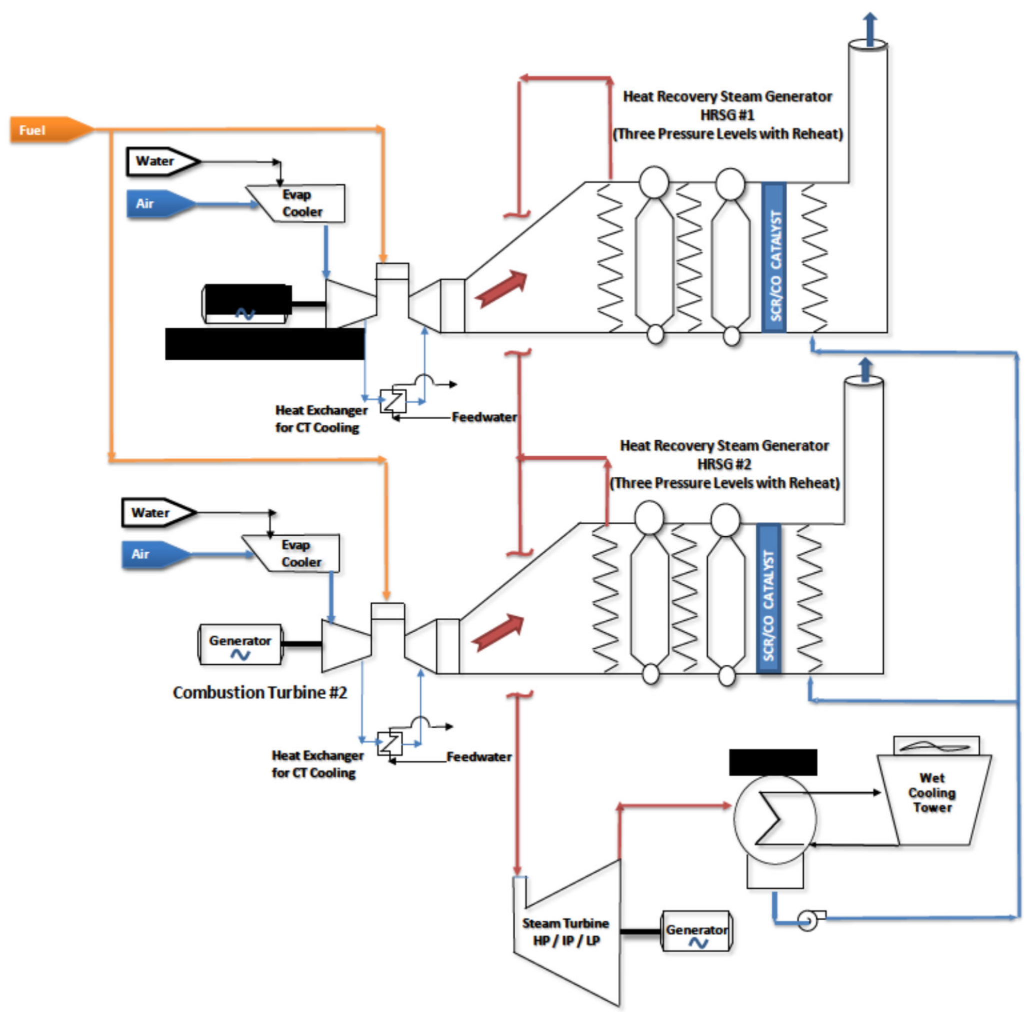
- High firing temperatures (~2900°F)
- Advanced materials of construction
- Advanced thermal barrier coatings
- Additional cooling of CT assemblies (depending on the CT model, additional cooling applies to the CT rotor, turbine section vanes, and the combustor). Refer to Figure 7-1, which depicts a dedicated additional cooler for the CT assemblies in Case 7.

The high firing temperature and additional features listed above result in increased MW output and efficiency of the CT as well as in the CC plant.

Hot exhaust gas from each CT is directed to a HRSG, with one HRSG per CT. Steam generated in the HRSGs is directed to the STG. HRSGs may be optionally equipped with additional supplemental firing, however, this feature is not included in Case 7. (Supplemental HRSG firing, while increasing the MW output of the STG, reduces plant efficiency.)

A wet cooling tower system provides plant cooling for Case 7. A wet cooling tower is preferred over the alternative ACC approach since plant performance is better (i.e., greater MW output and higher efficiency) and capital cost is generally lower. However, ACCs are often selected in areas where the supply of makeup water needed for a wet cooling tower is scarce or expensive, such as in desert areas in the southwestern United States.

Figure 7-1 — Case 7 Configuration



7.1.2 Electrical & Control Systems

Case 7 includes one 60-Hz electric generator per CT with an approximate rating of 390 megavolt amperes (MVA) and output voltage of 13.8 kV. The STG includes one 60-Hz electric generator with an approximate 350-MVA rating. The output power from the three generators is converted to a higher voltage by GSUs for transmission to the external grid, transmitted through an onsite facility switchyard.

The CC facility is controlled by a central DCS, which is linked to a CT control system provided by the CT manufacturer. This DCS includes controls for the steam cycle systems and equipment as well as BOP systems and equipment (e.g., water systems, fuel systems, main cooling systems).

7.1.3 Offsite Requirements

Offsite provisions in Case 7 include:

- **Fuel Gas Supply:** A half-mile-long pipeline and a dedicated metering station.
- **High-Voltage Transmission Line:** A one-mile long transmission line.
- **Water Supply for Cooling Tower, Evaporative Coolers, Makeup to Steam Cycle, and Miscellaneous Uses:** It is assumed that the water supply source is near the power plant site and the interconnection for water is at the plant's site boundary. Blowdown waste from the cooling tower and other areas of the plant is sent to an approved discharge location after appropriate treatment of the wastewater, and the wastewater interconnection is assumed to be located at the power plant's site boundary.

7.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $958/kW. Table 7-1 summarizes the cost components for this case. This estimate is based on an EPC contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 7-1 covers owner's costs, which include project development, studies, permitting, and legal; owner's project management; owner's engineering; and owner's participation in startup and commissioning. The estimate is presented as an overnight cost in 2019 dollars and thus excludes Allowance for Funds Used During Construction or interest during construction. In addition to the cost of external systems noted above (e.g., fuel gas supply and transmission line), an estimated amount is included for the cost of land.

Table 7-1 — Case 7 Capital Cost Estimate

Case 7 EIA – Capital Cost Estimates – 2019 $s			
Configuration		Combined Cycle 2x2x1 H-Class	
Combustion Emissions Controls		Dry Low NOx combustor with axial fuel staging	
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst	
Fuel Type		Natural gas / No. 2 Backup	
Post Firing		No Post Firing	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	1083	
Net Plant Heat Rate, HHV Basis	Btu/kWh	6370	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	10%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (acres)	$	60	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	2,520,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,800,000	
Miles	miles	0.50	
Metering Station	$	4,500,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	18	
Plant Construction Time	months	24	
Total Lead Time Before COD	months	42	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		60,000,000
Mechanical – Major Equipment	$	294,000,000	
Mechanical – Balance of Plant	$	196,000,000	
Mechanical Subtotal	$		490,000,000
Electrical Subtotal	$		93,000,000
Project Indirects	$		150,000,000
EPC Total Before Fee	$		793,000,000
EPC Fee	$		79,300,000
EPC Subtotal	$		872,300,000
Owner's Cost Components (Note 2)			
Owner's Services	$		61,061,000
Land	$		1,800,000
Electrical Interconnection	$		2,520,000
Gas Interconnection	$		5,900,000
Owner's Cost Subtotal	$		71,281,000
Project Contingency	$		94,358,000
Total Capital Cost	$		1,037,939,000
	$/kW net		958

Case 7 EIA – Capital Cost Estimates – 2019 $s	
Configuration	**Combined Cycle 2x2x1** H-Class
Combustion Emissions Controls	Dry Low NOx combustor with axial fuel staging
Post-Combustion Emissions Controls	SCR Catalyst, CO Catalyst
Fuel Type	Natural gas / No. 2 Backup
Post Firing	No Post Firing
Capital Cost Notes	
1.Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distr butable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs. 2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.	

7.3 O&M COST ESTIMATE

Table 7-2 indicates O&M costs. Fixed O&M costs include staff and administrative costs, supplies, and minor routine maintenance. (Not included are property taxes and insurance.) Fixed costs also include the fixed payment portion of a long-term service agreement for the CTs. Additional O&M costs for firm gas transportation service are not included as the facility has dual-fuel capability.

Variable O&M costs include consumable commodities, such as water, lubricants, and chemicals. It also includes the periodic costs to change out the SCR and CO catalysts. The variable O&M costs also include the average annual cost of the planned maintenance events for the CTs and the STG over the long-term maintenance cycle. Planned maintenance costs for the CTs in a given year are based on the number of EOH the CT has run. Typically, a significant overhaul is performed for this type of CT every 25,000 EOH, and a major overhaul is performed every 50,000 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH. Case 7 assumes the operating profile results in an EOH-driven maintenance overhaul schedule. Refer to Case 6 for a starts-based overhaul schedule.) Planned major outage work on the STG is scheduled less frequently than the CTs, typically planned for every six to eight years.

Table 7-2 — Case 7 O&M Cost Estimate

Case 7 EIA – Non-Fuel O&M Costs – 2019 $s		
Combined Cycle 2x2x1		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**12.20 $/kW-year**
Variable O&M (Note 2)	$/MWh	**1.87 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include catalyst replacement, ammonia, water, and water discharge treatment cost.		

7.4 ENVIRONMENTAL & EMISSIONS INFORMATION

For the Case 7 CC configuration, NO_X emissions from the HRSG stacks when firing gas are indicated in Table 7-3. SCRs and CO catalysts are included in the HRSGs to reduce HRSG stack emissions of NO_X and CO below the emission levels in the CT exhaust gas.

Table 7-3 — Case 7 Emissions

Case 7 EIA – Emissions Rates		
Combined Cycle 2x2x1		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.0075
SO_2	lb/MMBtu	0.001
CO_2	lb/MMBtu	117
Emissions Control Notes		
1. Natural Gas, no water injection		

ENTERGY TEXAS, INC.
Lifespans of Combined Cycle Gas Turbine Power Plants
Placed In-Service After 2016

Line	Plant	Utility	Nameplate Capacity (MW)	In-Service Year	Retirement Year	Lifespan
		(1)	(2)	(3)	(4)	(5)
	30-34 Years					
1	Blue Water Energy Center	DTE Electric Company	1,146.0	2022	2052	30
2	Lake Charles Power Station	Entergy Louisiana, LLC	1,000.0	2020	2050	30
	35-39 Years					
3	Marshalltown Generating Station	Interstate Power and Light Company	694.8	2017	2052	35
4	Polk 2 Combined Cycle	Tampa Electric Company	1,120.0	2017	2052	35
5	Greensville Power Station	Virginia Electric and Power Company	1,710.0	2018	2054	36
	40 Years and Over					
6	Crystal River CC (Citrus County)	Duke Energy Florida, LLC	1,884.0	2018	2058	40
7	Asheville CC	Duke Energy Progress, LLC	586.8	2019	2059	40
8	Okeechobee Clean Energy Center	Florida Power & Light Company	1,723.1	2019	2059	40
9	Dania Beach Clean Energy Center	Florida Power & Light Company	1,251.8	2022	2062	40

Sources: DTE's Application for Approval of Certificates of Necessity, Michigan Public Service Commission, Case No. U-18419, Direct Testimony of William H. Damon at 16.

Entergy's Application for Approval to Construct Lake Charles Power Station, and for Cost Recovery, Docket No. U-34283, Direct Testimony of Phong D. Nguyen at 6.

Interstate Power and Light's Application for Ratemaking Principles, Iowa Utilities Board, Docket No. RPU-2012-0003, Application at 3-2.

Tampa Electric Company's Petition for Approval of Its 2020 Depreciation and Dismantlement Study and Capital Recovery Schedules, Florida Public Service Commission, Docket No. 20200264-EI.

Virginia Electric and Power Company's Application for Approval of a Certificate of Convenience and Necessity, State Corportation Commission of Virginia, Case No. PUE-2015-00075, Direct Testimony of Steven A. Rogers at 2.

Duke Energy Florida's 2021 Rate Case Settlement Agreement, Florida Public Service Commission, Docket Nos. 20190110-EI and 20190222-EI.

Duke Energy Progress's 2022 Rate Case, Public Service Commission of South Carolina, Docket No. 2022-254-E, Spanos Exhibit 1 at 40.

Florida Power & Light's 2021 Rate Case, Florida Public Service Commission, Docket No. 160021-EI, Exhibit NWA-1 (2016 Depreciation Study).

ENTERGY TEXAS, INC.
TIEC's Recommended Demand Allocation Factors
Using the 4CP Loss Factors
For the Twelve Months Ending December 31, 2021

		Production		Transmission Demand (AED-4CP)	
Line	Customer Class	Demand (AED-4CP)	Interruptible (AED-4CP)	>=230 kV	<230 kV
		(1)	(2)	(3)	(4)
1	Residential	48.0951%	48.4732%	48.0951%	53.4328%
2	Small General Service	2.8839%	2.9073%	2.8839%	3.2040%
3	General Service	16.9890%	17.1278%	16.9890%	18.8745%
4	Large General Service	5.5440%	5.5908%	5.5440%	6.1593%
5	Large Industrial Power Service	26.1838%	25.5940%	26.1838%	17.9916%
6	Lighting	0.3042%	0.3069%	0.3042%	0.3380%
7	Total Texas Retail	100.0000%	100.0000%	100.0000%	100.0000%
		PG / DD	**PG / DD / IS**	**TH / DD**	**TL / DD**