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SOAH DOCKET NO. 473-21-2606
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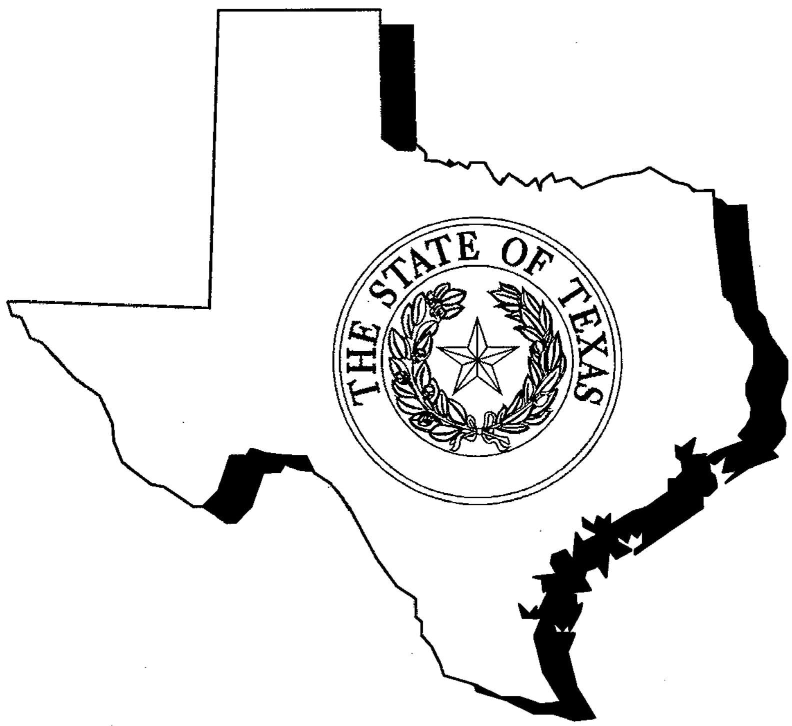
APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	**§ § § § §**	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**



DIRECT TESTIMONY OF

HEIDI GRAHAM

INFRASTRUCTURE DIVISION

PUBLIC UTILITY COMMISSION OF TEXAS

OCTOBER 29, 2021

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ATTACHMENTS

I. INTRODUCTION AND SCOPE OF TESTIMONY

Q. Please state your name and business address.

A. My name is Heidi Graham, and my business address is 1701 North Congress Avenue, Austin, Texas 78711-3326.

Q. By whom are you employed and in what capacity?

A. I am employed by the Public Utility Commission of Texas (Commission) as Lead Engineering Specialist in the Infrastructure Division.

Q. How long have you been employed at the Commission?

A. I have been employed by the Commission since September 1, 2014.

Q. What are your principal responsibilities at the Commission?

A. My responsibilities include reviewing applications to obtain or amend certificates of convenience and necessity; reviewing applications to obtain or amend rates; providing testimony and participating in settlement negotiations for contested cases; and participating in rulemakings and form development.

Q. Please state your educational background and professional experience.

A. I have provided a summary of my educational background and professional regulatory experience in Attachment HG-1 to my direct testimony.

Q. Have you testified as an expert before the Commission or the State Office of Administrative Hearings (SOAH)?

A. Yes. Attachment HG-2 provides a summary of the dockets in which I have filed direct testimony or memoranda in lieu of testimony.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Staff of the Commission.

Q. Please state the purpose of your testimony and the issues you address in this proceeding.

A. The purpose of my testimony is to make recommendations and to comment on the invested capital, accumulated depreciation, depreciation expense, and operations and maintenance expenses proposed by El Paso Electric Company (EPE). Specifically, I will address the following issues from the Commission's Preliminary Order filed on June 28, 2021[1]:

- 12. What is the amount, if any, of accumulated depreciation on that property?
- 13. Does EPE's requested invested capital or revenue requirement include any amounts no longer used and useful in the provision of electric service?
- 24. What are EPE's reasonable and necessary operations and maintenance expenses?
- 28. What is EPE's reasonable and necessary depreciation expense? For each class of property, what are the proper and adequate rates and methods for depreciation, including service lives and salvage value?

Q. Please summarize the background of this proceeding.

A. On June 1, 2021, EPE filed an application seeking authority to change its rates. The application includes depreciation rate testimony and workpapers prepared by EPE witness John J. Spanos (Mr. Spanos). The application also includes depreciation expense and accumulated depreciation testimony and workpapers prepared by EPE witness Larry J. Hancock (Mr. Hancock).

Q. If you do not address an issue in your testimony, should that be interpreted as Staff supporting EPE's position on that issue?

A. No. The fact that I do not address an issue in my testimony should not be construed as agreeing with, endorsing, or consenting to any position taken by EPE on that issue.

[1] Preliminary Order (Jun. 28, 2021).

Q. What information did you rely on to perform your analysis?

A. I relied on information found in Mr. Spanos's Direct Testimony; Mr. Hancock's Direct Testimony; EPE's responses to Requests for Information from Staff and intervenors; other filings in EPE's application; filings in Docket No. 44941 – *Application of El Paso Electric Company to Change Rates*[2]; filings in Docket No. 46831 – *Application of El Paso Electric Company to Change Rates*[3]; filings in Docket No. 39896 – *Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment*[4] (Application of ETI to Change Rates); filings in Docket No. 40443 – *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*[5] (Application of SWEPCO to Change Rates); and the National Association of Regulatory Utility Commissioners (NARUC) manual, *Public Utility Depreciation Practices* (1996).

II. SUMMARY OF ANALYSES AND RECOMMENDATIONS

Q. Please summarize your analyses and recommendations.

A. The following summarizes my analyses:

- I reviewed the testimony filed by Mr. Hancock for accumulated depreciation. I have not identified any adjustments to his proposed accumulated depreciation.
- I have not identified any adjustments to the proposed operations and maintenance expense.
- I reviewed the results of the actuarial analyses related to Mr. Spanos's proposed life characteristics for generation units and plant accounts. Mr. Spanos's service life

[2] *Application of El Paso Electric Company to Change Rates,* Docket No. 44941 (Aug. 25, 2016).

[3] *Application of El Paso Electric Company to Change Rates,* Docket No. 46831(Dec. 18, 2017).

[4] *Application of Entergy Texas, Inc. for Authority to Change rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment*, Docket No. 39896 (Nov. 2, 2012). (Application of ETI to Change Rates).

[5] *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443 (Mar. 6, 2014). (Application of SWEPCO to Change Rates).

estimates were based on his judgment, including consideration of primary factors such as statistical analysis of data; information gathered from field personnel, engineers, and managers; and the survivor curve estimates from the study performed by Gannett Fleming Valuation and Rate Consultants, LLC for EPE, as stated in Mr. Spanos's testimony, Exhibit JJS-2, and Schedule D-5 – 2019 Depreciation Study as of December 31, 2019.[6]

- I performed actuarial analyses, using Staff's Excel-based models, on individual plant accounts to analyze the reasonableness of Mr. Spanos's proposed life parameters. I have not identified any adjustments to the survivor curve shape and average service life (life parameters) recommended by Mr. Spanos for each individual account included in the depreciation study contained in Exhibit JJS-2 of Mr. Spano's testimony.
- I reviewed the net salvage analysis for EPE's proposed net salvage values for generation units and mass property accounts. I have not identified any adjustments to the proposed net salvage values.
- Consistent with Commission precedent, I am proposing the exclusion of interim retirements for production plant. The removal of the inclusion of interim retirements results in an approximately $7,074,616 reduction in the depreciation expense proposed by EPE based on plant as of December 31, 2020.
- I recommend the use of depreciation rates calculated by Mr. Spanos in EPE's response to the City of El Paso's Request for Information 7-37[7] instead of the proposed depreciation rates resulting from the use of interim retirements. I also recommend the consolidated depreciation rates and the depreciation expense included in Attachment HG-4, which result from the application of the depreciation rates

[6] Direct Testimony of John J. Spanos at 804 (Jun. 1, 2021). (Spanos Direct).

[7] Attachment HG-4, EPE's Response to the City of El Paso's Seventh Request for Information 7-37 (Aug. 9, 2021). (EPE's Response to CoEP 7-37).

calculated by Mr. Spanos in EPE's response to the City of El Paso's Request for Information 7-37, and which are based on Mr. Hancock's Schedule D-4.[8]

III. ANALYSIS OF EPE'S PROPOSED DEPRECIATION RATES

Q. What standards did you apply to review EPE's depreciation rates?

A. I applied Public Utility Regulatory Act[9] (PURA) § 36.056(a), which requires the Commission to establish proper and adequate rates and methods of depreciation for each class of property of an electric utility. I also applied 16 Texas Administrative Code (TAC) § 25.231(b)(1)(B), which states that depreciation expense shall be based on original cost and computed on a straight-line basis as approved by the Commission and that other methods of depreciation may be used when it is determined that an alternate depreciation methodology is a more equitable means of recovering the cost of the plant.

Q. What method was used to calculate depreciation rates for EPE?

A. In his testimony, Mr. Spanos states that he generally used actuarial or retirement rate methods of analyses[10] and the straight-line remaining life technique to calculate EPE's depreciation rates. He also states that he used the life span technique to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated. In this technique, the survivor characteristics of such facilities are described by the use of interim survivor curves and estimated probable retirement dates.[11] For General Plant Accounts 391, 393, 394, 395, 397, and 398, Mr. Spanos used the straight-line remaining life method of amortization.[12]

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[8] Direct Testimony of Larry J. Hancock, Schedule D-4 (Jun. 1, 2021).

[9] Public Utility Regulatory Act Tex. Util. Code §§ 11.001-66.016.

[10] Spanos Direct at 758, Exhibit JJS-2.

[11] *Id.* at 711.

[12] *Id.* at 709.

Q. Have you conducted a detailed analysis of EPE's proposed depreciation rates?

A. Yes, I have.

Q. What properties are included in your analysis?

A. There are five distinct groups of property, each of which has separate depreciation rates by plant account: (1) steam production, (2) other production, (3) transmission, (4) distribution, and (5) general. The steam production functional group primarily contains boiler plant equipment, engines and engine-driven generators, and turbogenerator units. The other production functional group primarily contains fuel holders, producers, accessories, prime movers, and generators. The transmission functional group primarily contains towers, poles, station equipment, and conductors used to transmit electricity to various points for entry into the distribution system. The distribution functional group primarily consists of lines and associated facilities used to distribute electricity. The general functional group contains facilities and equipment associated with the overall operation of the business, such as office buildings, warehouses, service centers, transportation, power operated equipment, office and computer equipment, tools, and other miscellaneous equipment. All general plant is used in overall operations of the business rather than with a specific production, transmission, or distribution function.

Q. When did the last change in depreciation rates occur for EPE?

A. The majority of EPE's depreciation rates were settled in its 2015 rate case, Docket No. 44941.[13] However, some new assets had depreciation rates established in EPE's 2017 rate case, Docket No. 46831.[14]

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[13] Attachment HG-5, *Application of El Paso Electric Company to Change Rates,* Docket No. 44941, Finding of Fact No. 38 (Aug. 25, 2016).

[14] Attachment HG-6, *Application of El Paso Electric Company to Change Rates,* Docket No. 46831, Finding of Fact No. 38 (Dec. 18, 2017).

IV. ANALYSIS OF EPE'S INCLUSION OF INTERIM RETIREMENTS

Q. What is the interim retirement rate method?

A. The interim retirement rate method involves using interim retirement curves to model the retirement of individual assets within primary plant accounts for each generating unit prior to the terminal retirement of the unit. The life span procedure assumes all assets are depreciated (straight-line) for the same number of periods and retire at the same time (the terminal retirement date). Adding interim retirement curves to the procedure reflects the fact that some of the assets at a power plant will not survive to the end of the life of the unit and can be depreciated (straight-line) more quickly and retired earlier than the terminal life of the unit. The goal of interim retirement curves is to project how many of the assets that are currently in service will retire each year in the future using historical analysis and judgment. These curves are chosen based primarily on an analysis of the historical retirement pattern of the generation assets and consultation with the utility personnel. Interim retirements for each plant account are modeled using Iowa Curves. Applying interim retirements recognizes that generating units will have retirements of depreciable property before the end of their lives. However, the Commission has consistently rejected the application of interim retirement rates of production plants, as they are based on the future projection of retirements.

Q. **What are the most recent examples of rate cases with interim retirements that were fully litigated?**

A. The two most recent fully litigated rate cases where interim retirements were an issue are the Application of SWEPCO to Change Rates and the Application of ETI to Change Rates in Docket Nos. 40443 and 39896, respectively. [15]

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[15] Attachment HG-7, *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs,* Docket No. 40443, Finding of Fact No. 195 (Mar. 6, 2014); Attachment HG-8, *Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment,* Docket No. 39896, Finding of Fact No. 100 (Nov. 2, 2012).

Q. Does EPE propose the inclusion of interim retirements for all accounts?

A. No. At this time Spanos is proposing the utilization of interim retirements for Steam Production Plants: Account No. 311 – Structures and Improvements, Account No. 312 – Boiler Plant Equipment, Account No. 313 – Engines and Engine-Driven Generators, Account No. 314 – Turbogenerator Units, Account No. 315 – Accessory Electric Equipment, Account No. 316 – Miscellaneous Power Plant Equipment; Gas Turbine Plant: Account No. 341 – Structures and Improvements, Account No. 342 – Fuel Holders, Account No. 343 – Prime Movers, Account No. 344 – Generators, Account No. 345 – Accessory Electric Equipment, Account No. 346 – Miscellaneous Power Plant Equipment; Transmission Plant: Account No. 350.10 – Land Rights Isleta; and General Plant: Account No. 390 – Structures and Improvements. [16]

Q. Has the Commission excluded interim retirements when it comes to depreciation rates in the past?

A. Yes. The Commission has specifically excluded interim retirements from prior depreciation rate calculations in fully litigated rate cases.[17] In Docket 39896, the Commission found that the interim retirement method should not be used to determine production plant depreciation rates. In Docket No. 40443, the most recent fully litigated rate case where interim retirements were an issue, the Commission found that the rate that interim retirements will be made is not known and measurable; incorporation of interim retirements would best be done when those retirements are actually made and; it is not reasonable to incorporate interim retirements.[18] Commission Staff has consistently recommended excluding interim retirements.

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[16] Spanos Direct at 798-802, Exhibit JJS-2.

[17] *Application of ETI to Change* Rates, Finding of Fact No. 100; *Application of SWEPCO to Change* Rates, Finding of Fact No. 195.

[18] *Application of SWEPCO to Change* Rates, Finding of Fact No. 195.

Q. What do you recommend?

A. Based on the Commission's precedent, I propose the exclusion of interim retirements in the calculation of depreciation rates related to the accounts listed previously in my testimony. I recommend the use of the depreciation rates calculated by Mr. Spanos in EPE's response to the City of El Paso's Request for Information 7-37 in the determination of depreciation expenses without interim retirements.[19]

Q. What is the impact of excluding interim retirements on depreciation expense?

A. The removal of interim retirements results in an approximately $7,074,616 reduction in the depreciation expense proposed by EPE based on plant as of December 31, 2020.

Q. Were there disallowances for invested capital proposed by Staff witnesses?

A. No. There were no disallowances for invested capital identified by Staff witnesses.

V. ANALYSIS OF NET SALVAGE VALUES

Q. What is net salvage value?

A. Net salvage is the sum of the gross salvage minus the cost of removing the item. A positive net salvage means a company gets back more money in gross salvage than it costs the company to remove the item. Positive net salvage decreases the depreciation rate. A negative net salvage means a company pays more money to remove the item than it gets back in gross salvage. Negative net salvage increases the depreciation rate. Net salvage value is expressed as a ratio or a percent of the total original plant for calculating the depreciation rate.

Q. Are you recommending any adjustments to the way EPE addressed net salvage?

A. No. I did not identify any changes that should be made to EPE's proposed net salvage.

[19] EPE's Response at CoEP 7-37.

Q. Does this conclude your testimony?

A. Yes.

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Work Experience

Program Specialist VII, Lead Engineering Specialist

4/2020 – Present, Public Utility Commission of Texas, Austin, Texas

Review applications to obtain or amend certificates of convenience and necessity (CCN); review applications to increase rates; provide testimony for contested cases and participate in negotiating settlements for those cases; and participate in rulemakings and application and form development.

Program Specialist VII, Director of the Water Utility Engineering Section

5/2016 – 4/2020, Public Utility Commission of Texas, Austin, Texas

Lead a team of experts who review applications to obtain or amend CCNs; review applications to increase rates; provide testimony for contested cases and participate in negotiating settlements for those cases; and participate in rulemakings and application and form development.

Engineering Specialist V
9/2014 – 5/2016, Public Utility Commission, Austin, Texas

Process CCN applications. Perform depreciation studies, quality of service evaluations, design rates for rate applications, and testify in hearings.

Engineering Specialist V
12/2006 – 8/2014, Texas Commission on Environmental Quality, Austin, Texas

Review plans, specifications, and engineering reports for new or modified public water systems to ensure compliance with Federal and State standards. Process CCN applications. Perform depreciation studies, quality of service evaluations, design rates for rate applications, and testify in hearings.

Education

8/1983 - 5/1988, University of Missouri, Rolla, Missouri

Bachelor's Degree in Mechanical Engineering

Heidi Graham
Public Utility Commission of Texas (PUC)
List of Previous Testimonies

Testimonies for TCEQ Staff

Docket	Company	Application Type
SOAH 582-08-4354	James Maib dba H2O Systems Plus	Rate application - Water
SOAH 582-08-2863	Lower Colorado River Authority	Rate Appeal - Water
SOAH 582-08-4353	Interim-La Ventana	Sale, Transfer, Merger - Water
SOAH 582-09-0660	North San Saba WSC	Rate Appeal - Water
SOAH 582-09-0592	City of Nixon	CCN Amendment - Water
SOAH 582-10-3422	Denton Co. WCID No. 1	Rate Appeal - Water
SOAH 582-10-5999	City of Kerrville	CCN Amendment - Water
SOAH 582-13-4616	HHJ dba Decker Utilities	Rate Application - Water and Sewer
SOAH 582-13-4616	M.E.N. WSC	Cost of Service Appeal - Water

Testimonies for PUCT Staff

PUC Docket	SOAH Docket	Company	Application Type
42858	473-14-0366	SJWTX, Inc.	Rate Application - Water
42857	473-14-5138	City of Austin	Wholesale Appeal
42866	473-14-5144.WS	West Travis County PUA	Wholesale Appeal
42862	473-14-5139	Town of Woodloch	Rate Appeal – Water and Sewer
42860	473-14-5140	Douglas Utility Company	Rate Settlement – Water and Sewer
42864	473-14-5146	Enchanted Harbor	Rate Application - Water
42919	473-15-0372	Double Diamond	Rate Application - Water
42924	473-15-0371	Crystal Springs Water Co. Inc.	CCN Amendment - Water
42942	473-15-0623.WS	Castle Water, Inc.	Rate Application - Water
43554	473-15-1230.WS	Mansions of Turkey Creek	Rate Appeal – Water and Sewer
44046	473-15-4390.WS	Laguna Vista/Laguna Tres	Sale Transfer Merger
44657	473-16-0927.WS	Interim-La Ventana	Sale Transfer Merger
43076	473-16-2094.WS	Consumers Water, Inc.	Rate Application - Water
45570	473-16-2873.WS	Monarch Utilities I, LP	Rate Application – Water and Sewer
46256	473-17-1641.WS	Liberty Utilities	Rate Application –Sewer
46662	473-17-4964.WS	North Texas MWD	Wholesale Appeal
47814	473-18-1344.WS	City of Forney	Wholesale Appeal
50944	473-20-4709.WS	Monarch Utilities I, LP	Rate Application – Water and Sewer
50788	473-20-4071.WS	Windermere Oaks WSC	Rate Appeal – Water and Sewer
51091	473-21-0246.WS	Rio Ancho/Aqua Texas	Formal Complaint

The following files are not convertible:

Attachment HG-3.xlsx
Attachment HG-4.xlsx

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PUBLIC UTILITY COMMISSION
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PUC DOCKET NO. 44941
SOAH DOCKET NO. 473-15-5257

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

This Order addresses the application of El Paso Electric Company (EPE) for authority to change rates. An amended and restated stipulation and agreement was executed that resolves all of the issues in this proceeding. The application is approved.

The Commission adopts the following findings of fact and conclusions of law:

I. Findings of Fact

Introduction and Procedural History

1. EPE is an electric utility, a public utility, and a utility.

2. On August 10, 2015, EPE filed an application with the Commission seeking approval of a $71,483,595 Texas jurisdiction retail increase in base (non-fuel) and other miscellaneous revenues and changes to the structure and terms of its tariff.

3. Concurrent with the filing of the application with the Commission, EPE filed a similar petition and statement of intent with each incorporated municipality in its Texas service area that has original jurisdiction over its rates.

4. EPE proposed an effective date of September 14, 2015.

5. EPE also requested that, if the new rates were suspended for a period beyond 155 days after August 10, 2015, then final rates will relate back and be made effective for consumption on and after the 155th day after August 10, 2015, which equates to consumption on and after January 12, 2016.

6. EPE used the 12-month test year beginning April 1, 2014 through March 31, 2015.

7. Notice of EPE's application was published once each week for four consecutive weeks in a newspaper having general circulation in each county in EPE's Texas service territory. In addition, EPE provided individual notice to EPE's Texas retail customers, each municipality within EPE's service area with original jurisdiction over EPE's retail rates,

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and each party to EPE's last fuel reconciliation, *Application of El Paso Electric Company to Reconcile Fuel Costs*, Docket No. 41852, Order (Jul. 11, 2014).

8. EPE timely appealed to the Commission the actions of the following municipalities exercising original jurisdiction within their service territory: City of El Paso, Town of Anthony, Town of Horizon City, Town of Clint, Village of Vinton, Town of Van Horn, City of San Elizario, and City of Socorro. All such appeals were consolidated for determination in this docket.

9. The following parties were granted intervenor status in this docket: City of El Paso (CEP), Office of Public Utility Counsel (OPUC), the State of Texas agencies and institutions of higher education (State Agencies), Texas Industrial Energy Consumers (TIEC), Freeport-McMoran Copper & Gold, Inc. (FMI), ArcelorMittal USA LLC (AM),[1] Wal-Mart Stores Texas, LLC and Sam's East, Inc. (collectively, Walmart), W Silver, Inc. (W Silver), U.S. Department of Defense and all other Federal Executive Agencies (DoD/FEA), ECO ELP, Inc. (ECO ELP), Coalition of Cities Served by El Paso Electric (consisting of the municipalities of the City of San Elizario, City of Clint, and City of Horizon City) (Coalition), Ysleta Independent School District (ISD), El Paso ISD, Socorro ISD, Clint ISD, San Elizario ISD, Fabens ISD, Anthony ISD, Canutillo ISD, Tornillo ISD, El Paso County, Housing Authority of City of El Paso, Region 19 Education Service Center, and El Paso County Community College District (collectively, Rate 41 Group), Sunrun Corporation (Sunrun), Energy Freedom Coalition of America (EFCA), NRG Residential Solar Solutions, LLC (NRG), Solar Energy Industries Association (SEIA), City of Socorro, and Rockney Bacchus, *pro se*. Commission Staff also participated in this docket.

10. On August 11, 2015 the Commission referred this case to the State Office of Administrative Hearings (SOAH) to conduct an evidentiary hearing and prepare a proposal for decision, if necessary.

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[1] ArcelorMittal USA LLC was purchased by Bayou Steel Group during the course of this proceeding. Bayou Steel Group is the successor-in-interest to the intervenor ArcelorMittal USA LLC and the facility is now known as BD Vinton, LLC. For ease in reference and consistent with the intervention, Bayou Steel Group will be referred to as ArcelorMittal USA LLC. (AM) in the text of this Order.

11. On August 14, 2015, SOAH issued Order No. 1, establishing among other things, the suspension of the effective date of the proposed tariff changes for 150 days until February 11, 2016.

12. On September 11, 2015, the Commission issued the preliminary order, setting forth the issues to be addressed in this proceeding.

13. On December 31, 2015, SOAH issued Order No. 9, granting EPE's motion to sever the rate case expense issues and establishing *Review of Rate Case Expenses Incurred by El Paso Electric Company and Municipalities in Docket No. 44941*, SOAH Docket No. 473-16-1685, Docket No. 45475 (Docket No. 45475).

14. On January 22, 2016, SOAH issued Order No. 13, granting EPE's request to abate the procedural schedule to facilitate settlement negotiations among the parties.

15. On March 29, 2016, EPE and a majority of the parties moved to implement a non-unanimous stipulation and agreement and approve interim rates (March settlement agreement). The March settlement agreement would resolve all issues in this case except one contested revenue requirement issue involving EPE's interest in Units 4 and 5 of the Four Corners power plant.

16. The parties who signed and filed the March settlement agreement were EPE, Commission Staff, CEP, State Agencies, TIEC, FMI, AM, W. Silver, DoD/FEA, Coalition, City of Socorro, Rate 41 Group, Walmart, NRG, and SEIA.

17. Rockney Bacchus did not sign the March settlement agreement but did not oppose it.

18. OPUC, ECO ELP, Sunrun, and EFCA opposed the March settlement agreement, though they did not oppose the interim rates specified in the March settlement agreement.

19. On March 31, 2016, SOAH issued Order No. 16, approving an uncontested interim rate increase of $37 million to be charged in bills beginning April 1, 2016, and subject to surcharge or refund.

20. On April 5, 2016 OPUC, ECO ELP, Sunrun, and EFCA requested that a hearing be held on the March settlement agreement and that EPE be ordered to issue additional notice to

address the scope of the March settlement agreement concerning the proposed treatment of residential customers with distributed generation (DG).

21. On April 25, 2016, SOAH issued Order No. 19, establishing a procedural schedule for a hearing on the merits of the March settlement agreement. Order No. 19 also rejected the request by OPUC, ECO ELP Sunrun, and EFCA that EPE issue additional notice concerning the March Settlement Agreement's residential customer DG tariff provision.

22. On May 2, 2016, OPUC, ECO ELP Sunrun, and EFCA appealed the ruling in SOAH Order No. 19 concerning notice.

23. On May 4, 2016, the signatories to the March settlement agreement filed the first amendment to the March settlement agreement.

24. On May 23, 2016, the Commission issued the Order on Appeal of SOAH Order No. 19, which granted the appeal and required EPE to reissue notice.

25. On July 15, 2016, EPE and other parties filed in this proceeding and in Docket No. 45475 the amended and restated agreement, which would settle and resolve all issues in this proceeding, including a revenue requirement issue involving EPE's interest in Units 4 and 5 of the Four Corners power plant and all issues in Docket No. 45745 concerning the recovery of rate case expenses. The fact that the residential customer DG tariff provision is not proposed in the amended and restated agreement obviated the need for additional notice required by the Commission's Order on Appeal of SOAH Order No. 19.

26. Along with the amended and restated agreement, EPE and other parties also filed a joint motion to implement it.

27. The following parties are signatories to the amended and restated agreement: EPE, Commission Staff, CEP State Agencies, TIEC, FMI, AM, W Silver, DoD/FEA, Coalition, City of Socorro, Rate 41 Group, Walmart, NRG, SEIA, OPUC, ECO ELP Sunrun and EFCA (collectively, Signatories). Rockney Bacchus neither joins nor opposes the amended and restated agreement. The amended and restated agreement is thus uncontested.

28. On July 25, 2016, SOAH issued Order No. 24 in Docket No. 44941 and Order No. 3 in Docket No. 45475, consolidating the proceedings, admitting the various exhibits identified

in Order No. 24 into evidence, including the amended and restated agreement and testimony from EPE and Commission Staff in support of the amended and restated agreement, dismissing the consolidated proceeding from the SOAH docket, and returning the matter to the Commission for further processing as a settled case.

29. On August 4, 2016, EPE filed updated rate case expense information. CEP and Coalition filed updated information on August 5, 2016 and the City of Socorro filed its rate case expense information on August 8, 2016. On August 9, Commission Staff moved to admit the supplemental testimony of Mark Filarowicz into the record. On August 10, 2016, EPE moved for admission of the rate case expense invoices with supporting affidavits. On August 11, 2016, the Commission's administrative law judge issued Order No. 1, admitting additional evidence in the record of this proceeding.

Description of the Amended and Restated Agreement

30. The signatories agree that the amended and restated agreement results in just and reasonable rates.

Overall Revenues

31. The amended and restated agreement provides that EPE should receive an overall increase of $37 million in Texas base rate and other revenues, effective for electricity consumed on and after January 12, 2016.

32. This rate increase should be collected through interim rates in bills on and after April 1, 2016. (Amended and restated Agreement art. I.A.1.)

Four Corners Issue

33. The amended and restated agreement provides that EPE receive an incremental increase of $3.7 million in annual revenue requirement for base rates (in addition to the $6,081,409 deemed to be included in the $37 million increase) associated with its interest in Units 4 and 5 of the Four Corners power plant (Four Corners incremental rate amount). The $3.7 million Four Corners incremental rate amount is in addition to, and shall not result in a reduction to, the $37 million rate increase.

34. The $3.7 million Four Corners incremental rate amount shall apply to consumption on and after January 12, 2016, and except for the relate back time period subject to PURA

§ 36.211, recovery shall be through a rider terminating on July 12, 2017, 18 months after the relate back date. (Amended and restated Agreement art. I.B.)

Plant Additions

35. The amended and restated agreement provides that EPE's additions to plant in service from July 1, 2009 through March 31, 2015 are deemed reasonable and necessary and included in rate base, with two exceptions: the Copper gas turbine (which continues to be excluded from rate base) and the Newman Elevated Solar Facility (whose rate base treatment is reserved for EPE's next rate proceeding).

36. This plant in service provision has no bearing on the Four Corners incremental rate recovery amount. (Amended and restated agreement art. I.C.)

Return on Equity

37. The amended and restated agreement provides EPE shall utilize a return on equity of 9.7% only for purposes of calculating allowance for funds used during construction. (Amended and restated agreement art. I.D.)

Depreciation

38. The amended and restated Agreement specifies the adjusted depreciation rates proposed by the city of El Paso witness Jacob Pous shall be utilized effective January 1, 2016. These depreciation rates are shown on Attachment A to the amended and restated agreement.

39. The amended and restated agreement also provides that effective January 1, 2016, EPE will record all gains or losses for the retirement of transportation equipment as a component of accumulated provision for depreciation and amortization of electric plant (FERC Account Number 108). (Amended and restated agreement art. I.E.)

State Income Tax

40. Under the amended and restated Agreement, effective January 1, 2016, EPE will begin normalizing state income tax expense, and amortizing over a 15-year period the test year-end balance of accumulated deferred state income tax expense that has not yet been included in cost of service. (amended and restated agreement art. I.F.)

Nuclear Decommissioning

41. Under the amended and restated agreement, effective February 1, 2016, EPE's rates will be deemed not to include funding for the Palo Verde Nuclear Generating Station decommissioning.

42. EPE shall be allowed, in its discretion, to make whatever contributions to the decommissioning funds, if any, it deems prudent or necessary. (Amended and restated agreement art. I.G.)

Environmental Consumables

43. Under the amended and restated agreement, effective January 1, 2016, the expenses for environmental consumables will be removed from base rates and be recovered as eligible fuel costs. (Amended and restated agreement art. I.H.)

Allocation of the $37 Million Revenue Increase and Four Corners Incremental Rate Amount

44. The amended and restated agreement specifies how (a) the $37 million revenue increase is allocated among the rate classes in Attachment B to the amended and restated agreement, and (b) the $3.7 million Four Corners incremental rate amount is allocated among the rate classes in Attachment C to the amended and restated agreement. (Amended and restated agreement art. I.I.)

Rate Design and Tariff Approval

45. The amended and restated agreement also addresses tariff and rate design issues (Amended and restated agreement art. I.J.) as follows:
    - The customer charge for Rate 1, Residential Service shall be set at $6.90.
    - The application fees under EPE's Schedule DG shall not apply to residential customers.
    - The customer charge for Rate 2, Small General Service shall be set at $9.95.
    - The customer charge for Rate 24, General Service shall be set at $27.50, with the balance of the increase distributed to this class to be accomplished by increasing the other base charges by an equal percentage.
    - A rate limiter will be applied for Rate 24, General Service, regarding houses of worship.

- A rate limiter will be applied for the two customer accounts migrating from Rate 43 to Rate 25, Large Power Service.
- The increase distributed to Rate 41 shall be applied by increasing each of the components of the monthly base rate by an equal percentage. EPE also agrees to provide for informational purposes in its next rate proceeding a cost of service analysis that presents Rate 41 as a separate class even if EPE proposes to eliminate the class in that proceeding.
- EPE's proposed provision for Highly Variable Demand is not adopted.
- EPE's proposed Schedule CS, Community Solar Rate is not being adopted in this proceeding because it is subject to a separate pending proceeding.
- EPE's existing Demand and Energy Loss Factors shall remain in effect. EPE agrees to submit a System Loss Study in EPE's 2016 Fuel Reconciliation proceeding for applicability in the fuel reconciliation period beginning April 1, 2016.
- A modified time of use (TOU) rate for residential customers shall be offered that is based on an on-peak period of 4 months and 6 hours/day, with a Customer charge of $8.40 per customer per month.
- EPE's proposed tariff language changes with rates for the various classes consistent with the amended and restated agreement shall be approved upon final resolution of this case.

Rate Case Expenses Recovery

46. Under the amended and restated Agreement, EPE shall be entitled to rate recovery of its and its municipalities' rate case expenses incurred through the later of (a) July 8, 2016, or (b) 14 days prior to the date of the open meeting in which the Commission first considers a final order implementing the amended and restated agreement (rate case expense deadline) less $600,000.

    a. The Commission first considered a final order on August 18, 2016, which means the agreed cut-off date for rate case expenses under the amended and restated agreement is August 4, 2016.

b. EPE, the city of El Paso, and the Coalition agreed with Commission Staff to submit their final invoices for rate case expenses to be recovered from ratepayers by August 5, 2016, to allow Commission Staff review, and EPE, the city of El Paso, and the Coalition did so. The City of Socorro also submitted its invoices.

c. Commission Staff concluded after review of the invoices submitted by EPE and its municipalities that the total amount of rate case expenses to be recovered under the amended and restated agreement is $3,127,384.49, and given the circumstances and the agreed reduction in the actual expenses reflected in this total, this amount was a reasonable and necessary expense.

47. Under the amended and restated agreement, if the Commission considers a final order in more than one open meeting and requires the parties to brief a matter, the rate case expense deadline shall be 14 days prior to the date of the open meeting in which the Commission adopts a final order.

48. Under the amended and restated agreement, there would be no recovery from ratepayers of rate case expenses incurred by EPE after the rate case expense deadline.

49. EPE agreed to reimburse the reasonable rate case expenses of a municipality entitled to reimbursement of rate case expenses under § 33.023 of PURA[2] (in this Docket No. 44941, those parties being the city of El Paso, Coalition, and the City of Socorro) incurred after the rate case expense deadline, but under the amended and restated agreement, such expenses would not be recoverable from ratepayers.

50. The amount of rate case expenses to be surcharged is $3,127,384.49. Under the amended and restated agreement, recoverable rate case expenses shall be collected through a separate rate case expense surcharge that will be based on the expenses being amortized over two years and allocated to customer classes as illustrated in Attachment E to the amended and restated agreement. EPE shall cease billing of the rate case expense surcharge in the month that the total approved amount has been collected. The amount of any over-recovery or

[2] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-66.016 (West 2016) (PURA).

under-recovery of the approved rate case expense surcharge amounts by class shall be included in the deferred fuel balance for that class as a refund or surcharge, respectively.

Consistency of the Amended and Restated Agreement with PURA and Commission Requirements

51. The amended and restated agreement is the result of good faith negotiations by the parties, and these efforts, as well as the overall result of the amended and restated agreement viewed in light of the record as a whole, support the reasonableness and benefits of the terms of the amended and restated agreement.

Revenue Requirement

52. The $37 million revenue requirement increase, together with the Four Corners incremental rate recovery amount (both effective for consumption on and after January 12, 2016), contemplated by the amended and restated agreement will allow EPE the opportunity to earn a reasonable return over and above its reasonable and necessary operating expenses.

53. The $37 million revenue requirement increase in the amended and restated agreement is consistent with applicable provisions of Chapter 36 of PURA and Commission rules.

54. The $3.7 million Four Corners incremental rate recovery amount is a reasonable resolution of that issue.

55. The record supports the inclusion in rate base of all of EPE's capital additions from July 1, 2009 through March 31, 2015, except for the Copper gas turbine (which shall continue to be excluded from rates) and the Newman Elevated Solar Facility (whose rate base treatment is reserved for EPE's next rate proceeding).

56. The approval of the capital additions in rate base has no bearing on the Four Corners incremental rate recovery amount.

57. A return on equity of 9.7%, effective January 12, 2016, only for purposes of calculating allowance for funds used during construction is reasonable.

58. It is reasonable for purposes of this proceeding to adopt the depreciation rates proposed by the amended and restated agreement. The adopted depreciation rates are set forth in Attachment A to the amended and restated agreement.

59. It is also reasonable that, effective January 1, 2016, EPE will record all gains or losses for the retirement of transportation equipment as a component of accumulated provision for depreciation and amortization of electric plant (FERC Account Number 108).

60. It is reasonable that, effective January 1, 2016, EPE will begin normalizing state income tax expense in accordance with the amended and restated agreement and amortizing over a 15-year period the test year-end balance of accumulated deferred state income tax expense that has not yet been included in cost of service.

61. It is reasonable that, effective February 1, 2016, EPE's rates will be deemed not to include funding for Palo Verde Nuclear Generating Station decommissioning.

62. It is reasonable that EPE shall be allowed, in its discretion, to make contributions to the decommissioning funds, if any, it deems prudent or necessary.

63. It is reasonable that, effective January 1, 2016, EPE's expenses for environmental consumables (within the meaning of 16 Texas Administrative Code (TAC) § 25.236(a)(3) will be removed from base rates and be recovered as eligible fuel costs.

64. It is reasonable that EPE recover its rate case expenses in the manner specified in the amended and restated agreement.

Allocation of Revenue

65. The allocation of the $37 million revenue increase among rate classes in Attachment B to the amended and restated agreement is just and reasonable.

66. The allocation of the $3.7 million Four Corners incremental rate recovery amount from among rate classes in Attachment C to the amended and restated agreement is just and reasonable.

67. The allocation of the rate case expenses among rate classes in Attachment E to the amended and restated agreement is just and reasonable.

Rate Design and Tariff Approval

68. The $6.90 customer charge for Rate 1, Residential Service, specified by the amended and restated agreement, is reasonable.

69. Exempting residential customers from the Schedule DG application fee is reasonable.

70. The $9.95 customer charge for Rate 2, Small General Service, specified by the amended and restated agreement, is reasonable.

71. It is reasonable that the customer charge for Rate 24, General Service, shall be $27.50, with the balance of the increase distributed to this class to be accomplished by increasing the other base charges by an equal percentage, as specified in the amended and restated agreement.

72. A rate limiter to be applied for Rate 24, General Service, regarding houses of worship, as shown in Rate Schedule 24A, is reasonable.

73. A rate limiter to be applied for the two customer accounts migrating from Rate 43 to Rate 25, Large Power Service, as described in Rate Schedule 25, is reasonable.

74. It is reasonable that the increase distributed to Rate 41 shall be applied by increasing each of the components of the monthly base rate by an equal percentage, as the amended and restated agreement specifies.

75. It is also reasonable that, in its next rate proceeding, EPE will provide for informational purposes a cost of service analysis that presents Rate 41 as a separate class even if EPE proposes to eliminate the class in that proceeding.

76. It is reasonable not to adopt EPE's proposed provision for Highly Variable Demand.

77. It is reasonable to address EPE's proposed Community Solar tariff in the separately pending proceeding, Docket No. 44800,[3] and not in this proceeding.

78. It is reasonable that EPE's existing Demand and Energy Loss Factors shall remain in effect, and that in its 2016 fuel reconciliation, EPE submit a System Loss Study for applicability in the fuel reconciliation period beginning April 1, 2016.

79. It is reasonable to approve a modified TOU rate for residential customers, which is based on an on-peak period of four months and six hours/day. with a customer charge of $8.40 per customer per month.

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[3] *Application of El Paso Electric Company to Implement a Voluntary Community Solar Pilot Program in Texas*, Docket No. 44800 (pending).

80. The settlement rates reflected in the rate schedules included in Attachment D to the amended and restated agreement, including the additional tariff provisions reflected therein and in Sections 2 and 3 of EPE's proposed tariff, are just and reasonable.

81. Surcharges in addition to the base rate increase are necessary to capture: (a) the fact that rates relate back to consumption on and after January 12, 2016; (b) the Four Corners incremental rate recovery amount is to be included in a separate surcharge, except for the time period subject to the relation back, and (c) recovery of rate case expenses.

II. Conclusions of Law

1. EPE is a public utility as that term is defined in PURA § 11.004(1) and an electric utility as that term is defined in PURA § 31.002(6).

2. The Commission exercises regulatory authority over EPE and jurisdiction over the subject matter of this application pursuant to PURA §§ 14.001, 32.001, 36.001-.211, and 39.552.

3. SOAH has jurisdiction over this proceeding under PURA § 14.053 and Texas Government Code § 2003.049 (West 2016).

4. This docket was processed in accordance with the requirements of PURA and the Administrative Procedure Act, Tex. Government Code Chapter 2001 (West 2016).

5. EPE provided notice of its August 10, 2015, application in compliance with PURA § 36.103 and 16 TAC § 22.51(a) and (b).

6. The Commission has jurisdiction over an appeal from municipalities' rate proceedings pursuant to PURA § 33.051.

7. Because the residential DG tariff provision was removed from the amended and restated agreement, no additional notice concerning that provision was necessary.

8. The amended and restated agreement, taken as a whole, is a just and reasonable resolution of all the issues it addresses, results in just and reasonable rates, terms, and conditions, is supported by a preponderance of the credible evidence in the record, is consistent with the relevant provisions of PURA, and, thus, should be approved.

9. The revenue requirement, cost allocation, revenue distribution, and rate design contemplated by the amended and restated agreement result in rates that are just and reasonable, comply with the ratemaking provisions of PURA, and are not unreasonably discriminatory or preferential.

10. EPE's rates resulting from the amended and restated agreement are just and reasonable and meet the requirements of PURA § 36.003.

11. The amended and restated agreement resolves all issues pending in this docket.

12. The tariff sheets and rate schedules include in the amended and restated agreement are just and reasonable and accurately reflect the terms of the amended and restated agreement.

13. The Commission's adoption of a final order consistent with the amended and restated agreement satisfies the requirements of the Administrative Procedure Act §§ 2001.051 and 2001.056 without the necessity of a decision on contested case issues resulting from a hearing on the merits.

14. The requirements for informal disposition pursuant to 16 TAC § 22.35 have been met in this proceeding.

III. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following order:

1. Consistent with the amended and restated agreement, EPE's application is approved.

2. Consistent with the amended and restated agreement, the rates, terms, and conditions described in this Order are approved.

3. Consistent with the amended and restated agreement, the tariffs, rate schedules and riders approved on an interim basis in SOAH Order No. 16 are approved as final.

4. EPE shall observe the depreciation rates approved in this Order until further order.

5. Effective January 1, 2016, EPE's expenses for environmental consumables (within the meaning of 16 TAC § 25.236(a)(3)) will be removed from base rates and will be allowed as eligible fuel expenses going forward and included in EPE's fixed fuel factor.

6. Within 20 days of the date of this Order, EPE shall file a clean record copy of the approved tariffs to be stamped 'Approved' by Central Records and retained by the Commission.

7. Because the final approved rates except for the separate, additional surcharges for recovery of the Four Corners incremental rate recovery amount and rate case expenses are the same as the interim rates, no refunds of the interim rates are necessary.

8. EPE shall file proposed surcharge tariffs consistent with this Order within 20 days of the date of this Order in *Compliance Surcharge Tariff for Final Order in Docket No. 44941 (Application of El Paso Electric Company to Change Rates),* Tariff Control No. 46235. No later than 10 days after the date of the tariff filing, any intervenor in that proceeding may file comments on the individual sheets of the tariff. No later than 15 days after the date of the tariff filing, Commission Staff shall file its comments recommending approval, modification, or rejection of the individual sheets of the tariff. Responses to the Commission Staff's recommendation shall be filed no later than 20 days after the filing of the tariff. The Commission shall by letter approve, modify, or reject each tariff sheet, effective the date of the letter.

9. The surcharge tariff sheets shall be deemed approved and shall become effective on the expiration of 20 days from the date of filing, in the absence of written notification of modification or rejection by the Commission. If any surcharge sheets are modified or rejected, EPE shall file proposed revisions of those sheets in accordance with the Commission's letter within 10 days of the date of that letter, and the review procedure set out above shall apply to the revised sheets.

10. Copies of all tariff-related filings shall be served on all parties of record.

11. Entry of this Order consistent with the amended and restated agreement does not indicate the Commission's endorsement or approval of any principle or methodology that may underlie the amended and restated agreement. Entry of this Order shall not be regarded as precedent as to the appropriateness of any principle or methodology underlying the amended and restated agreement.

12. All other motions, requests for entry of specific findings of fact, conclusions of law, and ordering paragraphs, and any other requests for general or specific relief, if not expressly granted herein, are denied.

Signed at Austin, Texas the 25th day of August 2016.

PUBLIC UTILITY COMMISSION OF TEXAS

DONNA L. NELSON, CHAIRMAN

KENNETH W. ANDERSON, JR., COMMISSIONER

BRANDY MARTY MARQUEZ, COMMISSIONER

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PUBLIC UTILITY COMMISSION
FILING CLERK

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the application of El Paso Electric Company for authority to change rates. An uncontested agreement was executed that resolves all of the issues between the parties to this proceeding. Consistent with the agreement and this Order, the application is approved.

The Commission adopts the following findings of fact and conclusions of law:

I. Findings of Fact

Introduction and Procedural History

1. El Paso Electric Company (EPE) is an electric utility, a public utility, and a utility.

2. On February 13, 2017, EPE filed an application for approval of a $42.547 million Texas-jurisdiction-retail increase in base rates and other miscellaneous revenues and changes to the structure and terms of its tariff.

3. Concurrent with the filing of the application with the Commission, EPE filed a similar petition and statement of intent with each incorporated municipality in its Texas service area that has original jurisdiction over its rates.

4. EPE proposed an effective date of March 20, 2017.

5. EPE also requested that, if the new rates were suspended for a period beyond March 20, 2017, then final rates would relate back and be made effective for consumption on and after July 18, 2017.

6. EPE used a test year of October 1, 2015 through September 30, 2016.

7. Notice of EPE's application was published once each week for four consecutive weeks in a newspaper having general circulation in each county in EPE's Texas service territory. In addition, EPE provided individual notice to EPE's Texas retail customers, each

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municipality within EPE's service area with original jurisdiction over EPE's retail rates, and each party to EPE's last general rate case.[1]

8. EPE timely appealed to the Commission the actions of the following municipalities exercising original jurisdiction within their service territory: the City of El Paso, the town of Anthony, the Town of Horizon City, the Town of Clint, the Village of Vinton, the Town of Van Horn, the City of San Elizario, and the City of Socorro. All such appeals were consolidated for determination in this docket.

9. The following parties were granted intervenor status in this docket:
the City of El Paso; the Office of Public Utility Counsel (OPUC); Texas Industrial Energy Consumers (TIEC); Freeport-McMoran Copper & Gold, Inc. (FMI); Wal-Mart Stores Texas, LLC and Sam's East, Inc. (collectively, Walmart); W. Silver, Inc. (W. Silver); the U.S. Department of Defense and all other Federal Executive Agencies (DoD-FEA); ECO ELP, Inc. (ECO ELP); El Paso County (EPCO); a coalition of cities served by EPE (consisting of the municipalities of the City of San Elizario, the Town of Clint, and the Town of Horizon City) (Coalition); Ysleta Independent School District (ISD), El Paso ISD, Socorro ISD, Clint ISD, San Elizario ISD, Fabens ISD, Anthony ISD, Canutillo ISD, Tornillo ISD, the Housing Authority of the City of El Paso, the Region 19 Education Service Center, and the El Paso County Community College District (collectively, the Rate 41 Group); the Energy Freedom Coalition of America (EFCA); the Solar Energy Industries Association (SEIA); the City of Socorro (Socorro); Vinton Steel, LLC (Vinton Steel); the Environmental Defense Fund (EDF); the University of Texas at El Paso (UTEP); and pro se intervenors Vincent M. Perez, Richard Schecter, and Dr. Marjaneh M. Fooladi. Commission Staff also participated in this docket.

10. On February 14, 2017, the Commission referred this case to the State Office of Administrative Hearings (SOAH) to conduct an evidentiary hearing and prepare a proposal for decision, if necessary.

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[1] *Application of El Paso Electric Company to Change Rates*, Docket No. 44941, Order (Aug. 25, 2015).

11. On February 17, 2017, SOAH issued Order No. 1 suspending the effective date of the proposed tariff changes for 150 days from EPE's originally-proposed effective date, or until August 17, 2017, among other things.

12. On March 9, 2017, the Commission issued a preliminary order determining the issues to be addressed in this proceeding.

13. On June 5, 2017, SOAH issued Order No. 5 granting EPE's motion to sever the rate case expense issues and establishing *Review of Rate Case Expenses Incurred by El Paso Electric Company and Municipalities in Docket No. 46831*, SOAH Docket No. 473-17-4239, Docket No. 47228 (Docket No. 47228).

14. At the August 18, 2017 prehearing conference, EPE agreed to extend the jurisdictional deadline—which EPE had previously agreed to extend to November 30, 2017—to January 15, 2018.

15. On August 21, 2017, the hearing on the merits convened.

16. On August 24, 2017, SOAH issued Order No. 9 cancelling further hearings to facilitate settlement discussions.

17. On November 2, 2017, EPE and other parties filed in this proceeding and in Docket No. 47228 the agreement which settles and resolves all of the issues in this proceeding.

18. Along with the agreement, EPE and other parties also filed a joint motion to implement the agreement.

19. The following parties are signatories to the agreement: EPE, Commission Staff, the city of El Paso, TIEC, FMI, W. Silver, DoD-FEA, Coalition, Socorro, Rate 41 Group, Walmart, SEIA, OPUC, Vinton Steel, UTEP, and Vincent M. Perez, (collectively, the signatories). ECO ELP, EDF, Richard Schecter, and Dr. Marjaneh M. Fooladi do not oppose the Commission entering a final order consistent with the agreement, but do not join in the agreement.

20. On November 6, 2017, SOAH issued Order No. 10 in Docket No. 46831 and Order No. 3 in Docket No. 47228 consolidating the proceedings; admitting the various identified exhibits into evidence, including the agreement and testimony from EPE and Commission

Staff in support of the agreement; dismissing the consolidated proceeding from the SOAH docket; and returning the matter to the Commission for further processing.

Description of the Agreement

21. The signatories agree that the agreement results in just and reasonable rates and that the public interest will be served by resolution of the issues in the manner prescribed by the agreement.

Overall Revenues

22. The agreement provides that EPE should receive an overall increase of $14.5 million in Texas-base-rate and other revenues, effective for electricity consumed on and after July 18, 2017. (Agreement art. I.A.)

Future Change to Corporate Federal Income Tax Expense

23. The agreement provides a mechanism to capture a reduction in the federal income-tax rates for corporations. (Agreement art. I.B.)

24. If the federal income-tax rate for corporations is decreased before EPE files its next base-rate case, then EPE will record, as a regulatory liability, taking into account changes in billing determinants, the difference between (a) the amount of federal income-tax expense that EPE collects through the revenue requirement approved in this proceeding and reflected in its rates and (b) the amount of federal income-tax expense calculated using the new federal income-tax rate, taking into account any other federal corporate-tax changes, such as the deductibility of interest costs. This regulatory liability will accumulate from (a) the later of (i) the date that the new base rates established in this case for EPE became effective or (ii) the date on which the tax-rate reduction became effective until (b) the refund tariff described below becomes effective.

25. EPE will file a refund tariff with the Commission and municipal regulatory authorities within 120 days after the enactment of the law making the tax-rate change reflecting (a) the reduction in federal-income-tax rates and (b) a credit for the regulatory liability referenced above over a twelve-month period. The tariff will calculate the difference in tax expense as the difference in: (i) federal-income-tax expense collected in rates (i.e., reflecting the federal-income-tax rate embedded in the tax factor indicated on Attachment

1 to the agreement) and (ii) the federal-income taxes that would have been collected in rates had the changes in the federal-income-tax rates, and other associated changes in the federal-income-tax calculation, been in effect at the time settlement rates were established. The proposed refund amount will be allocated to rate classes based upon the allocation of rate base as shown in Attachment 2 to the agreement.

26. In each subsequent year, EPE will file to update the refund factor to reflect any over- or under-recovery of federal-income-tax expense and to reflect any subsequent changes in federal-income-tax rates or calculations that would affect the settlement income-tax calculation reflected on Attachment 1 to the agreement. The refund factors in each subsequent year will be filed within 90 days after the end of the fiscal year, with a final reconciliation determined at the time of the final order in the base-rate case.

27. The refund factor will be discontinued upon the effective date of rates in EPE's next base rate case.

28. The amount and timing of the reduction in rates to reflect a tax-rate decrease will be subject to any new federal rules or state laws or regulations that address how a utility's rates should be adjusted to account for the reduction of federal-income-tax rates.

29. The regulatory treatment of any excess deferred taxes resulting from a reduction in the federal-income-tax rate will be addressed in EPE's next base-rate case.

Financial Matters

30. The agreement provides that effective beginning August 1, 2017, EPE's weighted average cost of capital (WACC) shall be 7.725% based upon a 5.922% cost of debt, an authorized return on equity (ROE) of 9.65%, and an authorized regulatory capital structure of 51.652% long-term debt and 48.348% equity. The foregoing WACC, cost of debt, ROE, and capital structure will apply, in accordance with PURA[2] and the Commission's rules, in all Commission proceedings or Commission filings requiring application of EPE's cost of debt, WACC, ROE, or capital structure to the same extent as if these factors had been determined in a final order in a fully-litigated proceeding. (Agreement art. I.C.)

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[2] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-58.302 (West 2016 & Supp. 2017), §§ 59.001-66.016 (West 2007 & Supp. 2017) (PURA).

Prudence Finding Regarding Investment

31. Under the agreement, the signatories agree that all EPE investment through the end of the test year (September 30, 2016), as presented in EPE's rate filing package, is used and useful and prudent and included in rate base. (Agreement art. I.D.)

Jurisdictional Allocation of Certain Solar Facilities

32. The agreement specifies that the 50-megawatt (MW) Macho Springs solar-power purchase agreement (PPA) and the 10-MW Newman solar PPA will be system resources for purposes of jurisdictional allocation. (Agreement art. I.E.)

Imputed Capacity

33. Under the agreement, the classification of costs incurred by EPE as either base-rate capacity charges or fuel charges for the 50-MW Macho Springs solar PPA and the 10-MW Newman solar PPA shall be as follows for the term of these contracts: Effective beginning August 1, 2017, the imputed capacity charge for the 50-MW Macho Springs solar PPA shall be $2.35 per kilowatt (kW) per month, and the imputed capacity charge for the 10-MW Newman solar PPA shall be $2.33 per kW per month. All remaining costs incurred under these two PPAs shall be classified as fuel expenses. (Agreement art. I.F.)

Four Corners Decommissioning

34. The agreement provides for the rate treatment of EPE's share to decommission units 4 and 5 at the Four Corners Power Plant. (Agreement art. I.G.)

35. The agreement specifies that, consistent with EPE's request in this proceeding and the settlement agreement in Docket No. 44805,[3] the Commission's Order in the instant docket should authorize EPE's recovery of the costs of decommissioning units 4 and 5 at the Four Corners Power Plant in the amount of $6,992,622 on a total company basis, or $5,532,395 on a Texas jurisdictional basis, with this cost to be recovered over a seven-year period beginning August 1, 2017. This equates to an annual amortization in the amount of $998,946 on a total company basis, or $790,342 on a Texas jurisdictional basis, which represents one-seventh of the requested authorized recovery.

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[3] *Application of El Paso Electric Company for Reasonableness and Public Interest Findings on the Disposition of Coal-Fired Generating Facilities in New Mexico and Mine Closing Costs Adjustments*, Docket No. 44805, Order (Mar. 30, 2017).

36. The unamortized balance of the Four Corners decommissioning costs will not be included in rate base or accrue any carrying costs.

37. This amount for Four Corners decommissioning is subsumed in, and is not separate from, the overall $14.5 million revenue requirement increase.

Depreciation

38. The agreement provides that beginning August 1, 2017, EPE will use the depreciation rates as proposed in the direct testimony of Commission Staff witness Reginald J. Tuvilla (filed June 30, 2017) and reflected in his Attachment RJT-4, which is Attachment 3 to the agreement. (Agreement art. I.H.)

Nuclear Decommissioning

39. Under the agreement, beginning July 18, 2017, EPE will recover annually $2,132,186 (Texas jurisdiction) for nuclear-decommissioning funding. (Agreement art. I.I.)

Baseline Values for Distribution-Cost-Recovery Factor (DCRF) Filing

40. Under the agreement, if EPE files an application for approval of a distribution-cost recovery factor under PURA § 36.210 and 16 Texas Administrative Code (TAC) § 25.243 after July 18, 2017, then the baseline values to be used in that application are as shown in Attachment 4 to the agreement. (Agreement art. I.J.)

Baseline Values for Transmission-Cost-Recovery Factor (TCRF) Filing

41. The agreement specifies that if EPE files an application for approval of a transmission-cost recovery factor under PURA § 36.209 and 16 TAC § 25.239 after July 18, 2017, then the baseline values to be used in that application are as shown in attachment 5 to the agreement. (Agreement art. I.K.)

Forbearance of DCRF and TCRF Filings

42. EPE agrees that it will not file a DCRF or TCRF rate-change application prior to January 1, 2019. (Agreement art. I.L.)

Continuation of Certain Docket No. 44941 Rate Treatments

43. The agreement provides that EPE will continue to abide by four rate treatments contained in the amended and restated settlement agreement in Docket No. 44941 as follows: (a) those concerning the Copper gas generation turbine; (b) gains or losses for the retirement

of transportation equipment; (c) normalizing state income-tax expense; and (d) the costs of environmental consumables. (Agreement art. I.M.)

Allocation of the $14.5 Million Revenue Increase

44. The agreement specifies how the $14.5 million revenue increase is distributed among the rate classes in attachment 6 to the agreement. (Agreement art. I.N.)

Distributed Generation

45. The agreement contains provisions addressing residential and small-general-service customers with distributed generation (DG) and DG-related subjects. (Agreement art. I.O.)

46. The DG provisions are contained in attachment 7 to the agreement, which is provided as attachment A to this Order.

47. For convenience, attachment A to this Order is also referred to as the *DG Agreement*, which is summarized in this Order.

48. EPE, Commission Staff, EFCA, SEIA, and EPCO support the DG Agreement; the City of El Paso and OPUC, who are signatories, and ECO ELP and the EDF, do not oppose the DG Agreement.

49. For specified purposes, DG residential and small-general-service customers shall remain constituents of the residential-service or small-general-service rate classes, as applicable, as further explained in section 1 of the DG Agreement.

50. The DG Agreement addresses grandfathering provisions for residential customers and small-general-service customers who submit an application for interconnection and receive an email from EPE that states the application has been received and is under review prior to the day the Commission issues an order implementing the agreement. Such customers will not be subject to the minimum-bill provision. This subject is more fully explained in section 2 of the DG Agreement.

51. The DG Agreement addresses customer billing for DG customers (residential-service and small-general-service) who are not grandfathered. This subject is more fully explained in section 3 of the DG Agreement.

52. Under section 4 of the DG Agreement, EPE agrees to work with the local DG community, the city of El Paso and other municipalities in EPE's Texas service territory, Commission Staff, and OPUC on a commercially reasonable education program regarding DG service for existing and potential customers.

53. The DG Agreement addresses DG metering costs in section 5.

54. The DG Agreement addresses net energy metering in section 6.

55. The DG Agreement addresses interconnection-application fees in section 7.

56. In section 8 of the DG Agreement, EPE agrees to reset the demand ratchet for customers installing DG, installing storage, or both, following interconnection, of the DG or storage, effectively restarting the historical demand used for purposes of applying the tariffed demand ratchet.

57. The DG Agreement addresses the collaborative process EPE and interested stakeholders will undertake prior to EPE proposing modifications to the rate structure and conditions applicable to DG customers in the DG Agreement. This subject is addressed in section 9 of the DG Agreement.

58. Section 10 of the DG Agreement addresses certain restrictions on EPE proposing certain changes to DG rate and rate structures.

Rate Design and Tariff Approval

59. The agreement addresses tariff and rate-design issues (Agreement art. I.P.) as follows:
    (A) Design of Rates: The tariff sheets in attachment 8 to the agreement reflect the signatories' agreements concerning the design of rates.
    (B) Residential Customer Charge: The customer charge applicable to the Residential Service Rate, Schedule No. 01, shall be $8.25 per month.
    (C) Small General Service Customer Charge: The customer charge applicable to Small General Service, Schedule No. 02, shall be $10.75 per month.
    (D) Rate 24—General Service: New customers with an expected load greater than 400 kW shall take service under the time-of-use (TOU) alternative but have a one-time opportunity to opt out of the TOU alternative at the end of 12 months of service

under that rate and take service thereafter under the standard service rate. For any new customer choosing to opt out of the TOU alternative, the customer will be held harmless for the period of time they took service under the TOU alternative and be required to pay no greater than the lesser of bills calculated under the standard service or the TOU alternative.

(E) Rate 41—City and County Service Rate: EPE's proposal to apply a power factor penalty is not adopted. EPE's proposal for a rate design that is based on an hours-of-use rate structure, similar to rate 24, is not adopted. Instead, the existing declining block structure is maintained. However, the current differential between the blocks is reduced and the demand charge increased, as presented in attachment 8 to the agreement. In addition, EPE agrees that, with the exception of accounts that take non-metered service, EPE will install demand meters (at no cost to the customer) on all rate-41 accounts. EPE will activate the demand function (at no cost to the customer) for those rate-41 accounts with demand meters but that do not have the demand reading capability functioning. Accounts that are currently unmetered shall remain unmetered unless there is a mutual agreement to convert the account to a metered account.

(F) Rate 38—Noticed Interruptible Power Service: The minimum level of firm demand to be required from qualifying customers by rate 38 shall be reduced from 1,500 kW to 600 kW. In addition, EPE's proposed 10% charge for failure to interrupt should be modified consistent with the agreement as follows:

1st Non-Compliance—Rebill the bill month at the applicable firm service rate.

2nd Non-Compliance—Rebill the year-to-date at the applicable firm-service rate plus 5% (of rebilled interruptible amount, not including fuel).

3rd Non-Compliance—Rebill the year (unbilled interruptible portion) at applicable firm-service rate plus 5% (of rebilled interruptible amount, not including fuel), and the customer thereafter is not eligible to take interruptible service, but may reapply after twelve months.

(G) Rate Schedule DG: The following text, which has been modified from what EPE had proposed be added to the end-use-customer-affirmation-schedule portion of the agreement for interconnection and parallel operation of distributed generation, shall not be added to the end-use-customer-affirmation schedule but shall be a separate customer acknowledgement that EPE requires upon application for interconnection of distributed generation:

> I acknowledge (i) that El Paso Electric Company's customer classifications, rates, charges, and fee structures are subject to change at any time upon approval of the authorities or entities that govern and/or regulate El Paso Electric Company, and (ii) such changes could affect the economics (i.e., costs and benefits) of my distributed generation, including the magnitude and existence of any net savings on my bill.

The signatories' agreement to this provision of the agreement should in no way be interpreted as an agreement to any future change proposed by EPE or a party participating in a future proceeding or to the lawfulness of any particular proposal including specifically any proposal to place residential customers who have interconnected DG into a separate class, and the parties reserve all rights to contest any such proposal.

(H) EPE's proposed tariff-text changes with rates for the various classes consistent with the agreement, Attachment 8, should be approved upon final resolution of this case.

59A. The language of the separate customer acknowledgement that EPE requires upon application for interconnection of distributed generation described in finding of fact 59(G) is ambiguous.

59B. The following language provides better notice to customers and it is appropriate that the acknowledgement that EPE requires for the end-use-customer-affirmation schedule contain this language:

> I acknowledge (i) that El Paso Electric Company's customer classifications, rates, charges, and fee structures are subject to change at any time upon approval of the municipalities, Public Utility Commission of Texas, or the

Federal Energy Regulatory Commission under their respective authorities to regulate El Paso Electric Company, and (ii) such changes could affect the economics (costs, any credits, and other benefits) of my distributed generation, including the magnitude and existence of any net savings on my bill.

Rate-Case Expenses Recovery

60. The agreement provides for the review and recovery of EPE's rate-case expenses. (Agreement art. I.Q.)

61. The signatories agree that the rate-case expense Docket No. 47228 should be consolidated with this Docket No. 46831.

62. The signatories agree that under PURA § 36.061(b)(2), EPE should recover its reasonable and necessary rate-case expenses associated with this proceeding for services rendered through August 31, 2017, as well as all deferred rate-case expenses, subject to Commission Staff's review of the reasonableness and necessity of such expenses.

63. The signatories further agree that under PURA § 33.023(b), the City of El Paso, the Coalition, and Socorro (collectively, the cities) should be reimbursed by EPE for their reasonable and necessary rate-case expenses associated with this proceeding for services rendered through August 31, 2017, as well as deferred rate-case expenses, and that EPE should recover those amounts.

64. Commission Staff reviewed rate-case-expense invoices for EPE and the cities for services rendered through August 31, 2017. Based on this review, the signatories agree to the disallowance of $58,000 of the total rate-case expenses requested and find the remaining amount of $3,390,588.75 to be reasonable and necessary expenses and in compliance with 16 TAC § 25.245. To the extent the hourly rate for any service exceeded $550, only $550 per hour is included in this amount.

65. The signatories further agree that rate-case expenses associated with this proceeding incurred after August 31, 2017 by EPE and Cities will be captured in a regulatory asset and preserved for recovery consideration in EPE's next general base-rate case. EPE will not accrue any return on the regulatory asset in this subsection.

66. The signatories agree that rate-case expenses discussed above through August 31, 2017, will be recovered through a rate-case-expense surcharge over three (3) years, and that this rate-case-expense surcharge will become effective as prescribed by the Commission. These expenses shall be allocated to customer classes as shown on attachment 9 to the agreement. In order to avoid having two concurrent rate-case-expense surcharges, the surcharge resulting from the instant proceeding shall incorporate the unrecovered amount of the rate-case expenses from Docket No. 44941, and the current surcharge from Docket No. 44941 shall be terminated. No return shall accrue on the rate-case expenses identified in this paragraph.

Commission Approval

67. The agreement, including the DG Agreement, is the result of good faith negotiations by the parties, and these efforts, as well as the overall result of the agreement viewed in light of the record as a whole, support the overall reasonableness and benefits of the terms of the agreement.

68. The allocation of the rate-case expenses among rate classes in attachment 9 to the agreement is just and reasonable.

69. The agreement is binding on each signatory only for the purpose of settling the issues as set out in the agreement and for no other purpose. Except to the extent that the agreement expressly governs a signatory's rights and obligations for future periods, the agreement, including all terms provided herein, shall not be binding or precedential on a signatory outside of this case except for a proceeding to enforce the terms of the agreement. The signatories acknowledge and agree that a signatory's support of the matters contained in the agreement may differ from its position or testimony in other proceedings. To the extent there is a difference, a signatory does not waive its position in such other proceedings. Because the agreement is a settlement agreement, a signatory is under no obligation to take the same position as set out in the agreement in other proceedings, whether those proceedings present the same or a different set of circumstances. The agreement is the result of compromise and was arrived at only for the purposes of settling this case.

70. The agreement is not intended to be precedential except to the extent that (a) the agreement in article I.D, is a final determination on the reasonableness and necessity of the cost of EPE's investment; (b) the agreement in article I.G is a final determination of the reasonableness and necessity of the final decommissioning costs for the Four Corners Power Plant; (c) the agreements in articles I.J and I.K are final determinations of the DCRF and TCRF baselines being established by this case; and (d) the agreements in article I, sections C (cost of capital), E (allocation of certain solar resources), F (imputed capacity), G with regard to the amortization period for Four Corners decommissioning cost, H (depreciation), I (nuclear decommissioning), and M (continuation of rate treatments from Docket No. 44941) are intended to be adopted by the Commission and remain in place until such time as they may be changed on a prospective basis.

71. A signatory's agreement to entry of a final order of the Commission consistent with the agreement should not be regarded as an agreement to the appropriateness or correctness of any assumptions, methodology, or legal or regulatory principle that may have been employed in reaching the agreement.

II. Conclusions of Law

1. EPE is a public utility as that term is defined in PURA § 11.004(1) and an electric utility as that term is defined in PURA § 31.002(6).

2. The Commission exercises regulatory authority over EPE and jurisdiction over the subject matter of this application under PURA §§ 14.001, 32.001, 36.001–.211, and 39.552.

3. SOAH exercised jurisdiction over this proceeding under PURA § 14.053 and Texas Government Code § 2003.049.[4]

4. This docket was processed in accordance with the requirements of PURA, the Administrative Procedure Act,[5] and the Commission's rules.

5. EPE provided notice of the application in compliance with PURA § 36.103 and 16 TAC § 22.51(a) and (b).

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[4] Tex. Gov't Code Ann. § 2003.049 (West 2016).

[5] Tex. Gov't Code Ann. § 2001.001-.902 (West 2016 & Supp. 2017) (APA).

6. The Commission has jurisdiction over an appeal from municipalities' rate proceedings under PURA § 33.051.

7. The agreement, taken as a whole, is a just and reasonable resolution of all the issues it addresses, results in just and reasonable rates, terms, and conditions, is supported by a preponderance of the credible evidence in the record, is consistent with the relevant provisions of PURA, and should be approved.

8. The revenue requirement, cost allocation, revenue distribution, and rate design contemplated by the agreement result in rates that are just and reasonable, comply with the ratemaking provisions of PURA, and are not unreasonably discriminatory or preferential.

9. EPE's rates resulting from the agreement are just and reasonable and meet the requirements of PURA § 36.003.

10. The agreement resolves all of the pending issues in this docket.

11. The tariff sheets and rate schedules included in the agreement are just and reasonable and accurately reflect the terms of the agreement.

12. The Commission's adoption of a final order consistent with the agreement satisfies the requirements of the APA §§ 2001.051 and 2001.056 without the necessity of a decision on contested case issues resulting from a hearing on the merits.

13. The requirements for informal disposition under 16 TAC § 22.35 have been met in this proceeding.

III. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following orders:

1. Consistent with the agreement and this Order, El Paso Electric Company's (EPE's) application is approved.

2. Consistent with the agreement and this Order, the rates, terms, and conditions described in this Order are approved.

3. EPE's tariffs attached to the agreement are approved.

4. Within 20 days of the date of this Order, EPE shall file a clean record copy of the approved tariffs to be stamped "Approved" by Central Records and retained by the Commission.

5. EPE shall file proposed surcharge tariffs consistent with this Order within 20 days of the date of this Order in *Compliance Tariff for the Final Order in Docket No. 46831 (Application of El Paso Electric Company to Change Rates),* Tariff Control No. 47840. No later than 10 days after the date of the tariff filing, any intervenor in the instant proceeding may file comments on the individual sheets of the tariff. No later than 15 days after the date of the tariff filing, Commission Staff shall file its comments recommending approval, modification, or rejection of the individual sheets of the tariff. Responses to Commission Staff's recommendation shall be filed no later than 20 days after the filing of the tariff. The Commission shall by letter approve, modify, or reject each tariff sheet, effective the date of the letter.

6. The surcharge tariff sheets shall be deemed approved and shall become effective on the expiration of 30 days from the date of filing, in the absence of written notification of modification or rejection by the Commission. If any surcharge sheets are modified or rejected, EPE shall file proposed revisions of those sheets in accordance with the Commission's letter within 10 days of the date of that letter, and the review procedure set out above shall apply to the revised sheets.

7. Copies of all tariff-related filings shall be served on all parties of record.

8. EPE shall provide separately to a customer the following acknowledgement in lieu of the acknowledgement proposed in the settlement agreement upon a customer's application for interconnection of distributed generation.

> I acknowledge (i) that El Paso Electric Company's customer classifications, rates, charges, and fee structures are subject to change at any time upon approval of the municipalities, Public Utility Commission of Texas, or the Federal Energy Regulatory Commission under their respective authorities to regulate El Paso Electric Company, and (ii) such changes could affect the economics (costs, any credits, and other benefits) of my distributed generation, including the magnitude and existence of any net savings on my bill.

9. If the federal income-tax rate for corporations is decreased before EPE files its next base-rate case, EPE shall record the difference between the amount of federal income-tax expense that EPE collects through the revenue requirement approved in this proceeding and reflected in its rates and the amount of federal income-tax expense calculated using the new federal income-tax rate,. EPE shall calculate this difference in accordance with finding of fact 24 and article I.B of the settlement agreement. This difference shall be treated as a regulatory liability, and EPE shall file a refund tariff with the Commission and municipal regulatory authorities within 120 days after the enactment of the law making a federal tax-rate change. In each subsequent year, within 90 days after the end of the fiscal year, EPE shall file to update the refund factor.

10. EPE is authorized to establish a regulatory asset to record any rate-case expenses associated with this proceeding that EPE and the cities incurred after August 31, 2017. EPE shall not accrue any return on this regulatory asset. In EPE's next general base-rate case, EPE and the cities shall seek Commission review and recovery of any rate-case expenses recorded in this regulatory asset or forfeit such expenses.

11. Entry of this Order consistent with the agreement does not indicate the Commission's endorsement or approval of any principle or methodology that may underlie the agreement. Entry of this Order consistent with the agreement shall not be regarded as binding holding or precedent as to the appropriateness of any principle or methodology underlying the agreement.

12. All other motions, requests for entry of specific findings of fact, conclusions of law, and any other requests for general or specific relief, if not expressly granted herein, are denied.

Signed at Austin, Texas the 18th day of December 2017.

PUBLIC UTILITY COMMISSION OF TEXAS

DeAnn T. Walker

DEANN T. WALKER, CHAIRMAN

Brandy M. Marquez

BRANDY ~~MARTY~~ MARQUEZ, COMMISSIONER

Arthur C. D'Andrea

ARTHUR C. D'ANDREA, COMMISSIONER

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ATTACHMENT 7 TO THE STIPULATION AND AGREEMENT IN EL PASO ELECTRIC COMPANY'S RATE CASE IN DOCKET NO. 46831-- DISTRIBUTED GENERATION

The provisions in this Attachment 7 are a component part of the Stipulation and Agreement (Agreement) in El Paso Electric Company's (EPE's) Docket No. 46831. This Attachment 7 is supported by EPE, the Public Utility Commission Staff, Energy Freedom Coalition of America, Solar Energy Industries Association and the County of El Paso, while the OPUC, the City of El Paso, ECO ELP and the Environmental Defense Fund do not oppose it.

1. **No Separate Rate Class**: Distributed Generation ("DG") customers shall remain constituents of the Residential Service or Small General Service rate classes, as applicable, for cost allocation, revenue distribution, and rate design purposes. Residential and Small General Service DG customers will pay the same retail charges as the rest of their respective classes except as described below and provided for in the applicable tariff, based on the customer's selection of rate options.

2. **Grandfathering:** Residential and Small General Service customers who submit an application for interconnection and receive an email from EPE that states the application has been received and is under review prior to the day the Commission issues an order implementing this Agreement will not be subject to the Minimum Bill provision at their current residence or place of business for a grandfathering term of 20 years from the date of interconnection of their DG installation. Should the original interconnection customer move or sell the premises at which the DG system is installed, the grandfathering will continue to apply to that DG system for subsequent owners for the remainder of the grandfathering term. In addition, if a customer whose facility is subject to being grandfathered removes the entire DG system and relocates some or all of the facility to a new premise, the grandfathering will continue to apply to that DG system at a single new location, subject to confirmation by the company.

Grandfathered customers are subject to the same charges, including monthly customer charge, applicable to non-DG customers served under the applicable retail tariff and similarly will not be eligible to take service under the Experimental Demand Charge Monthly Rate.

3. **Customer Billing for Non-grandfathered DG Customers:**

Residential Service – Residential DG customers not subject to Grandfathering will be served on a default basis under the Standard Monthly Service Rate for their applicable rate schedule, subject to a Monthly Minimum Bill of $30.00. The customer's base rate monthly bill will consist of the greater of: (i) the total of base rate charges, including the monthly customer charge; or (ii) the customer's Monthly Minimum Bill.

Non-grandfathered Residential DG customers may otherwise voluntarily elect to take service under one of the following options:

(a) Alternate Time-of-Use Monthly Rate Customers may elect to receive service under the time-of-use (TOU) rate option provided for all residential customers under Rate 01, subject to a Minimum Monthly Bill of $26.50. The customer's base rate monthly bill will consist of the greater of: (i) the total of base rate charges, including the monthly customer charge; or (ii) the customer's Monthly Minimum Bill. The Net Energy Metering (NEM) billing provision will be applied by TOU period for the billing cycle.

(b) Experimental Demand Charge Monthly Rate - Customers may elect to receive service under the demand charge rate option provided for residential DG customers under Rate 01, the customer's base rate monthly bill will consist of (i) the applicable monthly customer charge, (ii) a monthly demand charge of $3.16 per kW applicable to monthly peak metered demand, (iii) TOU energy charges and all applicable riders. The NEM billing provision will be applied by TOU period for the billing cycle. This option is not subject to a minimum bill provision. This optional rate will be available for DG customers only.

In addition to any applicable minimum bill, existing applicable riders and charges (e.g., the Energy Efficiency Cost Recovery Factor, the Military Base Discount Rate Factor, the Fixed Fuel Factor, Rate 48, Relate-back, Rate Case expense) and any new rate riders, (e.g. a DCRF or TCRF), will be billed on the basis of the customer's monthly base charges and net energy consumption or production.

Small General Service – Small General Service DG customers not subject to Grandfathering will be served on a default basis under the Standard Monthly Service Rate for their applicable rate schedule, subject to a Monthly Minimum Bill of $39.00. The customer's base rate monthly bill will consist of the greater of: (i) the total of base rate charges, including the monthly customer charge; or (ii) the customer's Monthly Minimum Bill.

Non-grandfathered Small General Service DG customers may otherwise voluntarily elect to take service under one of the following options:

(a) Alternate Time-of-Use Monthly Rate – Customers may elect to receive service under the TOU rate option provided for all small general service customers under Rate 02, subject to a Minimum Monthly Bill of $36.50. The customer's base rate monthly bill will consist of the greater of: the total of base rate charges, including the monthly customer charge; or the customer's Monthly Minimum Bill. The NEM billing provision will be applied by TOU period for the billing cycle.

(b) Experimental Demand Charge Monthly Rate - Customers may elect to receive service under the demand charge rate option provided for small general service DG customers under Rate 02, the customer's base rate monthly bill will consist of (i) the applicable monthly customer charge, (ii) a monthly demand charge of $4.58 per kW applicable to monthly peak metered demand, (iii) TOU energy charges and all applicable riders. The NEM billing provision will be applied by TOU period for the billing cycle. This option is not subject to a minimum bill provision. This optional rate will be available for DG customers only.

In addition to any applicable minimum bill, existing applicable riders and charges (e.g., the Energy Efficiency Cost Recovery Factor, the Military Base Discount Rate Factor, the Fixed Fuel Factor, Rate 48, Relate-back, Rate Case expense) and any new rate riders, (e.g. a DCRF or TCRF), will be billed on the basis of the customer's monthly base charges and net energy consumption or production.

4. **Cooperation Regarding Education Program:** EPE agrees to work with the local DG community, the City of El Paso and other municipalities in EPE's Texas service territory, Commission Staff, and the OPUC on a commercially reasonable education program regarding DG service for existing and potential customers.

5. **DG Metering Costs:** Metering costs for DG customers taking service under the Standard Monthly Service rate are recovered through the applicable base rates. No additional charges apply for DG customers relative to non-DG customers.

   For DG customers electing service on the optional TOU or Demand rate option, additional charges as provided for in the applicable tariff will apply.

6. **Net Metering:** No changes are proposed or made to either the process of NEM for billing purposes or the application of Rate 48 for purposes of crediting net energy exports for eligible customers. The NEM billing provision will be applied by TOU period for the billing cycle for DG customers electing pricing options which include TOU energy pricing.

7. **Interconnection Application Fee**: The application fee included in Rate DG for an Interconnection Application for small and large generation facilities will not include specific cost recovery related to the GIS system. Interconnection application fees will be effective for new applications with rate approval under this settlement, and are not subject to the relate-back provision:

   Interconnection Application Fees
   Rated Capacity <= 100kW: $85.00
   Rated Capacity > 100kW: $230.00

   Amendments and addenda to an existing interconnection agreement undertaken in order to record increases of DG capacity or additions of storage will be subject to an interconnection application fee not to exceed 50% of the fee applicable for new interconnections. Amendments and addenda shall not result in forfeiture of grandfathering provisions where an agreement has previously been grandfathered. Cancellation of interconnection agreements and complete and permanent removal of existing interconnected DG or storage shall result in forfeiture of grandfathering provisions but will not be subject to a fee of any kind.

8. **Commercial and Industrial Customer Demand Ratchets**: EPE will reset the demand ratchet for customers installing DG and/or storage following interconnection of the DG and/or storage, effectively restarting the historical demand used for purposes of applying the tariffed demand ratchet.

9. **Collaboration Regarding DG Benefits:** Prior to proposing modifications to the rate structure and conditions applicable to DG customers as described in this Attachment #5 of the Agreement, EPE will collaborate with interested stakeholders in good faith to determine the cost and benefits of DG to EPE and EPE customers. This process should be informed by the November 2016 NARUC Manual Distributed Energy Resources Rate Design and Compensation and any supplements or amendments thereto, studies commissioned in other jurisdictions regarding the costs and benefits of distributed generation, and the MIT Energy Initiative's Utility of the Future.

10. **Forbearance Agreement**: For a period no less than three years after the Commission enters its final order in this proceeding, EPE will not initiate a proceeding to propose changes that would result in a rate structure change or rate increase to any DG customer that is different than the rate increase applicable to all other customers in their current class. For this same period, EPE will not propose a change in rate classes that would separate a DG customer from its current rate class unless all members of its current class are affected in the same manner. This restriction does not prevent periodic adjustments to charges under the riders in EPE's tariffs to pass through changes in costs as prescribed by the riders, and will not apply in instances where EPE is required by the PUCT or local municipality to file a rate proceeding. During this period, this provision does not affect the Commission's exercise of regulatory authority over EPE, including but not limited to rulemaking projects and EPE compliance with any such rule of general utility applicability.

PUC DOCKET NO. 40443
SOAH DOCKET NO. 473-12-7519

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES AND RECONCILE FUEL COSTS	§ § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER ON REHEARING

This Order addresses the application filed on July 27, 2012 by Southwestern Electric Power Company (SWEPCO) for authority to change its rates and reconcile its fuel costs. The primary contested issue regarding the proposed increase involves the portion of SWEPCO's share of the costs of the Turk coal plant in Hempstead, Arkansas that are allocated to Texas.

SWEPCO's application sought a total-company revenue requirement of $1.033 billion, exclusive of fuel revenues. The requested Texas retail revenue requirement exclusive of fuel revenues was $329 million, which reflected an increase in annual Texas retail revenues of $83.37 million over its adjusted test-year revenues.[1] The increase primarily consists of the inclusion of the newly constructed Turk coal plant and Stall gas plant. For the fuel reconciliation period from April 1, 2009 through December 31, 2011, SWEPCO sought to reconcile a cumulative fuel under-recovery balance of $3,936,492, including interest, and proposed no surcharge. SWEPCO's reconciliation included proposed revisions to Dolet Hills Lignite Company benchmark price.

The State Office of Administrative Hearings' administrative law judges (ALJs) issued a proposal for decision on May 20, 2013. The ALJs' recommended approval of the application, with certain adjustments. Regarding the Turk plant, the ALJs recommended the disallowance of all Turk costs over approximately $934 million as being imprudently incurred in continuing construction after June 2010. The ALJs further recommended that approximately $260 million be allowed for the estimated costs to retrofit the Welsh Unit 2 coal plant that SWEPCO should have undertaken instead of completing the Turk plant. However, the ALJs recommended in the

[1] Rebuttal Testimony of Jennifer L. Jackson, SWEPCO Ex. 88, JLJ-1R at 2.

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alternative that it is also reasonable for the Commission to either remand the issues involving the Welsh Unit 2 plant for additional evidence, or for SWEPCO to institute a new proceeding.

The ALJs recommended approval of a post-test-year adjustment for the Turk plant, as the unavoidable investment in the plant is to be recovered in base rates. The ALJs recommended the disallowance of certain litigation settlement costs, costs for a second auxiliary boiler, SWEPCO's annual incentive program, and part of the long-term financial incentives that include performance units. The ALJs recommended some adjustments to the requested operating and maintenance expenses, weather normalization and residential kWh growth in the post-test year, and class cost allocation and rate design. The ALJs recommended the adoption of SWEPCO's fuel reconciliation with the exception of disallowing the proposal regarding the Dolet Hills Lignite Company benchmark price.

Regarding other issues, the ALJs rejected SWEPCO's request to recover purchased capacity, consumables and allowances through fuel, and recommended that the transmission cost recovery factor and distribution cost recovery factor baselines be set during the compliance phase of this docket. Finally, the ALJs did not recommend the adoption of the International Brotherhood of Electrical Workers Local Union No. 738's request that SWEPCO be ordered to hire employees or maintain specific staffing levels.

The Commission reduces SWEPCO's total company revenue requirement by $98.6 million, thereby granting SWEPCO a total company revenue requirement of $935 million. The resulting Texas retail revenue requirement granted by the Commission is $293.9 million. Regarding the fuel reconciliation, the Commission adopts the ALJs' recommendation that the proposal be rejected and that SWEPCO's fuel expense during the fuel reconciliation period be reduced by $2,543,065. The disallowance results in an under-recovery balance of negative $4,648,310. The Commission adopts the proposal for decision, including findings of fact and conclusions of law, to the extent not inconsistent with this order.

I. Procedural History

The Commission issued an order on October 10, 2013. Motions for rehearing were filed on October 30, 2013. Subsequently, on December 20, 2013, an order granting rehearing was issued, which also announced the Commission's decision to reverse its findings and conclusions regarding the consolidated tax savings adjustment. That order set January 23, 2014 as the hearing date for further consideration of the Commission's ruling on the issue of whether the allowance for funds used during construction (AFUDC) is included in the cap on capital costs of the Turk plant established in Docket No. 33891.[2] At the Commission's open meeting on January 23, 2014, the Commission reopened the record and admitted additional exhibits offered into the record by SWEPCO and joint intervenors[3] to further consider the AFUDC issue. The Commission decided to reverse its determination on the AFUDC issue, with Commissioner Anderson respectfully dissenting on that issue. The Commission also ruled on other technical corrections to the Commission's decision on other issues in this docket. Additional findings regarding this procedural history are added as findings of fact 18A and 18B.

II. Discussion

SWEPCO is a fully-integrated electric utility that provides service to retail and wholesale customers in Texas, Arkansas, and Louisiana. SWEPCO's Texas service area is entirely in the Southwest Power Pool. SWEPCO's Texas service area is generally along the northeastern Texas border and the eastern side of the Texas Panhandle. SWEPCO serves approximately 180,650 direct retail customers in Texas. Of SWEPCO's eleven wholesale customers, six are electric cooperatives in Texas that serve an additional 320,000 retail customers. The Federal Energy Regulatory Commission (FERC) regulates SWEPCO's wholesale electric operations.[4]

[2] *Application of Southwestern Electric Power Company for a Certificate of Convenience and Necessity Authorization for Coal Fired Power Plant in Arkansas*, Docket No. 33891, Order (Aug. 12, 2008).

[3] The joint intervenors are: Texas Industrial Energy Consumers (TIEC), Cities Served by SWEPCO (Cities), State Agencies, and the Cities Advocating Reasonable Deregulation (CARD).

[4] Direct Testimony of Venita McCellon-Allen, SWEPCO Ex. 25A at 8-10.

A. Conditions of Docket No. 33891 CCN regarding permits

The Commission conditionally granted SWEPCO an amendment to its certificate of convenience and necessity (CCN) for the Turk plant in Docket No. 33891. The Turk plant is a 600 MW ultra-supercritical pulverized coal-fueled steam generator powering a single re-heat steam turbine generator that began commercial operations in December 2012 as a base load generating station.[5] One of the conditions was that SWEPCO obtain "all permits and agreements required for the construction and operation of the Turk Plant."[6] Subsequently, SWEPCO's Arkansas certificate of environmental compatibility and public need (CECPN) was declared invalid in June 2009. That decision was affirmed by the Supreme Court of Arkansas in June 2010. Intervenors argued that the Arkansas CECPN should be treated as a necessary permit because it was contemplated by the Commission in Docket No. 33891 to be necessary. The ALJs were persuaded that the Arkansas CECPN was not necessary to construct and operate the plant, which was all that the Commission's order in Docket No. 33891 required.[7] The Commission agrees with and adopts the ALJs' recommendation that SWEPCO obtained all the permits that were necessary to construct and operate the Turk plant as required in the order granting the CCN in Texas. Upon rehearing, the Commission notes that finding of fact 51 as phrased does not accurately reflect the ALJs' recommendation or the Commission's determination on this point. Accordingly, it is modified to reflect that SWEPCO re-evaluated the need for the Arkansas CECPN after it was invalidated and determined that the CECPN was not necessary to construct and operate the Turk plant.

B. Turk decisional prudence

The ALJs recommended in their proposal for decision that SWEPCO failed to sustain its burden to prove that the decision to complete construction of the Turk plant was prudent. Specifically, the ALJs found that a reasonably prudent utility manager would have been monitoring the changing economics of the Turk plant and would have realized on or before June 2010 that continued construction of the Turk plant was too costly. Further, the ALJs

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[5] Proposal for Decision at 14 (May 20, 2013). (PFD).

[6] Docket No. 33891, Order at 20, Ordering Paragraph No. 1 (Aug. 12, 2008).

[7] PFD at 22-23.

recommended that SWEPCO should have stopped construction of Turk in June 2010 and instead installed sulfur dioxide emission controls on unit 2 of the Welsh coal plant. The ALJs' recommendation allows recovery in rate base of SWEPCO's share of the unavoidable investment in the Turk Plant as of June 30, 2010 plus the estimated cost to install sulfur dioxide (SO_2) emission controls on Welsh Unit 2.

In analyzing SWEPCO's decision to complete the Turk plant and the ALJs' conclusion that the decision was uneconomic and therefore imprudent, the Commission looks to the prudence standard, which contemplates that (1) there may be more than one prudent option within the range available to a utility in any given context; (2) any choice within the select range of reasonable options is prudent; (3) the Commission should not substitute its judgment for that of the utility; and (4) the reasonableness of a decision must be judged in light of the circumstances, information, and available options existing at the time, without benefit of hindsight.[8] The Commission also notes that a utility's conduct is prudent when it involves "the exercise of judgment and the choosing of one of that select range of options which a reasonable utility manager would exercise or choose in the same or similar circumstances given the information or alternatives available at the point in time such judgment is exercised or option is chosen."[9]

The Commission's approval of a CCN amendment for a generation plant does not authorize the utility to continue with construction regardless of changing conditions. Rather, a company has a duty to its ratepayers to continue to evaluate the project during construction.[10] SWEPCO offered two studies to show it sufficiently monitored the economic viability of continued construction of the plant: the ICF study performed by SWEPCO during the 2009-2010 construction period (completed in 2009) and the 2010 draft presentation (that was prepared following the loss of the Arkansas CECPN but never distributed to the AEP board of directors). The ALJs found that these two studies were insufficient to be viewed as contemporaneous

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[8] *Nucor Steel v. Public Utility Commission of Texas*, 26 S.W 3d 742, 752 (Tex. App.—Austin 2000, pet. denied).

[9] *AEP Texas North Co. v. Public Utility Commission of Texas*, 297 S.W. 3d 435, 450 (Tex. App.—Austin 2009).

[10] *El Paso Elec. Co. v. Pub. Util. Com'n of Texas*, 917 S.W.2d 846, 855 (Tex. App.—Austin 1995), dismissed by agreement, judgment vacated, opinion not vacated, *El Paso Elec. Co. v. Pub. Util. Com'n*, 917 S.W.2d 872 (Tex. App.—Austin 1996, no writ).

evidence that SWEPCO took care to identify, gather information about, and evaluate the risks and options available to it when faced with extraordinary changes in circumstances.[11] The ALJs also found that SWEPCO had no process for continued evaluation of the economics of the Turk plant and never considered cancelling the Turk plant.[12] The Commission agrees with the ALJs that SWEPCO had no such processes to monitor the changing economics of the project.

A utility without contemporaneous evidence to support its decision-making process faces a heavy burden and the Commission will subject its after-the-fact justifications to rigorous review.[13] In *Gulf States*, the court noted that a lack of documentation supporting a utility's decision impedes the Commission's ability to determine whether the utility conducted a reasoned investigation of all relevant factors and alternatives before reaching its decision. However, the court went on to determine that a utility's decision may have still been prudent if through independent, retrospective analyses, the utility is able to demonstrate that a reasonable utility manager, having investigated all relevant factors and alternatives as they existed at the time the decision was made, would have found the utility's actual decision a reasonably prudent course.[14]

While the Commission finds that SWEPCO did not meet its duty to monitor the project's economics while construction was ongoing, this failure is not fatal to a determination that SWEPCO's decision to complete the plant was prudent. Upon the rigorous review of SWEPCO's after-the-fact justifications for its decision, the Commission may find that the evidence regarding the circumstances during construction ultimately validates the prudence of SWPECO's decision to complete construction of the Turk plant.

Natural gas prices have historically been more volatile than coal prices, and there was no indication that the relative price stability of the two fuels would materially change from that historically experienced.[15] In fact, average gas prices rose from 2009 to 2010 by 11%.[16] Also,

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[11] PFD at 35.

[12] PFD at 39.

[13] *Gulf States Utilities Co. v. Pub. Util. Com'n of Texas*, 841 S.W.2d 459, 476 (Tex. App.—Austin 1992, writ denied).

[14] *Id.*

[15] Rebuttal Testimony of Karl R. Bletzacker, SWEPCO Ex. 68 at 7-8.

[16] *Id.* at 8.

SWEPCO's generation strategy of fuel diversity to counter the volatility of gas prices was well documented,[17] and the Commission has long been supportive (if not demanding) of fuel diversity strategies. Further, by June 2010, engineering for the Turk plant was already 93% complete and overall plant construction was 39% complete, which also weighed heavily against halting construction.[18] Additionally, evidence indicated that during that time frame, SWEPCO still needed the capacity provided by the Turk plant to meet the needs of its native load customers including wholesale customers.[19] Finally, SWEPCO and the co-owners had already invested $947 million in the Turk plant, had additional contract commitments of $425 million, and the uncommitted costs associated with completing the Turk plant were less than the cost of constructing a natural gas-fired combined-cycle plant.[20]

The decrease in natural gas prices after the CCN was granted, coupled with the lack of contemporaneous evidence of the prudence of moving forward with the plant, makes this decision more difficult. However, the Commission recognizes that gas prices have historically been volatile, fuel diversity in a generation fleet is highly desirable, and generation plants should be designed to provide service to customers for 40-plus years. Likewise, the duration of the economic recession was uncertain. Given these circumstances, and the significant progress towards completion that SWEPCO had already made, SWEPCO's completion of the plant, which is projected to be in service for 55 years, was a prudent decision. It was an option that a reasonable utility manager could choose in these circumstances, given the information or alternatives available at that point in time.[21]

Accordingly, the Commission departs from the ALJs' recommendation on this issue and finds that continued construction of the Turk plant was reasonably prudent and that Texas's jurisdictional share up to the limit of the cost cap imposed in Docket No. 33891 should be included in rate base. New findings of fact 36A, 39A, 40A and B, and 56A, B, C, and D, and 69A, B, and C are added; findings of fact 39, 40, 42, 56, 60, 63, 68 and 69 are deleted; and

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[17] Direct Testimony of Thomas P. Brice, SWEPCO Ex. 26 at 59.

[18] Direct Testimony of Venita McCellon-Allen, SWEPCO Ex. 25A at 42.

[19] Direct Testimony of Scott C. Weaver, SWEPCO Ex. 27 at Exhibit SCW-5.

[20] Rebuttal Testimony of Thomas P. Brice, SWEPCO Ex. 66 at 12.

[21] *AEP Texas North*, at 450.

findings of fact 43, 44, 45, 46, 51, 53, 57, and 70 are modified to reflect this decision. Additionally, conclusions of law 25 and 27 are modified, and 26, 28, and 30 are deleted.

C. Turk litigation and settlement costs

Litigation challenging the construction of the Turk plant was aggressively pursued by the Sierra Club, the National Audubon Society, and the Hempstead County Hunting Club.[22] The ALJs recommended that all litigation costs and the settlement costs associated with the Sierra Club and the Audubon Society's litigation were reasonably incurred, but found that the settlement amount of $28 million paid to the Hempstead County Hunting Club was exorbitant on its face and was not adequately justified by SWEPCO.[23] The Commission agrees with the ALJs recommendation as to the litigation costs, but disagrees regarding the settlement costs with the Hunting Club and the environmental groups. The Commission finds that, although the amount of the settlement with the Hunting Club was extremely high, the settlement was necessary to the completion of the Turk plant; and therefore the cost was prudently incurred and should be allowed in rate base. Additionally, upon rehearing, the Commission corrects the amount to be included in rate base as $28.5 million, which is consistent with the evidence in the record.[24] Finding of fact 79A is corrected accordingly. Regarding the settlements with the Sierra Club and the Audubon Society, the Commission finds that, because these settlements were so intertwined with the commitment to retire the Welsh Unit 2 plant, a determination of whether these settlements are reasonable should be severed and deferred to a subsequent proceeding that addresses the early retirement of that facility. To reflect these decisions, findings of fact 79 and 80 are modified, 79A (as corrected) and 80A are added, and 82 is deleted. Conclusions of law 31 and 32 are deleted.

D. Turk auxiliary boiler

With regard to the Turk auxiliary boiler, the Commission agrees with the ALJs that while the larger boiler is used and useful, the prudently incurred cost of the boiler itself is limited to the

[22] PFD at 42.

[23] PFD at 46.

[24] Direct Testimony of J. Civins, SWEPCO Exhibit 30A at ex. C).

amount spent to procure the smaller boiler.[25] Had SWEPCO properly managed its plant construction activities, the smaller boiler would have been installed and the costs of procuring the larger boiler would have been avoided.[26] The Commission further finds that some, but not all, of the associated engineering and installation costs associated with the larger boiler that are sought by SWEPCO could have also been avoided. While the ALJs properly addressed the prudently incurred procurement costs, they did not address the costs associated with erecting the auxiliary boiler in the plant. Accordingly, the Commission modifies the decision to allow recovery of the cost of erecting the boiler because, regardless of whether the large boiler or small boiler was installed, these costs would have been incurred. The amount to be included in rate base is $3.289 million for procurement of the small boiler plus $4.268 million to erect the larger boiler, with the total prudently incurred cost of $7.557 million. Accordingly, the Commission modifies findings of fact 107 and 108, deletes 110, 111, 112, and 113, and adds new 111A. Conclusion of law 33 is also modified to reflect these decisions.

E. Cost Cap of Docket No. 33891 CCN

The Commission established a cap on capital costs of the Turk plant in Docket No. 33891 when it granted the conditional CCN.[27] Because of the disallowance of a portion of the capital costs of the Turk plant proposed by the ALJs, the proposal for decision did not fully address whether the cost cap limited recovery of AFUDC. However, in light of the Commission's determination that the completion of the Turk plant was prudent, the cost cap's application to AFUDC must be addressed.

The estimated capital cost of the Turk plant was $1.522 billion.[28] The Commission determines that the final order in Docket No. 33891 was ambiguous and not conclusive regarding whether the Commission at that time intended to include AFUDC in the $1.522 billion cap on capital costs. Therefore, the Commission looks beyond the order in Docket No. 33891 to the

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[25] PFD at 58 and 316.

[26] PFD at 58.

[27] Docket No. 33891, Order at 20, Ordering Paragraph No. 2 (Aug. 12, 2008).

[28] Id. at 14, Finding of Fact No. 22.

underlying record evidence in that docket.[29] In doing so, the Commission finds that the cap was based on estimates of construction costs excluding AFUDC as testified to by parties to that docket. Based on that evidence, the Commission now concludes that the AFUDC was a separately calculated component of capital costs that was not intended to be included in the cap. Accordingly, the Commission determines that the order in Docket No. 33891 did not include AFUDC in the cap on capital costs, and that SWEPCO may recover the Texas jurisdictional share of those costs from ratepayers.

SWEPCO's ownership share of Turk plant is 73.3% (SWEPCO owns 440 MW of the 600 MW plant, including the 88 MW that became "merchant" when Arkansas CECPN was invalidated). The other three owners of the plant account for the remaining 26.7% (160 MW). Texas's jurisdictional allocation for production plant is 32.7% of SWEPCO's 73.3%.

	Cap on Capital Cost
Total Turk Plant	$1.522 billion
SWEPCO's 73.3% of Turk	$1.116 billion
Texas Jurisdictional Allocation	$ 364.93 million

The Commission finds that SWEPCO's share of total construction costs of $1.106 billion, less the relatively small reductions identified in this order on rehearing, does not exceed SWEPCO's share of the cost cap ($1.116 billion) and should be included in rate base. Additionally, SWEPCO's share of the roughly $250 million in AFUDC should also be included in rate base because the Commission finds that the AFUDC was not intended to be included in the cost cap. Accordingly, finding of fact 116 is modified, and findings of fact 116A – F are added, findings of fact 117 and 118 are deleted, and conclusion of law 36A is added to reflect this decision.

F. Welsh Unit 2

The ALJs found that SWEPCO did not justify with thorough analysis its decision to retire Welsh 2 more than 20 years prior to the end of its useful life. The ALJs further recommended that the Commission find that SWEPCO should have halted construction of Turk in June 2010

[29] At the January 23, 2014 open meeting, SWEPCO's exhibits numbered 111 – 115, 117, 118, and 120 were marked and admitted to the evidentiary record.

and instead install sulfur dioxide emission controls on Welsh Unit 2 so that it could remain in service in place of the Turk plant. Thus, the ALJs concluded that SWEPCO was imprudent in retiring Welsh Unit 2.[30]

As previously discussed in reference to settlement and litigation costs, the Commission determines that the issue of whether SWEPCO's decision to reduce production and ultimately retire Welsh Unit 2 was prudent should be deferred to a future proceeding that addresses the actual retirement of the plant when it occurs. To reflect this determination, findings of fact 120 through 123 are deleted, 119 is modified, and 125A is added. Additionally conclusions of law 29 and 36 are deleted.

G. Rate of return

To determine the core issue of SWEPCO's appropriate return on equity, the ALJs analyzed the appropriate proxy group that is comparable to SWEPCO for the process of estimating return on equity (ROE), considered whether SWEPCO's ROE should be increased by a floatation adjustment, and reviewed the ROE's recommended by the various witnesses.[31] Ultimately, the ALJs recommended that SWEPCO's ROE be set at 9.65%.[32] The ALJs further found SWEPCO's proposed cost of long-term debt of 5.96% to be reasonable, and recommended adoption of SWEPCO's proposed capital structure consisting of 50.9% long-term debt and 49.1% equity. Accordingly, the overall rate of return proposed by the ALJs is calculated to be 7.77%.[33]

The Commission adopts the ALJs' recommendations on the rate of return. The Commission also notes a correction to include new finding of fact 152A to reflect the decision against a floatation adjustment to the rate of return.[34] Because it is unknown whether SWEPCO's parent company will procure the capital used to make equity infusions through retained earnings of the parent company, debt issuances of the parent company or a stock

[30] PFD at 62.

[31] PFD at 139.

[32] PFD at 141.

[33] PFD at 145.

[34] PFD at 140.

issuance, a flotation adjustment to the ROE would not be appropriate as its not known and measurable.

H. Consolidated Tax Savings Adjustment

In the final order, the Commission adopted the proposal for decision and reduced SWEPCO's cost of service by a consolidated tax savings adjustment of $13,992,254 (total company). When this issue was initially considered, SB 1364 was not yet effective. However, the order was issued on October 10, 2013, after the bill's effective date of September 1, 2013. The bill amended PURA § 36.060(a) to state:

> If an expense is allowed to be included in utility rates or an investment is included in the utility rate base, the related income tax benefit must be included in the computation of income tax expense to reduce rates. <u>If an expense is not allowed to be included in utility rates or an investment is not included in the utility rate base, the related income tax benefit may not be included in the computation of the income tax expense to reduce the rates.</u>

The new law contained no savings clause for pending proceedings, therefore the adjustment was improper. Accordingly, the Commission determines upon rehearing that it erred in making the consolidated tax savings adjustment in light of SB 1364's effective date of September 1, 2013. Accordingly, finding of fact 230 is modified and 231 deleted, and conclusion of law 20 is modified.

I. Pirkey (Sabine) Mine Reclamation Costs

In its motion for rehearing, SWEPCO noted that its proposed recovery of Sabine mine reclamation costs, including a $53 million reduction to rate base, was uncontested by any party and apparently adopted by the Commission as reflected in the schedules attached to the final order. However, the proposal for decision and the Commission's order provided no supporting findings of fact. The Commission agrees that appropriate findings should be included in the order on rehearing and does so by adding findings of fact 146A – D.

J. Fuel Reconciliation

SWEPCO requested a good cause exception to recover consumables and allowances as fuel on a going-forward basis. The Commission is persuaded by the arguments of Commission Staff regarding this issue and rejects the ALJs' recommendation to disallow the request. Accordingly, finding of fact 322 is modified and conclusion of law 47 is modified.

K. Miscellaneous

Corrections to the findings of fact and conclusions of law are necessary to appropriately reflect the Commission's determinations regarding the following issues.

First, the findings regarding the unique aspects of SWEPCO's overall compensation program do not accurately reflect the ALJs' recommendation that the Commission adopts. Therefore, the Commission modifies finding of fact 147 to clarify that the portion of SWEPCO's annual and long-term incentive payments that are capitalized and that are financially-based are excluded from SWEPCO's rate base because the benefits of such payments inure most immediately and predominantly to SWEPCO's shareholders, rather than its electric customers. Also, an error in finding of fact 220 is corrected to reflect that, of SWEPCO's annual incentive compensation of $10,728,117, $3,523,732 is disallowed as financial goals. These same findings are clarified to reflect that the part of the long-term incentive compensation program that includes performance units is disallowed as being based on financial measures, and the part that includes restricted stock units is allowed — $3,130,757 is disallowed from the $5,175,829 in long-term incentive compensation.

Further, in accordance with other corrections noted by the ALJs in their July 2, 2013 letter, the amount of credit line fees is corrected in finding of fact 186. The Commission also modified finding of fact 242 to reflect its clarification that the test-year expenses for injuries and damages exceeds the average of the expense in the three previous years, and the amount should be disallowed completely and not amortized.

Also, the ordering provisions reflect the ALJs clarification that SWEPCO should provide a calculation in its compliance filing to include 12 months' weather normalized residential sales based on a 10-year normal to reflect the ALJs' recommendation adopted by the Commission.

In response to motions for rehearing, the Commission makes a necessary correction to the labor cost disallowance in finding of fact 213. Likewise, the amount of expense for temporary labor is corrected in finding of fact 244, and the references to cost causation principles as well as direct and spread collection methods in findings of fact 276 and 279 are corrected. Finally, in response to motions for rehearing, the Commission agrees that finding of fact 286 should be deleted because it does not comport with the Commission's decision on this issue as reflected in the previous findings regarding the appropriate load factor.

The Commission adopts the following findings of fact and conclusions of law:

III. Findings of Fact

Procedural History

1. Southwest Electric Power Company (SWEPCO) is an investor-owned electric utility serving retail and wholesale customers in Texas, Louisiana, and Arkansas.

2. SWEPCO serves 180,650 Texas retail customers.

3. The Federal Energy Regulatory Commission (FERC) regulates SWEPCO's wholesale electric operations.

4. Customer choice has been delayed for the entirety of SWEPCO's service area under Public Utility Regulatory Act (PURA) § 39.501.

5. On July 27, 2012, SWEPCO filed an application requesting approval of: (1) a proposed increase in annual base rate revenues of approximately $83 million over adjusted test-year revenues (Texas retail); (2) a set of proposed tariff schedules presented in the electric utility rate filing package for generating utilities (RFP) accompanying SWEPCO's application; (3) a request for final reconciliation of SWEPCO's fuel and purchased-power costs for the April 1, 2009 through December 31, 2011 reconciliation period; and (4) certain waivers to the instructions in RFP schedule V accompanying SWEPCO's application.

6. SWEPCO employed the calendar year 2011 as its 12-month test year.

7. SWEPCO provided notice by publication for four consecutive weeks before the effective date of the proposed rate change in newspapers having general circulation in each county of SWEPCO's Texas service territory. SWEPCO also mailed notice of its proposed rate change to all of its customers. Additionally, SWEPCO timely served notice of its statement of intent to change rates on all municipalities retaining original jurisdiction over its rates and services.

8. The following parties were granted intervenor status in this docket: Office of Public Utility Counsel; the Texas State Agencies; Texas Industrial Energy Consumers; East Texas Electric Cooperative, Inc. and Northeast Texas Electric Cooperative, Inc.; Rayburn Country Electric Cooperative, Inc.; International Brotherhood of Electrical Workers Local Union 738 (IBEW); Cities Advocating Reasonable Deregulation (CARD); Cities Served by SWEPCO (Cities); and Wal-Mart Stores Texas, LLC; and Sam's East, Inc. (Wal-Mart). The Staff (Staff) of the Public Utility Commission of Texas (Commission or PUC) was also a participant in this docket.

9. On July 30, 2012, the Commission referred this case to the State Office of Administrative Hearings (SOAH).

10. On August 22, 2012, the Commission issued its preliminary order, identifying the issues to be addressed in this proceeding.

11. On September 5, 2012, the SOAH Administrative Law Judges (ALJs) issued SOAH Order No. 3, which approved an agreement among the parties establishing SWEPCO's existing rates as temporary rates for service on and after that date, with such temporary rates being subject to reconciliation back to January 29, 2013, and with refund or surcharge to the extent that rates ultimately established differ from the temporary rates.

12. SWEPCO timely filed with the Commission petitions for review of the rate ordinances of the municipalities exercising original jurisdiction within its service territory. All such appeals were consolidated for determination in this proceeding.

13. On November 9, 2012, SWEPCO added to its total company revenue requirement $3,786,335, which results in an additional $519,762 to the Texas retail base rate increase.

14. The hearing on the merits commenced on February 4 and concluded on February 14, 2013.

15. During the hearing, the parties agreed to sever rate case expenses from this proceeding, with SWEPCO agreeing to initiate a separate proceeding to address rate case expenses.

16. Initial post-hearing briefs were filed on March 6 and reply briefs were filed on March 20, 2013.

17. On April 17, 2013, the ALJs issued Order No. 33, closing the administrative record as of April 4, 2013, and granting consideration of TIEC's letter sur-reply brief and SWEPCO's sur-reply response brief.

18. SWEPCO agreed to extend the jurisdictional deadline to June 24, 2013.

18A. The Commission issued an order in this docket on October 10, 2013. Motions for rehearing were filed on October 30, 2013. Subsequently, on December 20, 2013, an order granting rehearing was issued, which also announced the Commission's decision to reverse its findings and conclusions regarding the consolidated tax savings adjustment. That order also set January 23, 2014 as the hearing date for further consideration of the Commission's ruling on the issue of whether the allowance for funds used during construction (AFUDC) is included in the cap on capital costs of the Turk plant established in Docket No. 33891.

18B. At the Commission's open meeting on January 23, 2014, the Commission reopened the record and admitted additional exhibits offered into the record by SWEPCO and joint intervenors to further consider the AFUDC issue. The Commission decided to reverse its determination on the AFUDC issue, with Commissioner Anderson respectfully dissenting. The Commission also ruled on other technical corrections to the Commission's decision on other issues in this docket.

<u>Stall Power Plant</u>

19. In June 2010, SWEPCO brought on line the Stall power plant (Stall), which is a natural gas-fired, nominally-rated 507 megawatts (MW) combined-cycle power plant in Shreveport, Louisiana.

20. SWEPCO received a certificate of convenience and necessity (CCN) authorization for Stall in *Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization for a Combined Cycle Power Plant in Louisiana*, Docket No. 33048, Order (Mar. 8, 2007).

21. Stall is used and useful in serving customers, and the costs to build it were prudently incurred.

22. SWEPCO has met the requirements to include the costs of Stall in rate base at its original cost.

Turk Power Plant

23. The John W. Turk, Jr. power plant (Turk plant) is a coal-fueled, nominally-rated 600 MW baseload plant in southwest Arkansas, approximately 15 miles northeast of the City of Texarkana, Arkansas.

24. The Turk plant has a total of four co-owners, and SWEPCO's share is 73.3% or 440 MW.

25. The Turk plant includes an ultra-supercritical pulverized coal steam generator operating at advanced steam conditions powering a single re-heat steam turbine generator, making it one of the cleanest, most efficient coal-fueled plants in the United States.

Turk Plant – Conditions of CCN

26. The Commission approved SWEPCO's application to amend its CCN to include its ownership in the Turk plant in *Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization for a Coal Fired Power Plant in Arkansas*, Docket No. 33891, Order (Aug. 12, 2008).

27. The Commission's final order in Docket No. 33891 was conditioned upon SWEPCO receiving all necessary permits and agreements required for the construction and operation of the Turk plant.

28. SWEPCO received all necessary permits and agreements required for the construction and operation of the Turk plant.

29. SWEPCO received a certificate of environmental compatibility and public need (CECPN) from the Arkansas Public Service Commission (APSC) on November 21, 2007.

30. The Arkansas Supreme Court reversed the APSC's granting of a CECPN in May 2010.

31. On June 24, 2010, SWEPCO filed a Notice with the APSC that it would proceed with the construction and operation of the Turk plant in accordance with the exemption provided by Ark. Code § 23-18-504(a)(5) and that accordingly it would not seek to recover the costs of the Turk plant in rates subject to regulation by the APSC.

32. An Arkansas CECPN is not a necessary permit required for the construction and operation of the Turk plant.

33. The Commission's final order in Docket No. 33891 established a cap of $1.522 billion on Turk plant capital costs. Texas ratepayers are not responsible for any costs above the Texas jurisdictional share of the $1.522 billion capital costs cap.

Turk Decisional Prudence

34. A reasonable utility manager would have implemented a process for monitoring the expected value of the Turk plant compared to its remaining cost to complete on an ongoing basis after receiving CCN approval for the plant.

35. SWEPCO did not implement any process for monitoring the economic viability of the Turk plant on a continuing basis after it received the CCN.

36. SWEPCO did not prudently monitor the economic viability of the Turk plant following its receipt of a Texas CCN in 2008 through June 2010.

36A. A reasonable utility manager in the same or similar circumstances given the information or alternatives available at the point in time after SWEPCO received its Texas CCN could have found that finishing construction of the Turk plant fell within a range of reasonably prudent options.

37. In Docket No. 33891, SWEPCO justified the Turk plant to the Commission based on the relative price of coal to natural gas. SWEPCO's witness testified that the break-even price for the Turk plant was $8.25 per Million British Thermal Units (MMBtu).

38. The price of natural gas declined in a steep and sustained fashion in the months and years following SWEPCO's receipt of the conditional CCN for the Turk plant in August of 2008. The price of natural gas fell below the break-even price of $8.25 per MMBtu by October 2008 and continued to decline.

39. DELETED.

39A. It was not clear in 2009 that the decline in natural gas prices would continue long-term because of the historically volatile nature of natural gas prices.

40. DELETED.

40A. Natural gas prices have historically been more volatile than coal prices, and there was no indication that the relative price stability of the two fuels would materially change from that historically experienced.

40B. Average gas prices rose from 2009 to 2010 by 11%.

41. In September 2008, a global financial crisis sent the United States into a recession. The recession reduced economic activity, which reduced the need for new generation facilities. SWEPCO's customers reduced their usage during this time. By the time SWEPCO's March 2010 capacity, demand, and reserves report (CDR) was compiled, SWEPCO's projections of peak demand had fallen 132 to 164 MW for the 2013-2017 period compared to the projections used in the early 2008 CDR table submitted in Docket No. 33891.

42. DELETED.

43. SWEPCO's March 2010 CDR shows that had SWEPCO cancelled Turk, it would have required an average of only 28 more megawatts per year until 2017 to meet its required capacity margin.

44. From 2009 to the present, there has been ample capacity for SWEPCO to purchase power in the Southwest Power Pool (SPP) to meet capacity needs.

45. In June 2010, gas prices remained at approximately one-half of SWEPCO's break-even price for the Turk plant of $8.25 per MMBtu. American Electric Power Company's 2010 fundamental forecast predicted gas prices even lower than the 2009 version. Specifically,

AEP predicted that prices would remain below $5.00 per MMBtu in real 2008 dollars until 2015, below $6.00 until 2020, and would only reach $6.82 by 2030.

46. SWEPCO failed to show it sufficiently monitored the economics of the continued construction of the plant. SWEPCO had no process to identify, gather information about, and evaluate the risks and options available when changes in circumstances called for continued evaluation of the economics of the Turk plant.

47. A reasonable utility manager would have re-evaluated the need for continuation of the Turk plant in light of the changed capacity margin forecasts in 2010.

48. SWEPCO did not analyze the changed capacity margin forecasts in 2010 with regard to considering other alternatives to continuation of building the Turk plant.

49. In June 2010, after the Arkansas Supreme Court invalidated SWEPCO's Arkansas CECPN, the AEP Board of Directors approved continued construction of the Turk plant as a merchant plant.

50. A reasonable utility manager would have re-evaluated the need for continued construction of the Turk plant after the required Arkansas CECPN was invalidated.

51. SWEPCO re-evaluated the need for the Arkansas CECPN after it was invalidated and determined that an Arkansas CECPN was not necessary to construct and operate the Turk plant.

52. A reasonable utility manager would have re-evaluated the need for the continued construction of the Turk plant when faced with numerous lawsuits.

53. SWEPCO did not re-evaluate the need for continued construction of the Turk plant or consider other factors or alternative courses of action in light of potentially expensive and protracted litigation. Instead, the Company entered into costly settlements that restricted its ability to continue to operate the Welsh Unit 2.

54. A reasonable utility manager would have re-evaluated the need for the continued construction of the Turk plant in light of falling gas prices to determine whether long-term gas forecasts made the construction and operation of the Turk plant uneconomical.

55. SWEPCO did not re-evaluate the need for continued construction of the Turk plant or consider other factors or courses of action when long-term gas prices declined significantly.

56. DELETED.

56A. By June 14, 2010, engineering for the plant was already 93% complete and overall plant construction was 39% complete.

56B. The uncommitted costs associated with completing the Turk plant were less than the cost of a combined cycle combustion turbine plant.

56C. The combined estimated value of SWEPCO's regulated and unregulated shares of the Turk plant exceeded the cost-to-complete by nearly $600 million.

56D. SWEPCO needed the capacity provided by the Turk plant to meet the needs of its native load customers, which includes wholesale customers, and the co-owners of the Turk plant were depending on the plant's completion.

57. A reasonable utility manager would have re-evaluated the need for the continued construction of the Turk plant in light of changing economic conditions.

58. SWEPCO performed no analysis of whether it made sense to construct rather than cancel the Turk plant in light of changing economic conditions.

59. SWEPCO did not re-evaluate its decision to continue building the Turk plant, consider other relevant factors, or consider other courses of action in light of changing economic and regulatory circumstances.

60. DELETED.

61. The 2009 report prepared for SWEPCO by ICF International (ICF) consisted of a comparison of the Turk plant to a natural gas option.

62. The 2009 ICF report did not compare the Turk plant to other alternatives such as retrofitting Welsh Unit 2 or purchasing power. The analysis was not conducted because SWEPCO thought it might be a good idea to determine whether the Turk plant was

economic, but only because the Louisiana Public Service Commission asked SWEPCO to perform the analysis concerning its request for construction work in progress (CWIP).

63. DELETED.

64. SWEPCO prepared an analysis of the economic viability of the Turk plant (June 2010 Presentation) in anticipation of a June 14, 2010 AEP board meeting to discuss the Company's options in view of the Arkansas Supreme Court decision reversing the APSC's granting of a CECPN.

65. The June 2010 presentation quantified the net present value of the Turk plant compared to estimated costs to complete construction under various scenarios.

66. The June 2010 presentation showed that the Turk plant had a negative value under some scenarios.

67. The June 2010 presentation was not presented to AEP's board of directors.

68. DELETED.

69. DELETED.

69A. SWEPCO met its burden of proving that a reasonable utility manager, having investigated all relevant factors and alternatives as they existed at the time the decision was made, would have found the utility's actual decision to continue constructing the Turk plant after it lost the CECPN for the plant in June 2010 reasonably prudent.

69B. A reasonable utility manager in the same or similar circumstances during construction of the Turk plant could have found that the plant was economic compared to market valuations and long-term uncertainties.

69C. SWEPCO's decision to complete the Turk Plant was within the range of options that a reasonable utility manager would choose under the same or similar circumstances.

70. It is reasonable to allow the final approved capital investment in the Turk plant in rate base.

Turk Litigation and Settlement Costs

71. In 2010, the Sierra Club, National Audubon Society, the Hempstead County Hunting Club (HCHC), and a number of individuals affiliated with one or more of these groups, filed separate complaints – one headed up by HCHC and the other by the Sierra Club – with the federal district court in the Western District of Arkansas against the U.S. Army Corps of Engineers, the U.S. Department of Interior, and the U.S. Fish and Wildlife Service.

72. The lawsuits challenged the Corps' issuance of permits for the Turk plant that authorized SWEPCO to fill wetlands and to construct the water intake structure and six river crossings for transmission lines.

73. In the last quarter of 2010, the Sierra Club and HCHC litigants obtained a temporary injunction stopping the activities authorized by the Corps, and the U.S. Court of Appeals for the Eighth Circuit upheld that injunction, concluding, among other things, that the plaintiffs had shown a likelihood of success.

74. As long as the injunction was in place, SWEPCO could not complete construction necessary to operate the Turk plant at full capacity.

75. SWEPCO determined that each month of delay would have resulted in about $10 million in allowance for funds used during construction (AFUDC) added to the cost of the Turk plant.

76. In addition to the approximately $10 million in costs per month for construction delays, SWEPCO also was incurring significant litigation costs.

77. Both groups of plaintiffs eventually raised state law claims challenging SWEPCO's authority to construct the Turk plant without a CECPN. These claims were never resolved on the merits.

78. In affirming the injunction, the Eighth Circuit noted that the plaintiffs were particularly likely to succeed on the merits because of SWEPCO's own actions, including proceeding with Turk plant construction in the absence of a CECPN (despite its prior statements that it would not do so), and "careless errors in mapping and flagging of wetland boundaries." The court likened SWEPCO's actions to "bureaucratic steamrolling," and concluded that

any harm to SWEPCO from the injunction was largely self-inflicted. *Sierra Club v. United States Army Corps of Engineers*, 645 F.3d 978.

79. Following the Eighth Circuit's decision affirming the preliminary injunction, SWEPCO entered into settlement agreements with the HCHC and the Sierra Club/Audubon Society plaintiffs resolving all claims asserted by these groups.

79A. The cost of the Sierra Club and National Audubon Society settlement was $12 million, the cost of the HCHC settlement was $28.5 million, and the litigation costs sought to be capitalized was $16.9 million.

80. SWEPCO has met its burden to show that its $28 million settlement with HCHC and the $16.9 million in litigation costs were prudent, and necessary and reasonable expenses.

80A. Because the settlements with the Sierra Club and the Audubon Society were so intertwined with SWEPCO's commitment to retire the Welsh Unit 2 plant, a determination of whether these settlements were prudent is appropriately severed and deferred to a subsequent proceeding that addresses the early retirement of that facility.

81. The Turk plant permit litigation settlements were intended to avoid additional construction delay costs.

82. DELETED.

Post-Test-Year Adjustment

83. The Turk plant entered service on December 20, 2012, and is used and useful in serving customers.

84. The Commission's post-test-year adjustment rule in P.U.C. SUBST. R. 25.231(c)(2)(F)(i)(III) requires that a rate base addition be deemed by the Commission to be in service before the rate year begins.

85. SOAH Order No. 3 approved the parties' agreement that SWEPCO's current rates will be deemed temporary rates as of January 29, 2013, which date is the beginning of the rate year under P.U.C. SUBST. R. 25.5(102).

86. The Turk plant has met the post-test-year adjustment standards to be included in rate base at its test-year-end CWIP balance, adjusted for Texas jurisdictional AFUDC differences.

87. SWEPCO has proposed two post-test-year adjustments totaling $72.661 million to include Turk transmission CWIP in rate base.

88. P.U.C. SUBST. R. 25.231(c)(2)(F) governs the requirements for post-test-year adjustments for rate base additions.

89. P.U.C. SUBST. R 25.231(c)(2)(F)(i)(II) requires that each post-test-year adjustment comprise at least 10% of the electric utility's requested rate base, exclusive of post-test-year adjustments and CWIP.

90. SWEPCO's Turk plant-related transmission CWIP amount does not comprise at least 10% of SWEPCO's requested rate base, exclusive of post-test-year adjustments and CWIP.

91. SWEPCO's proposal to reclassify Turk plant related transmission CWIP into plant in service does not meet the requirements of P.U.C. SUBST. R. 25.231(c)(2)(F)(i)(II).

Turk Land Costs

92. The Turk plant is located on an approximately 2,875 acre site.

93. Under the Turk plant related litigation settlements discussed above, SWEPCO agreed that it would not build any additional generating units on the Turk site.

94. Land for a power plant is not available in any acreage possible, and SWEPCO was not capable of purchasing only exact fractions of properties that would just meet its needs.

95. The Turk generating unit itself occupies only a small portion of the site, and other facilities take up much of the site.

96. A second generating unit at the Turk site would require approximately 38 acres—or roughly just 1.3 percent of the total land at the Turk site.

97. SWEPCO's agreement to not build any additional generating units on the Turk plant site was prudent.

98. The full cost of purchasing the Turk plant site is appropriately included in rate base.

Turk Auxiliary Boiler

99. SWEPCO purchased and proposes to recover two auxiliary boilers related to the Turk plant.

100. The Turk plant needs only one auxiliary boiler.

101. The original design of SWEPCO's Turk plant included a large auxiliary boiler.

102. The specifications for the larger auxiliary boiler were included in SWEPCO's Arkansas air permit application.

103. SWEPCO engineers subsequently discovered a design flaw; the solution for which resulted in the need for a much smaller auxiliary boiler.

104. SWEPCO purchased the smaller auxiliary boiler.

105. SWEPCO engineers did not communicate the need for a smaller auxiliary boiler to SWEPCO's environmental permitting personnel for two years.

106. SWEPCO did not attempt to make any changes to its air permit application until several months before the issuance of the final Turk plant air permit.

107. Rather than jeopardize its air permit, SWEPCO purchased the larger auxiliary boiler and incurred costs to engineer and install the balance of plant.

108. The larger boiler is used and useful, but the prudently incurred cost of the boiler itself is limited to the amount spent to procure the smaller boiler—$3.289 million. Had SWEPCO properly managed its plant construction activities, the smaller boiler would have been installed and the costs of procuring the larger boiler would have been avoided.

109. The smaller auxiliary boiler is not used and useful.

110. DELETED.

111. DELETED.

111A. The amount of $4.268 million was reasonably incurred to erect the larger auxiliary boiler.

112. DELETED.

113. DELETED.

114. A reasonable utility manager would have ensured that the appropriate and cost-effective design solution was the design for which necessary permits were received for the Turk plant.

Turk CCN Costs Cap

115. In Docket No. 33891, the Commission set the Turk plant cost cap at $1.522 billion.

116. SWEPCO's 73.3% share of the $1.522 billion cap is $1.116 billion. Texas's jurisdictional allocation for production plant is 32.7% of SWEPCO's 73.3%.

116A. SWEPCO's share of total construction costs of the Turk plant is $1.106 billion, less the relatively small reductions identified in this order on rehearing. This amount does not exceed SWEPCO's share of the cost cap ($1.116 billion) and should be included in rate base. Texas's jurisdictional share should be recovered from Texas rate payers.

116B. Allowance for funds used during construction (AFUDC) is generally treated as a capital cost in accounting for production plant investment.

116C. The final order in Docket No. 33891 was ambiguous and was not conclusive regarding whether the Commission at that time intended to include AFUDC in the $1.522 billion cap on capital costs.

116D. The cap established in Docket No. 33891 was based on estimates of construction costs excluding AFUDC as testified to by parties to that docket.

116E. AFUDC was a separately calculated component of capital costs that was not intended to be included in the cap.

116F. SWEPCO's share of the roughly $250 million in AFUDC should be included in rate base because the AFUDC was not intended to be included in the cost cap. Texas's jurisdictional share should be recovered from Texas rate payers.

117. DELETED.

118. DELETED.

Welsh Unit 2

119. SWEPCO did not justify with thorough analysis its decision to retire Welsh Unit 2 more than 20 years prior to the end of its useful life.

120. DELETED.

121. DELETED.

122. DELETED.

123. DELETED.

124. The retirement of Welsh Unit 2 has not yet occurred. Consequently, it is inappropriate to consider the unit's retirement costs before it actually happens.

125. It is reasonable for SWEPCO to institute a new proceeding so that the Commission may evaluate the benefits and burdens of retiring Welsh Unit 2.

125A. The determination of whether SWEPCO's decision to reduce production and ultimately retire Welsh Unit 2 was prudent is deferred to a future proceeding that addresses the actual retirement of the plant when it occurs.

Turk Plant – Other Issues

126. SWEPCO recorded $1,372,891,214 as CWIP for direct Turk plant costs at test-year end.

127. The Turk plant went into commercial operation on December 20, 2012.

128. The rate year for SWEPCO's proposed rate increase began on January 29, 2013.

129. On January 29, 2013, SWEPCO's then-existing rates were deemed to be temporary rates for service on or after that date and subject to reconciliation back to January 29, 2013 with a refund or surcharge to the extent that the rates ultimately established by the Commission differ from the temporary rates.

Prepaid Pension Asset and ADFIT Impacts

130. The prepaid pension asset arises under generally accepted accounting principles (GAAP) in accordance with Statement of Financial Accounting Standards No. 87 (FAS 87). The prepaid pension asset represents the amount by which the accumulated contributions to the pension fund exceed the accumulated FAS 87 pension cost.

131. Accounting in accordance with GAAP requires that both the balance sheet and income statement effects be taken into account. GAAP in accordance with FAS 87 requires the amount by which the cash contributions made to the pension fund exceed the accumulated pension cost to be recorded on the balance sheet as a prepaid asset.

132. Investment income on the prepaid pension asset reduces pension cost calculated under FAS 87.

133. As of December 31, 2011, SWEPCO had a prepaid pension asset on its books of $113.2 million calculated in accordance with GAAP. The prepaid pension asset consisted of two amounts for ratemaking purposes:

(a) $80.7 million which is associated with pension cost charged to operation and maintenance (O&M) expense; and

(b) $32.5 million associated with pension cost charged to CWIP.

134. The $80.7 million portion of SWEPCO's prepaid pension asset associated with pension cost charged to O&M expense is appropriately included in rate base.

135. SWEPCO properly included $28.2 million in accumulated deferred federal income tax (ADFIT) as an offset to rate base; this amount is 35% of the $80.7 million prepaid pension asset amount included in rate base.

136. The $32.5 million portion of SWEPCO's prepaid pension asset associated with pension cost capitalized to CWIP will not be included in rate base.

137. SWEPCO is permitted to accrue allowance for funds used during construction (AFUDC) on the portion of its prepaid pension asset capitalized to CWIP.

Oxbow Investment

138. In December 2009, Central Louisiana Electric Company (CLECO) and SWEPCO formed the Oxbow Lignite Company, which acquired the Oxbow Mine Reserves from Red River Mining Company (RRMC) for approximately $25.7 million.

139. As part of that transaction, the Dolet Hills Lignite Company (DHLC), a wholly owned subsidiary of SWEPCO, acquired the RRMC's mining assets for an additional $15.8 million.

140. The Oxbow lignite acquisition was necessary to extend the life of the Dolet Hills power plant from 2016 through 2019 to at least 2026.

141. It is reasonable for SWEPCO to include in rate base its share of the investment in the Oxbow lignite reserves, $14,532,294 as of the end of the test year.

Mountaineer Carbon Capture & Storage Project

142. SWEPCO seeks to recover the costs of an engineering and design study associated with the Mountaineer Carbon Capture and Storage (CCS) project, conducted at SWEPCO affiliate Appalachian Power Company in West Virginia.

143. SWEPCO seeks to include $2,379,609 in rate base as a regulatory asset and to recover this asset through a five-year amortization period, which results in $475,922 included in cost of service.

144. The CCS project studied a method of separating CO2 from the flue gas generated from a coal fired power plant and storing the CO2 underground.

145. SWEPCO has no current plans to build a CCS facility.

146. The Mountaineer CCS costs should be excluded from rate base because they are not used and useful.

Pirkey (Sabine) Mine Reclamation Costs

146A. SWEPCO proposes that the amounts of Pirkey final mine closing costs that have been collected from customers pursuant to the final order in Docket No. 12855, including the carrying costs accrued through December 31, 2011, be an offset to invested capital when setting base rates in this proceeding, in lieu of continuing to accrue interest on that balance.

146B. Because SWEPCO has reduced rate base by this balance, SWEPCO will cease accruing interest at its weighted average cost of capital, pursuant to the final order in Docket No. 12855.

146C. Beginning in January 1, 2012, SWEPCO will begin recording final mine closure and reclamation costs at a rate of $15,639 per month, subject to adjustment in subsequent fuel proceedings.

146D. To recognize the time value of money, the amounts of final mine closure and reclamation costs that have been collected from customers consistent with the above finding will be an offset to invested capital when setting SWEPCO's base rates, consistent with the treatment contemplated by P.U.C. SUBST. R. 25.231(c)(2)(C)(v).

Capitalized Incentive Compensation

147. The portion of SWEPCO's annual and long term incentive payments that are capitalized and that are financially-based should be excluded from SWEPCO's rate base because the benefits of such payments inure most immediately and predominantly to SWEPCO's shareholders, rather than its electric customers.

Rate of Return

148. A capital structure composed of 50.9% long-term debt and 49.1% equity is reasonable in light of SWEPCO's business and regulatory risks.

149. A capital structure composed of 50.9% long-term debt and 49.1% equity will help SWEPCO attract capital from investors.

150. A return on equity (ROE) of 9.65% will allow SWEPCO a reasonable opportunity to earn a reasonable return on its invested capital.

151. The results of the discounted cash flow model and risk premium approach support an ROE of 9.65%.

152. A 9.65% ROE is consistent with SWEPCO's business and regulatory risk.

152A. SWEPCO's ROE should not be increased by a floatation adjustment because it is unknown whether SWEPCO's parent company will procure the capital used to make equity infusions through retained earnings of the parent company, debt issuances of the parent company or a stock issuance.

153. The same rate of return should be applied to all equity investment recovered through base rates, including the Dolet Hills Lignite Company equity.

154. SWEPCO's proposed 5.96% embedded cost of debt is reasonable.

155. The costs of SWEPCO's interest rate risk management agreements and insurance premiums, totaling $27,903,089, are reasonable and properly included in the cost of debt.

156. SWEPCO's overall rate of return is as follows:

Component	Cost	Weighting	Weighted Cost
Debt	5.96	50.90%	3.03
Equity	9.65	49.10%	4.74
Overall		100.00%	7.77

Turk O&M

157. SWEPCO proposes to include $17.6 million in cost of service for the non-fuel-related operation and maintenance (O&M) costs as an attendant impact associated with the Turk.

158. The O&M impact for Turk was developed mainly by using SWEPCO's operational knowledge of its own Pirkey Power Plant (Pirkey) and the Oklaunion Power Plant (Oklaunion), which is owned by SWEPCO affiliate Public Service Company of Oklahoma.

159. Both Pirkey and Oklaunion have ideal characteristics to use as a proxy for Turk—they are the youngest single-unit, solid-fuel plants in the western AEP region and are retrofitted with flue-gas desulfurization systems.

160. Adjustments were made to existing plant O&M values to account for differences in fuel, major equipment, and operational conditions.

161. In addition, because the Pirkey and Oklaunion Plants have a long operating history of which SWEPCO is highly knowledgeable, SWEPCO was able to rely on that experience to estimate the Turk plant annual O&M expense.

162. SWEPCO's proposed O&M cost for Turk is reasonable, and now that the Turk plant is in service, these costs are appropriately included in rates.

Planned Outage Expense

163. SWEPCO proposes to include approximately $30.6 million of planned outage expense in base rates.

164. Although the Commission looks at the test year to determine base rates, the costs a utility incurs in the test year should be generally representative of the costs the utility will incur in the future.

165. SWEPCO's test-year expense for planned outages is disproportionately higher than the average expense for previous years, and it is also significantly higher than projected expenses for future years.

166. SWEPCO's proposal should be reduced by $6,854,327 to normalize test-year expenses.

Welsh Unit Two

167. After reaching a litigation settlement agreement with the Sierra Club, National Audubon Society, and Audubon Arkansas, SWEPCO agreed to limit the output of Welsh Unit 2 to no more than 60% of capacity once the Turk plant begins commercial operation.

168. SWEPCO did not reflect the reduction of Welsh Unit 2 capacity in non-fuel O&M expenses.

169. Because Welsh Unit 2 is now running at a lower capacity, a reduction in variable O&M expenses is reasonable.

170. Using the 60% capacity factor as agreed to in the litigation settlement, it is reasonable to reduce non-fuel O&M expenses for Welsh Unit 2 by $571,402 to recognize the decreased output of Welsh Unit 2.

2010 Severance Costs

171. To address recession-related negative impacts on energy consumption, AEP in 2010 sought to further streamline business operations where possible.

172. SWEPCO and the AEP system undertook a program to reduce on-going payroll costs through sustainable headcount reductions critically examining work processes, organizational structures and employment levels to produce sustainable cost savings.

173. The number of SWEPCO employees who accepted the severance package was 164. In addition, 938 AEP Service Corporation (AEPSC) employees accepted the severance package.

174. The impact of the program resulted in an annual O&M savings for SWEPCO of $6.8 million, and $7.8 million for AEPSC costs billed to SWEPCO.

175. SWEPCO proposes to defer recovery of the entire $30.6 million cost of the severance program, which consists of direct SWEPCO severance costs of $17,856,045, and allocated AEPSC severance costs of $12,770,833, by amortizing $6,125,376 per year into cost of service over a five-year period. The portion allocated to the Texas jurisdiction for the severance program cost amortization is $2,083,057 per year.

176. SWEPCO used the Texas portion of the 2010 severance expense reductions to partially offset the Texas portion of the operating cost and return at SWEPCO's Stall plant.

177. Because SWEPCO failed to show that deferring the severance costs is warranted, the severance costs should not be included in SWEPCO's test-year revenue requirement because those costs occurred in 2010, which is outside the test year.

178. It is reasonable to remove $6,125,376 (total company) (Texas jurisdiction amount of $2,083,057) to account for the severance costs that occurred in 2010.

Vegetation Management

179. SWEPCO's proposal to recover distribution O&M base rate expenses of $6.8 million total, consisting of the 2011 test-year amount of $4.7 million and an additional amount of $2.1 million, is reasonable.

180. The additional amount of distribution O&M expense in the amount of $2.1 million is reasonable and necessary to carry forward SWEPCO's vegetation management program to improve overall reliability on targeted circuits and decrease outages caused by trees.

181. SWEPCO's proposal to recover transmission O&M base rate expenses in the amount of $4.2 million total company, consisting of the 2011 test-year amount of $3.2 million and an additional amount of $1 million, is reasonable and necessary.

182. The additional amount of transmission O&M expense in the amount of $1 million is to be spent across all three states in SWEPCO's service territory, and Texas customers will pay for the Texas retail jurisdictional allocation of approximately 38%.

183. SWEPCO's proposal to recover the additional amount of $1 million is reasonable and necessary to carry out the Company's vegetation management program to complete end-to-end maintenance on transmission lines that do not fall under North American Electric Reliability Corporation standards and also to identify and remove danger trees from outside the line right-of-way.

184. SWEPCO commits to spending the entirety of the increased amounts of $2.1 million for distribution O&M expense and $1 million for transmission O&M expense solely on vegetation management.

185. SWEPCO should periodically report to the Commission its vegetation management activities for both transmission and distribution showing information regarding circuits trimmed, trimming progress completed, and the funds spent.

Credit Line Fees

186. SWEPCO demonstrated that the level of its credit line fees, totaling $940,637, is reasonable, and that it is necessary to incur these fees to support maintenance of the AEP Money Pool, which provides SWEPCO with short-term financing on terms that are beneficial to the company and its customers.

187. SWEPCO properly accounted for the effects of short-term debt, which the credit line fees support, through its calculation of AFUDC. The inclusion of short-term debt in the AFUDC calculation lowers both SWEPCO's return on assets and its depreciation expense, to the benefit of SWEPCO customers.

Obsolete Inventory

188. The Commission's rate filing package for generating utilities recognizes that obsolete inventory is an expense of doing business.

189. SWEPCO expensed $1.042 million (total Company) in obsolete inventory during the test year.

190. SWEPCO's level of obsolete inventory expense write-off during the test year is substantially greater than that of the past four years.

191. SWEPCO's requested $1.042 million in obsolete inventory expense is not reasonable and unlikely to be recurring and should be denied.

192. It is reasonable to set SWEPCO's level of obsolete inventory expense using a five-year average, which results in a reduction in the obsolete inventory expense of $0.105 million on a Texas retail basis, or a reduction of $0.108 million to SWEPCO's revenue requirement.

Production Plant Net Salvage

193. The plant demolition studies SWEPCO used to develop terminal removal cost and salvage for each of SWEPCO's generating facilities are reasonable. These studies were prepared by an experienced consulting engineering firm and incorporate reasonable methodology, data, assumptions, and engineering judgment.

194. It is reasonable for SWEPCO to escalate the terminal removal cost and salvage in the demolition studies (which are stated in first quarter 2012 dollars) to the expected final retirement date of each plant using a 2.5% inflation rate from the "Livingston Survey" dated December 2011 published by the research department of the Federal Reserve Bank of Philadelphia.

195. The rate at which interim retirements will be made is not known and measurable. Incorporation of interim retirements would best be done when those retirements are actually made. It is not reasonable to incorporate interim retirements, resulting in a reduction in the depreciation expense of $1 million on a Texas retail basis.

196. A 55-year estimated life span for the Turk plant is reasonable and results in a $9.1 million decrease in annual depreciation expense on a total Company basis for plant as of December 31, 2011, and a corresponding $3.0 million decrease in depreciation expense on a Texas jurisdictional basis.

197. Increasing the Stall plant's life span from 35 years to 40 years is reasonable. The 40-year life span results in a $1.7 million reduction in annual depreciation expense on a total

Company basis for plant in service as of December 31, 2011, and a corresponding reduction in Texas retail depreciation expense of $550,000.

198. A 60-year estimated life span for the Dolet Hills plant is reasonable, and results in a reduction in depreciation expense of $1.114 million and a reduction to the Company's proposed revenue requirement of $1.152 million.

199. A 60-year estimated life span for the Welsh Unit 2 plant is reasonable (2040 retirement date), and results in a reduction to depreciation expense of $1.042 million and a reduction in revenue requirement of $1.079 million.

Transmission Plant

200. The life parameter of 50 S0 for Federal Regulatory Energy Commission (FERC) Account 355–Poles and Fixtures is reasonable.

201. The net salvage rate of negative 13% for FERC Account 353–Station Equipment is reasonable.

202. The net salvage rate of negative 67% for FERC Account 355–Poles and Fixtures is reasonable.

203. The net salvage rate of negative 40% for FERC Account 356–Overhead Conductor is reasonable.

Distribution Plant

204. SWEPCO agreed with CARD's recommended life parameter of 54 L0 for FERC Account 364–Distribution Poles. This life parameter is reasonable and its adoption reduces SWEPCO's initially requested depreciation expense by $716,339 on a total Company basis and $254,802 on a Texas jurisdictional basis.

205. The net salvage rate of negative 16% for FERC Account 362–Substation Equipment is reasonable.

206. A life parameter of 50 R1.5 for FERC Account 367–Underground Conductor is reasonable. This life parameter results in a $493,969 decrease in annual depreciation expense on a total Company basis for plant as of December 31, 2011, and a corresponding reduction of $175,705 on a Texas retail jurisdictional basis.

General Plant

207. Asbestos removal in 1996 and the sale of an office building in 2004 should be removed from the removal cost and salvage data for FERC Account 390–General Plant for 1984-2011 upon which the net salvage rate for the account should be based. The net salvage rate of negative 3% resulting from this modification is reasonable and reduces SWEPCO's initially requested depreciation expense by $97,594 on a total Company basis and $32,938 on a Texas jurisdictional basis.

Depreciation Reserve

208. The use of the remaining life depreciation method to recover differences between theoretical and actual depreciation reserves is the most appropriate method.

209. It is reasonable for SWEPCO to calculate depreciation reserve allocations on a straight-line basis over the remaining, expected useful life of the item or facility.

Payroll

210. SWEPCO made two adjustments to its test-year payroll. The Company updated payroll costs by annualizing the base payroll to the salary rates in effect at the end of the test year and by recognizing the effect of the merit and general increases that were awarded in 2012.

211. Because these payroll increases were awarded in 2012, they represent appropriate known and measurable adjustments to test-year expenses.

212. SWEPCO double-counted the Turk plant payroll by including Turk plant employees in the *pro forma* payroll O&M as well as in the post-test-year adjustment.

213. SWEPCO's labor costs should be disallowed by the sum of $197,688 and $50,932, or $248,620.

Incentive Compensation

214. SWEPCO sought to recover in rate base a total amount of $10,728,117 paid as annual incentive compensation to its employees and $5,175,829 paid for long-term incentive compensation.

215. The PUC permits a utility to recover in its base rate incentives that are designed to achieve "operational measures" and that are necessary and reasonable to provide utility services, but not incentive programs that are designed to achieve "financial measures."

216. Operational measures are those designed to encourage a utility's employees to meet goals and standards relating to the efficient operation of the utility, a benefit to shareholders and ratepayers alike.

217. Financial measures are those designed to encourage employees to achieve financial targets, a benefit primarily to shareholders.

218. SWEPCO's "Regulatory," "Strategic," and "Margin Generating" annual incentive goals relate to financial measures.

219. SWEPCO's long term incentive awards in the form of performance units relate to financial measures.

220. Of SWEPCO's annual incentive compensation of $10,728,117, $3,523,732 should be disallowed as financial goals. Of SWEPCO's long-term compensation, all but $2,045,072 of the total should be disallowed as financial goals.

Executive Perquisites

221. The $16,350 related to executive perquisites should not be included in rates because they provide no benefit to ratepayers and are not reasonable or necessary for the provision of electric service.

Relocation

222. SWEPCO's proposed relocation expense, in the amount of $574,588, is reasonable and necessary.

Pensions

223. It is reasonable to base pension expense in SWEPCO's cost of service upon the cost of $8,306,420 on a total Company basis calculated in the 2012 actuarial report prepared in accordance with FAS 87.

OPEBs

224. It is reasonable to base post-retirement benefits other than pensions, also known as OPEBs, in SWEPCO's cost of service upon the cost of $5,928,523 on a total Company basis calculated in the 2012 actuarial report prepared in accordance with FAS 106.

Post-Employment Benefits

225. It is reasonable to base the postemployment benefit cost, negative $947,747, on a total Company basis that is calculated in the 2012 actuarial report prepared in accordance with FAS 112.

226. In arriving at the adjustment to postemployment cost included in the adjusted test-year expenses it is appropriate to apply the expense ratio of 71.3% to the differential between the postemployment cost calculated in the 2012 actuarial report and the postemployment cost calculated in the 2011 actuarial report.

Supplemental Retirement Plan Expense

227. SWEPCO's non-qualified executive retirement benefits in the amount of $191,007 are not reasonable or necessary to provide utility service to the public, not in the public interest, and should not be included in SWEPCO's cost of service.

Federal Income Tax and Consolidated Tax Savings Adjustment [PO Issue 23]

228. SWEPCO is a member of an AEP affiliated group that is eligible to file a consolidated tax return.

229. SWEPCO files a consolidated tax return.

230. Pursuant to PURA § 36.060(a) as amended by SB 1364, SWEPCO should not make a consolidated tax savings adjustment in this proceeding.

231. DELETED.

Storm Amortization [PO Issue 15]

232. In SWEPCO's recent base rate case, *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 37364, Final Order (April 16, 2010), the Commission approved recovery of a storm regulatory asset of $3.6 million, to be amortized over three years or $100,000 per month. Thus, beginning in

May 2010, SWEPCO began amortizing $100,000 per month. Therefore, during the test year, SWEPCO properly recorded $1.2 million of amortization.

233. SWEPCO made a post-test-year adjustment to reduce its test-year amortization from $1.2 million to $300,000 to reflect the fact that all but $300,000 of the regulatory asset would be amortized by the effective date of rates resulting from this proceeding.

234. It is reasonable for SWEPCO to recover the remaining $300,000 of the approved regulatory asset in the temporary rate true-up that will follow this case.

Fuel and Logistics Expense Allocation

235. The costs incurred by SWEPCO during the test year for the Fuel and Logistics class of affiliate service were reasonable and necessary and charged at a price not higher than that AEPSC charged to other benefited AEP operating companies.

Director & Officer Liability Insurance

236. AEP and its subsidiaries, including SWEPCO, are the primary beneficiaries of its director and officer liability insurance (DOLI) and fiduciary liability insurance (FLI) policies. DOLI and FLI policies exist to allow quality directors, officers, and fiduciaries to make sound business decisions without a cloud of uncertainty regarding potential lawsuits hanging over their heads. These sound business decisions can result in lower costs, which certainly benefit customers.

237. SWEPCO's DOLI and FLI expenses are an element of SWEPCO's reasonable and necessary test-year operating expenses.

Convenience Payments

238. AEP uses the services of a law firm, Jackson Kelley, to assist in the monitoring of federal carbon legislation, which is separate from providing an advocacy role related to carbon legislation. As a matter of "convenience," Ohio Power Company made the payments for the benefit of multiple AEP affiliates, including SWEPCO. Legislation related to carbon emissions could have a direct impact on SWEPCO's generating fleet.

239. The monitoring of legislation is a Commission-recognized reasonable and necessary business expense to ensure that SWEPCO is properly positioned to react to and comply with legislation.

Injuries and Damages Expense

240. In the test year, SWEPCO incurred $4,540,265 as injuries and damages expense.

241. The test-year amount was substantially in excess of the injuries and damages expenses incurred by SWEPCO in the three preceding years.

242. It is reasonable to adjust the test-year amount by a $550,000 reduction, which is the amount the test year exceeds the average of the expense in the three previous years.

Office Supplies Expense

243. The office supplies expenses incurred by SWEPCO were properly included in Account 921 and are part of the reasonable and necessary cost of doing business in the utility industry.

Temporary Labor

244. SWEPCO's temporary labor costs of $169,136 are reasonable and necessary as test-year operating expenses.

Turk Independent Monitor Costs

245. In its November 9, 2012 Errata filing, SWEPCO removed from its requested cost of service $337,303 for Turk independent monitor (E3 Consulting) costs that had been inadvertently included in SWEPCO's request. There is no further adjustment to be made.

Separation Costs

246. The AEP system made a payment to Susan Tomasky, former President of AEP Transmission, in connection with her retirement. The payment was accompanied by a release of claims agreement containing, among other items, certain non-solicitation, confidentiality, and cooperation obligations.

247. SWEPCO's portion of the separation payment made to Ms. Tomasky was not an element of SWEPCO's reasonable and necessary test-year operating expenses.