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APPLICATION OF SOUTHWESTERN	§	PUBLIC UTILITY COMMISSION
ELECTRIC POWER COMPANY FOR	§	
AUTHORITY TO CHANGE RATES	§	OF TEXAS

ORDER ON REHEARING

This order addresses the application of Southwestern Electric Power Company (SWEPCO) for authority to change its rates, filed on December 16, 2016. SWEPCO originally sought a $69 million increase to its Texas retail revenue requirement, primarily to reflect investments in environmental controls. However, SWEPCO also proposed a significant modification to the manner in which its transmission costs should be recovered. In addition, SWEPCO sought additional cost recovery for vegetation management, rate-case expenses, and a regulatory asset for certain costs under the Southwest Power Pool's open-access tariff.

A hearing on the merits was held between June 5 and June 15, 2017 at the State Office of Administrative Hearings (SOAH). On September 22, 2017, the SOAH administrative law judges (ALJs) filed their proposal for decision (PFD) in which they recommended a Texas retail revenue requirement increase of approximately $51 million. The SOAH ALJs rejected SWEPCO's new method to recover transmission costs and recommended granting its requested rate-case expenses, and regulatory asset. In response to parties' exceptions and replies to the PFD, on November 8, 2017, the SOAH ALJs filed a letter making changes to the PFD.

Except as discussed in this order, the Commission adopts the PFD as modified, including findings of fact and conclusions of law. The Commission's decisions result in a Texas retail base-rate revenue requirement of $369,234,023, which is an increase of $50,001,133 from SWEPCO's present Commission-authorized Texas retail base-rate revenue requirement. New findings of fact 17A through 17J are added to address the procedural history of this docket after the close of the evidentiary record at SOAH. The Commission incorporates by reference the abbreviations table provided in the PFD.

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I. Discussion

A. Dolet Hills Power Station

The Commission disagrees with and therefore does not adopt the SOAH ALJs' finding that SWEPCO failed to meet its burden of proof through its contemporaneous analysis of the Dolet Hills investment. The Commission finds that, when all of the evidence related to the contemporaneous analysis is considered, SWEPCO met its burden of proof.

The Commission finds that, taking into account all of the information that was available and considered by SWEPCO at the time of the decision to retrofit Dolet Hills, Mr. Franklin and SWEPCO acted as a reasonably prudent utility manager and owner of a power plant in the determination to retrofit the plant. In particular, the Commission finds it important that Mr. Franklin relied upon the study performed for the majority owner of the power plant, Cleco Power LLC (Cleco). SWEPCO and Cleco had a long and ongoing professional relationship related to Dolet Hills. Cleco owns 50% of the Dolet Hills power plant and is responsible for the operations and maintenance of the plant. As such, Cleco has the obligation to make all repairs, replacements, and capital additions to the plant. However, Cleco is required to consult with SWEPCO's operating committee representative in making major decisions. Further, the business relationship between Cleco and SWEPCO related to Dolet Hills had been ongoing since at least 1981, or for more than 30 years, at the time of the decision to retrofit the power plant. Over those years, SWEPCO had collaborated with Cleco in its management role on the operations and maintenance of the power plant and all capital improvements. The Commission finds it is reasonable for SWEPCO to have had confidence in this longstanding relationship as part of its decision-making process as to the retrofits. This determination is based on the operating agreement and long-term relationship between these two electric utilities and the specific decisions that were made here. This determination depends on the specific facts of this case and cannot be extended to all situations in which an electric utility is a partner in ownership of a power plant.

SWEPCO evaluated in the first half of 2011 whether the Pirkey plant should be retired. During that same time period, Cleco evaluated whether the Dolet Hills plant should be retired. As discussed below, Pirkey and Dolet Hills are comparable plants, and Cleco reached the same conclusion as SWEPCO: retirement was not the appropriate option. It was reasonable for

Mr. Franklin to have confidence in Cleco's decision because SWEPCO reached the same conclusion for its sister plant during the same time period.

Another important factor in the Commission's determination was Cleco's selection of Sargent & Lundy to perform a study of whether to complete retrofits on the power plant. Sargent & Lundy, an engineering firm that is "highly regarded in the industry,"[1] is the same firm that designed, engineered, and managed procurement functions for both the Dolet Hills and Pirkey power plants. Thus, the firm had specific knowledge of the Dolet Hills power plant in addition to its general engineering expertise related to coal-fired power plants and environmental controls. Further, SWEPCO oversaw construction of both plants. It had a long-standing relationship—over 30 years—with this engineering firm that performed the relevant study on the issues of retirement and retrofits for the Dolet Hills plant. Mr. Franklin also reviewed and relied upon Sargent & Lundy's engineering study in his decision-making process. The Commission finds it was reasonable for Mr. Franklin and SWEPCO to have confidence in the study performed by Sargent & Lundy as part of the decision-making process on the retrofits for Dolet Hills. This finding is based on the specific facts of this case, including the study performed by Sargent & Lundy and SWEPCO's longstanding relationship with this firm, and it does not have implications for any other studies performed by engineering firms.

In addition, Mr. Franklin had then-current experience related to very similar issues at the Pirkey power plant. The Dolet Hills and Pirkey power plants were built in the same time period based on a similar design from the same engineering firm, Sargent & Lundy. Similar equipment was used to construct both plants. Pirkey was completed in 1985, and Dolet Hills was completed in 1986. Both are lignite plants, and both plants experience similar maintenance issues. The plants also had very similar capacity factors. SWEPCO had performed its own analysis and study on whether to retrofit or retire the Pirkey power plant. This analysis was performed during the same time period that Cleco performed its study on the Dolet Hills power plant. As with Cleco's analysis of Dolet Hills, SWEPCO's analysis also showed that retrofitting the Pirkey plant with environmental controls was the better option. The Commission finds it was reasonable for Mr. Franklin and SWEPCO to have relied upon the analysis of the Pirkey plant in order to bolster

[1] Application, Direct Testimony of Paul W. Franklin at 15 (Dec. 16, 2016).

confidence in the study performed by Sargent & Lundy as part of the decision-making process on the Dolet Hills retrofits. The fact that both studies came to the same conclusions for these very similar plants deserves some weight in the prudence analysis.

The Commission also finds that an important element for consideration by Mr. Franklin and SWEPCO was the fact that in 2009, the Louisiana Public Service Commission and the Arkansas Public Service Commission approved the acquisition of the Oxbow Mine Reserves. The coal mine providing fuel for Dolet Hills was becoming depleted, so that either a new source of coal had to be obtained or the plant had to be retired. A study was conducted to consider whether to obtain a new source of coal or to retire Dolet Hills and replace it with a new natural-gas-fired combined-cycle unit. Although this study was not performed in the 2012 time period of the decision to retrofit the plant, the study supported decisions by this Commission and other state commissions to acquire new coal reserves and continue operating the Dolet Hills plant. This is yet another factor that was considered by Mr. Franklin and SWEPCO in deciding to retrofit the Dolet Hills power plant. As with the other elements, this fact alone should not have been determinative of the ultimate decision. However, considering all of the information available to Mr. Franklin and SWEPCO at the time of the decision, the Commission finds they came to the decision to retrofit Dolet Hills in a prudent manner.

Lastly, the Commission finds that weight should be given to the fact that once Mr. Franklin reached his recommendation on the retrofits at the Dolet Hills plant, SWEPCO and American Electric Power Service Corporation's executive management also reviewed the information and approved the decision. Therefore, there were multiple layers of review and approvals in the decision-making process by SWEPCO's executive management team to retrofit Dolet Hills.

Based on the facts related to Dolet Hills, the Commission finds it was unnecessary for SWEPCO to perform an independent study on whether to retire the power plant. Under the operating agreement between the owners of the power plant, SWEPCO did not have the unilateral authority to decide to retire the plant. SWEPCO's only option would have been to sell its portion of the power plant that would not have been compliant with new environmental regulations. Instead, SWEPCO reasonably relied upon all of the information discussed previously in order to decide whether to retire the plant or make the necessary capital investments for compliance with the new environmental requirements. Further, given that Cleco had decided to move forward with the retrofit, the Commission finds it reasonable to conclude that SWEPCO would have paid for part of the cost even if it had sold its interests because it would not have received the full cost of the retrofits through the sales price.

Based on the Commission's determination that SWEPCO met its burden of proof on the contemporaneous determination to invest in the retrofits for Dolet Hills, it is not necessary for the Commission to determine whether Mr. Strunk's retroactive analysis in his rebuttal testimony was appropriately admitted into evidence. Nonetheless, the Commission agrees with the SOAH ALJs' determinations that Mr. Strunk's analysis was admissible and that his analysis provides a separate basis of support for the determination that the retrofits were prudent.

The Commission concludes that SWEPCO's evidence of contemporaneous analysis was sufficient to meet its burden of proof to show that the Dolet Hills investment was prudent. To reflect this conclusion, the Commission deletes finding of fact 30 and adds new findings of fact 30A through 30V.

B. Production-Maintenance Expense

Proposed findings of fact 168 through 174 reached the correct conclusion to use SWEPCO's test-year production-maintenance expense, but the reasoning did not comport with the Commission's cost-of-service rule. Also, the proposed findings of fact did not explicitly state the amount of SWEPCO's test-year expense. In order to correct the reasoning in findings of fact 168 through 174 and include the amount of the test-year expense, the Commission modifies finding of fact 168, deletes findings of fact 170, 171, 172, and 174, and adds findings of fact 174A, 174B, and 174C. (The ALJs recommended deleting finding of fact 173 in their letter dated November 8, 2017.)

C. Contingency Factor for Net Salvage and Demolition Study

The Commission determines that a 10% contingency factor is more appropriate than a 15% contingency factor for SWEPCO's demolition studies. The Commission finds that its own rules allow a maximum contingency factor of only 10% for the demolition of a nuclear power plant, and the demolition of SWEPCO's natural gas and coal power plants will be less complex, risky, and costly than the demolition of a nuclear power plant. Further, the Commission is not persuaded by SWEPCO's evidence that a 15% contingency factor is appropriate. Therefore, the Commission modifies findings of fact 177, 178, and 180 to reflect a 10% contingency factor for SWEPCO's demolition studies.

D. Adjustment to Accumulated Depreciation

The SOAH ALJs stated in the discussion section of the PFD that they adopted CARD's position for FERC Accounts 353 and 356 and SWEPCO's position for FERC Account 390. However, the PFD did not accurately reflect the evidentiary record regarding CARD's position for FERC Accounts 353 and 356 and SWEPCO's position for FERC Account 390. The Commission modifies findings of fact 183, 184, and 190 to reflect the evidence in the record.

E. Rate-Case Expenses

In Docket No. 45712,[2] SWEPCO agreed not to seek the recovery of its rate-case expenses related to that proceeding. However, in this docket, SWEPCO identified expenses related to Docket No. 45712 in the amount of $161,025 and sought recovery for them. The SOAH ALJs found that those costs were not rate-case expenses because they were not incremental. However, the Commission determines that there is no basis in PURA or the Commission's rules for the term *rate-case expenses* not to include all expenses that are associated with Docket No. 45712. Therefore, the Commission finds that the $161,025 in expenses are rate-case expenses from Docket No. 45712 and should not be recovered. Accordingly, the Commission deletes finding of fact 236, modifies finding of fact 237, adds findings of fact 237A and 237B, and adds conclusion of law 29A. In addition, the Commission modifies conclusion of law 29 to clarify that while utilities seek recovery of their rate-case expenses from ratepayers, municipalities seek reimbursement of their rate-case expenses from utilities. Ultimately, ratepayers bear the cost of rate-case expenses incurred by both utilities and municipalities.

F. Distributed Renewable Generation

The Commission agrees with the SOAH ALJs and finds that SWEPCO's proposed distributed-renewable-generation (DRG) tariff complies with 16 TAC § 25.217 and represents a necessary change. However, the Commission is not in agreement with the SOAH ALJs that grandfathering the existing 47 DRG customers under the current DRG tariff is necessary or

[2] *Application of Southwestern Electric Power Company for Approval of a Distribution Cost Recovery Factor*, Docket No. 45712, Order (July 1, 2016).

complies with the law. As a result, the Commission deletes finding of fact 319 and replaces it with new finding of fact 319A.

Additionally, the Commission notes that SWEPCO continues to offer a qualified-facility tariff in compliance with the requirements of 16 TAC § 25.242. Net metering is an available option under that tariff for qualified facilities. To clarify the order on this point, the Commission adds new finding of fact 319B.

G. Lighting and Power and Large Lighting and Power

To better reflect the SOAH ALJs' stated conclusion that Commission Staff's proposed rates for lighting-and-power and large-lighting-and-power customers should not be adopted because Commission Staff failed to meet its evidentiary burden to justify the adoption of those rates, the Commission deletes findings of fact 321, 322, and 323 and replaces them with finding of fact 321A.

H. Metal Melting Secondary and Primary Rate Design

To better reflect the SOAH ALJs' stated conclusion that Commission Staff's rate proposal for metal-melting-secondary and primary-rate-design customers should not be adopted because it is not supported by sufficient evidence, the Commission deletes finding of fact 327 and replaces it with finding of fact 327A.

Additionally, the Commission adds conclusion of law 9A to reflect the SOAH ALJs' legal analysis regarding burden of proof as it pertains to their analysis of Commission Staff's proposed rates discussed in this section and sections F and G above.

I. Winter Declining Block Rates

The Commission declines to adopt the SOAH ALJs' recommendation that it approve the agreement reached by SWEPCO and the Office of Public Utility Council to reduce the differential between the winter declining-block rates by 20%. The Commission finds that maintaining SWEPCO's current second block rate will not only keep this rate closer to cost of service, but it will also tend to mitigate against rate shock coming out of this proceeding because it is a lower rate than in the first block. The Commission further finds that, with the adoption of amendments to 16 TAC § 25.181 in 2012, utilities have a financial incentive to develop energy-efficiency programs that focus on reducing the winter peak as well as the summer peak, and that these incentives represent a more straightforward and lasting way of achieving progress in reducing the winter peak. As a result of this discussion, the Commission modifies findings of fact 331 and 332.

J. Federal-Income-Tax Expense

The Commission takes official notice of recent changes to federal tax law that reduce the income-tax rate for corporations that is applicable to SWEPCO from 35% to 21%.[3] The Commission adopts a mechanism to address SWEPCO's reduced corporate federal-income-tax expense. The Commission adds findings of fact 346A and 346B and corresponding ordering paragraphs.

K. Deadline Extensions

The Commission's jurisdiction to establish rates extends beyond the date that a proposed rate is suspended, and the deadline to establish rates is not a jurisdictional deadline. To reflect that, the Commission modifies findings of fact 11 and 16 and adds new conclusion of law 3A.

L. Gradualism Methodology

The Commission concludes that any gradualism methodology should evaluate the differences in the actual rates that customers pay. Consistent with this approach, the gradualism methodology the Commission adopts in this proceeding requires that each class's present revenue be evaluated inclusive of revenues from both the transmission-cost recovery factor and the distribution-cost recovery factor. The Commission modifies finding of fact 314 and adds new finding of fact 314A to clarify its position on gradualism methodology.

M. Minor or Non-Substantive Changes

In addition to the changes described above, the Commission makes several minor modifications or corrections to the proposed findings of fact and conclusions of law.

Finding of fact 75 is modified to correct two dates. Finding of fact 154 is modified to clarify that while the adjustments to the cash working capital should reflect SWEPCO's methodology, the exact values will be based on inputs determined from other Commission findings. Findings of fact 156 and 157 are modified to clarify that the capital structure proposed

[3] Public Law 115-97, An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018.

by SWEPCO and recommended by the SOAH ALJs was uncontested. Finding of fact 214 is modified to correct an inaccurate figure. Finding of fact 228 is modified to correct an incorrect citation. Findings of fact 229 and 230 are modified to correct dates. The Commission finds that proposed finding of fact 243 is not a proper finding of fact and is unnecessary, and therefore deletes it. The Commission modifies finding of fact 306 to refer to FERC Account 365 as well as FERC Account 364.

The Commission also makes several minor changes to the proposed conclusions of law. Conclusion of law 1 is modified to correct a citation, conclusion of law 12 is modified for clarity, and conclusion of law 15 is modified to correct two typographical errors.

Finally, the Commission makes non-substantive changes to findings of fact and conclusions of law for such matters as capitalization, spelling, punctuation, style, grammar, and readability.

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

II. Findings of Fact

Procedural History

1. Southwestern Electric Power Company (SWEPCO) is a wholly-owned subsidiary of American Electric Power Company (AEP) and is a fully integrated electric utility serving retail and wholesale customers in Texas, Louisiana, and Arkansas.

2. SWEPCO serves approximately 184,000 Texas retail customers, all of whom are affected by SWEPCO's application to change rates.

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

4. On December 16, 2016, SWEPCO filed its petition and statement of intent with the Commission. The petition and statement of intent request establishment of new base rates, including approval of the following items: (1) the recovery of capital investment in environmental retrofits for SWEPCO's solid-fuel generation fleet; (2) the prudence of the retirement of Welsh unit 2 and recovery of its remaining book value; (3) recovery of SWEPCO's transmission costs based on requirements of the Southwest Power Pool (SPP)

Open Access Transmission Tariff (OATT); (4) an increase of $2 million over test-year costs to expand its vegetation-management program; (5) deferred accounting for SPP-OATT-Schedule-Z2 billing; and (6) recovery of rate-case expenses in the current docket, as well as from six prior dockets.

5. SWEPCO's application also proposes revisions to most tariffs and schedules, requests the Commission set SWEPCO's transmission-cost recovery factor (TCRF) and distribution-cost recovery factor (DCRF) to zero and establish the baseline values consisting of the inputs to the calculations that will be used to calculate SWEPCO's TCRF and DCRF in future proceedings, and requests approval of a new tariff offering applicable to new distributed-renewable-generation (DRG) customers.

6. SWEPCO proposes to increase its annual Texas retail revenues by $69,031,439, or 24.4% over its adjusted test-year revenues, exclusive of fuel.

7. SWEPCO employed the 12-month period ending June 30, 2016 as its test year.

8. SWEPCO provided notice of its application by publication for four consecutive weeks in newspapers having general circulation in each county of SWEPCO's Texas service territory. Individual notice of its proposed rate change was provided to all of its retail customers by bill inserts and direct mailing. Additionally, SWEPCO timely served notice of its statement of intent to change rates on all municipalities retaining original jurisdiction over its rates and services.

9. The following intervening parties participated in this docket: Office of Public Utility Counsel (OPUC); Cities Advocating Reasonable Deregulation (CARD); Texas Industrial Energy Consumers (TIEC); Nucor Steel-Longview (Nucor); Texas Cotton Ginners Association (TCGA); East Texas Electric Cooperative, Inc. and Northeast Texas Electric Cooperative, Inc. (ETEC/NTEC); Sierra Club and Dr. Lawrence Brough (Sierra Club); East Texas Salt Water Disposal Company and East Texas Oil and Gas Producers (ETSWD); and Wal-Mart Stores of Texas, LLC and Sam's East, Inc. (Wal-Mart). Commission Staff also participated in this docket.

10. On December 19, 2016, the Commission referred this case to the State Office of Administrative Hearings (SOAH).

11. On January 13, 2017, SWEPCO agreed to extend the statutory deadline until October 31, 2017.

12. On January 26, 2017, the Commission issued its preliminary order identifying the issues to be addressed in this proceeding.

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

14. On April 25, 2017, SWEPCO filed a motion to sever the consideration of rate-case expenses incurred in connection with this proceeding and to abate the rate-case expense proceeding until after the Commission's order in this docket is final. SOAH granted SWEPCO's motion on May 10, 2017. Rate-case expenses will be considered in *Review of Rate Case Expenses Incurred by Southwestern Electric Power Company and Municipalities in Docket No.* 46449, SOAH Docket No. 473-17-3979, PUC Docket 47141.

15. The hearing on the merits commenced on June 5, 2017, and concluded on June 15, 2017.

16. On June 16, 2017, SWEPCO agreed to further extend the statutory deadline until November 9, 2017.

17. The parties submitted initial post-hearing briefs on July 6, 2017, and reply briefs on July 20, 2017. Proposed findings of fact and conclusions of law were filed July 24, 2017, and the record closed on that date.

17A. The SOAH ALJs issued a proposal for decision on September 22, 2017.

17B. Parties filed exceptions to the proposal for decision on October 16, 2017.

17C. On October 24, 2017, SWEPCO filed a letter agreeing to extend the statutory deadline in this case to December 1, 2017.

17D. Parties filed replies to exceptions on October 30, 2017.

17E. On November 8, 2017, the SOAH ALJs filed their response to the exceptions and replies and made certain changes and clarifications to the proposal for decision.

17F. On November 16, 2017, Chairman DeAnn T. Walker filed a memorandum in this docket.

17G. On November 17, 2017, the Commission held an open meeting at which this docket was discussed.

17H. On November 29, 2017, SWEPCO filed a letter agreeing to extend the statutory deadline in this case to December 28, 2017.

17I. On December 13, 2017, Chairman DeAnn T. Walker filed two memoranda in this docket.

17J. On December 27, 2017, SWEPCO filed a letter agreeing to extend the statutory deadline in this case to January 18, 2017.

Rate Base

18. SWEPCO's application involves $4,443,635,081 in rate base.

19. Since the close of its most recent base-rate-case test year, SWEPCO has invested a total of nearly $700 million in capital upgrades at five units located at four of its solid fuel generating plants.

20. Approximately 50% of SWEPCO's requested $69 million net base-rate increase is the recovery of and return on the environmental retrofits.

21. A number of regulations promulgated by the United States Environmental Protection Agency (EPA) contributed to the requirement that SWEPCO further control emissions from its solid fuel generation fleet.

22. In June 2011, AEP, on behalf of SWEPCO and the other AEP operating companies, announced the AEP system-wide generation compliance plan, which included both retrofits and retirements across the AEP system. In total, AEP's system-wide compliance plan included the retirement of nearly 6,000 megawatts (MW) of coal-fired generation and the retrofit of another 10,000 MW of coal-fired generation.

23. SWEPCO chose to retrofit a total of five generating units at four facilities and to retire one unit—SWEPCO's Welsh unit 2.

Dolet Hills

24. Dolet Hills is a lignite-fired power plant located in De Soto Parish, Louisiana.

25. Dolet Hills is co-owned by Cleco Power LLC, SWEPCO, North Texas Electric Cooperative, and Oklahoma Municipal Power Authority. Cleco is the majority owner and operator. SWEPCO's ownership share is 262 MW, approximately 40%.

26. Under the Dolet Hills joint operating agreement, Cleco, as majority owner and operator, is responsible for decision-making for all the owners regarding the operation, maintenance, and capital improvements at the plant. SWEPCO has the contractual role under the Joint Operating Agreement to review major investment decisions by Cleco through SWEPCO's position as a participant on the Dolet Hills operating committee.

27. SWEPCO management approved Cleco's proposal to install selective non-catalytic reduction technology at Dolet Hills in order to comply with the requirements of EPA's Cross State Air Pollution Rule (CSAPR). SWEPCO's total company share of that investment is approximately $4.2 million.

28. SWEPCO management approved Cleco's proposal to install an activated carbon injection system, a dry sorbent injection system, a fabric filter, and new induced draft fans in order to comply with the requirements of EPA's Mercury and Air Toxics Standards (MATS) Rule. SWEPCO's total company share of that investment is approximately $52 million.

29. No witness in this case contended that a resource-planning economic analysis would be required to support the cost of the CSAPR retrofits.

30. [Deleted.]

30A. SWEPCO provided contemporaneous evidence sufficient to establish that its management reasonably and prudently concurred with Cleco's proposals to implement retrofits at Dolet Hills.

30B. Taking into account all of the information that was available and considered by SWEPCO at the time of the decision to retrofit Dolet Hills, Mr. Franklin and SWEPCO acted as a reasonably prudent utility manager and owner of a power plant in the determination to retrofit the plant.

30C. SWEPCO and Cleco had a long and ongoing professional relationship related to Dolet Hills.

30D. It was reasonable for SWEPCO to factor its confidence in its longstanding relationship with Cleco into its decision to support the retrofits to Dolet Hills.

30E. Cleco had Sargent & Lundy, an engineering firm that is highly regarded in the industry, perform a study of whether to complete retrofits to Dolet Hills.

30F. During the first half of 2011, Cleco studied whether Dolet Hills should be retired.

30G. Sargent & Lundy is the same firm that designed, engineered, and managed procurement functions for both the Dolet Hills and Pirkey power plants. The firm therefore had specific knowledge of the Dolet Hills plant.

30H. SWEPCO oversaw construction of both the Dolet Hills and Pirkey power plants.

30I. SWEPCO has had a longstanding relationship—over 30 years—with Sargent & Lundy.

30J. Mr. Franklin reviewed Sargent & Lundy's engineering study.

30K. It was reasonable for Mr. Franklin and SWEPCO to rely upon the Sargent & Lundy study in their decision-making process.

30L. At the time the retrofits were being considered, Mr. Franklin had then-current experience related to very similar issues at the Pirkey power plant.

30M. The Dolet Hills and Pirkey power plants are both lignite plants that were built in the same time period with a similar design from the same engineering firm. SWEPCO was responsible for the construction of both plants, and similar equipment was used to construct both plants. Pirkey was completed in 1985, and Dolet Hills was completed in 1986. Both plants experience similar maintenance issues and have very similar capacity factors.

30N. SWEPCO had performed its own analysis and study regarding whether to retrofit the Pirkey power plant in the same time period as Cleco performed the study on whether to retrofit the Dolet Hills power plant. Both studies came to the same conclusions.

30O. It was reasonable for Mr. Franklin and SWEPCO to have relied upon SWEPCO's analysis of the Pirkey power plant in order to bolster confidence in the study performed by Sargent & Lundy as part of the decision-making process on the Dolet Hills retrofits.

30P. In 2009, the Louisiana Public Service Commission and the Arkansas Public Service Commission approved the acquisition of the Oxbow Mine Reserves. A study related to the mine in 2009 considered whether to retire Dolet Hills or replace it with a new natural-gas-fired combined-cycle unit.

30Q. Mr. Franklin and SWEPCO reasonably considered the 2009 study as one factor in making the decision to retrofit Dolet Hills.

30R. Once Mr. Franklin reached his recommendation on the retrofits at the Dolet Hills plant, executive management of SWEPCO and American Electric Power Service Corporation also reviewed the information and approved the decision. There were therefore multiple layers of review and approvals in the decision-making process by SWEPCO to retrofit Dolet Hills.

30S. Under the operating agreement between the owners of Dolet Hills, SWEPCO did not have the unilateral authority to decide to retire the plant.

30T. SWEPCO's only option other than retrofits would have been to sell its share of Dolet Hills, which would not have been compliant with new and pending environmental regulations.

30U. Given that Cleco had decided to move forward with retrofitting Dolet Hills, SWEPCO would have paid for a part of the cost even if it had sold its interests because it would not have received the full cost of the retrofits through its sales price.

30V. Under the circumstances during the time period retrofits to Dolet Hills were being considered, it was unnecessary for SWEPCO to perform an independent study on whether to retire Dolet Hills.

31. SWEPCO conducted an independent economic analysis comparing the relative economics of retrofitting Dolet Hills (including both the MATS and CSAPR retrofit costs) versus a retire-and-replace alternative, using information that was reasonably available to SWEPCO at the time the retrofit decisions were made.

32. SWEPCO's economic analysis compared the retrofits to both replacement of the Dolet Hills capacity with a new combined-cycle gas turbine and with market purchases, and considered various gas-price and carbon dioxide price sensitivities.

33. SWEPCO's economic analysis appropriately captured the pertinent costs for the various scenarios it compared, and included reasonable forecasts of gas prices, lignite costs, and potential carbon dioxide costs.

34. SWEPCO's economic analysis reasonably excluded future uncertain environmental compliance costs, other than carbon dioxide, since those costs were either inapplicable to Dolet Hills, or not material to the outcome of the economic analysis.

35. SWEPCO's independent economic analysis supports the reasonableness of SWEPCO's decision to make the MATS and CSAPR retrofits at Dolet Hills.

36. Based on the retrospective analysis, SWEPCO's decision to concur with Cleco's proposal to make the MATS and CSAPR retrofits at Dolet Hills falls within the select range of options that a reasonable utility manager would choose, given the information available to SWEPCO management at the time of the decisions.

Flint Creek, Pirkey, and Welsh Units 1 and 3

37. The Flint Creek plant is located in Benton County, Arkansas, near the town of Gentry. SWEPCO and Arkansas Electric Cooperative Corporation each own half of the 528 MW plant. SWEPCO is responsible for operating the plant.

38. The Henry W. Pirkey plant is located near Hallsville, Texas, in Harrison County. Pirkey is jointly owned by SWEPCO, Oklahoma Municipal Power Authority, and North Texas Electric Cooperative. SWEPCO owns about 86% (580 MW) of the net unit capacity and is responsible for the operation and maintenance of the plant.

39. The Welsh plant is located near Cason, Texas, in Titus County. The plant consists of three units. Welsh unit 2 has been retired. Welsh units 1 and 3 have a combined capacity of 1066 MW.

40. A number of environmental regulations contributed to the requirement to improve control of emissions from SWEPCO's Flint Creek, Pirkey, and Welsh plants. These regulations include the MATS Rule, the Regional Haze Rule, CSAPR, and revisions to certain National Ambient Air Quality Standards.

41. The regulatory environment in the 2009-2011 time period was complex and evolving. Some of the regulations had overlapping effects and overlapping compliance timelines, and a comprehensive approach to fleet management was required.

42. SWEPCO performed a series of economic analyses of unit-disposition alternatives at the Welsh, Flint Creek, and Pirkey plants. The series of monthly economic analyses, beginning in January 2011 through May 2011 (monthly economic analyses), provided the economic comparisons of those alternatives that aided SWEPCO in deciding the future disposition of those units.

43. The unit-disposition studies included the projected operating and capital costs of the alternatives studied, as well as varying assumptions on the timing and amount of retrofit capital that reasonably reflected uncertainties regarding the timing and evolution of the various environmental programs in play.

44. Multiple commodity-price forecasts were employed in each set of analyses so that the unit-disposition alternatives (*i.e.*, unit retrofit, or unit retirement and replacement) could be evaluated under a range of commodity-price assumptions. These included sensitivities for future gas prices, market energy prices, carbon dioxide prices, and other commodity inputs.

45. In the monthly economic analyses, under all 15 commodity-price assumptions studied but for one, the Welsh unit 1 and 3 retrofits were projected to provide savings over retirement of all three units.

46. In the monthly economic analyses, under all 15 commodity price assumptions studied but for one, the Flint Creek retrofit was projected to provide savings over retirement.

47. In the monthly economic analyses, under all 15 commodity price assumptions studied, the Pirkey retrofit was projected to provide savings over retirement.

48. The economic evaluations that informed SWEPCO's decision to retrofit Flint Creek, Pirkey, and Welsh units 1 and 3 were robust. These analyses were tested under several sets of input assumptions. The analyses indicated that retrofitting the units was the better path forward for SWEPCO and its customers.

49. SWEPCO made decisions founded on facts known at the time. SWEPCO's decision to retrofit Flint Creek, Pirkey, and Welsh units 1 and 3 was among that range of decisions that a reasonable utility manager would make in the same or similar circumstances.

50. After the monthly economic analyses, Welsh unit 1 and 3, Flint Creek, and Pirkey unit disposition analyses were conducted again at various points in time over the next several years. These additional analyses were conducted under updated assumptions regarding SWEPCO's load forecast, commodity price forecasts, and capital cost assumptions for environmental retrofits and replacement capacity.

51. The subsequent analyses verified that SWEPCO's decision to install the environmental retrofits and continue to operate those units continued to be a reasonable course of action for SWEPCO's customers.

52. AEP Services Company (AEPSC), on behalf of SWEPCO, reasonably and prudently planned and constructed the environmental retrofit projects at SWEPCO's Flint Creek, Pirkey, and Welsh units 1 and 3.

<u>Decision to Retire Welsh Unit 2</u>

53. SWEPCO announced the retirement of Welsh unit 2 in June 2011. At the time, all three Welsh units were operating fully uncontrolled for the types of environmental requirements then being implemented.

54. Regulations affecting Welsh unit 2 included the prevention of significant deterioration and NAAQS programs, the MATS Rule, CSAPR, and the best available retrofit technology technology requirements associated with the implementation of EPA's regional haze program, and others, as well as the proposals associated with these rules.

55. At the time of the retirement decision, it was reasonably expected by SWEPCO and in the electric industry in general that regulations impacting plants such as the Welsh units would require installation of Flue Gas Desulfurization and selective-catalytic reduction controls. Utilities also anticipated carbon-regulation impacts.

56. As early as 2008, this Commission found that the potential for imposition of future carbon costs should be taken into account in considering whether to grant SWEPCO a certificate of convenience and necessity for the Turk plant construction.

57. SWEPCO management reasonably believed at the time that the uncontrolled status of Welsh unit 2 could at some time in the future (and not only in response to the particular regulations and programs in play in early 2011) lead to requirements for installation of extensive and expensive new controls.

58. Welsh unit 1, 2, and 3 disposition analyses were conducted in late 2010, and then on a monthly basis from January 2011 through May 2011, prior to the June 9, 2011 press release announcing SWEPCO's Welsh, Flint Creek, and Pirkey unit-disposition decisions.

59. The monthly economic analyses regarding Welsh unit 2 were less conclusive than for the other units SWEPCO decided to retrofit. Under the 15 commodity price assumptions studied, 9 assumptions favored retrofits and 6 assumptions favored retirement.

60. SWEPCO examined a range of reasonable options, then considered and selected retirement of Welsh unit 2 as a reasonable alternative from those options based on information and circumstances at the time.

61. Compliance deadlines for environmental programs such as NAAQS and the MATS Rule were reasonably viewed by SWEPCO management as requiring a decision to retire Welsh unit 2 in June 2011.

62. SWEPCO's credit rating would have been at risk if the Company undertook the full cost to retrofit Dolet Hills, Flint Creek, Pirkey, and all three Welsh units, estimated under the information available at the time to total $2 billion.

63. The decision to retire Welsh unit 2 was part of a reasonable and balanced resource portfolio management strategy, which by retrofitting some units and retiring others, allowed SWEPCO to manage the overall concentration of solid fuels in the portfolio as a hedge against future, more-stringent environmental-compliance requirements.

64. SWEPCO management prudently determined to retire Welsh unit 2.

The Appropriate Ratemaking Treatment for the Retirement of Welsh Unit 2

65. SWEPCO retired Welsh unit 2 in April of 2016.

66. Welsh unit 2 no longer generates electricity and is not used by and useful to SWEPCO in providing electric service to the public.

67. Under the FERC uniform system of accounts, the appropriate accounting treatment for the retirement is to credit plant in service with the original cost of Welsh unit 2 and debit accumulated depreciation with the same amount. This would leave a debit balance in accumulated depreciation equal to the undepreciated balance of Welsh unit 2.

68. Because Welsh unit 2 is no longer used and useful, SWEPCO may not include its investment associated with the plant in its rate base, and may not earn a return on that remaining investment.

69. Allowing SWEPCO a return of, but not on, its remaining investment in Welsh unit 2 balances the interests of ratepayers and shareholders with respect to a plant that no longer provides service.

70. It is reasonable for SWEPCO to recover the remaining undepreciated balance of Welsh unit 2 over the 24-year remaining lives of Welsh units 1 and 3.

71. The appropriate accounting treatment that results in the appropriate ratemaking treatment is to record the undepreciated balance of Welsh unit 2 in a regulatory-asset account.

Turk Power Plant Cost Cap

72. When certifying the construction of the Turk power plant, the Commission established a construction cost cap of $1.522 billion (total plant) that was based on SWEPCO's estimate of the cost to construct the Turk plant. *Application of Southwestern Electric Power Company for a Certificate of Convenience and Necessity Authorization for a Coal Fired Power Plant in Arkansas*, Docket No. 33891 (Aug. 12, 2008).

73. Allowance for funds used during construction (AFUDC) comprises the financing costs associated with cash outlays for the construction of an asset such as the Turk plant. The Commission construed the cost cap and determined that it did not include AFUDC, and that SWEPCO's share of the cap is $1.116 billion on a total company basis. In *Application*

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

74. As a result of exceeding the cost cap ordered in Texas, SWEPCO excluded more than \$58 million (Texas retail) of construction cost from its rate base in this proceeding.

75. SWEPCO reached the \$1.116 billion total-company cost cap in April 2012. The Turk plant went into service in mid-December 2012, leaving a period of 8.5 months in which AFUDC accrued on capital costs that exceeded the cost cap.

76. SWEPCO properly determined the amount of AFUDC on investment above the cost cap on a monthly basis using actual dollars above the cost cap and actual monthly AFUDC rates.

77. SWEPCO excluded from its rate base the \$1.313 million of actual AFUDC (Texas retail) associated with the construction costs that exceed the cap.

Materials and Supplies Adjustment

78. SWEPCO agreed that test-year plant material and operating supplies account should be adjusted to remove obsolete inventory that was written off during the test year. The adjustment reduces SWEPCO's total-company rate base by \$834,000.

79. A substantial portion of SWEPCO's environmental retrofits were placed in service during the test year. The Flint Creek retrofits were placed in service in June 2016 and the Welsh units 1 and 3 retrofits were placed in service in April 2016.

80. Given the placement in service of new projects, SWEPCO's approach of using year-end inventory for environmental-control chemicals in this case is more representative of an ongoing inventory balance than a 13-month average, because a 13-month average would include months that had a zero amount for Flint Creek and Welsh units 1 and 3.

81. Once SWEPCO has a test year that includes values for each month, a 13-month average will likely be more appropriate.

Accumulated Deferred Federal Income Taxes

82. Among other (uncontested) costs, supplemental-executive-retirement-plan (SERP) costs and accrued book severance benefits expenses were considered in SWEPCO's lead-lag

study. All of the dollars associated with SWEPCO's operating expenses, including the contested items, were properly included in its cash-working-capital study.

83. As a result, the treatment of the accumulated-deferred-federal-income-taxes assets associated with SERP costs and accrued book severance benefits is consistent with the rate-base treatment of the items giving rise to the deferred taxes.

Treatment of Transmission Invested Capital

84. SWEPCO proposes to change the Commission's traditional method of transmission ratemaking. Under SWEPCO's proposal, rate recovery would be based on the payments made by SWEPCO under the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) tariff. The SPP OATT tariff includes costs that SWEPCO pays for ancillary-service markets and third-party transmission, but additionally includes the costs that SWEPCO effectively pays to itself as a transmission owner.

85. A similar proposal was litigated and expressly rejected by the Commission. *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695 (Feb. 23, 2016) (SPS Docket No. 43695).

86. Southwestern Public Service Company (SPS) operates in the Southwest Power Pool (SPP) like SWEPCO.

87. There has not been any change under SWEPCO's last case in the methodology for changes under the SPP OATT.

88. SWEPCO's proposal would remove 94% of the Company's transmission invested capital from the Commission's jurisdiction.

89. Commission regulation of retail transmission starts with retail regulation of SWEPCO's transmission, based on a rate of return on rate base plus operation and maintenance expenses, depreciation, and taxes, assigned to the Texas retail jurisdiction.

90. The Commission then accounts for FERC jurisdictional costs paid by SWEPCO, and FERC jurisdictional revenues received by SWEPCO.

91. Under Texas regulation, FERC jurisdictional costs are not ignored but are in fact, incorporated.

92. There are two sets of FERC jurisdictional costs recovered from ratepayers. The first set is FERC jurisdictional costs SWEPCO pays to SPP for costs incurred by participating in SPP's ancillary-service markets. In this case, these costs are $5.1 million Texas jurisdictional. The second set of costs is SWEPCO's payments through SPP to third parties for use of their transmission systems, which in this proceeding is $56.9 million Texas jurisdictional. Both of these sets of costs are passed through to SWEPCO ratepayers under the Commission's traditional method of transmission ratemaking.

93. SWEPCO also receives revenues paid to SWEPCO from SPP for load-share payments to SWEPCO for the use of transmission plant by other utilities and the provision of ancillary services to SPP. In this case, the revenues received were $66.2 million Texas jurisdictional including $1.2 million for ancillary services. These revenues offset a portion of the transmission costs assigned to the retail jurisdiction.

94. Under retail regulation, the costs that SWEPCO pays SPP for use of its own transmission are offset by the revenues that SWEPCO receives from SPP for ownership of the portion of its own transmission that it uses. This approach is consistent with the matching principle.

95. Under the company's approach, payments to SPP from SWEPCO for its own use of its own transmission system, as well as for its use of third parties' transmission systems and its payments for ancillary services, become the revenue requirement. Because there is no retail regulation, the revenues received from third parties for use of the SWEPCO transmission system (revenue credits) disappear from the calculation.

96. SWEPCO asserted that under the SPP OATT, it is entitled to an extra $8.4 million related to retail Texas ratemaking.

97. SWEPCO's proposal seeks to include the amount it charges itself for the use of its Texas retail transmission system, but to ignore the identical amount it receives from itself.

98. Over 55% of the approximately $8.4 million is due to FERC's higher rate of return on equity (ROE) which is 11.2%, plus project-specific enhancements. SWEPCO's revenue requirement is increased by $4.7 million because of the use of an 11.2% ROE instead of SWEPCO's last authorized ROE of 9.65%.

99. SWEPCO failed to give ratepayers the benefit of $1.23 million of revenue credits related to payments from SPP received by SWEPCO for ancillary services. These ancillary service credits are not transmission-related; they are instead related to the use of Commission-regulated generation plant that provides ancillary services to SPP. Retail ratepayers fully support SWEPCO's generation plant that provides the ancillary services, and are entitled to receive all of the benefits from these services.

100. The remaining money, $3.5 million at SWEPCO's requested ROE, is the basis upon which the original $8.4 million figure was calculated, and comes from a combination of other components of FERC ratemaking that are more favorable to the utility than costs allowed by the Commission, mixed with errors made by SWEPCO because it did not correctly calculate the amount that SWEPCO would receive under the SPP OATT.

101. FERC ratemaking includes costs that the Commission does not allow in rates, including 100% of stock-based compensation, 100% of cash incentive compensation, and executive perquisites (except personal use of corporate aircraft).

102. Additionally, FERC's formula ratemaking with a future test year yields higher rates than a Texas historical test year. The billing determinants used to set transmission rates at FERC include forward-looking future test-year costs, which are mismatched against historical test-year Texas billing determinants, thereby inflating SWEPCO's rates.

103. SWEPCO also incorrectly calculated various complex load-share calculations to the detriment of Texas ratepayers.

104. The $8.4 million reflects significant differences between FERC and Commission regulatory policies. Although the underlying transmission system and Texas retail loads are the same, relying on FERC rate schedules to calculate retail transmission costs adversely affects Texas retail customers.

105. SWEPCO has not proven that the increased costs accompanying the change in methodology are reasonable and necessary for the provision of service.

106. Under SWEPCO's filed case, SWEPCO's functionalized transmission-related rate base under the current regulatory method is $291,849,357. By comparison, SWEPCO's Texas

jurisdictional transmission rate base was $17,541,958. This approximately $274 million difference is caused by the treatment of transmission investment capital as FERC jurisdictional.

107. The Commission's traditional method of transmission ratemaking is reasonable and appropriate for determining SWEPCO's rates.

108. SWEPCO's proposed method for recovery of transmission invested capital is contrary to good public policy.

109. Under the Commission's regulation, SWEPCO recovers all reasonable retail costs. SWEPCO recovers its retail rate of return based on a test-year level of investment and expense that is matched to test-year loads. The company pays for all costs associated with third-party transmission and ancillary-services markets, and it receives credits from other parties' payments for its transmission and ancillary services. The amount that SWEPCO pays SPP to use its own transmission system is netted against the amount that SPP pays SWEPCO for the company's ownership of the portion of its own transmission system that the company uses, so proper matching of costs and revenues takes place.

Capitalized Vegetation Management Costs

110. SWEPCO capitalized vegetation-management costs of $1,330,063 for transmission and $3,236,057 for distribution.

111. During the test year, SWEPCO capitalized vegetation-management costs of $912,183 for transmission and $633,832 for distribution.

112. SWEPCO also capitalized test-year costs of $68,677 for hazard-tree removal and $474,699 for right-of-way (ROW) widening projects.

113. SWEPCO's capitalization of all of these costs is contrary to the clear language of the FERC uniform-system-of-accounts instruction that costs incurred "in connection with the first clearing and grading of land and rights-of-way" may be capitalized.

114. Under FERC rules, costs of trimming trees, clearing brush, and applications of herbicides occurring subsequent to construction of a line are expensed as operations and management (O&M) costs to FERC Account 571 (Maintenance of Overhead Lines).

115. SWEPCO's approach is inconsistent with the reasoning in at least one FERC audit of a different utility (American Transmission System, Inc.), and also with this Commission's order in *Application of Entergy Texas, Inc., for Approval of a Transmission Cost Recovery Factor*, Docket No. 45084 (Oct. 7, 2016), concerning Entergy Texas, Inc.

116. SWEPCO demonstrated that its transmission-and-distribution-vegetation-management-project-activity costs are known, measurable, and recurring.

117. Vegetation-management costs of $1,330,063 for transmission and $3,236,057 for distribution are excluded from rate base.

118. SWEPCO may recover in rates as test-year O&M expense $912,183 of transmission cost and $633,832 of distribution cost.

119. SWEPCO also may recover in rates as test-year O&M vegetation-management costs of $68,677 for hazard-tree removal and $474,699 for ROW widening, and these costs are removed from transmission invested capital.

Other Transmission Capital Projects

120. SWEPCO incurred a total amount of $92.7 million of transmission capital investment placed in service during the period January 1, 2016 through June 30, 2016.

121. SWEPCO initially improperly included $779 for a project labeled *T/SEP/Pirkey-Tenaska345kC-Relo* in its transmission invested capital.

122. With the exception of $779 for the project erroneously included in the test year, the entirety of the transmission investment is used and useful in providing service to the public and is reasonable and necessary.

Other Distribution Capital Projects

123. SWEPCO incurred a total amount of $157 million of distribution capital investment placed in service during the period January 1, 2012 through June 30, 2016.

124. SWEPCO agreed that $54,410 of transmission plant was erroneously classified as distribution plant for the North Mineola project. This amount should be reclassified as transmission plant.

125. Two other projects were also erroneously classified as distribution plant and should be reclassified to transmission plant: Pittsburg ($14,712) and Bryan Mills ($9,213).

126. The total amount of capital investment misclassified as distribution plant should be re-classified as and included in transmission plant. This transmission capital investment incurred during the period January 1, 2012, through June 30, 2016, is used and useful in providing service to the public and reasonable and necessary.

127. Apart from the reclassifications to transmission plant discussed immediately above, the entirety of the distribution investment is used and useful in providing service to the public and reasonable and necessary.

Capitalized Supplemental Executive Retirement Plan

128. Since the end of 2011, the test year for SWEPCO's last base-rate case, SWEPCO identified $1,363,305 of non-qualified pension expense capitalized to construction work in progress (CWIP) and $8,721 capitalized to removal work in progress.

129. The capitalized portion of SWEPCO's supplemental-executive-retirement-plan (SERP) payments that are financially based are properly excluded from SWEPCO's rate base because they are not reasonable or necessary to provide utility service to the public, are not in the public interest, and should not be included in SWEPCO's cost of service.

130. SWEPCO's accounting system cannot provide the exact amount of capitalized financial incentives closed to plant in service or the amount remaining in CWIP as of the end of the test year. An appropriate approximation for the amount of capitalized financial incentives included in SWEPCO's requested plant in service balance is the same proportion as the test-year-end balance of completed construction not classified to CWIP, which is 83.17%.

131. $1,141,151, which is 83.17% of the total SERP invested-capital request, is removed from invested capital.

Capitalized Incentive Compensation

132. Since the end of 2011, the test year for SWEPCO's last base-rate case, the amount of incentive compensation based on financial measures that SWEPCO capitalized to rate base

included $13,696,685 capitalized to CWIP (added to FERC Account 107) and $571,079 capitalized to removal work in progress (added to FERC Account 108).

133. 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.

134. SWEPCO's accounting system cannot provide the exact amount of capitalized financial incentives closed to plant in service or the amount remaining in CWIP as of the end of the test year. An appropriate approximation for the amount of capitalized financial incentives included in SWEPCO's requested plant in service balance is the same proportion as the test year-end balance of completed construction not classified to CWIP, which is 83.17%.

135. Therefore, 83.17% of the capitalized amounts are removed: $11,391,898 from plant in service and $474,982 from removal work in progress, with the remainder to remain in the CWIP balance.

<u>Dolet Hills Lignite Target Inventory Level</u>

136. The factors that influence planned inventory levels include the probability of interruptions of the fuel supply, how long such interruptions may last, and how much fuel is necessary to provide for these contingencies.

137. A 45-day-inventory target for Dolet Hills plant has been in use for many years. It was presented by SWEPCO in a previous, settled rate case, *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 37364 (Apr. 16, 2010), which was SWEPCO's first request for a change in base rates since the Dolet Hills plant went into operation. A 45-day target was also proposed in Docket No. 40443, SWEPCO's last base-rate case, where its use was unchallenged and was accepted by the Commission. *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443 (Mar. 6, 2014).

138. Historic inventory levels for Dolet Hills are in line with a target inventory of 45 days.

139. Since the Docket No. 40443 test year, the Dolet Hills lignite reserves have been depleted and all of the draglines and mining operations are moving to the Oxbow reserve, an adjacent lignite reserve situated farther from the Dolet Hills plant. The move will add approximately five miles to the length of the conveyor belt for a total distance of 12 miles. This approximately 71% increase in the length of the conveyor belt increases the possibility and potential length of an unplanned outage for lignite deliveries to the Dolet Hills plant.

140. This increased risk supports the continued need for a target inventory of 45 days, as proposed by SWEPCO.

Sierra Club Settlement

141. SWEPCO concluded a settlement of approximately $14 million with the Sierra Club in December 2011, via consent decree, which ended all remaining meaningful construction-period litigation concerning the Turk plant.

142. SWEPCO management had already prudently determined to retire Welsh unit 2 and announced that decision in June 2011, well before the settlement with the Sierra Club. SWEPCO's decision to retire Welsh unit 2, while documented in the Sierra Club settlement, was not a result of the settlement.

143. The Sierra Club settlement addressed concerns in the financial community that the Turk plant might be stranded by litigation, with consequent significant harm to SWEPCO's financial condition, ended construction delay costs of approximately $10 million per month, and concluded costly litigation that had gone on in multiple forums for five years.

144. SWEPCO management prudently entered into the Sierra Club settlement.

Welsh Unit 2 60% Annual Capacity Factor Limitation

145. The Sierra Club settlement required the annual capacity factor of Welsh unit 2 to be limited to no more than 60% on a twelve-month rolling average until retirement of the unit.

146. The 60% capacity-factor limitation was not a new agreement, but paralleled the settlement SWEPCO had reached with the Arkansas Department of Environmental Quality and the Caney Creek Federal Land Manager in March 2008 to reduce sulfur-dioxide emissions at

the Caney Creek Wilderness Area. This provision of the settlement added no substantial incremental burden on the operation of Welsh unit 2.

147. The decline in Welsh unit 2's capacity factor was the product of two factors independent of the Sierra Club settlement: the commercial start of the Turk plant in January 2013, and SWEPCO's integration into the SPP integrated marketplace, which provided SWEPCO with greater access to less expensive generation from across SPP's entire footprint starting in March 2014.

148. SWEPCO management prudently agreed to include the 60% capacity-factor limitation in the Sierra Club settlement.

Long-Term Wind-Energy Purchase Contracts

149. As part of the Sierra Club settlement, SWEPCO entered into certain long-term wind purchase-power agreements (PPAs).

150. When the full-term of the long-term wind PPAs are considered over their entire life, an economic benefit is expected for SWEPCO's customers.

151. SWEPCO management prudently agreed to include the long-term PPAs in the Sierra Club settlement.

Cash Working Capital

152. Cash working capital represents the amount of working capital, not specifically addressed in other rate-base items, that is necessary to fund the gap between the time expenditures are made and the time corresponding revenues are received.

153. The cash working-capital allowance associated with federal income tax expense was calculated by SWEPCO consistently with the calculations of other negative balances and is proper.

154. The cash working-capital methodology in SWEPCO's lead-lag study was unchallenged and is reasonable. The exact adjustments to cash working capital shall reflect SWEPCO's methodology with the determinations of the value of the inputs determined from the findings in this order.

Pensions

155. The amount requested by the company for pension and other postemployment benefits (OPEB) (including postretirement benefits and postemployment benefits) was determined by actuarial or other similar studies in accordance with generally accepted accounting principles. With the exception of SERP, SWEPCO's pension and OPEB costs were not challenged.

Rate of Return and Cost of Capital

156. A capital structure composed of 51.54% long-term debt and 48.46% equity was uncontested and is reasonable in light of SWEPCO's business and regulatory risks.

157. A capital structure composed of 51.54% long-term debt and 48.46% equity was uncontested and will help SWEPCO attract capital from investors.

158. A ROE of 9.60% will allow SWEPCO a reasonable opportunity to earn a reasonable return on its invested capital.

159. The results of the discounted-cash-flow model and risk-premium approach support an ROE of 9.60%.

160. A 9.60% ROE is consistent with SWEPCO's business and regulatory risk.

161. SWEPCO's proposed 4.90% embedded cost of debt is reasonable.

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

COMPONENT	CAPITAL STRUCTURE	COST OF CAPITAL	WEIGHTED AVG COST OF CAPITAL
LONG-TERM DEBT	51.54%	4.90%	2.53%
COMMON EQUITY	48.46%	9.60%	4.65%
TOTAL	100.00%		7.18%

Cost of Service

Welsh Unit 2 O&M

163. Test-year O&M expenses from Welsh unit 2 will not recur in the future due to the plant's retirement in April of 2016.

164. There is no corresponding increase in generation at other SWEPCO units to replace the Welsh-unit-2 capacity.

165. Test-year expenses that are nonrecurring should not be included in future rates.

166. Because Welsh unit 2 is no longer in service, a reduction in variable O&M expenses is reasonable.

167. Welsh-unit-2 O&M expenses of $332,493 (total company) should be disallowed.

Production Maintenance Expense

168. SWEPCO proposes to include its test-year expenses of approximately $148.1 million in generation O&M expenses in base rates.

169. The prudence of SWEPCO's generation O&M expenses and practices was not challenged.

170. [Deleted.]

171. [Deleted.]

172. [Deleted.]

173. [Deleted.]

174. [Deleted.]

174A. In determining a utility's allowable expenses under the Commission's cost-of-service rule, only the electric utility's historical test-year expenses, as adjusted for known and measurable changes, are considered.

174B. SWEPCO did not request, and no party proved, a known and measurable change to the production-maintenance expense.

174C. The test-year expenses of approximately $148.1 million are reasonable and necessary expenses.

Adjustment to Accumulated Depreciation

175. It was reasonable for SWEPCO to adjust its accumulated-depreciation-account balance downward by $112,501,487 when conducting its depreciation study to consider only the depreciation rates that the Commission has ordered for SWEPCO and not the depreciation rates ordered by other jurisdictions in which SWEPCO operates.

176. This adjustment ensures that the undepreciated cost of SWEPCO's assets will be spread over the remaining lives of those assets.

Adjustment to Accumulated Depreciation Production Plant

177. The plant demolition studies SWEPCO used to develop terminal removal cost and salvage for each of SWEPCO's generating facilities, when adjusted to account for a 10% contingency factor, are reasonable.

178. It was not reasonable for the demolition studies used in SWEPCO's depreciation studies to include a 15% contingency factor. Instead, a reasonable contingency factor for the demolition studies is 10%.

179. It is common practice to include contingency amounts in cost estimates for contract work across all industries.

180. The 10% contingency factor for inclusion in SWEPCO's demolition studies is reasonable, because the demolition of SWEPCO's natural-gas and coal power plants are less complex, less risky, and less costly than the demolition of a nuclear power plant, which is allowed a maximum contingency factor of 10% by Commission rule.

181. It was reasonable for the demolition studies to consider the applicable variables such as quantities and prices as of a specific point in time, and it would be improper to change the applicable date and associated price for only one of those variables.

182. It is reasonable for SWEPCO to escalate the terminal removal cost and salvage in the demolition studies (which are stated in year-end 2016 dollars) to the expected final retirement date of each plant using a 2.25% inflation rate from the *Livingston Survey* dated December 2015 and published by the research department of the Federal Reserve Bank of Philadelphia.

Transmission Plant

183. It is reasonable to apply an R1.5-73 Iowa-curve-life combination for FERC Account 353–*Transmission Station Equipment*.

184. It is reasonable to apply an R2.5-70 Iowa-curve-life combination for FERC Account 356–*Overhead Conductors & Devices*.

Distribution Plant

185. It is reasonable to apply an R3.0-70 Iowa-curve-life combination for FERC Account 361–*Structures & Improvements*.

186. It is reasonable to apply an S0.5-55 Iowa-curve-life combination for FERC Account 362–*Distribution Substation Equipment*.

187. It is reasonable to apply an R0.5-55 Iowa-curve-life combination for FERC Account 364–*Distribution Poles*.

188. It is reasonable to apply an R1.5-50 Iowa-curve-life combination for FERC Account 367–*Distribution Underground Conductor*.

189. It is reasonable to apply an L0.0-50 Iowa-curve-life combination for FERC Account 368–*Distribution Line Transformers*.

General Plant

190. It is reasonable to apply an L0.5-55 Iowa-curve-life combination for general plant.

Payroll Adjustment

191. SWEPCO's proposed base payroll is based on the salaries of its employees for the final pay period at the end of the test year (annualization) plus post-test-year test-year pay increase of 3.5% for which all increases were approved and then implemented by April 2017.

192. Because these payroll increases were awarded in 2017, they represent appropriate known and measurable changes.

193. SWEPCO's calculation in this proceeding matches the adjustment approved in Docket No. 40443, which is to annualize salaries of employees on the payroll at the end of the test year and then apply a known and measurable increase that was awarded post-test year.

Annual Incentive Compensation

194. The Commission has repeatedly ruled that a utility cannot recover the cost of financially-based incentive compensation because financial measures are of more immediate benefit to shareholders and financial measures are not necessary or reasonable to provide utility services.

195. SWEPCO's annual incentive plan includes both financially-based and performance-based goals.

196. Compensation to employees under the annual incentive plan is based in part on an earnings-per-share trigger.

197. A certain amount of incentives to achieve operational measures is reasonable and necessary to the provision of electric service. However, SWEPCO failed to prove that its proposal removed all of the costs associated with the financially-based components of the annual incentive plan.

198. Staff's recommended adjustment to eliminate $2,277,726 associated with the annual incentive plan, plus corresponding flow through reductions, results in allowable expense for the plan that is reasonable and necessary to the provision of electric service, and should be included in the cost of service.

Long-Term Incentive Compensation

199. SWEPCO removed the entirety of its financially based long-term incentive compensation in the amount of $2,140,880. However, the $359,705 of restricted stock units are not based on financial measures as are other SWEPCO or AEP incentive plans and are appropriate to include in SWEPCO's rates.

Financial Counseling Expense

200. The $4,071 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.

Supplemental Executive Retirement

201. SWEPCO requests recovery of $99,654 in directly incurred non-qualified pension expense and an additional $310,422 that was allocated from AEP Services Company (AEPSC) ($410,076 total).

202. SWEPCO provides non-qualified supplemental executive retirement plans for highly compensated individuals such as key managerial employees and executives that, because of limitations imposed under the Internal Revenue Code, would otherwise not receive retirement benefits on their annual compensation over $270,000 per year.

203. SWEPCO's non-qualified supplemental executive retirement plans are discretionary costs designed to attract, retain, and reward highly compensated employees whose interests are more closely aligned with those of the shareholders than the customers.

204. SWEPCO's requested non-qualified supplemental executive retirement benefits are not reasonable or necessary to provide utility service to the public, are not in the public interest, and should not be included in SWEPCO's cost of service.

Pensions and Other Post-Retirement Benefits

205. The amount requested by the company for pension and OPEB (including post-retirement benefits and post-employment benefits) was determined by actuarial or other similar studies in accordance with generally accepted accounting principles. With the exception of SERP, SWEPCO's pension and OPEB costs were not challenged.

Distribution Plant Maintenance

206. SWEPCO's proposal to recover distribution O&M base-rate expenses of $9.3 million total, consisting of the test-year amount of $7.3 million and an additional amount of $2 million, is reasonable.

207. The additional amount of distribution O&M expense in the amount of $2 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.

208. SWEPCO commits to spending the entirety of the increased amounts of $2 million for distribution O&M expense solely on vegetation management.

209. It is reasonable to open a compliance docket where SWEPCO will file regular reports indicating how it is spending the additional amount of vegetation-management expense allowed in its cost of service, and will also report on the effect such additional spending is having on its distribution outage rates.

Affiliate Charges

210. SWEPCO adjusted the lead-lag study to include an increase of $73,188 to the interest expense based on a change in the date on which AEPSC pays invoices.

211. SWEPCO agreed to reverse the $73,188 adjustment to the lead-lag study.

212. A component of the shared-facilities charges SWEPCO incurred from affiliates included the carrying costs associated with those facilities. Because these carrying costs are unnecessary and unreasonable, $795,480 should be removed from SWEPCO's affiliate expense. SWEPCO should also make a corresponding decrease to FERC Account 922 of $509,723 in revenue that SWEPCO has received related to carrying costs. This results in a net reduction of $285,757, on a total-company basis.

213. All remaining affiliate transactions for which recovery was sought were reasonable and necessary, were allowable, and were charged to SWEPCO at a price no higher than was charged by the supplying affiliate to other affiliates, and the rate charged was a reasonable approximation of the cost of providing the service.

Injuries and Damages

214. In the test year, SWEPCO incurred $5,327,950 as injuries and damages expense.

215. In the test year, SWEPCO incurred $1,255,000 as litigation expense.

216. The test-year amount for litigation was substantially in excess of the litigation expenses incurred by SWEPCO in the three preceding years.

217. It is reasonable to adjust the test-year amount by a $837,667 reduction, which is the amount the test-year litigation expense exceeds the average litigation expense in the three previous years.

Directors'/Officers' Liability Insurance

218. The existence of directors' and officers' (D&O) liability insurance improves the utility's ability to attract and retain qualified directors and officers and enables them to make decisions without fear of personal liability.

219. The Commission has already found D&O liability insurance to be an element of SWEPCO's reasonable and necessary operating expenses. *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Order on Rehearing, Finding of Fact Nos. 236, 237 (Mar. 6, 2014).

220. OPUC recommends a total-company reduction of $24,501 to reflect new annual premiums that began in March 2016. SWEPCO does not contest this recommendation and the Commission should adopt it.

Storm Damage/Storm Recovery Costs

221. Pursuant to the Commission's cost-of-service rule, in determining a utility's allowable expenses, only the electric utility's historical test-year expenses as adjusted for known and measurable changes will be considered.

222. OPUC witness Mr. Marcus recommends a disallowance of more than $1 million of expenses incurred during SWEPCO's historical test year based on a contention that SWEPCO experienced significant storm damage in the test year that is not representative of ordinary test-year expenses. He recommends that storm-damage expense (excluding straight-time labor) be established on a five-year average of 2011-2015 expenses.

223. Mr. Marcus' five-year averaging recommendation is unreasonable for its inclusion of the amounts incurred in the years 2011 and 2012, which were much less than the most recent years of 2013 through 2015.

224. The test-year level of storm-damage and storm-recovery expense was less than the amount incurred in 2015. The average of the two most recent historical years available at the time of filing (2014 and 2015) is $5,169,486 or only $49,753 less than the actual historical test-year amount. Thus, the historical test-year level of expense is only 3% higher than the average of 2014 and 2015. Such a small deviation does not support a normalization adjustment, nor does it constitute a "known and measurable change" under the Commission's cost-of-service rule.

Rate Case and Regulatory Commission Expense

225. In SOAH Order No. 7, the SOAH ALJs granted SWEPCO's request that the review of rate-case expenses associated with this proceeding be severed into a separate docket for review at the conclusion of this case.

226. SWEPCO also seeks recovery in this proceeding of $1.544 million of rate-case expenses incurred in six other prior dockets. SWEPCO amended its request to add an additional amount of $51,793 related to one of those six proceedings.

227. The company is seeking rate-case-expense-rider recovery of only incremental rate-case expenses, such as legal, consultants, and Cities' expenses, and other incremental expenses. Payroll of employees, SWEPCO or AEPSC, are not included in SWEPCO's requested rate-case expense rider recovery because they do not represent incremental costs incurred because of the six proceedings.

228. For expenses incurred in *Application of Southwestern Electric Power Company for Rate Case Expenses Severed from PUC Docket No. 40443*, Docket No. 42370 (Jun. 24, 2015), SWEPCO agrees that there was no detailed information for charges totaling $1,125, and, therefore, those charges should be removed for recovery in this case. An additional $8,325 should be removed as unsupported, as the invoice provided for that expense does not provide the necessary detail into the actual work performed.

229. For expenses incurred in *Application of Southwestern Electric Power Company for Approval of Transmission Cost Recovery Factor*, Docket No. 42448 (Nov. 24, 2014) (Docket No. 42448), SWEPCO agrees that a total of $112,651 should have been properly assigned to costs associated with *Application of Southwestern Electric Company for Approval of a Transmission Cost Recovery Factor*, Docket No. 42089 (Mar. 4, 2014), and should therefore be removed from recovery in this case.

230. Staff witness Ruth Stark recommended approval of SWEPCO's request with some reductions in the amounts requested. In addition to Docket Nos. 42730 and 42448, Ms. Stark recommended approval of recovery in: *Application of Southwestern Electric Power Company to Reconcile Fuel Costs*, Docket No. 42527 (Feb. 18, 2015) (Docket No. 42527); *Application of Southwestern Electric Power Company for Authority to Revise Fixed Fuel Factors and to Implement an Interim Fuel Surcharge*, Docket No. 44701 (Jul. 30, 2015) (Docket No. 44701); *Application of Southwestern Electric Power Company for Approval to Amend Transmission Cost Recovery Factor*, Docket No. 45691 (Sept. 23, 2016) (Docket No. 45691); and *Application of Southwestern Electric Power Company for Approval to Amend Transmission Cost Recovery Factor*, Docket No. 44496 (Jul. 30, 2015) (Docket No. 44496). The amounts recommended for approval by Ms. Stark are:

Docket No. 42370	$288,423
Docket No. 42448	$429,112

Docket No. 42527	$217,910
Docket No. 44701	$ 59,840
Docket No. 45691	$315,705
Docket No. 44496	$162,971
TOTAL	**$1,473,961**

231. SWEPCO does not oppose those adjustments proposed by Ms. Stark.

232. The amounts requested for these six dockets, as adjusted by Ms. Stark, are rate-case expenses recoverable through a surcharge. Commission precedent and the factual record in this proceeding support the recovery of the rate-case expenses identified above through the requested rider.

233. SWEPCO mistakenly included in its cost of service for regulatory-commission expenses $117,216 of incremental, external costs associated with this rate case that will be recovered through a separate surcharge. SWEPCO agrees that $117,216 should be removed from cost of service. Consistent with SOAH Order No. 7, SWEPCO will seek recovery of incremental expenses associated with this rate case (*e.g.*, outside legal and consultants, notice costs, employee travel) in a separate proceeding.

234. The remaining dollars related to Docket No. 46449 (this case) included in regulatory commission expense consist of test-year internal AEPSC expenses that are not recovered through the rate-case-expense rider. Because these remaining expenses are not recovered in the rate-case-expense rider, they should be included in SWEPCO's test-year regulatory-commission expense.

235. In settling its DCRF case, *Application of Southwestern Electric Power Company for Approval of a Distribution Cost Recovery Factor*, Docket No. 45712 (Jul. 1, 2016), SWEPCO agreed to not seek recovery of rate-case expenses associated with that proceeding.

236. [Deleted.]

237. Pursuant to its agreement in the settlement of Docket No. 45712, SWEPCO has not sought and will not request recovery of incremental costs associated with that docket, such as outside legal and consultants and employee travel.

237A. However, in this docket, SWEPCO sought $161,025 for other expenses associated with Docket No. 45712, including, for example, payroll for SWEPCO or AEPSC employees that is associated with Docket No. 45712.

237B. There is no basis in PURA or the Commission's rules for the term rate-case expenses not to include all expenses that are associated with Docket No. 45712.

Back-Billed SPP Z2 Costs

238. Attachment Z2 is an SPP tariff that compensates project sponsors for self-funding creditable transmission upgrades that are subsequently used by others to fulfill transmission-service requests.

239. SPP invoiced its members for back-billed Z2 costs in the fall of 2016, and gave its members the options of paying the amount either in full or in five-year installments. SWEPCO chose the pay-in-full option, and on November 15, 2016, SWEPCO paid $16.3 million in back-billed Attachment Z2 costs. SWEPCO also expects to receive $12.2 million in back-billed credits over the next five years.

240. SWEPCO requested to place the $4.1 million difference between its Attachment Z2 costs and credits in a regulatory asset for deferred accounting treatment.

241. Deferred accounting is appropriate only for costs that are legitimately recoverable from customers but cannot be otherwise recovered in rates.

242. SWEPCO has not demonstrated that deferred accounting is necessary for its back-billed Attachment Z2.

243. [Deleted.]

244. SWEPCO's Attachment Z2 costs should not be placed in a regulatory asset or recovered through an amortization established in this proceeding.

Transmission Expenses and Revenues

245. SWEPCO is both a transmission owner and a transmission customer within the SPP.

246. As a transmission owner, SWEPCO is subject to charges calculated in accordance with the SPP OATT.

247. Transmission customers within SPP must pay Schedule 9 and Schedule 11 expenses.

248. Transmission owners are entitled to receive Schedule 9 and Schedule 11 revenues from SPP.

249. In the test year, SWEPCO paid $73,540,732 (total company) of Schedule 9 expenses and received $91,964,938 (total company) of Schedule 9 revenues.

250. In the test year, SWEPCO paid $58,790,573 (total company) of Schedule 11 expenses and received $48,141,288 of Schedule 11 revenues.

251. Instead of using its test-year Schedule 9 and Schedule 11 expenses and revenues to calculate the cost of service, SWEPCO used a calculation based on SWEPCO's August 2016 Revenue Requirement and Rates (RRR) file.

252. Using its method described above, SWEPCO calculated $84,686,367 (total company) of Schedule 9 expenses and $101,148,061 of Schedule 9 revenues.

253. Using its method described above, SWEPCO calculated $59,388,516 (total company) of Schedule 11 expenses and $47,680,011 of Schedule 11 revenues.

254. SPP changes its RRR files often, and the RRR file has changed several times during the pendency of this matter.

255. Shifts in variables in the RRR file can cause an SPP member's Schedules 9 and 11 expenses net of its Schedules 9 and 11 revenues to be significantly higher or lower.

256. SWEPCO does not know what its charges under SPP's Schedules 9 and 11 will be for the period during which the rates set in this proceeding will be in effect.

257. The August 2016 RRR file is not a known and measurable change to SWEPCO's test-year Schedules 9 and 11 revenues and expenses, and using the August 2016 RRR file to calculate SWEPCO's Schedules 9 and 11 revenues and expenses would be unreasonable.

258. SWEPCO's cost of service in this case should be determined using SWEPCO's actual Schedules 9 and 11 revenues and expenses.

259. The impact of removing SWEPCO's proposed post-test-year and pro-forma adjustments to its SPP charges and related transmission expenses and revenues is to reduce SWEPCO's

total company revenue requirement by $3,021,732 and its Texas retail revenue requirement by $1,206,184.

Factoring Expense

260. The bank credit line fees should be adjusted to include only the bank fees of $1,119,931 and not the carrying cost amount of $1,978,889. The final approved ROE should be included in the final factoring rate calculation to properly synchronize factoring expense to the approved revenue requirement.

Ad Valorem Taxes

261. If SWEPCO is allowed recovery of the remaining book value of Welsh unit 2 upon retirement, even without a return, this asset will be included in SWEPCO's property base for determining SWEPCO's ad-valorem-tax expense, since it still contributes to rate recovery and therefore remains a portion of the value of SWEPCO's assets. Only if SWEPCO receives no recovery at all in rates will the remaining net book value of Welsh unit 2 upon retirement be excluded from SWEPCO's asset base for determining its ad-valorem-tax expense.

262. Staff's calculation of a capitalization rate of 5.348% makes use of the ad valorem taxes that were capitalized during the test year, not for any specific tax year. The test year includes ad valorem taxes from parts of the 2015 and 2016 tax years, is not matched with a specific tax year, and should not be used.

263. SWEPCO appropriately used its 2015 tax year to calculate the effective tax rate and to synchronize the ad valorem tax payments for that year with plant values at January 2, 2015. The actual capitalized amount of $2,600,800 for 2015 should be the basis for the proper capitalization rate in this case.

264. Construction activity recorded in Account 107 – Construction Work in Progress (CWIP) – is the starting point for determining ad valorem taxes to be capitalized. SWEPCO's CWIP balance at June 30, 2015, the beginning of the test year, was $577.8 million. At the end of the test year SWEPCO's CWIP balance was $168.2 million. When placed in service, taxes on assets previously in CWIP are expensed and not capitalized. The significant decrease

in CWIP will decrease capitalized ad valorem taxes. Staff's recommendation does not consider this change.

Meter Reading Expense

265. SWEPCO's total-company test-year level of meter-reading expenses, $614,613, is reasonable.

266. Labor-cost savings associated with the deployment of advanced meters are captured by the test-year-ending-head-count adjustment employed by SWEPCO.

Dues and Contributions

267. SWEPCO did not oppose OPUC witness William Marcus's proposal to reduce the company's total-company dues and contributions expense by $45,100. Subject to that reduction, SWEPCO's dues and contributions expense is reasonable.

Green Country Capacity Purchase

268. The request for proposals (RFP) that resulted in the signing of the Green Country PPA sought bids to supply up to 200 MW of capacity and associated energy for a term of three to five years beginning June 1, 2016. Potential bidders were notified by the issuance of a public news release, and the RFP documents were available on the SWEPCO web site. After evaluating the resulting proposals, an agreement was reached for capacity, energy, and related ancillary services from the Green Country Energy Facility.

269. As part of meeting its load-serving-entity obligation in the SPP, SWEPCO had no choice but to purchase capacity, as it would have otherwise been short of the required capacity under SPP planning criteria.

270. It was prudent for SWEPCO to enter into the Green Country PPA.

Weather Normalization

271. Weather data are not randomly distributed by year. There can be weather trends, including both warming and cooling trends.

272. The use of a 30-year period for normalizing weather is not a reasonable means of capturing such trends.

273. The use of 10 years of data is a reasonable means of capturing such weather trends.

274. The use of 10 years of data is more sensitive to weather patterns during the test year.

275. The weather-normalization adjustment should be applied to adjust billing units and allocation factors for a 10-year weather-normalization period, based on the class billing determinants and external allocation factors used to calculate rates using a 10-year weather-normalization period.

Jurisdictional Cost Allocation

276. SWEPCO's proposal to base the jurisdictional allocation of transmission capacity costs on the 12 Coincident Peak (12CP) methodology is reasonable and consistent with Commission precedent.

Cost Allocation

Allocation of Production Costs

277. SWEPCO allocates production costs to various classes under the average and excess Demand-4 coincident peak (A&E-4CP) methodology. This methodology allocates a percentage of costs, equal to the system load factor, based on average demand, and the remainder of those costs based on excess demand.

278. In SPS Docket No. 43695, the only Commission docket in which this issue has been litigated, the Commission determined that the system load factor should be calculated by using the single annual coincident peak, rather than the average of four coincident peaks.

279. SWEPCO used the single coincident peak in calculating its system load factor for Schedule O-1.6.

280. The use of the annual coincident peak in calculating system load factor is consistent with the definition of load factor in the Commission's rules.

281. The use of the annual coincident peak for calculating system load factor is consistent with SWEPCO's generation and transmission planning.

282. The use of the annual coincident peak for calculating system load factor is consistent with the National Association of Regulatory Commissioners (NARUC) manual.

283. The use of the annual coincident peak for calculating system load factor is consistent with SPP planning.

284. In using the A&E-4CP methodology, SWEPCO should calculate its system load factor using the single annual coincident peak.

Class Cost Allocation of Transmission Costs

285. SWEPCO proposes to allocate transmission costs to retail classes based on the 12CP demand allocator.

286. SWEPCO is a summer-peaking utility.

287. The electricity demands in the summer months are the primary drivers for the amount of transmission capacity needed for SWEPCO to provide reliable service.

288. SWEPCO's demands during the four summer months ranged from 4623 MW to 5149 MW, while no off-peak month had demand in excess of 4051 MW.

289. The Commission has a longstanding policy of allocating transmission costs based primarily on peak demands in the four summer months.

290. SWEPCO has submitted the same position in support of the 12CP methodology in this case that it did in its prior case.

291. In Docket No. 40443, the Commission rejected SWEPCO's proposal to allocate transmission costs based on the 12CP methodology, and instead required SWEPCO to use the A&E/4CP methodology.

292. The A&E/4CP method for allocating transmission costs to the retail classes is standard and the most reasonable methodology.

293. SWEPCO should use the A&E/4CP method for allocating transmission costs to the retail classes.

Major Customer Account Representative Expense

294. A major account representative is a utility employee who provides services either to large customers or to national chains.

295. During the test year, SWEPCO (total company) spent $1,082,908 on major account representatives.

296. SWEPCO uses major account representatives to work with 69 large commercial and 68 industrial customers.

297. It is reasonable to allocate major-account-representatives expenses solely to the large commercial and industrial customers who benefit from that service.

298. Major account representative costs should not be assigned to residential and general-service customers who do not receive these services.

299. Allocating the costs of major-account-representatives to the large commercial and industrial customers is consistent with cost-causation principles.

300. Assigning a weighting factor reflecting the 69 large commercial and 68 industrial customers who receive the service is reasonable to properly allocate the costs of the major-account representatives to these classes.

301. Applying a new allocation factor to Account 908 that correctly reallocates major-account-representative costs to the Large Commercial and Industrial Classes is appropriate.

302. Allocating the $369,336 (Texas retail) of major-account-representative expenses to the Large Commercial and Industrial Classes is reasonable.

Uncollectible Expense Allocation

303. Uncollectible expenses are caused by non-paying former customers, and the current customers in a particular class are not the cause of uncollectible expense created by other former members of that class.

304. No paying customer regardless of class contributed more to these costs than any other paying customer.

305. It is reasonable to allocate the uncollectible expenses broadly across all classes based on revenue.

Primary/Secondary Distribution Split for Accounts 364 and 365

306. SWEPCO proposes to allocate costs in FERC Accounts 364 and 365 between the primary and secondary distribution systems based on the "investment method," which splits the cost based on the investment used to provide primary and secondary distribution services.

307. Under the investment method, most poles are directly assigned to primary or secondary service. The number of connections associated with a pole is only taken into account in cases where a pole is shared by primary and secondary distribution facilities.

308. The investment method appropriately takes into account the total investment in the poles, rather than merely the number of poles or length of conductor.

309. The size and length of a pole used in the construction of distribution facilities depends on operational requirements specific to the particular installation involved, without regard to whether primary or secondary distribution facilities are under construction.

310. The investment method is reasonable and should be adopted for purposes of allocating FERC Account 364 and 365 costs between the primary and secondary distribution facilities.

Revenue Distribution and Rate Design

Revenue Distribution

311. Most of the parties to this case agree that some level of gradualism should be employed in the revenue distribution.

312. SWEPCO's proposed approach of grouping major rate classes for purposes of implementing the revenue distribution was approved by the Commission in SWEPCO's most recent base-rate proceeding, Docket No. 40443.

313. SWEPCO's proposed revenue distribution moves all customer classes closer to cost of service, sets larger customer groups of similar size and type at cost of service, and facilitates sustainable migration among customer rates.

314. SWEPCO's proposed gradualism methodology, which reduces the subsidization among individual rate classes, is reasonable and should be adopted, except that a class's present revenues should be evaluated inclusive of existing TCRF and DCRF revenues, which are base-rate related revenues.

314A. Any gradualism methodology should evaluate the differences in the actual rates that customers pay.

Distributed Generation

315. SWEPCO proposes a new distributed-renewable-generation (DRG) tariff under which the company will bill the customer for all electricity supplied by SWEPCO at standard retail rates, and will pay the customer for the electricity supplied to SWEPCO at the company's avoided cost of energy.

316. Under the new offering, SWEPCO's avoided-energy-cost payments to the DRG customer will reflect an average monthly day-ahead SPP market price.

317. In order to mitigate current DRG customer impacts, SWEPCO proposes to "grandfather" current DRG customers so that these already existing customers continue to take service under the current DRG tariff.

318. SWEPCO's proposed new DRG tariff is consistent with Commission rules and should be adopted.

319. [Deleted.]

319A. SWEPCO's proposal to indefinitely grandfather existing DRG customers is not reasonable.

319B. SWEPCO offers service under its qualified-facility (QF) tariff, titled "Purchased Power Service." Net metering is an available option under that tariff for QFs that have a design capacity of 100 kW or less.

Other Rate Design Issues

320. In general, SWEPCO's proposed rate design retains the rate structures and relationships approved by the Commission in the company's last base-rate case, Docket No. 40443. The company's proposed rate design provides a reasonable basis for establishing rates in this proceeding.

Lighting and Power (LP) and Large Lighting and Power (LLP) Rates

321. [Deleted.]

321A. Commission Staff did not sufficiently discuss the need for a new rate for LP transmission level customers that currently does not exist as part of SWEPCO's approved rates. Commission Staff's references to schedules and workpapers are not sufficient to explain why a recommendation to adopt a new rate should be approved.

322. [Deleted.]

323. [Deleted.]

324. Wal-Mart's proposals regarding adjustment of the LP demand charge and LP minimum charge are inadequately supported by evaluation of customer impact, and internally inconsistent.

325. SWEPCO's proposed rate design for LP and LLP customers is reasonable and should be adopted.

326. TIEC has withdrawn, for purposes of this proceeding, its proposal to create a separate demand charge for LLP primary substation customers.

Metal Melting Primary and Secondary Rates

327. [Deleted.]

327A. Commission Staff did not support its Metal Melting secondary and primary rate proposal with sufficient evidence. In particular, Commission Staff failed to adequately explain why its proposal was superior to SWEPCO's filed rate design with respect to these rates.

328. SWEPCO's proposed rate design for Metal Melting secondary and primary customers is reasonable and should be adopted.

General Service Rates

329. SWEPCO's proposed general-service rate design is reasonable and should be adopted.

Electric Furnace, US Steel, and Cotton Gin Light and Power Rates

330. It is reasonable to set the rates for these three schedules, to the extent possible, on the basis of the rate schedule under which those customers took service during the test year.

Winter Declining Block Rates

331. OPUC's proposal to reduce the differential between the winter declining block energy rates by 20% moves residential customers further away from cost of service, is contrary to cost-causation principles, and should not be adopted.

332. The current differential in the declining block energy rates of $0.0098 is closer to cost of service and should remain in place.

TCRF and DCRF Issues

Baseline Values

333. Commission Staff's methodology for establishing TCRF and DCRF baselines should be adopted.

334. The baselines consistent with the baselines adopted by the Commission in SPS Docket No. 43695, while incorporating additional adjustments to baseline ad-valorem-tax and margins-tax values that reflect the elements of the distribution and transmission systems that are eligible for recovery through the TCRF and DCRF rules.

335. Baseline values for all of the variables required by the TCRF and DCRF rules are present in Commission Staff's proposed baselines.

336. Commission Staff's proposed DCRF and TCRF baselines should be adopted.

Refund of Over-Recovered Amounts of TCRF Revenues

337. Since the conclusion of SWEPCO's most recent base-rate case, the Commission has approved three separate TCRF riders for SWEPCO, in Docket Nos. 45691, 44496, and 42448.

338. In SWEPCO's most recent TCRF proceeding, the Commission directed that the instant proceeding address whether SWEPCO should refund to its customers the $269,185 of over-collected TCRF revenues.

339. The Commission may not allow a utility to over-recover costs using the TCRF mechanism.

340. The Commission's rules provide for truing-up and refunding over-collected TCRF revenues.

341. SWEPCO should be required to refund the identified TCRF over-collection to customers.

342. The refund of TCRF over-collections should be allocated based on the class allocation used in Docket No. 45691.

Other Issues

343. The business of the AEPSC Commercial Operations Group, led by an AEP Senior Vice President, is to coordinate the dispatch of AEP's generation fleet, including that of

SWEPCO, to economically supply customers' native load requirements in the least-cost manner and to produce off-system sales margins to help lower customer rates.

344. Since the launch of the SPP integrated marketplace (IM) on March 1, 2014, the Day-Ahead Operations group within Commercial Operations has existed to manage the new complexities and responsibilities resulting from the launch of SPP's day-two market. These employees are also responsible for safely and reliably optimizing the generation fleet by assessing unit status and capability, economically scheduling curtailments and outages, and providing technical analysis regarding unit commitment decisions to various groups within Commercial Operations.

345. SWEPCO generation is bid into the SPP IM based on "offer curves" that represent the incremental cost of dispatching generation at any given point of dispatch. Offer curves quantify the cost in dollars to generate the next MWh for an online generating unit at a given operating point.

346. The evidence establishes that SWEPCO has correctly bid its coal units into the SPP IM based on the incremental costs of the units and has realized revenues in excess of the associated incremental costs from the SPP IM.

<u>Change to Corporate Federal-Income-Tax Expense</u>

346A. It is appropriate for the Commission's order to address changes to SWEPCO's corporate federal-income-tax expense.

346B. It is appropriate for the Commission to require SWEPCO to record, as a regulatory liability, taking into account changes in billing determinants, the difference between (a) the amount of federal-income-tax expense that SWEPCO 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.

III. Conclusions of Law

1. SWEPCO is subject to the Public Utility Regulatory Act (PURA). Tex. Util. Code §§ 11.001-58.302 (West 2016 & Supp. 2017), §§ 59.001-66.016 (West 2007 & Supp. 2017).

2. SWEPCO 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)

3. The Commission exercises regulatory authority over SWEPCO, and jurisdiction over the subject matter of this application under PURA §§ 14.001, 32.001, 32.101, 33.002, 33.051, and 36.001-.112.

3A. The Commission's jurisdiction to establish rates extends beyond the date a proposed rate is suspended. PURA §§ 36.003-.004, 36.051-.065, 36.108(c), and 36.111.

4. SOAH has jurisdiction over matters related to the conduct of the hearing and the preparation of a proposal for decision in this docket, under PURA § 14.053 and Tex. Gov't. Code § 2003.049.

5. This docket was processed in accordance with the requirements of PURA and the Texas Administrative Procedure Act, Texas Government Code chapter 2001.

6. SWEPCO provided notice of its application in compliance with PURA § 36.103 and 16 Texas Administrative Code (TAC) § 22.51(a).

7. Under PURA § 33.001, each municipality in SWEPCO's service area that has not ceded jurisdiction to the Commission has jurisdiction over the company's application, which seeks to change rates for the distribution services within each municipality.

8. Pursuant to PURA § 33.051, the Commission has jurisdiction over an appeal from a municipality's rate proceeding.

9. SWEPCO has the burden of proving that the rate change it is requesting is just and reasonable under PURA § 36.006.

9A. The applicant has the burden of proof under PURA § 36.006 to demonstrate the reasonableness of its rates and rate design in a rate case. However, the burden of production shifts when another party proposes a change to the application. It is then incumbent on the challenging party to produce credible evidence that its proposal is more reasonable than the applicant's.

10. In compliance with PURA § 36.051, SWEPCO's overall revenues approved in this proceeding permit SWEPCO a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses.

11. Consistent with PURA § 36.053, the rates approved in this proceeding are based on original cost, less depreciation, of property used and useful to SWEPCO in providing service.

12. The rates approved in this proceeding are consistent with 16 TAC § 25.231(b)(1)(B), which states that depreciation expense based on original cost and computed on a straight-line basis as approved by the Commission shall be used; it also provides that other methods may be used when the Commission determines such depreciation methodology is a more equitable means of recovering the costs of plant.

13. The rates approved in this proceeding are consistent with 16 TAC § 25.231(c)(2)(A)(ii), which states that the reserve for depreciation is the accumulation of recognized allocations of original cost, representing the recovery of initial investment over the estimated useful life of the asset.

14. The return on equity (ROE) and overall rate of return authorized in this proceeding are consistent with the requirements of PURA §§ 36.051 and 36.052.

15. Prudence is the exercise of that 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. *Gulf States Utilities Company v. Public Utility Commission of Texas*, 841 S.W.2d 459, 475 (Tex. App—Austin 1992, writ denied).

16. There may be more than one prudent option within the range available to a utility in a given context. Any choice within the select range of reasonable options is prudent, and the Commission should not substitute its judgment for that of the utility. The reasonableness of an action or decision must be judged in light of the circumstances, information, and

available options existing at the time, without benefit of hindsight. *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Order on Rehearing at 5 (citing *Nucor Steel v. Public Utility Commission of Texas*, 26 S.W.3d 742, 752 (Tex. App.—Austin 2000, pet. denied)).

17. A utility may demonstrate the prudence of its decision-making through contemporaneous evidence. Alternatively, the utility may obtain an independent, retrospective analysis that demonstrates 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 be a reasonably prudent course. *Gulf States*, 841 S.W.2d at 476.

18. SWEPCO prudently determined to implement the environmental-compliance retrofits at its Dolet Hills, Flint Creek, Pirkey, and Welsh units 1 and 3 generating facilities.

19. SWEPCO prudently determined to retire Welsh unit 2.

20. It was prudent for SWEPCO to enter into the Sierra Club settlement.

21. The Supreme Court of Texas has held that "the Commission possesses the authority to authorize deferred accounting treatment," but "this authority is not unfettered." The Commission's discretion to use deferred accounting to alleviate regulatory lag is limited to when it is "necessary to carry out the provisions of PURA." *Office of Pub. Util. Counsel v. Public Util. Comm'n of Texas*, 888 S.W.2d 804, 808 (Tex. 1994) (citing *State v. Pub. Util. Comm'n of Texas*, 883 S.W.2d 190, 196 (Tex. 1994)).

22. Investor-owned utilities may include in rate base a reasonable allowance for cash working capital as determined by a lead-lag study conducted in accordance with 16 TAC § 25.231(c)(2)(B)(iii)(IV).

23. The lead-lag study conducted by SWEPCO considered the actual operations of SWEPCO, adjusted for known and measurable changes, and is consistent with 16 TAC § 25.231(c)(2)(B)(iii).

24. Crediting distributed-renewable-generation (DRG) outflows at the avoided cost of energy is consistent with the requirements of 16 TAC § 25.217(e)(1) and (f)(1).

25. The Commission may not allow a utility to over-recover costs using the transmission-cost recovery factor (TCRF) mechanism.

26. The Commission's rules provide for truing-up and refunding over-collected TCRF revenues.

27. The ROE and overall rate of return authorized in this proceeding are consistent with the requirements of PURA §§ 36.051 and 36.052.

28. Affiliate expenses to be included in SWEPCO's rates must meet the standards articulated in PURA §§ 36.051 and 36.058 and in *Railroad Commission of Texas v. Rio Grande Valley Gas Co.*, 683 S.W.2d 783 (Tex. App.—Austin 1984, no writ).

29. Utilities seeking recovery or municipalities seeking reimbursement of rate-case expenses have the burden to prove the reasonableness of such expenses by a preponderance of the evidence to include those amounts in customers' rates.

29A. The other expenses associated with Docket No. 45712 in the amount of $161,025 are rate-case expenses. They are not recoverable in this proceeding because SWEPCO agreed in its settlement of Docket No. 45712 not to seek recovery of rate-case expenses associated with that proceeding.

30. The costs SWEPCO is seeking to recover are for participating in proceedings under PURA and are, therefore, recoverable pursuant to PURA § 36.061(b).

31. SWEPCO's rates, as approved in this proceeding, are just and reasonable in accordance with PURA § 36.003.

IV. Ordering Paragraphs

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

1. The proposal for decision prepared by the SOAH administrative law judges is adopted to the extent consistent with this order.

2. SWEPCO's application is granted to the extent consistent with this order.

3. The transmission-cost-recovery-factor and the distribution-cost-recovery-factor baseline values as requested by SWEPCO shall be developed and set during the compliance phase of this docket in *Compliance Tariff for Final Order in Docket No. 46449 (Application of Southwestern Electric Power Company for Authority to Change Rates)*, Control No. 47929.

4. SWEPCO shall establish a regulatory-asset account in which the remaining undepreciated balance of Welsh unit 2 shall be debited.

5. SWEPCO 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 SWEPCO 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 SWEPCO became effective or (ii) the date on which the tax-rate reduction became effective until (b) the refund tariff described below becomes effective.

6. SWEPCO will file a refund tariff with the Commission and municipal regulatory authorities within 120 days after this order is signed 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 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 the rates approved in this proceeding were established.

7. In each subsequent year, SWEPCO 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 income-tax calculation reflected on Attachment A, Schedule VI to the number run performed by Commission Staff on December 20, 2017. 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 next base-rate case.

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

9. 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.

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

11. SWEPCO shall file tariffs consistent with this order within 20 days of the date of this order in *Compliance Tariff for Final Order in Docket No. 46449 (Application of Southwestern Electric Power Company for Authority to Change Rates)*, Control No. 47929. No later than ten days after the date of the tariff filings, Staff shall file its comments recommending approval, modification, or rejection of the individual sheets of the tariff proposal. Responses to Commission Staff's recommendation shall be filed no later than 15 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.

12. The 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 sheets are modified or rejected, SWEPCO shall file proposed revisions of those sheets in accordance with the Commission's letter within ten days of the date of that letter, and the review procedure set out above shall apply to the revised sheets.

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

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

Signed at Austin, Texas the 19th day of March 2018.

PUBLIC UTILITY COMMISSION OF TEXAS

DeAnn T. Walker

DEANN T. WALKER, CHAIRMAN

BRANDY MARTY MARQUEZ, COMMISSIONER

ARTHUR C. D'ANDREA, COMMISSIONER

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