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APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

SOUTHWESTERN ELECTRIC POWER COMPANY'S INITIAL BRIEF

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SOUTHWESTERN ELECTRIC POWER COMPANY'S INITIAL BRIEF

Southwestern Electric Power Company (SWEPCO or the Company) submits its initial brief in this proceeding.

I. Introduction/Summary

SWEPCO's actual return on equity since the Commission last adjusted SWEPCO's base rates in Docket No. 46449 has been below market requirements and the return authorized by the Commission in that case. SWEPCO's load growth has not been such that it allows revenues to keep pace with costs, despite significant cost control efforts.[1] The cost drivers of this case are multifaceted and are addressed individually below.

II. Invested Capital - Rate Base

A. Generation, Transmission, and Distribution Capital Investment

As discussed below, the prudence of SWEPCO's transmission and distribution capital investment is uncontested. Further, no specific generation capital project has been contested, but more general issues regarding SWEPCO's generation investment have been raised and are addressed below.

SWEPCO has invested approximately $636.7 million in its transmission system since the end of the test year (June 30, 2016) in its last base rate case, Docket No. 46449.[2] In his direct testimony, SWEPCO witness Wayman L. Smith describes SWEPCO's transmission capital additions, discusses the American Electric Power Company, Inc. (AEP) and SWEPCO transmission systems, and explains how SWEPCO's transmission system is planned and operated.[3] Mr. Smith describes the major categories of transmission capital additions – Asset Improvements, Customer Service, Reliability, and Regional Transmission Organization (RTO) – and provides

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1 Direct Testimony of A. Malcolm Smoak, SWEPCO Ex. 3 at 4:19-5:1.

2 Direct Testimony of Wayman L. Smith, SWEPCO Ex. 12 at 10:23-24.

3 SWEPCO Ex. 12 at 3:4-13:2.

examples of each.[4]

Mr. Smith also describes the processes in place to keep the cost of transmission projects reasonable, including best engineering practices, competitive bidding, and estimating and budgeting processes.[5] These same processes ensure that affiliate charges to transmission capital investment are reasonable.[6]

It is undisputed that SWEPCO's transmission capital investment since its last base rate case funded facilities that are used and useful in providing service to the public. No party has challenged the prudence of this investment. Therefore, the Commission should approve as prudent the Company's requested transmission plant balance.

Between July 1, 2016, and March 31, 2020, SWEPCO invested approximately $143.5 million in distribution capital additions for which it seeks a prudence determination in this case.[7] In his direct testimony, SWEPCO witness Drew W. Seidel describes SWEPCO's distribution capital additions and discusses the budgeting, estimating, outsourcing, planning, contracting, materials acquisition, and cost review processes that SWEPCO employs to ensure that the costs associated with distribution capital projects are reasonable.[8] In particular, his testimony demonstrates the following:

- SWEPCO and American Electric Power Service Corporation (AEPSC) employ ongoing rigorous internal budgeting and cost control processes to ensure costs are kept to the minimum reasonable level.[9]
- SWEPCO keeps the cost of distribution projects reasonable through proper control of project scope, and efficient engineering, procurement, and construction practices.[10]
- Labor contracts for distribution capital projects are competitively bid on a routine basis.[11]

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4 SWEPCO Ex. 12 at 10:5-23:16.

5 SWEPCO Ex. 12 at 23:17-25:4.

6 SWEPCO Ex. 12 at 26:5-17.

7 Direct Testimony of Drew W. Seidel, SWEPCO Ex. 10 at 34:15-19.

8 SWEPCO Ex. 10 at 34:15-37:5.

9 SWEPCO Ex. 10 at 23:14-18.

10 SWEPCO Ex. 10 at 24:10-25:10.

11 SWEPCO Ex. 10 at 26:10-27:4.

- SWEPCO's average distribution capital expenditures for the years 2017-2019 were less than the Texas and South Central peer groups' median cost per line mile.[12]
- Project managers oversee and monitor expenditures during construction to ensure that the costs are reasonable and the project scope is achieved.[13]

It is undisputed that the distribution capital investment for which SWEPCO seeks a prudence determination funded facilities that are used and useful in providing service to the public. No party has challenged the prudence of this investment. Therefore, the Commission should approve as prudent the Company's requested distribution plant balance.

Both AEPSC and SWEPCO regularly review capital projects that could provide economic, environmental, reliability, or safety-related benefits for SWEPCO's generating fleet. The first step in any capital addition evaluation is to research alternatives that may exist, and when warranted to perform cost-benefit analyses to estimate a project's value. Once the need for a capital project is determined, the most efficient way to manage the project is selected. This can mean that a project is expedited, or sole-sourced if there is a lack of competition for a given piece of equipment or service. However, typical practice is to competitively bid capital projects to ensure that a fair market price is paid for the good or service. After a competitive bid is accepted, contracts are finalized and the project is executed.[14]

Once work on a large capital project begins, SWEPCO benefits from the Project Controls & Construction and Engineering Services organization within AEPSC because this group has vast experience in the execution and management of large projects, which helps contain and control costs as they are incurred by the project. If the project is smaller, it may be managed either by the Engineering Services organization within AEPSC or by SWEPCO's regional engineering group, depending on the total overall cost, scope, and complexity of the project. As a project is being executed, this structure maximizes efficiency while minimizing administrative costs to the greatest extent possible. A small project that may be effectively managed by one person at the regional level will be performed as such. However, for those large capital projects that require oversight and control from various groups and disciplines, the Project Controls & Construction and Engineering Services organizations can control cost and schedule when it is not practical for

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12 SWEPCO Ex. 10 at Exhibits DWS-3 and DWS-4.

13 SWEPCO Ex. 10 at 36:16-18.

14 Direct Testimony of Monte McMahon, SWEPCO Ex. 7 at 17:11-24.

SWEPCO to do so directly.[15]

Rate Filing Package Schedule H-5.2b contains a comprehensive list of capital additions placed in service before the conclusion of the Test Year that SWEPCO has made to its plants, including the total cost and the in-service date for all capital work orders greater than $100,000.[16] No party challenged the prudence of any individual generation capital project. However, SWEPCO has added subsections 3 and 4 below to the briefing outline to address Sierra Club's allegations related to the Flint Creek and Welsh generation plants and CARD's allegation regarding coal and lignite inventories.

1. Dolet Hills Power Station

The Dolet Hills Power Station (Dolet Hills plant) is located southeast of Mansfield, Louisiana and is a 650 net MW lignite fueled generating plant. Lignite for the Dolet Hills plant is mined from the adjacent Dolet Hills and the Oxbow reserves (collectively referred to as DH Mines). The Dolet Hills plant is owned by Cleco Power, LLC (CLECO), SWEPCO, Northeast Texas Electric Cooperative, Inc. (NTEC), and Oklahoma Municipal Power Authority. SWEPCO's ownership interest is 262 MW or 40.234% of the unit's total capacity. CLECO operates and manages the Dolet Hills plant pursuant to the Dolet Hills Power Station Ownership, Construction and Operating Agreement between CLECO and SWEPCO, effective November 13, 1981.[17]

In May 2020, lignite production operations at the DH Mines ceased based on SWEPCO's and CLECO's determination that all economically recoverable lignite had been depleted. Despite diligent efforts to reduce mining costs, SWEPCO and CLECO determined that mining activities should cease and the plant should be retired by the end of 2021. SWEPCO and CLECO evaluated mining operations and costs of operating the Dolet Hills plant beyond 2021. That analysis, which is included in the workpapers to the direct testimony of SWEPCO Vice President of Regulatory and Finance, Thomas Brice, demonstrates that retirement of the Dolet Hills plant is expected to result in savings for customers.[18] Specifically, SWEPCO studied the expected total SWEPCO system cost to serve customers under the scenario where the Dolet Hills plant continues to serve

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[15] SWEPCO Ex. 7 at 18:1-13.

[16] SWEPCO Ex. 7 at 19:26-28.

[17] Direct Testimony of Thomas P. Brice, SWEPCO Ex. 4 at 5:17-6:4.

[18] SWEPCO Ex. 4 at 6:7-12.

customers through 2026 and the scenario where the Dolet Hills plant is retired by December 31, 2021. That study demonstrates that the expected least cost path for SWEPCO and its customers lies in retirement of the Dolet Hills plant.[19]

The Commission has provided the Administrative Law Judges (ALJs) with a Preliminary Order in this proceeding that identifies a list of issues or areas that must be addressed.[20] The 67th Preliminary Order issue to be addressed is the question, "Is SWEPCO's decision to retire the Dolet Hills Power Station no later than December 31, 2021 prudent?" The prudence of that decision is supported by Mr. Brice's direct and rebuttal testimonies and workpapers.[21] No party has challenged the prudence of that decision.

a. As an operating plant, the Commission's Cost of Service rule requires that the Dolet Hills plant remain in rate base

During 2021 seasonal operation, the Dolet Hills plant is planned to run during the peak summer months when the plant typically is most needed by SWEPCO's customers. Even at other times outside of seasonal operation, the plant remains available if called upon by SWEPCO's and CLECO's respective RTOs for reliability reasons.[22] Until its retirement at the end of 2021, the Dolet Hills plant will continue to be offered into the energy market year round, incurring expenses required to ensure the unit is available to operate when called upon by the Southwest Power Pool (SPP).[23]

Pursuant to the Commission's Cost of Service rule, rates are to be based upon a utility's cost of rendering service to the public during a historical test year, adjusted for known and measurable changes.[24] The utility's invested capital used to provide service to customers (referred to as "rate base" in the Cost of Service rule) is also measured at the end of the test year. The Cost of Service rule allows post test year adjustments to test year rate base, but only when very specific criteria are met. 16 Tex. Admin. Code (TAC) § 25.231(c)(2)(F)(i) sets out the requirements for a

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[19] Rebuttal Testimony of Thomas P. Brice, SWEPCO Ex. 33 at 6:8-15.

[20] Tex. Gov't. Code Ann, § 2003.049(e) ("At the time the office receives jurisdiction of a proceeding, the commission shall provide to the administrative law judge a list of issues or areas that must be addressed.").

[21] SWEPCO Ex. 4; Workpapers to the Direct Testimony of Thomas P. Brice, SWEPCO Ex. 4A; and SWEPCO Ex. 33.

[22] SWEPCO Ex. 33 at 6:20-7:1.

[23] Rebuttal Testimony of Monte McMahon, SWEPCO Ex. 37 at 2:3-6.

[24] 16 Tex. Admin. Code (TAC) § 25.231(a).

post test year adjustment to test year data for rate base additions. 16 TAC § 25.231(c)(2)(F)(iii) sets out the requirements for a post test year adjustment to test year data for rate base decreases. While the rule provides an additional hurdle for a post test year rate base addition (i.e., addition comprises at least 10% of the utility's requested rate base), both sections contain the same temporal component – the plant in question must be in service (additions) or removed from service (decreases) prior to the Rate Year.[25]

The term Rate Year is defined in the Commission's rules as the 12-month period beginning with the first date that rates become effective.[26] By law, the final rate set in this proceeding is effective for energy consumption on and after the 155th day after the date SWEPCO's RFP was filed.[27] In this case, that effective date is March 18, 2021. The Dolet Hills plant was providing service to customers during the Test Year and prior to the Rate Year and will continue to provide service through the end of 2021.[28] Because the Dolet Hills plant was still in service prior to the Rate Year, by the terms of the Cost of Service rule, it remains in SWEPCO's rate base for the purpose of setting rates in this proceeding.

The fact is a utility's rate base continually changes – existing investment is depreciated over time, investment is retired, and investment is added. If the Commission is going to use actual historical investment to set rates, a line must be drawn after which the Commission will no longer allow post test year adjustments to test year investment. The Commission has drawn that line with the date that the new rates become effective – the beginning of the Rate Year.[29] SWEPCO's invested capital in the Dolet Hills plant cannot be removed from SWEPCO's rate base used to set rates in this proceeding consistent with the requirements of the Cost of Service rule.

Texas Industrial Energy Consumers (TIEC) witness Ms. LaConte describes the Commission's choice on Dolet Hills ratemaking as an either/or choice: "The base rates to be approved in this proceeding should either be based on the assumption that (1) Dolet Hills is an

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[25] 16 TAC § 25.231(c)(2)(F)(i)(III) and (iii)(II).

[26] 16 TAC § 25.5(101).

[27] Public Utility Regulatory Act (PURA), Tex. Util. Code Ann. § 36.211(b).

[28] SWEPCO has now provided notice to SPP that the Dolet Hills plant will retire at the conclusion of December 31, 2021.

[29] SWEPCO Ex. 33 at 9:3-12.

operational plant or (2) Dolet Hills has been retired."[30] The answer to this simple question is that the rates in this proceeding must be set based on the fact that the Dolet Hills plant is an operational plant properly included in SWEPCO's rate base that will be used to set those rates.

This aspect of the Cost of Service rule is equally applicable to Cities Advocating Reasonable Deregulation (CARD) witness Mr. Scott Norwood's recommendation to remove from rate base SWEPCO's investment in Dolet Hills plant fuel inventory. That fuel inventory remains an integral part of SWEPCO's invested capital providing service to customers. SWEPCO is required to maintain a reliable fuel supply for all of its plants, including Dolet Hills. The 45-day inventory target approved by the Commission in SWEPCO's previous rate case, Docket No. 46449, continues to be prudent for operating the Dolet Hills plant. The Dolet Hills plant must be available for seasonal burn and RTO reliability throughout 2021 in SPP for SWEPCO, and in the Midcontinent Independent System Operator (MISO) market for CLECO.[31] Being available requires an adequate amount of fuel inventory. That fuel inventory was a part of SWEPCO's rate base at the end of the Test Year and when the rates to be approved in this case became effective. In fact, as of mid-April 2021, SWEPCO had over 60 days of full load inventory at the Dolet Hills plant for reliability and in preparation for the 2021 summer seasonal period.[32] From a dollar perspective, as of March 2021, SWEPCO had $109 million of fuel inventory on its books for the Dolet Hills plant.[33]

This same analysis applies to Commission Staff witness Ms. Ruth Stark's and Office of Public Utility Counsel (OPUC) witness Ms. Constance Cannady's recommendation to remove the Oxbow Mine Reserves associated with the Dolet Hills plant and Ms. Cannady's recommendation to remove SWEPCO's investment in the Dolet Hills Lignite Company (DHLC) from rate base. SWEPCO's investment in the Oxbow reserves are a part of SWEPCO's Test Year rate base and, as of March 2021, SWEPCO had $7.3 million in investment on its books, when the rates to be set in this proceeding became effective.[34] And DHLC continues to deliver lignite to the Dolet Hills

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[30] Direct Testimony of Billie LaConte, TIEC Ex. 4 at 9:1-3 (using the page number in the upper right hand corner of the page).

[31] Rebuttal Testimony of Mark Leskowitz, SWEPCO Ex. 49 at 6:10-7:1.

[32] SWEPCO Ex. 49 at 6:20-21.

[33] Rebuttal Testimony of Michael Baird, SWEPCO Ex. 36 at 19:3-5.

[34] SWEPCO Ex. 36 at 21:22-22:1.

plant.[35] These investments cannot be removed from the rate base used to set rates in this proceeding consistent with the Cost of Service rule.

b. Attempts to remove the Dolet Hills plant from rate base with alternative rate mechanisms are contrary to the Cost of Service rule, ignore the realities of ratemaking, and are unfair

The recommendation of CARD witness Mr. Mark Garrett and others essentially is to pull SWEPCO's investment in the Dolet Hills plant from rate base after its retirement, after rates have been set in this proceeding. Such recommendations, whether termed as putting SWEPCO's Dolet Hills investment into a rate rider that will expire or setting up a regulatory liability to capture post-retirement revenue collection or a regulatory asset to capture pre-retirement incurred costs, are contrary to the plain language of the Cost of Service rule and amount to an attempt to create a new type of post test year adjustment to rate base under that rule. For example, at hearing Staff witness Ms. Stark conceded that it was her proposal to remove the undepreciated value of the Dolet Hills plant from SWEPCO's rate base but that the "effect" of her proposal was to remove that investment from rate base as of December 31, 2021, well beyond the beginning of the Rate Year in this proceeding.[36]

Further, while these parties advocate for the removal of SWEPCO's investment in the Dolet Hills plant from rate base after its retirement, these parties do not recommend an increase to SWEPCO's rate base for investment placed in service from the end of the Test Year on March 31, 2020 through the date of the Dolet Hills plant retirement at the end of 2021. In other words these parties want to remove SWEPCO's invested capital in the Dolet Hills plant at the time of its retirement, but ignore all other capital placed in service in the 21 months that will have passed since the end of the Test Year. As mentioned above, the fact is a utility's rate base is continually changing with retirements, depreciation, and additions. In the considerable experience of SWEPCO witness Thomas Brice, rate base tends to increase over time, not decrease. In fact, since the end of the Test Year (March 31, 2020) through March 31, 2021, SWEPCO's gross plant has increased by $244 million while its net plant has increased by $88 million.[37] These increases in

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[35] SWEPCO Ex. 36 at 22:10-18.

[36] Tr. at 407:20-408:15 (Stark Cross) (May 20, 2021) ("Yes, I did remove it from rate base, but the effect of removing it at December 31st.").

[37] SWEPCO Ex. 36 at 17:10-12.

gross and net plant are reflective of increased investments at a point in time nine months before the Dolet Hills plant will be retired and will continue to increase through the time the Dolet Hills plant is retired. To remove costs associated with the Dolet Hills plant from rates after its retirement and well after the rates in this proceeding became effective without accounting for additional investment placed into service through that same date is asymmetrical and will not afford SWEPCO an opportunity to earn a reasonable return on its capital invested to serve customers, as is required by law.[38]

Staff witness Ms. Stark alleges that, if Dolet Hills costs, both invested capital and operations and maintenance (O&M) expense, are not removed from SWEPCO's cost of service, customers will be paying for a plant that will not be providing service to those customers. This allegation ignores the reality of ratemaking. As recognized by the United States Supreme Court, "Customers pay for service, not for the property used to render it."[39] This reality is demonstrated by the rate history of the Dolet Hills plant itself. The Dolet Hills plant began providing service to customers 35 years ago, in 1986. However, SWEPCO filed no request to adjust its base rates in Texas until many years later. The Commission did not place SWEPCO's investment in the Dolet Hills plant or the O&M expenses to operate the plant into rates until 2010, in Docket No. 37364. In other words, the Dolet Hills plant provided service to Texas customers for 25 years before SWEPCO's investment in the plant and the non-fuel expenses associated with it were placed in Texas rates.[40] During this time, customers were not being provided service for free. After the retirement of the Dolet Hills plant, customers will not be paying for a plant that is not providing service any more than customers received service for free from the Dolet Hills plant during its first 25 years of service. Customers do not pay for individual investments made to provide service to them – the utility does. Instead, customers pay for service at rates set by the Commission that will allow the utility an opportunity to earn a reasonable return on its investments made to provide service.[41]

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[38] SWEPCO Ex. 33 at 10:7-20.

[39] *Board of Pub. Util Comm'n v. New York Tel Co*, 271 U.S. 23, 32 (1926), *see also Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs,* Docket No. 40443, Proposal for Decision (PFD) at 67 ("a ratepayer pays for services and does not make contributions to or acquire an interest in a utility's assets or liabilities") (May 20, 2013).

[40] SWEPCO Ex. 33 at 5:20-6:7.

[41] SWEPCO Ex. 33 at 11:5-11.

The implication of Ms. Stark's allegation and the recommendations of the intervenor witnesses is that the cost of providing service to customers will be less at the end of 2021, when the Dolet Hills plant will retire, than the cost of providing service to customers during the Test Year. There is simply no evidence that this will be the case.

c. SWEPCO's Excess Accumulated Deferred Federal Income Tax (Excess ADFIT) offset proposal mitigates the customer impact that results from the application of the Cost of Service rule

Generally accepted accounting principles (GAAP) and standard regulatory practice call for the remaining undepreciated value of Dolet Hills to be depreciated through 2021. In fact, this is required by the Commission's Cost of Service rule, which requires that a rate base asset be depreciated over the estimated useful life of the asset.[42] At hearing, the former Chief Accountant for the Federal Energy Regulatory Commission (FERC), Steven Hunt, testified that GAAP, the FERC Uniform System of Accounts (USofA), and the Texas Cost of Service rule all require that an asset be depreciated over the service life of that asset.[43] SWEPCO realizes that depreciating the Dolet Hills plant over its end of 2021 service life for ratemaking purposes would have a significant impact on SWEPCO's base rates that are to be set in this proceeding.[44] For that reason, SWEPCO proposes to offset the undepreciated value of the Dolet Hills plant (an asset) with Excess ADFIT (a liability).

When the United States Congress reduced the federal corporate income tax rate to 21% in 2018, an excess of ADFIT was created for SWEPCO. In SWEPCO's previous general base rate case, Docket No. 46449, the Commission ordered that excess deferred taxes resulting from the reduction in the federal income tax rate be addressed in SWEPCO's next base-rate case.[45] SWEPCO proposes that the balance of the unprotected Excess ADFIT and the refund provision associated with the protected Excess ADFIT be used to offset the undepreciated value of Dolet Hills.[46]

SWEPCO's Excess ADFIT offset proposal is consistent with both PURA and the Cost of

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[42] 16 TAC § 25.231(c)(2)(A)(ii).

[43] Tr. at 307:2-310:15 (Hunt Cross) (May 20, 2021).

[44] SWEPCO Ex. 4 at 7:3-11.

[45] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Order on Rehearing at Ordering Paragraph No. 10 (Mar. 19, 2018).

[46] SWEPCO Ex. 4 at 7:12-8:1.

Service rule. Under the Cost of Service rule, ADFIT is expressly recognized as a deduction (offset) to invested capital.[47] While ADFIT has always been an offset to invested capital in the Cost of Service rule, in this case SWEPCO proposes to use its Excess ADFIT to offset a specific item of invested capital – SWEPCO's undepreciated capital invested in the Dolet Hills plant. SWEPCO makes this proposal to mitigate the rate impact produced by the change in the service life of the Dolet Hills plant that is required by the Cost of Service rule and consistent with GAAP and the FERC USofA. From a layman's perspective, SWEPCO's proposal to offset the recovery of its Dolet Hills investment from customers with the Excess ADFIT simply balances an investment prudently incurred to provide service to customers with the Excess ADFIT legitimately returnable to customers.[48]

The Commission has allowed a similar Excess ADFIT offset in the context of a storm restoration regulatory asset, thus reducing the amount of the restoration regulatory asset recoverable from customers. For instance, the signatories to the settlement in Docket No. 48577 agreed to offset AEP Texas' catastrophe reserve regulatory asset with unprotected Excess ADFIT. While the Commission's Order in Docket No. 48577 does not constitute binding precedent, the Commission did expressly find that "[t]he Settlement Agreement's treatment of ADFIT is appropriate."[49] While the asset in Docket No. 48577 might be different, this finding is an indication that the Commission is open to using Excess ADFIT as a means to reduce the cost of an asset includable in customer rates and that such an offset is consistent with PURA.[50]

SWEPCO's Excess ADFIT offset proposal explicitly reduces the amount of Dolet Hills plant invested capital includable in rate base, which is a direct benefit to customers today. This fact was not acknowledged by the Staff and intervenor witnesses addressing the proposal. Should the Commission decide to order a refund of the Excess ADFIT in lieu of SWEPCO's offset proposal, then SWEPCO's Texas Retail rate base will need to be increased by approximately

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[47] 16 TAC § 25.231(c)(2)(C)(i). While the reduction in the corporate tax converted a portion of ADFIT into Excess ADFIT, until refunded, that Excess ADFIT is a regulatory liability that would offset rate base.

[48] SWEPCO Ex. 33 at 16:3-12.

[49] *Application of AEP Texas, Inc. for Determination of System Restoration Costs*, Docket No. 48577, Order at Finding of Fact (FoF) No. 54 (Feb. 28, 2019).

[50] SWEPCO Ex. 36 at 6:21-7:7.

$39 million.[51]

d. SWEPCO offers to further mitigate the customer impact that results from the application of the Cost of Service rule

The amount of unprotected Excess ADFIT and the protected Excess ADFIT refund provision will not completely offset the Dolet Hills plant's undepreciated value.[52] After the Excess ADFIT offset, SWEPCO proposes to expense the remaining value of SWEPCO's investment in the Dolet Hills plant over four years, the anticipated period between rate cases.[53] As detailed on Exhibit MAB-2R to the rebuttal testimony of SWEPCO witness Mr. Michael Baird, the remaining net book value of the Dolet Hills plant after the Excess ADFIT offset is $11.5 million total company or $6.4 million on a Texas retail basis. The annual amortization expense is $1.6 million on a Texas retail basis.[54] Absent this additional mitigation proposal, the $6.4 million of remaining net book value would be depreciated over the service life of the Dolet Hills plant through the end of 2021.

2. Retired Gas-Fired Generating Units

In January 2019 SWEPCO retired Knox Lee Unit 4. Additionally, in May 2020 the Company retired Knox Lee Units 2 and 3, Lieberman Unit 2, and Lone Star Unit 1. In deciding to retire these four units, the Company considered the age and condition of the units' equipment, the significant capital investment required for them to continue operating, and their relatively high cost to generate electricity. In light of those considerations, SWEPCO determined it was in the best interest of its customers to retire the generating units. A brief description of each unit is as follows:

- Knox Lee Unit 2 entered service in 1950. During its 70-year useful life, this small generating unit provided peaking capacity services. The expected retirement date provided in the Company's most recent base rate case for Knox Lee Unit 2 was 2020.
- Knox Lee Unit 3 entered service in 1952. During its 68-year useful life, this small generating unit provided peaking capacity services. The expected retirement date provided in the Company's most recent base rate case for Knox Lee Unit 3 was 2020.

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51 SWEPCO Ex. 36 at 14:11-19.

52 SWEPCO Ex. 4 at 7:13-8:7.

53 Direct Testimony of Michael Baird, SWEPCO Ex. 6 at 49:15-18.

54 SWEPCO Ex. 36 at 5:19-6:3.

- Knox Lee Unit 4 entered service in 1956. During its 64-year useful life, this generating unit provided peaking capacity services. The expected retirement date provided in the Company's most recent base rate case for Knox Lee Unit 4 was 2019.
- Lieberman Unit 2 entered service in 1949. During its 71-year useful life, this small generating unit provided peaking capacity services. The expected retirement date provided in the Company's most recent base rate case for Lieberman Unit 2 was 2019.
- Lone Star Unit 1 entered service in 1954. During its 66-year useful life, this small generating unit provided peaking capacity services. The expected retirement date provided in the Company's most recent base rate case for Lone Star Unit 1 was 2019.[55]

SWEPCO accounted for these retirements in accordance with the FERC USofA. The Commission requires major utilities such as SWEPCO to maintain their books and records according to the FERC USofA.[56] Under the FERC USofA, SWEPCO recorded the cost of these plants in plant in service at the time the plant was dedicated to public use. Over time SWEPCO depreciated the assets using Commission approved depreciation rates, which is recorded in accumulated depreciation. Upon retirement, the requirements of the FERC USofA are specific and mandatory:

> When a retirement unit is retired from electric plant, with or without replacement, the book cost thereof shall be credited to the electric plant account in which it is included, determined in the manner set forth in paragraph D, below. If the retirement unit is of a depreciable class, the book cost of the unit retired and credited to electric plant shall be charged to the accumulated provision for depreciation applicable to such property.[57]

Staff witness Ms. Stark recommends the Commission remove the undepreciated value of these plants at the time of their retirement from accumulated depreciation thereby reducing SWEPCO's rate base. Ms. Stark's sole basis for this recommendation is the Commission's ratemaking treatment ordered in Docket No. 46449 for SWEPCO's Welsh Unit 2 and not the ratemaking treatment provided for the retirement of Lieberman 1 in that same case. The retirement circumstances of the retired gas units in this case are the same as Lieberman 1 in Docket No. 46449. There are important distinctions between the circumstances addressed in Docket No. 46449 for Welsh and those that prevail in this case for these gas units.

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[55] SWEPCO Ex. 7 at 9:11-10:22.

[56] 16 TAC § 25.72(c).

[57] 18 CFR Pt. 101 (FERC USofA) at Electric Plant Instruction 10.B(2) ("Additions and Retirements of Electric Plant").

Welsh Unit 2 was not the first utility generating unit to be retired with some amount of undepreciated value. Yet, Docket No. 46449 was the first time that the Commission departed from the prescribed accounting treatment and removed the undepreciated value of a retired generating unit from rate base. Thus, the treatment of Welsh Unit 2 in that docket was unique.[58] Indeed, the circumstances with respect to Welsh Unit 2's retirement was unique even within the context of Docket No. 46449 itself because Lieberman Unit 1 had been retired in 2015,[59] before the conclusion of the test year addressed in Docket No. 46449. Yet, the Commission made no adjustment in Docket No. 46449 to rate base associated with Lieberman Unit 1. Instead, the Commission allowed the ratemaking for Lieberman Unit 1 to follow the requirements of the FERC USofA. Staff presents no compelling reason to depart from that practice with respect to these retired gas-fired generating units.

To apply the Docket No. 46449 Welsh Unit 2 rate treatment to the retirement of any generation unit independent of the circumstances would constitute bad policy and provide inappropriate incentives to parties in utility rate cases to recommend that the Commission extend the depreciable lives of generation units in an effort to cause unit retirements with excessive undepreciated value. For an example of such a situation, the Commission need look no further than some parties' positions in this case regarding the Dolet Hills plant. Utilities should be provided an incentive to make prudent generation unit retirement decisions that are in the best interest of customers without facing financial penalties when a generating unit retires with some amount of undepreciated value.[60]

3. Flint Creek and Welsh Capital Investment

Short of addressing the prudence of any generation capital project, Sierra Club makes the sweeping request that the Commission disallow all Test Year capital investment (as well as all Test Year O&M expense) made at the Flint Creek and Welsh plants.[61] The Flint Creek Power Plant, a jointly owned plant located in Benton County, Arkansas which was placed in service in 1978. The unit is fueled with coal from the Powder River Basin (PRB) that is delivered to the

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[58] SWEPCO Ex. 36 at 26:19-27:5.

[59] SWEPCO Ex. 7 at 6:17-21.

[60] SWEPCO Ex. 36 at 27:6-14.

[61] Direct Testimony of Devi Glick, Sierra Club Ex. 2A at 7:15-19.

plant by rail. An activated carbon injection (ACI) system and a dry flue gas desulfurization system, including an integrated fabric filter assembly, were installed in 2016 to address environmental requirements.[62] The Welsh Power Plant is located near Cason, Texas in Titus County. Welsh Unit 1 was placed into commercial operation in 1977. Unit 3 was placed in service in 1982. These units burn PRB coal that is transported to the plant by rail. An ACI system was installed in 2016 on Units 1 and 3, to address environmental requirements.[63] In Docket No. 46449, the Commission found that the environmental retrofits installed at the Flint Creek and Welsh plants in 2016 were prudent. Specifically, the Commission found "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 [sic]1 and 3."[64]

Sierra Club's requested disallowance of all capital investment placed in service and O&M incurred during the Test Year is based on two equally inaccurate allegations: (1) SWEPCO incurred $153 million in net losses at the Flint Creek Power Plant and incurred $144 million in net losses at the Welsh Power Plant over the past six years; and (2) SWEPCO is projected to incur $161 million in net losses continuing to invest in and operate Flint Creek and incur $266 million in net losses at Welsh over the next decade.[65]

Regarding this first allegation, the fact is that SWEPCO offered the Flint Creek and Welsh plants in the SPP Integrated Marketplace (SPP IM) based on their incremental energy costs and the dispatch of the units resulted in revenues above those costs not net losses. Over the years 2016 through 2020, the revenues from sales of Welsh 1 & 3 and Flint Creek generation units were $196 million in excess of the variable costs of those units.[66] SWEPCO continues to operate these units in the same manner as was reviewed by the Commission in SWEPCO's previous base rate case, Docket No. 46449. In that case, the Commission found that SWEPCO had correctly bid its solid fueled generating units into the SPP IM based on the incremental costs of the units, realizing revenues in excess of the associated incremental costs of dispatch.[67]

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[62] SWEPCO Ex. 7 at 4:12-19.

[63] SWEPCO Ex. 7 at 5:4-11.

[64] Docket No. 46449, Order on Rehearing at FoF No. 52.

[65] Sierra Club Ex. 2A at 6:9-16.

[66] Rebuttal Testimony of Jason Stegall, SWEPCO Ex. 47 at 4:9-13.

[67] Docket No. 46449, Order on Rehearing at FoF Nos. 345-46.

In her historical analysis, Sierra Club witness Ms. Glick was able to manufacture historical net losses only by including in her calculations the capital investment made by SWEPCO to enable operation of the plant for years into the future and expensing that capital investment in the year made. This is inaccurate and inconsistent with how SWEPCO recovers the cost of capital investments from customers over the expected life of the capital investment. In addition, Ms. Glick includes the annual fixed O&M costs incurred at the units, which is inappropriate when considering only the incremental costs of generating energy in the calculation.[68] It is also important to note that Ms. Glick's historical calculation incorporates hundreds of millions of dollars of capital investment already found to be prudent by the Commission. Only by incorrectly expensing in one year the hundreds of millions of dollars of environmental compliance capital investment made in 2015 and 2016 can Ms. Glick's calculation arrive at the historical losses she alleges.[69]

Regarding Sierra Club's second allegation, concerning alleged projected future losses, Ms. Glick's forward-looking analysis is simply an extension of her historical analysis and it includes the same flaws, including the expensing of capital investment in the year made, along with all fuel and O&M costs, and comparing all of these expenditures to projected revenues. More importantly, her analysis also completely omits any consideration of the costs that SWEPCO will incur to serve customers without these plants. In other words, Ms. Glick's allegation is flawed because it considers only one side of the analysis – where the plant continues to operate – and fails to consider the cost to customers of a scenario where the plant is retired and replacement energy and capacity costs are incurred. Her analysis does not constitute a unit disposition analysis that studies the costs to serve customers with a unit's retirement versus the costs to serve customers with a unit's retrofit and continued operation.[70]

Ms. Glick's allegations of historical and projected losses at the Flint Creek and Welsh plants are not credible and do not constitute a basis for the disallowance of every dollar of capital investment placed in service and O&M expense incurred during the Test Year at these plants.

4. Coal and Lignite Inventory

SWEPCO witness Mark Leskowitz supports SWEPCO's request for coal inventory for the

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68 Rebuttal Testimony of Mark Becker, SWEPCO Ex. 48 at 3:18-4:4.

69 SWEPCO Ex. 48 at 6:22-7:4.

70 SWEPCO Ex. 48 at 7:10-21.

Welsh, Flint Creek, and Turk coal power plants and lignite inventory for the Pirkey and Dolet Hills power plants to be included in rate base.[71] SWEPCO must maintain solid fuel inventories to assure a continuous supply of coal and lignite of appropriate quality, delivered at a reasonable cost over a period of years so as to promote the generation of the lowest cost per kWh of electricity, within the constraints of safety, reliability of supply, unit design, and environmental requirements. Coal and lignite deliveries must be arranged so that sufficient fuel is available at all times to provide and maintain adequate and dependable electric service for SWEPCO's customers.[72]

Target inventory levels are determined based on the number of days that the plant may be expected to operate using just the fuel inventory available at the plant site. A "days-burn" is defined as the number of tons that the plant would burn in one day at full load. Each plant is initially allocated a base level of inventory as expressed in terms of a number of days-burn. Additions are made to this base amount in consideration of the criteria described below.[73] Using this methodology, SWEPCO requests a total solid fuel inventory amount of approximately 1.5 million tons (Welsh: 0.48 million tons; Flint Creek: 0.23 million tons; Turk: 0.22 million tons; Pirkey: 0.34 million tons; and Dolet Hills: 0.23 million tons).[74] These proposed amounts represent a 30-day burn level for each plant (except for Dolet Hills, which is a 45-day burn level), and they are the same as the target levels approved in the last base rate case.[75]

CARD witness Mr. Norwood recommends replacing the full-load burn per day in the inventory calculation with an average daily burn during the test year. The only basis he offers for his recommendation is the 2014-2019 energy production from SWEPCO's coal and lignite plants and his implicit assumption that future production will be the same as the past.[76] His suggestion of using an historic level of burn in the calculation would negatively impact SWEPCO's ability to reliably serve the needs of its customers and SPP, and the recommendation should be rejected.

The probability of interruptions of the fuel supply, how long such interruptions may last,

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[71] SWEPCO Ex. 49 at 2:13-14; Direct Testimony of Amy E. Jeffries adopted by Mark Leskowitz, SWEPCO Ex. 25 at 13:7-8.

[72] SWEPCO Ex. 25 at 13:18-14:1.

[73] SWEPCO Ex. 25 at 15:15-20.

[74] SWEPCO Ex. 49 at 3:5-7.

[75] SWEPCO Ex. 25 at 16:1-8.

[76] Direct Testimony of Scott Norwood, CARD Ex. 3 at 7:17-19, 8:12-16 (using the page number in the bottom center of the page).

and how much fuel is necessary to provide for these contingencies all influence targeted fuel inventory levels.[77] Supply disruptions could include labor stoppages at mining operations or by transportation employees; mine production and permitting difficulties; extreme weather events such as blizzards, hurricanes, and floods (which can affect both mines and all transportation modes); shortages of mining and transportation equipment and supplies; outages affecting loading or unloading equipment; capacity constraints due to inadequate funding of mining and transportation infrastructure; and derailments. These situations can result in significant and sometimes extended limitations on coal deliveries.[78]

SWEPCO also considers plant-specific criteria in determining the appropriate solid fuel inventory required at each plant. Of primary importance are the fuel supply source; available fuel transportation and unloading options and timing; the number of third-party suppliers; on-site storage capability; and whether the plant has a high capacity factor. Diversion and back-up supply capabilities involving other plants in the AEP System; the forecasted burn variability; and the distance and lead time that is necessary to transport coal from the mine to the plant also play a role.[79] These factors determine the proper amount of fuel needed to ensure each plant has sufficient coal stored to minimize operational risk for all conditions that could cause supply disruptions. These target inventory levels are reviewed each year with the Fuel Procurement Team and SWEPCO Senior Management and plant personnel.[80]

Using the historical average of fuel consumed to calculate fuel inventory levels, as recommended by Mr. Norwood, increases reliability risk for SWEPCO's customers. It unrealistically assumes that historical period operating conditions will persist into the future. Weather or unit outages can easily result in future conditions being different from the average historical burn rate. Furthermore, an average burn rate fails to account for the peak coal inventory needed during heavier use periods, and thus exposes SWEPCO customers to an increased reliability risk. For example, if SWEPCO used an average burn rate to set inventory levels and there was a supply disruption during a high generation month such as August, a plant could run

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77 SWEPCO Ex. 25 at 14:10-12.

78 SWEPCO Ex. 25 at 14:18-15:2.

79 SWEPCO Ex. 25 at 15:5-12; SWEPCO Ex. 49 at 5:6-9.

80 SWEPCO Ex. 49 at 5:9-13.

out of coal.[81]

Even though the average amount of coal utilized by SWEPCO has decreased over the years, SWEPCO must be prepared for periods when coal generation is in high demand. Sometimes a coal plant is not required by the market for a month, and other times when the same plant is required at near full capacity for an extended period. Because these units can be needed at full-load capacity, using the average burn rate to set inventory levels could place SWEPCO in a position of risk. Using the full-load burn rate ensures the Company's ability to provide reliable generation for SWEPCO's customers in times of uncontrollable events. Operational or weather issues can also occur at the mines, which could result in the plants not being available to run at full load for sustained periods in SPP.[82] Setting coal inventory targets based on the number of full-load burn days also avoids issues with historical averages, which can be skewed by events such as an unplanned plant outage or periods of high wind penetration.[83]

Coal plants are base load units in SPP during high peak load periods and may be required to run weeks at a time at or near full load due to reliability or market conditions. Setting inventory targets based on full-load burn ensures that adequate inventory is available to provide the necessary reliability for SWEPCO customers and SPP. This method of setting inventory was approved in SWEPCO's last two base rate cases (Docket Nos. 40443 and 46449). Therefore, Mr. Norwood's recommendation for a solid fuel inventory adjustment based on average burn rate should be denied.[84]

B. Prepaid Pension & OPEB Assets

SWEPCO records an additional cash investment in the pension trust fund as a prepaid pension asset in accordance with GAAP under ASC 715-30. The prepaid pension asset is the cumulative additional pension cash contributions beyond the amount of pension cost. Accordingly, an additional cash investment recorded as a prepaid pension asset should be included in rate base under PURA § 36.065.[85] SWEPCO's inclusion of the prepaid pension asset in rate base is uncontested.

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[81] SWEPCO Ex. 49 at 4:4-13.

[82] SWEPCO Ex. 49 at 5:17-6:9.

[83] SWEPCO Ex. 49 at 4:14-17.

[84] SWEPCO Ex. 49 at 4:17-23.

[85] SWEPCO Ex. 6 at 15:19-16:2.

C. Accumulated Deferred Federal Income Tax

In his direct testimony, Company witness Mr. David Hodgson describes normalized accounting for income taxes and explains that SWEPCO's federal income tax expense for the Test Year includes both currently due taxes and also deferred taxes that will be paid in future years.[86] Mr. Hodgson further explains that the deferred taxes are largely the result of accelerated depreciation for tax purposes and straight-line depreciation for regulatory and book purposes.[87] The Company established an ADFIT account to capture these future tax obligations.[88] As the deferred taxes are paid in future years, the ADFIT balance decreases dollar-for-dollar.[89] For ratemaking purposes, the ADFIT balance is used to offset rate base to recognize the Company's temporary cost-free use of the deferred taxes collected from customers but not yet remitted to the Federal government.[90] In this way, the use of ADFIT to offset rate base shares with customers the temporary savings associated with the deferred taxes.[91] There are no apparent disagreements regarding the Company's calculation of its ADFIT balance as of the Test Year. However, there is a disagreement between SWEPCO and Commission Staff about an adjustment to the ADFIT balance based on certain tax losses incurred by SWEPCO.

1. Net Operating Loss ADFIT

In this rate case, SWEPCO adjusted its ADFIT balance to reflect losses incurred from its stand-alone utility operations.[92] SWEPCO incurred net operating losses (NOLs) for several years prior to the Test Year where its accelerated depreciation deductions were greater than its taxable revenue.[93] The Internal Revenue Code (IRC) allows taxpayers like SWEPCO to carry forward NOLs to subsequent years to offset otherwise taxable income in a future period.[94] This is referred

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86 Direct Testimony of David A. Hodgson, SWEPCO Ex. 17 at 7:18-8:6; *see also* Rebuttal Testimony of David A. Hodgson, SWEPCO Ex. 45 at 8:1-2.

87 SWEPCO Ex. 17 at 9:16-18.

88 SWEPCO Ex. 17 at 8:4-6.

89 SWEPCO Ex. 17 at 10:3-7.

90 SWEPCO Ex. 45 at 8:3-13.

91 SWEPCO Ex. 45 at 8:3-13

92 SWEPCO Ex. 17 at 27:11-21.

93 SWEPCO Ex. 17 at 27:11-21

94 SWEPCO Ex. 17 at 11:5-7.

to as an NOL Carryforward or "NOLC."[95] For this rate case, SWEPCO has a stand-alone NOLC attributable to accelerated depreciation associated with its ADFIT balance.[96] Accordingly, SWEPCO reduced its ADFIT balance to reflect the NOLC associated with the ADFIT.[97] That is, as the deferred taxes become due in future years, the NOLC will offset the deferred taxes such that there are no temporary cost-free deferred tax funds available for the Company to use, and therefore, there are no temporary tax savings to pass on to customers.[98] The practical result of this adjustment is an increase to SWEPCO's rate base because the ADFIT balance is lower.[99]

Based on the pre-filed testimony submitted in this case[100] and the hearing testimony of Staff witness Ms. Stark,[101] this general concept is not controversial. However, Staff disagrees with the Company's proposal relating to the NOLC ADFIT in this rate case because SWEPCO participates in a tax allocation agreement with its parent and affiliates whereby SWEPCO receives payment for the benefit of its NOL to the extent the NOL is used to offset taxable income on the American Electric Power Corporation (AEP) consolidated federal income tax return.[102] Absent AEP's consolidated tax filing and tax allocation agreement, Ms. Stark would agree with SWEPCO's offset of ADFIT by the NOLC. Specifically, she testified at hearing as follows:

> Q. ...if there were no consolidated tax allocation agreement in the arrangement where you have the stand-alone net operating loss carry-forward and the ADFIT balance and they offset each other, that - - in your opinion, that would be okay if there were no tax allocation agreement? That's - - that was my question.
>
> A. If SWEPCO received no - - no money that it used to finance other assets, yes.
>
> Q. Okay. So if there was no tax allocation agreement with no benefit back to SWEPCO, you - - you would be okay with the arrangement in that context?

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95 SWEPCO Ex. 17 at 11:13.

96 SWEPCO Ex. 17 at 27:11-21.

97 SWEPCO Ex. 45 at 8:3-13

98 Tr. at 392:4-12 (Stark Cross) (May 20, 2021).

99 Tr. at 391:19-392:3 (Stark Cross) (May 20, 2021).

100 Direct Testimony of Ruth Stark, Staff Ex. 3.

101 Tr. at 392:25-393:13 (Stark Cross) (May 20, 2021).

102 Staff Ex. 3 at 29:11-42:7.

A. If that's what actually happened, yes.[103]

No other party submitted evidence addressing this issue.

SWEPCO's adjustment of the ADFIT balance by its stand-alone NOLC is supported by two witnesses, Mr. Hodgson and Mr. Brad Seltzer. Mr. Hodgson testifies that the Company's NOLC ADFIT approach complies with PURA § 36.060(a) because the NOLC was calculated and applied on a stand-alone basis without regard to any consolidated tax savings.[104] Mr. Hodgson further testifies that the NOLC ADFIT adjustment prevents cross-subsidization or intermingling the tax burdens and benefits of other AEP affiliates with SWEPCO customers.[105] Mr. Hodgson's testimony also explains that the Company's NOLC ADFIT proposal is consistent with IRC normalization requirements.[106] Mr. Seltzer, an expert on IRC normalization requirements, confirms that the Company's stand-alone NOLC ADFIT approach complies with IRS normalization requirements.[107] He further testifies that the IRS would most likely conclude that Staff's proposed adjustment would violate the IRS normalization consistency rules.[108] Mr. Seltzer disagrees with Staff's proposal to reduce the NOLC ADFIT by the payments SWEPCO received under the AEP tax allocation agreement.[109] Mr. Seltzer also testifies that the Company's approach follows published IRS guidelines regarding the consistency requirements, which provide that a utility's tax expense, depreciation expense, ADFIT, and rate base should all be calculated on a stand-alone basis.[110]

Ms. Stark, testifying on behalf of Staff, disagrees with the Company's approach. She argues that the payments SWEPCO received from its participation in the AEP consolidated tax return and tax allocation agreement should be considered in determining the rate base amount in this case.[111] Ms. Stark's disagreement is based on four primary points: 1) SWEPCO had a

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103 Tr. at 393:1-13 (Stark Cross) (May 20, 2021).

104 SWEPCO Ex. 45 at 2:16-3:13.

105 SWEPCO Ex. 45 at 3:13-20 and 7:5-8.

106 SWEPCO Ex. 17 at 11:15-14:18.

107 Rebuttal Testimony of Bradley M. Seltzer, SWEPCO Ex. 44 at 4:22-5:10.

108 SWEPCO Ex. 44 at 9:11-13.

109 SWEPCO Ex. 44 at 6:6-23.

110 SWEPCO Ex. 44 at 4:10-5:10.

111 Staff Ex. 3 at 31:10-21.

Test Year end book balance of $0 for its NOLC ADFIT account;[112] 2) SWEPCO's position in this case is a departure from its prior rate case (Docket No. 46449);[113] 3) IRS issued private letter rulings (PLRs) addressing normalization rules do not require stand-alone or separate company ratemaking;[114] and 4) SWEPCO's proposal is allegedly unfair.[115]

Mr. Hodgson and Mr. Seltzer filed rebuttal testimony in response to Ms. Stark demonstrating that:[116]

- SWEPCO's NOLC ADFIT should be considered on a stand-alone basis;
- SWEPCO's approach balances tax benefits and burdens with customers; and
- IRS normalization requirements support SWEPCO's approach.

a. Stand-Alone Tax Calculation

In his rebuttal testimony, Mr. Hodgson explains that SWEPCO is a member of a consolidated group and participates in the AEP consolidated federal income tax return.[117] However, for ratemaking purposes, SWEPCO calculates its tax expense on a separate return (a.k.a., stand-alone) basis.[118] This means that the tax expense included in rates directly coincides with the taxes generated by the utility to which the rates apply.[119] That is, SWEPCO's income tax expense is based solely on income from SWEPCO's operations. Mr. Hodgson further testifies that PURA § 36.060(a) requires a stand-alone tax calculation.[120] At the hearing, Ms. Stark agreed that PURA § 36.060(a) requires a stand-alone tax calculation.[121]

In accordance with PURA § 36.060(a), SWEPCO calculated its income tax expense, ADFIT balance, and NOLC ADFIT all on a stand-alone basis. Mr. Hodgson's testimony confirms

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[112] Staff Ex. 3 at 32:9-10.

[113] Staff Ex. 3 at 34:1-19.

[114] Staff Ex. 3 at 32:11-20.

[115] Staff Ex. 3 at 39:15-19.

[116] SWEPCO Ex. 44 and SWEPCO Ex. 45.

[117] SWEPCO Ex. 45 at 2:5-7.

[118] SWEPCO Ex. 45 at 2:7-10.

[119] SWEPCO Ex. 45 at 2:10-15.

[120] SWEPCO Ex. 45 at 2:16-3:13.

[121] Tr. at 423:9-424:14 (Stark Cross) (May 20, 2021).

this fact,[122] and Ms. Stark agrees.[123] However, Ms. Stark contends that SWEPCO is "cherry picking" the items it calculates on a stand-alone basis because the Company's calculation does not consider the payments it received from the AEP consolidated group for the NOLC.[124] She further argues that ignoring the payments from the AEP consolidated group discounts the economic realities of the impact such payments have on SWEPCO and its customers.[125] Staff's position is wrong.

During the 83rd legislative session (2013), the Texas Legislature enacted Senate Bill 1364, which repealed the prior version of PURA §36.060(a) and replaced it with the version now in effect.[126] The prior version required a consolidated tax adjustment, which (if still in effect) would require SWEPCO to consider the impact of its NOLC on the consolidated tax group. However, this consolidated tax adjustment requirement was specifically repealed in 2013.[127] SWEPCO is following the requirements of the current statute. It is not "cherry picking" anything. To consider the payments from the AEP consolidated group would be the opposite of stand-alone ratemaking, it would be a consolidated tax adjustment under the now-repealed former version of PURA § 36.060(a). The consolidated tax allocation payments relied on by Ms. Stark are the direct result of the AEP consolidated tax filing and the tax calculations and consequences of other AEP affiliates and the services utility affiliates provide to their customers.[128]

Staff argues that because SWEPCO's NOLC ADFIT book balance for the Test Year is $0 there should be zero offset to ADFIT.[129] However, SWEPCO's book balance reflects activity from the AEP consolidated group, not the stand-alone calculations required by PURA § 36.060(a).[130] Staff further argues that SWEPCO has deviated from its prior rate case (Docket No. 46449) in

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122 Tr. at 276:11-277:5 (Hodgson Redirect) (May 19, 2021).

123 Tr. at 424:7-14 (Stark Cross) (May 20, 2021).

124 Tr. at 394:8-21 (Stark Cross) (May 20, 2021).

125 Staff Ex. 3 at 39:23-40:13.

126 Act of May 25, 2013, 83rd Leg., R.S., chapter 787 (SB 1364), §1.

127 SWEPCO Ex. 45 at Exhibit DAH-4R (includes additional legislative analysis relating to SB 1364 and affirms Texas Legislature's repeal of the consolidated tax adjustment).

128 Tr. at 273:20-274:22 (Hodgson Redirect) (May 19, 2021); see also SWEPCO Ex. 45 at 7:5-7.

129 Staff Ex. 3 at 32:22-33:2.

130 Tr. at 272:23-273:15 (Hodgson Cross) (May 19, 2021); *see also* Tr. at 276:21-277:5 (Hodgson Redirect) (May 19, 2021).

which it did consider payments from the AEP consolidated group.[131] In response, Mr. Hodgson explains that SWEPCO only became aware of this issue during the preparation of this rate case.[132] Mr. Seltzer further addresses Staff's argument by confirming that SWEPCO (in good faith) thought it was in compliance with recently-revised PURA § 36.060(a) in its prior rate case, but now it understands that the stand-alone requirement includes the NOLC ADFIT.[133] While it is true that the treatment of the NOLC ADFIT balance did not follow the new version of PURA § 36.060(a) in Docket No. 46449, that does not mean that SWEPCO is required to follow the same treatment in this case. To the contrary (as discussed below), IRC normalization rules require SWEPCO to modify the prior treatment at its first available opportunity, which is this rate case.

In this rate case, SWEPCO proposes a stand-alone tax calculation in accordance with PURA § 36.060(a). SWEPCO does not consider the payments received from the AEP consolidated group because those payments do not reflect a stand-alone tax calculation or stand-alone ratemaking. Investments in rate base and expenses in cost of service should only be included in rates if they relate to the provision of utility service to the customers paying those rates.[134] The consolidated tax return and tax allocation payments received from the AEP consolidated group do not relate to the provision of service to SWEPCO's customers, and therefore should not be considered in the calculation of tax expense or rate base.

b. Benefits and Burdens

If SWEPCO did not participate in a consolidated tax filing and tax allocation agreement with its parent and affiliates (and did not receive payments in exchange for use of its NOLCs), Staff would not contest SWEPCO's NOLC ADFIT approach.[135] At its core, Staff's position is that SWEPCO's proposal on the NOLC ADFIT is unfair.[136] Ms. Stark testifies that SWEPCO has use of the money received from the consolidated group and customers should benefit from these consolidated payments.[137] She further argues that by using the consolidated payments to

131 Staff Ex. 3 at 34:1-19.

132 Tr. at 275:4-17 (Hodgson Redirect) (May 19, 2021).

133 SWEPCO Ex. 44 at 7:21-8:18.

134 SWEPCO Ex. 45 at 3:14-20.

135 Tr. at 393:1-13 (Stark Cross) (May 20, 2021).

136 Staff Ex. 3 at 39:17-41:18.

137 Staff Ex. 3 at 39:17-41:18.

potentially invest in rate base items, SWEPCO is getting a double recovery through its authorized return – first as an adjustment to ADFIT and second as a direct return on rate base.[138] Again, Staff's position is incorrect.

In his rebuttal testimony, Mr. Hodgson walks through several examples and shows that SWEPCO's approach in this case would have the same impact on rates as a similarly situated utility with no consolidated tax filing and tax allocation agreement.[139] Mr. Hodgson further shows that Staff's proposed adjustment would not have the same impact with a similarly situated utility with no tax allocation agreement.[140] Staff disagrees with SWEPCO's approach because of the AEP consolidated tax filing and tax allocation agreement, but SWEPCO's approach resembles the rate base treatment of a similarly situated utility without a consolidated tax filing and tax allocation agreement.

SWEPCO's approach ensures that the tax expense, depreciation expense, ADFIT, and rate base included in its rates relate exclusively to the stand-alone utility activity of SWEPCO as required by PURA § 36.060(a).[141] The rates requested in this proceeding do not (and should not) include benefits or burdens relating to the provision of utility services by other AEP utilities.[142] Staff agrees with the general principle that SWEPCO customers should not pay tax expense resulting from other AEP affiliates[143] nor should SWEPCO customers pay a return on rate base for plant used by another AEP affiliate.[144] However, Staff fails to apply this principle to the NOLC ADFIT in this case.

c. IRS Normalization

In his rebuttal testimony, Mr. Hodgson explains that the IRS normalization rules require consistency in the assumptions used to determine depreciation expense, tax expense, rate base, and

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138 Tr. at 394:8-21 (Stark Cross) (May 20, 2021).

139 SWEPCO Ex. 45 at 15:6-19:2.

140 SWEPCO Ex. 45 at 15:6-19:2

141 SWEPCO Ex. 45 at 2:12-15 and 5:2-5.

142 SWEPCO Ex. 45 at 12:14-13:21.

143 Tr. at 395:6-22 (Stark Cross) (May 20, 2021).

144 Tr. at 395:2-5 (Stark Cross) (May 20, 2021).

ADFIT.[145] SWEPCO computes each of these on a stand-alone basis.[146] Therefore, it is consistent for SWEPCO to use the stand-alone method to calculate and apply the NOLC ADFIT in this case. Mr. Seltzer confirms Mr. Hodgson's testimony and further provides that the normalization consistency requirements effectively support stand-alone ratemaking.[147] That is, the utility is viewed in isolation to avoid cross-subsidies inherent in consolidated returns. Mr. Seltzer explains that a stand-alone approach ensures that a utility's rates only include its cost of service and not the costs incurred by other members of the affiliated group.[148]

Citing federal law, applicable Treasury regulations, and several IRS issued PLRs, Mr. Hodgson testifies that SWEPCO's stand-alone calculation and application of the NOLC ADFIT in this rate case is consistent with IRS normalization requirements.[149] He then testifies that when accelerated depreciation creates an NOLC, the NOLC ADFIT must be included in rate base.[150] If the NOLC ADFIT is not included in rate base, it would constitute a normalization violation,[151] the consequences of which would be devastating to both SWEPCO and its customers.[152] Namely, there would be no ADFIT relating to accelerated depreciation to offset rate base. SWEPCO would no longer be able to use accelerated depreciation and deferred taxes resulting from prior accelerated depreciation would be due sooner.[153]

Ms. Stark testifies that none of the IRS PLRs referenced in Mr. Hodgson's testimony expressly use the words "stand-alone" or "separate company basis."[154] If SWEPCO was that concerned about a potential normalization violation, it should (according to Staff) request its own private letter ruling, which to date it has not.[155] She further testifies that because the AEP consolidated group has used the NOLCs on the consolidated income tax return, the stand-alone

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[145] SWEPCO Ex. 45 at 5:2-5.

[146] Tr. at 389:17-391:10 (Stark Cross) (May 20, 2021).

[147] SWEPCO Ex. 44 at 4:22-6:16.

[148] SWEPCO Ex. 44 at 4:22-6:16

[149] SWEPCO Ex. 17 at 11:8-13:2.

[150] SWEPCO Ex. 17 at 13:3-10.

[151] SWEPCO Ex. 17 at 13:10-11.

[152] SWEPCO Ex. 17 at 15:14-16:14.

[153] SWEPCO Ex. 17 at 15:14-16:14.

[154] Staff Ex. 3 at 32:11-20.

[155] Staff Ex. 3 at 36:1-8.

NOLC ADFIT no longer exists.[156] Staff's understanding of the normalization requirements is incorrect.

Mr. Seltzer acknowledges that the PLRs cited by Mr. Hodgson do not expressly address the impact of tax allocation payments.[157] However, he notes that PLR 201718015 (Feb. 7, 2017) involved a parent making a tax sharing payment to a utility in exchange for its NOL and the IRS did not change its advice based on that fact.[158] Mr. Seltzer specifically provides, in pertinent part: "[s]urely, if the payments under a tax sharing agreement must be taken into account in determining the allowable Deferred Tax Asset as Staff claims, the IRS could not, and would not, simply ignore the payment to the utility in its analysis."[159] Mr. Seltzer goes on to explain that any payments received by SWEPCO pursuant to its participation in the AEP consolidated tax filing and tax allocation agreement are not relevant to the normalization issue because they do not represent an interest-free loan from the Government.[160] His testimony directly contradicts Staff's position that the NOLC ADFIT is used up by the consolidated group and therefore should not be recognized on a stand-alone basis. As the normalization expert in this case, Mr. Seltzer's testimony clearly demonstrates that the consolidated tax allocation payments received by SWEPCO should have no bearing on the Company's stand-alone NOLC ADFIT.[161]

Mr. Seltzer's rebuttal testimony likewise addresses SWEPCO's changed approach since its last Texas rate case (Docket No. 46449).[162] He confirms that pursuant to Rev. Proc. 2017-47 and General Legal Advice Memorandum 132120-17, the IRS allows a safe harbor for taxpayers to correct normalization issues (prospectively) at their next available rate case.[163] SWEPCO only became aware of the NOLC ADFIT normalization issue in preparation of this case.[164] Therefore, this rate case is the first opportunity for SWEPCO to correct the error. Mr. Seltzer further testifies

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[156] Staff Ex. 3 at 31:17-19.

[157] SWEPCO Ex. 44 at 5:19-21.

[158] SWEPCO Ex. 44 at 6:3-6.

[159] SWEPCO Ex. 44 at 5:22-6:6.

[160] SWEPCO Ex. 44 at 6:17-7:13.

[161] SWEPCO Ex. 44 at 6:17-7:13

[162] SWEPCO Ex. 44 at 7:14-8:18.

[163] SWEPCO Ex. 44 at 7:14-8:18.

[164] Tr. at 275:4-17 (Hodgson Redirect) (May 19, 2021).

that it is not necessary for the Company to request a specific PLR in this instance because, as Mr. Hodgson points out, Texas law likewise requires stand-alone ratemaking – consistent with IRS normalization requirements.[165]

d. Conclusion

Based on the record evidence in this case, the Company's proposed calculation and application of its stand-alone NOLC ADFIT to rate base follows Texas law, equitably balances the benefits and burdens between SWEPCO and its customers, and is consistent with IRS normalization requirements. Staff's objections to the Company's approach are based entirely on tax allocation payments SWEPCO received as part of its participation in a consolidated federal income tax return and Staff concedes SWEPCO would be correct if not for the consolidated tax return and tax allocation payment. Consideration of such payments would violate stand-alone ratemaking required by Texas law and IRS normalization requirements.

2. Excess ADFIT

The Tax Cuts and Jobs Act (TCJA) contained significant changes to the Internal Revenue Code of 1986. For ratemaking purposes, the primary impact of the TCJA is the reduction of the corporate federal income tax rate from 35% to 21%, effective January 1, 2018.[166] As explained by Mr. Hodgson, this reduction of the corporate tax rate resulted in Excess ADFIT.[167] Deferred taxes were originally collected from customers at a 35% tax rate.[168] After the rate change, a portion of the deferred tax amounts (the difference between the 35% and the 21% tax rates) will not be paid to the IRS in future years. This amount of "Excess" ADFIT that was collected from customers and that will not be paid in future years as deferred taxes should be returned to customers in accordance with IRS normalization requirements.[169] This general principle is not in dispute.

SWEPCO and Commission Staff also agree that the Excess ADFIT available to be returned to customers is limited to the protected Excess ADFIT amortization amounts for years 2018 – 2021 and the unprotected Excess ADFIT balance for all years.[170] The protected Excess ADFIT

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165 SWEPCO Ex. 44 at 8:19-9:3.

166 SWEPCO Ex. 17 at 21:6-11.

167 SWEPCO Ex. 17 at 21:6-11.

168 SWEPCO Ex. 17 at 21:6-25:22.

169 SWEPCO Ex. 17 at 21:6-25:22

170 Tr. at 403:24-405:7 (Stark Cross) (May 20, 2021).

amortization amounts for years 2022 forward must be included in rates in accordance with IRS normalization requirements using the Average Rate Assumption Method.[171]

However, there are two apparent disputes between SWEPCO and Commission Staff regarding the calculation of Excess ADFIT available to be returned to customers.[172] The first issue involves the Texas Retail allocation factor and corresponding calculation of Excess ADFIT provided by SWEPCO in its RFP. The submitted information led to some confusion, so Staff recommended several adjustments based on its understanding of the allocation factor and resulting calculation.[173] In response, SWEPCO adjusted its Excess ADFIT calculation to reflect the 35.01% Texas Retail allocation factor established in Docket No. 46449, which was in effect when the tax rates were changed pursuant to the TCJA.[174] SWEPCO also corrected some sub-ledger information that updated the Excess ADFIT available to be returned to customers.[175] SWEPCO's rebuttal adjustments may have resolved this particular calculation issue with Staff.

The second contested issue involves SWEPCO and Staff's disagreement regarding the NOLC ADFIT issue discussed in Section II.C.1 above. SWEPCO's proposal to include the stand-alone NOLC ADFIT in its rate base calculation in accordance with PURA § 36.060(a) and IRS normalization requirements also affects its calculation of Excess ADFIT. Mr. Hodgson explains the Company's position in his rebuttal testimony.[176] Including the NOLC ADFIT in the overall Excess ADFIT balance ensures that the amount that is returned to customers is the exact amount that customers have paid in excess deferred taxes to the Company.[177] Excluding the NOLC ADFIT from the Excess ADFIT balance would refund amounts to customers that they did not pay in deferred taxes.[178] As detailed above, Staff disagrees with the Company's NOLC ADFIT position. For these same reasons, Staff recommends that the excess ADFIT calculation should exclude the

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171 Tr. at 403:24-405:7 (Stark Cross) (May 20, 2021).

172 Several parties dispute SWEPCO's proposal to use the Excess ADFIT to offset the unrecovered value of the Dolet Hills plant. For purposes of brevity, these arguments (addressed in Section II.A.1. above) are not restated here. This section of SWEPCO's Initial Brief addresses only the calculation of Excess ADFIT.

173 Staff Ex. 3 at 42:8-47:2.

174 SWEPCO Ex. 45 at 25:8-16 and 26:6-15.

175 Tr. at 564:23-565:7 (Hodgson Cross) (May 20, 2021).

176 SWEPCO Ex. 45 at 21:7-25:7 and 26:1-5.

177 SWEPCO Ex. 45 at 24:10-13.

178 SWEPCO Ex. 45 at 23:14-24:9.

stand-alone NOLC ADFIT used by SWEPCO.[179] Based on the arguments and evidence presented in the section above, SWEPCO recommends that the Excess ADFIT calculation should include the stand-alone NOLC ADFIT. Inclusion of the NOLC in the Excess ADFIT calculation ensures that customers are only refunded the amount of deferred income tax that they paid through rates.

Based on the record evidence in this case, the Company's revised calculation of the Excess ADFIT available to be returned to customers follows Texas law and IRS normalization requirements.

D. Accumulated Depreciation

In his direct testimony, Company witness Jason Cash describes how depreciation rates are calculated using total company plant in service and accumulated depreciation amounts.[180] Mr. Cash further explains that because SWEPCO operates in multiple jurisdictions it is necessary to adjust the accumulated depreciation amount to reflect Texas approved rates.[181] Company witness Mr. Baird further addresses the accumulated depreciation adjustment in his direct testimony.[182] Mr. Baird confirms that the adjustment corrects the blended jurisdictional accumulated depreciation balance for ratemaking purposes to reflect the depreciation rates approved by this Commission.[183] Based on the testimony and evidence presented by the other parties in this case, the accumulated depreciation calculation and adjustments are not contested.

E. Regulatory Assets and Liabilities

1. Self-Insurance Reserve

In its application, SWEPCO requested establishment of a self-insurance reserve under PURA § 36.064.[184] Mr. Brice testified that such a self-insurance reserve is in the interest of both the Company and its customers because it will ensure that customers will pay a representative amount each year toward that reserve and the variability of losses will be averaged out over time through use of the reserve.[185] This approach to recovering qualifying catastrophic losses is the

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[179] Staff Ex. 3 at 43:12-16.

[180] Direct Testimony of Jason Cash, SWEPCO Ex. 16 at 8:14-9:12.

[181] SWEPCO Ex. 16 at 8:14-9:12.

[182] SWEPCO Ex. 6 at 43:21-44:12.

[183] SWEPCO Ex. 6 at 43:21-44:12.

[184] *See* SWEPCO Ex. 4 at 10:17-12:4; Direct Testimony of Gregory S. Wilson, SWEPCO Ex. 28.

[185] SWEPCO Ex. 4 at 11:8-17.

fairest means of ensuring over time that customers pay for only actual costs incurred and that the Company recovers only its actual costs.[186] SWEPCO's request is patterned after the storm reserve approved for AEP Texas and the reserve would be used for a major storm during which incremental expenses exceed $500,000 for a single event and relate to the Company's Texas retail operations.[187] Such storm costs are outside SWEPCO's control and the Company cannot predict such costs.[188]

In support of its self-insurance request, SWEPCO presented the expert testimony of Gregory S. Wilson, a consulting actuary specializing in the area of property-casualty actuarial matters who has testified numerous times in support of self-insurance reserves for Texas utilities.[189] Mr. Wilson presented a cost-benefit analysis demonstrating that self-insurance at the levels proposed by SWEPCO is a lower cost alternative to purchasing insurance and is in the public interest.[190] His testimony also estimated the annual accruals needed to provide for expected property losses incurred by the Company for storm damage losses not covered by insurance and estimated a target amount to accumulate in the self-insurance reserve as well as the recommended time period over which accruals would be made.[191] Mr. Wilson proposed an annual accrual of $1,689,700 and a target property loss self-insurance reserve of $3,560,000.[192] The $1,689,700 annual accrual is composed of two elements -- $799,700 to provide for average annual expected losses from storms with T&D losses of at least $500,000 and $890,000 accrued over four years to achieve the $3,560,000 target reserve.[193]

In future rate filings, SWEPCO will treat the reserve amount as a reduction to its Texas jurisdictional rate base if the amounts credited to the reserve exceed the charges against the reserve and will increase rate base if the charges against the reserve exceed the amounts credited to it.[194]

Although no party directly challenges SWEPCO's evidence that the proposed self-

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[186] SWEPCO Ex. 4 at 11:12-15.

[187] SWEPCO Ex. 6 at 13:1-8.

[188] SWEPCO Ex. 6 at 13:10-13.

[189] SWEPCO Ex. 28 at 1:3-4, 1:14-18.

[190] SWEPCO Ex. 28 at 3:13-16, 10:12-12:7.

[191] SWEPCO Ex. 28 at 3:6-12.

[192] SWEPCO Ex. 28 at 4:15-17, 6:5-9:2.

[193] SWEPCO Ex. 28 at 4:17-21, 9:3-11.

[194] SWEPCO Ex. 6 at 14:14-19.

insurance reserve is in the public interest because it is less expensive than commercial insurance, CARD witness Mark Garrett asserts that the Company's cost benefit analysis does not include empirical evidence such as a specific quote for commercial insurance coverage.[195] However, Mr. Wilson supported his cost benefit analysis by testifying that commercial insurance includes costs for losses, loss adjustment expenses, non-loss related expenses, commissions, taxes and profit while a self-insurance reserve does not incur many of these costs.[196] In addition, Mr. Wilson testified that SWEPCO's experience is that this type of commercial coverage is significantly more expensive than self-insurance and that he understands that private coverage continues to be prohibitively expensive.[197] Mr. Wilson confirmed this information with SWEPCO's risk management department within a month of filing his direct testimony.[198] In his experience, in Texas commercial insurance is always going to be more expensive than self-insurance for this type of coverage of transmission and distribution lines.[199]

OPUC witness Ms. Cannady and TIEC witness Ms. LaConte did not oppose SWEPCO's request to establish a self-insurance reserve but proposed lower amounts for the annual accrual and target reserve, as set out in the following table:

	SWEPCO	**Cannady***	**LaConte****
Annual Accrual	$1,689,700	$1,552,779	$1,255,500
Target Reserve	$3,560,000	$3,180,000	$2,722,000

* Redacted Direct Testimony of Constance Cannady, OPUC Ex. 1 at 47:12; Schedule CTC-13, OPUC Ex. 21.
** Redacted Direct Testimony of Billie LaConte, TIEC Ex. 4 at 22:6-11.

Ms. Cannady and Ms. LaConte derived the reductions to SWEPCO's recommended annual accrual and target reserve by selectively excluding storm costs for the year 2000 as estimates. However, Mr. Wilson explained in rebuttal testimony that the 2000 amount was based on actual damage payments and, because SWEPCO did not keep records for each storm prior to 2005, he conservatively deducted the largest non-major storm experience over the period, resulting in an

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[195] Direct Testimony of Mark E. Garrett, CARD Ex. 2 at 37:2-39:14.

[196] SWEPCO Ex. 28 at 11:1-18.

[197] SWEPCO Ex. 28 at 12:1-7.

[198] Tr. at 289:17-290:5 (Wilson Cross) (May 19, 2021).

[199] Tr. at 286:5-287:4 (Wilson Cross) (May 19, 2021).

estimate for 2000 that is almost certainly lower than actual payments.[200] Ms. Cannady and Ms. LaConte inappropriately exclude a period of significant storm damages from their analysis.

2. Hurricane Laura Costs

SWEPCO's application requests authorization to charge the Texas jurisdictional Hurricane Laura restoration costs against the self-insurance reserve as a regulatory asset that will be reduced each month by the amount of reserve collected.[201] This request is consistent with PURA § 36.405, which provides for securitization of system restoration costs or recovery of those costs in a base rate proceeding. No party filed testimony addressing or opposing the Company's requested treatment of Hurricane Laura restoration costs. Issues relating to carrying costs and functionalization and allocation to customers will be reviewed in SWEPCO's next base rate case when the self-insurance regulatory asset or liability is reviewed and placed in base rates.

III. Rate of Return

A. Overall Rate of Return, Return on Equity, Cost of Debt

SWEPCO requests an overall rate of return of 7.22% weighted average cost of capital (WACC). Company witness Ms. Renee Hawkins sponsored the Company's requested capital structure and overall rate of return in this proceeding.[202] Ms. Hawkins calculated the 7.22% WACC using the requested capital structure, the recommended return on equity sponsored by Company witness Mr. Dylan D'Ascendis, and the Company's actual cost of debt as follows:

SWEPCO	% of Total Capitalization	Cost of Capital Rate	WACC(%)
Long-Term Debt	50.63%	4.18%	2.11%
Common Equity	49.37%	10.35%	5.11%
Total	100.00%		7.22%[203]

Ms. Hawkins' direct testimony explains how SWEPCO's proposed WACC was calculated.[204] Ms. Hawkins specifically explains that the proposed capital structure, when combined with the Company's 10.35% requested return on equity and its 4.18% cost of debt, results in an overall

200 Rebuttal Testimony of Gregory S. Wilson, SWEPCO Ex. 50 at 2:17-3:10.

201 SWEPCO Ex. 4 at 12:2-4.

202 Direct Testimony of Renee Hawkins, SWEPCO Ex. 9 at 3:12-5:10.

203 SWEPCO Ex. 9 at 3:17.

204 SWEPCO Ex. 9 at 4:3-5:10.

return of 7.22%.[205] No party contested the Company's proposed capital structure. However, Commission Staff and certain intervenors contested the Company's recommended return on equity, and made alternative recommendations, which (if authorized) would significantly reduce the Company's overall rate of return. Commission Staff also recommended an adjustment to the Company's actual cost of debt. The contested issues involving return on equity and cost of debt are addressed below.

1. Return on Equity

The return on equity (ROE) is the return that investors require to make an equity investment in a firm. It reflects investors' assessment of the total investment risk, including the business and financial risk, of the subject firm.[206] Because SWEPCO is a regulated public utility, regulation must act as a substitute for market competition in setting the ROE.[207] SWEPCO requests that the Commission authorize a market-based ROE of 10.35%.[208]

SWEPCO's request is based on an expert assessment of three well-established methodologies for estimating a market-based ROE: the discounted cash flow (DCF) model; the risk premium model (RPM); and the capital asset pricing model (CAPM).[209] Those methodologies were applied to a proxy group of electric utility holding companies ("Utility Proxy Group") with relatively similar risk to SWEPCO. They were also applied to a proxy group of non-price-regulated companies with relatively similar risk to SWEPCO.[210]

On direct, SWEPCO's ROE witness Mr. D'Ascendis' expert analysis revealed that the indicated range of ROEs applicable to the Utility Proxy Group ranged from 9.85% – 10.96%, before any adjustment due to SWEPCO's relatively smaller size and riskier bond rating.[211] On rebuttal, due to the fluid market conditions resulting from the COVID-19 pandemic, Mr. D'Ascendis updated his ROE analyses as of March 31, 2021.[212] His updated analysis indicated

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[205] SWEPCO Ex. 9 at 4:3-5:10.

[206] Direct Testimony of Dylan D'Ascendis, SWEPCO Ex. 8 at 14:22-15:1.

[207] SWEPCO Ex. 8 at 14:4-6.

[208] SWEPCO Ex. 8 at 57:14-16.

[209] SWEPCO Ex. 8 at 6:1-3.

[210] SWEPCO Ex. 8 at 48:3-49:18.

[211] SWEPCO Ex. 8 at 6:7-11.

[212] Rebuttal Testimony of Dylan D'Ascendis, SWEPCO Ex. 38 at 6:4-5.

that the range of reasonable ROEs for SWEPCO had increased to 10.14% - 10.97% (again before any relative risk adjustments). This clear uptick in resulting ROEs provides a directional indicator that the investor-required return increased over time.[213] Therefore, SWEPCO's requested 10.35% ROE is reasonable. It also is consistent with well-settled U.S. Supreme Court precedent and Commission rules, which require the Commission to allow an electric utility a reasonable opportunity to earn a reasonable rate of return that is:

- commensurate with returns on equity investments in enterprises having comparable risks;
- sufficient to assure confidence in the financial soundness of SWEPCO's operations; and
- adequate to maintain and support SWEPCO's credit and enable it to raise the money necessary for the proper discharge of its public duties.[214]

In contrast, Staff and intervenor ROE recommendations are based on faulty interpretations of current capital market conditions and the misapplication of some of their models.[215] The errors in CARD's ROE analysis are compounded by CARD's sole reliance on the DCF model.[216] Walmart's witness provided no independent analysis of the Company's cost of common equity.[217] In view of current markets and the updated results of Mr. D'Ascendis' ROE models, ROEs of 9.00% (CARD), 9.15% (TIEC), 9.35% (Staff), and "no higher than 9.60%"[218] (Walmart) are insufficient.[219]

a. SWEPCO's requested ROE is based on multiple well-established methodologies and produces a reasonable result

Mr. D'Ascendis' 10.35% ROE recommendation results from applying the constant growth DCF model, two versions of the RPM, and two versions of the CAPM. These models enjoy

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[213] SWEPCO Ex. 38 at 10:1-8.

[214] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944); *Bluefield Waterworks & Improvement Co v Pub. Serv. Comm'n of W Va.*, 262 U.S. 679, 692-93 (1923); 16 TAC § 25.231(c)(1).

[215] SWEPCO Ex. 38 at 7:11-8:9.

[216] SWEPCO Ex. 38 at 97:18-20.

[217] SWEPCO Ex. 38 at 5, n.1 and 137:9-138:11.

[218] Direct Testimony of Lisa V. Perry, Walmart Ex. 1 at 4:6 (using the page number in the bottom center of the page).

[219] SWEPCO Ex. 38 at 6:8-11.

support in both the financial literature and regulatory precedent.[220] Using multiple generally accepted models adds reliability and accuracy to the ROE estimate because no single model is so precise that it can be relied on to the exclusion of other theoretically sound models.[221]

Mr. D'Ascendis applied these models to a Utility Proxy Group[222] and to a Non-Price Regulated Proxy Group.[223] Using a utility proxy group is common. And given that the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy if they are comparable in total risk to the utility proxy group used to estimate the cost of common equity because they all compete for capital in the same markets.[224] Both of these proxy groups have a comparable, though not identical, risk profile to SWEPCO.[225]

For each model, Mr. D'Ascendis used averaging to arrive at a pinpoint ROE estimate. Using those pinpoints, Mr. D'Ascendis developed a range of reasonable ROEs for SWEPCO. The bottom of the indicated range (i.e., 9.85%) was calculated by averaging the average of all model results with the lowest model result (which is the DCF's 8.73%).[226] The top of the range is the average of all the model results.[227] Thus, this methodology results in a conservative range because the DCF model, which currently understates investor-required returns, is weighted 62.5% in setting the range, far more heavily than the 12.5% weighting given to each of the other models.[228] Using this methodology produced an estimated ROE range of 9.85 – 10.96% (on direct) and 10.14% – 10.97% (updated for rebuttal) before any relative risk adjustment.[229]

i. Mr. D'Ascendis' DCF analysis is reasonable

As part of his analysis, Mr. D'Ascendis used the single-stage constant growth DCF

220 SWEPCO Ex. 8 at 51:20-22.

221 SWEPCO Ex. 8 at 14:14-18 and 51:17-20.

222 SWEPCO Ex. 8 at 20, Table 3.

223 SWEPCO Ex. 8 at Schedule DWD-6.

224 SWEPCO Ex. 8 at 48:6-13; Tr. at 1015:22-1016:1 (Gorman Cross) (May 24, 2021).

225 SWEPCO Ex. 8 at 5:10-12 and 48:14-49:18.

226 SWEPCO Ex. 8 at 27:16-18.

227 SWEPCO Ex. 8 at 27:16-18.

228 SWEPCO Ex. 38 at 131:1-9 and Tr. at 1072:12-1079:23 (D'Ascendis Cross) (May 24, 2021).

229 SWEPCO Ex. 8 at 52:2-5.

model.[230] This approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. Under this model, the required ROE equals the dividend yield plus a growth rate. The dividend yield that Mr. D'Ascendis used was based on the proxy companies' dividends as of July 31, 2020, divided by the average closing market price for the 60 trading days ended July 31, 2020, adjusted to reflect the fact that dividends are paid periodically (e.g., quarterly) instead of continuously.[231] For the growth rates, Mr. D'Ascendis used analysts' five-year forecasts of earnings per share from *Value Line*, Zacks, and Yahoo! Finance.[232] Analysts' earnings per share forecasts are appropriate to use because over the long run, there can be no growth in dividends per share without growth in earnings per share.[233] The mean result of applying the single-stage DCF model is 8.63%, the median result is 8.82%, and the average of the two is 8.73%, which was updated to 9.32% in rebuttal to reflect more current conditions.[234]

ii. Mr. D'Ascendis' Risk Premium Models are reasonable

The RPM is based on the fundamental financial principle that investors require greater returns for greater risk. The RPM recognizes that equity capital is riskier than debt capital because equity shareholders are unsecured and last-in-line for any claim on a corporation's assets and earnings upon liquidation.[235] While one can directly observe bond returns and yields, investors' required ROE cannot be directly observed, so the risk premium must be estimated.[236]

Mr. D'Ascendis used two risk premium methods to derive an estimated ROE for SWEPCO. First, he used the Predictive Risk Premium Model (PRPM),[237] which estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk.[238] The PRPM is based on the variance of historical equity risk premiums.[239] The inputs to

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230 SWEPCO Ex. 8 at 25-27.

231 SWEPCO Ex. 8 at 26:3-8.

232 SWEPCO Ex. 8 at 27:3-14.

233 SWEPCO Ex. 38 at 115:15.

234 SWEPCO Ex. 38 at 9, Table 1.

235 SWEPCO Ex. 8 at 28:3-16.

236 SWEPCO Ex. 8 at 28:9-14.

237 SWEPCO Ex. 8 at 29-30.

238 SWEPCO Ex. 8 at 29:11-13.

239 SWEPCO Ex. 8 at 29:12-14.

the model are the historical returns on the common shares of each proxy group company minus the historical monthly yield on long-term U.S. Treasury securities.[240] Using statistical software, Mr. D'Ascendis calculated a predicted annual equity risk premium, to which he then added the forecasted 30-year U.S. Treasury bond yield of 2.09%.[241] Averaging the mean and median results of the Utility Proxy Group results in an ROE of 10.27%.

Second, Mr. D'Ascendis used the Total Market Approach.[242] The total market approach RPM adds a prospective public utility bond yield to an average of: 1) an equity risk premium that is derived from a Beta-adjusted total market equity risk premium; 2) an equity risk premium based on the S&P Utilities Index; and 3) an equity risk premium based on authorized ROEs for electric utilities.[243]

The first step in developing any of these three equity risk premiums is to determine the appropriate bond yield.[244] Because setting the cost of capital is prospective, it is essential to use a prospective (not historical) yield.[245] In determining the bond yield, Mr. D'Ascendis relied on a consensus forecast of 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with Q4 2021 and Blue Chip's long-term projections for 2022-2026 and 2027-2031.[246] He then adjusted that rate slightly upward to reflect the riskier bond rating of the Utility Proxy Group, as shown in the following table.[247]

Summary of the Calculation of the Utility Proxy Group Projected Bond Yield

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (Blue Chip)	3.03%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.61%
Adjustment to Reflect the Utility Proxy Group's Average Moody's Bond Rating of A3	0.14%
Prospective Bond Yield Applicable to the Utility Proxy Group	**3.78%**

240 SWEPCO Ex. 8 at 29:15-16.

241 SWEPCO Ex. 8 at 20:3-4.

242 SWEPCO Ex. 8 at 30-40.

243 SWEPCO Ex. 8 at 30:13-16.

244 SWEPCO Ex. 8 at 30:19-20.

245 SWEPCO Ex. 8 at 31:1-2.

246 SWEPCO Ex. 8 at 31:2-5.

247 SWEPCO Ex. 8 at 31:1-19 and 32, Table 5.

The components of the Beta-adjusted total market equity risk premium model are: (i) an expected market equity risk premium over corporate bonds; and (ii) the Beta-coefficient.[248] The total Beta-derived equity risk premium that Mr. D'Ascendis applied is based on an average of six equity risk premiums (ERP), three that are historical in nature and three that are prospective.[249]

The average equity risk premium of these six models is 9.92%. Adjusting by the Beta coefficient to account for the slightly lower risk of the Utility Proxy Group relative to the overall market results in an equity risk premium of 9.42%.[250]

Mr. D'Ascendis also estimated three equity risk premiums based on the S&P Utility Index holding period returns and two equity risk premiums based on the expected returns of the S&P Utilities Index, using *Value Line* and Bloomberg data, respectively.[251] As with the market equity risk premiums, he averaged each risk premium based on each source (i.e., historical, *Value Line*, and Bloomberg) to arrive at a utility specific equity risk premium of 5.77%.[252]

Finally, Mr. D'Ascendis derived an equity risk premium of 5.88% by performing a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A2-rated public utility bonds for 1,167 fully litigated electric utility rate cases from 1980 – 2019.[253] The results of this analysis readily show an inverse relationship between the equity risk premium and interest rates — that is, as interest rates decline, the equity risk premium for utilities increases.[254] The inverse relationship between the ERP and interest rates is supported by multiple academic studies and is recognized by Staff witness Mr. Mark Filarowicz. And although TIEC witness Mr. Michael Gorman criticized Mr. D'Ascendis' observation of the inverse relationship, Mr. Gorman's own data demonstrates the very inverse relationship that his testimony denies exists.[255]

Averaging the equity risk premium from these three methodologies results in an equity risk

[248] SWEPCO Ex. 8 at 32:6-7.

[249] SWEPCO Ex. 8 at 32:9-36:14 (describing each of the six ERPs applied by Mr. D'Ascendis).

[250] SWEPCO Ex. 8 at 37:4-12.

[251] SWEPCO Ex. 8 at 38:3-18.

[252] SWEPCO Ex. 8 at 38:18-21.

[253] SWEPCO Ex. 8 at 39:5-40:5.

[254] SWEPCO Ex. 8 at 39:12-40:1.

[255] SWEPCO Ex. 38 at 85:7-87:5.

premium of 7.02%. When that premium is added to the prospective Moody's A3-rated utility bond applicable to the Utility Proxy Group of 3.78%, it indicates an ROE of 10.8%.

iii. Mr. D'Ascendis' Capital Asset Pricing Models are reasonable

Mr. D'Ascendis also undertook two CAPM analyses – a traditional CAPM and the empirical CAPM (ECAPM), both of which are supported by academic research.[256] The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification.[257] The risk that cannot be eliminated through diversification is called market, or systematic risk.[258] The CAPM assumes that investors require compensation only for systematic risk.[259] The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market, as measured by the Beta coefficient.[260] The results of the CAPM support the idea that the Beta coefficient is related to security returns.

The ECAPM formula better reflects the reality that the empirical "security market line" described by the CAPM formula is not as steeply sloped as predicted. In other words, the returns on the low beta portfolios tend to be higher than predicted and the returns on the high beta portfolios tend to be lower than predicted.[261] In view of this theory and the practical research, Mr. D'Ascendis applied both models and averaged the results.[262]

The inputs to the CAPM are a Beta coefficient, a risk-free rate of return, and a risk premium. For the Beta coefficients, Mr. D'Ascendis considered *Value Line*, which calculated the coefficient of a five-year period, and Bloomberg Professional Services, which calculates the coefficient over a two-year period.[263]

For the risk-free rate, Mr. D'Ascendis used 2.09% for both applications of the CAPM. That

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256 SWEPCO Ex. 8 at 42:9-45:2.

257 SWEPCO Ex. 8 at 41:13-14.

258 SWEPCO Ex. 8 at 41:14-15.

259 SWEPCO Ex. 8 at 41:15-16.

260 SWEPCO Ex. 8 at 41:17-42:1.

261 SWEPCO Ex. 8 at 42:9-17 and 43, Figure 2.

262 SWEPCO Ex. 8 at 44:21-23.

263 SWEPCO Ex. 8 at 44:25-45:2.

rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for six quarters ending with the fourth calendar quarter of 2021.[264] The yield on long-term U.S. Treasury bonds is appropriate because it is virtually risk-free and its term is consistent with: (i) the long-term cost of capital to public utilities measured by the yields on Moody's A-rated public utility bonds; (ii) the long-term investment horizon inherent in utilities' common stocks; and (iii) the long-term life of the jurisdictional rate base to which the allowed fair rate of return (i.e., cost of capital) will be applied. In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.[265]

The market risk premium is derived from an average of three historical data-based market risk premiums and three prospective market-risk premiums, as described in the subsection above.[266] The six measures, when averaged, result in an average total market equity risk premium of 10.92%. The mean result of the CAPM/ECAPM is 12.61%, the median is 12.30%, and the average of the two is 12.46%. Consistent with Mr. D'Ascendis' reliance on the average of mean and median DCF, the indicated ROE for SWEPCO using these models is 12.46%.

Based on the results of the DCF, risk premium, and CAPM models, the range of appropriate ROEs for SWEPCO ranges from 9.85% – 10.96% (direct) and 10.14% - 10.97% (as updated for March 31, 2021), both of which support Mr. D'Ascendis' 10.35% recommendation even before applying a relative risk adjustment.

iv. Relative Risk Adjustment

Because no proxy group can be identical in risk to any single company, there must be an evaluation of relative risk between the company and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.[267] SWEPCO is relatively riskier than the companies in the proxy groups in two areas, which warrants a small upward adjustment to account for those risks: smaller size and credit quality.

Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues, and earnings. For example, smaller companies face

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[264] SWEPCO Ex. 8 at 45:4-8.

[265] SWEPCO Ex. 8 at 45:11-17.

[266] *See also* SWEPCO Ex. 8 at 46:3-22.

[267] SWEPCO Ex. 8 at 5:14-17.

more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse customer base.[268] Neither S&P nor Moody's have minimum company size requirements for any given rating level. This means, all else equal, a relative size analysis must be conducted for equity investments in companies with similar bond ratings.[269]

The average company in the Utility Proxy Group has a market capitalization 8.7 times the size of SWEPCO's estimated market capitalization.[270] To make the adjustment, Mr. D'Ascendis relied on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 – 2019 period, which indicated a 0.84% adjustment.[271] However, to be conservative, Mr. D'Ascendis recommends a size premium of 0.20%.

Similarly, a credit risk adjustment is warranted to reflect the lower credit rating of SWEPCO compared to the Utility Proxy Group.[272] Mr. D'Ascendis calculated that as requiring a 0.09% upward adjustment based on the applicable credit risk spread.[273]

Again, the ROE range without relative risk adjustments supports a 10.35% ROE. The relative risk adjustment underscores the reasonableness of SWEPCO's requested ROE.

b. The analyses by Staff and intervenors are flawed and lead to recommendations that are insufficient and not commensurate with SWEPCO's level of risk

Aside from SWEPCO, four parties presented ROE testimony in this proceeding: CARD, Commission Staff, TIEC, and Walmart (collectively, the Opposing Parties). Their pre-filed testimonies suffer from common flaws that lead to understating the ROE, so it is unsurprising that their recommendations generally fall within a narrow and insufficient range.

As explained earlier, one of the key legal standards in setting an ROE is that the return to

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[268] SWEPCO Ex. 8 at 52:15-20.

[269] SWEPCO Ex. 8 at 17:14-16.

[270] SWEPCO Ex. 8 at 55:5-7.

[271] SWEPCO Ex. 8 at 55:16-18.

[272] SWEPCO Ex. 38 at 9:1-9.

[273] SWEPCO Ex. 38 at 48:3-12.

the equity owner should be commensurate with returns on investment in other enterprises having comparable risk. Despite paying lip service to this well-established legal standard, the Opposing Parties nevertheless recommend ROEs for SWEPCO that are well below the average authorized ROE for vertically integrated utilities from 2017 to the present. The evidence in this proceeding establishes that the average authorized ROE for vertically integrated utilities from 2017 to the present is 9.69%.[274] And that 9.69% includes the unusually low ROE average from 2020, which was an outlier year.[275] The average ROE authorized for vertically integrated utilities in 2017 was 9.80 percent; in 2018, it was 9.68 percent; and in 2019, it was 9.73 percent. In contrast, the Opposing Parties' witnesses recommend ROEs of 9.0% (CARD); 9.15% (TIEC), 9.35% (Staff), and "no higher than 9.60%"[276] (Walmart). Yet none of those witnesses explain what makes SWEPCO so much less risky than other vertically integrated utilities that it would be able to attract capital with an ROE so far below the national average. Nor do they explain why they think SWEPCO is less risky today than it was just a few years ago. As Mr. D'Ascendis shows, multiple risk measures have increased for SWEPCO since Docket No. 46449, SWEPCO's last base rate case,[277] yet the Opposing Parties' witnesses recommend ROEs significantly below SWEPCO's currently authorized ROE.

Their recommended ROEs are also lower than any ROE the Commission has authorized recently, even for wires-only companies, which Opposing Parties generally view as less risky than vertically integrated utilities.[278] The lowest ROEs that have recently been authorized for Texas wires-only companies were 9.40%, and both of those occurred in the admittedly outlier year of 2020.[279] Yet, Mr. Filarowicz, who recommends the highest ROE of the Opposing Parties that presented a model-based analysis, recommended just a 9.35% for SWEPCO's vertically integrated operations. The risk profile of a vertically integrated utility is demonstrated by the positions taken by Opposing Parties in this case. As discussed in Section II.A above, challenges to SWEPCO's

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[274] Walmart Ex. 1 at 11:6-8.

[275] Tr. at 987:4-18 (Woolridge Cross); 1013:7-20 (Gorman Cross) (May 24, 2021).

[276] Walmart Ex. 1 at 4:6.

[277] SWEPCO Ex. 38 at 25:15-26:4 (Table 7).

[278] Tr. at 1036:19-24 (Filarowicz Cross); *see also* 983:1-6 (Woolridge Cross) (May 24, 2021).

[279] Direct Testimony of J. Randall Woolridge, CARD Ex. 4 at 16, Table 3 (using the page number in the bottom center of the page).

invested capital are focused on the generation function, with no challenge to SWEPCO's investment in the transmission and distribution functions. Opposing Parties are willing for SWEPCO to take on this added risk without recognizing the increased investor-required return relating to the added risk.

A "declining trend" in ROEs is not to blame. Walmart's pre-filed testimony states that "the average authorized ROE for vertically integrated utilities from 2017 through present is 9.69 percent, and the trend in these averages has been relatively stable."[280] Each of the other Opposing Parties admitted on cross that authorized ROEs have been stable from 2014 – 2019.[281] And Mr. Gorman and CARD witness Dr. J. Randall Woolridge agree with Mr. D'Ascendis in recognizing 2020 as an outlier.[282] Further, as Mr. D'Ascendis points out, using average annual data can obscure variations in returns, and when charting individual ROEs, rather than annual averages, there is no meaningful trend since 2016.[283]

Instead, Opposing Parties' witnesses either ignored or misinterpreted capital market conditions, which lends false credence to their below-market ROE recommendations. There is no doubt that much of the last 12 months has been characterized by extreme volatility, both in the equity and debt markets.[284] Yet certain of the Opposing Parties' witnesses focus on historically low interest rates as indicative of a lower cost of capital, ignoring the full impact of volatility on the market in general, and utilities specifically.[285] Indeed, from February 2020 to March 2021, utilities were generally more volatile, and therefore riskier, than the market indices, and had returns that underperformed the market.[286] Further, market volatility is expected to increase and remain elevated until at least January 2022.[287]

In addition, the outlook for utilities is not stable. As S&P noted, the utility industry

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[280] Walmart Ex. 1 at 11:6-8.

[281] Tr. at 989:2-6 (Woolridge Cross); 1013:7-20 (Gorman Cross); 1054:20-1055:8 (Filarowicz Cross) (May 24, 2021).

[282] Tr. at 987:4-18 (Woolridge Cross); 1013:7-20 (Gorman Cross) (May 24, 2021).

[283] SWEPCO Ex. 38 at 53:3-12.

[284] SWEPCO Ex. 8:8-9 and SWEPCO Ex. 38 at 26:15-16:1.

[285] SWEPCO Ex. 38 at 10:22-11:3.

[286] SWEPCO Ex. 38 at 14:8-11.

[287] SWEPCO Ex. 38 at 15:8-16:11.

performed poorly from a credit quality perspective and the negative outlooks or CreditWatch negative listings doubled and downgrades outpaced upgrades for the first time in a decade.[288] As Mr. Gorman acknowledged, in 2020, downgrades outpaced upgrades for the predominantly investment-grade [utility] industry.[289]

Rather than low interest rates being a sign of declining capital costs as certain Opposing Parties' witnesses assume, significant volatility tends to be associated with significant declines in Treasury yields as investors seek to avoid a capital loss by investing in Treasury bonds in a "flight to safety."[290] (Because Treasury yields are inversely related to Treasury bond prices, as investors bid up bond prices, they bid down the yields.)[291] And despite low Treasury yields in 2020, yields are not expected to remain low.[292] Consequently, as may be expected, increased market volatility increases the required return for utility investors, as shown by utility stocks trading in tandem with market indices during the current market dislocation.[293] Thus, when the drivers of risk are viewed in their entirety, it is clear that investor-required returns on utility stocks are increasing.[294]

In addition to ignoring or misinterpreting capital market conditions, the Opposing Parties' witnesses also misapply some of their models, as explained in the subsections below.

i. CARD witness Dr. Woolridge

Dr. Woolridge recommends an ROE of 9.0%. Dr. Woolridge's recommended ROE is the lowest of any witness and fails to meet the standards for setting a utility's authorized ROE. His recommendation is critically flawed because it is based solely on the DCF model, when ROEs are commonly (and more accurately) derived using multiple models.[295] Although Dr. Woolridge included a CAPM analysis in his testimony, he dismissed his own CAPM analysis.[296] His primary reliance on the DCF is also problematic because current market conditions cause the DCF model

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288 SWEPCO Ex. 38 at 23:2-6.

289 Tr. at 1019:16-24 (Gorman Cross) (May 24, 2021).

290 SWEPCO Ex. 38 at 11:9-16.

291 SWEPCO Ex. 38 at 11:14-16.

292 SWEPCO Ex. 38 at 12:3-9.

293 SWEPCO Ex. 38 at 18:1-20:13.

294 SWEPCO Ex. 38 at 11:3-4.

295 SWEPCO Ex. 38 at 107-109.

296 SWEPCO Ex. 38 at 125:12-17.

to understate the investor's expected return.[297]

In addition to relying solely on the DCF as the basis for his recommendation, Dr. Woolridge also misapplied his DCF. He uses retention growth rates (also called sustainable growth rates), which are inappropriate because: (i) they introduce increased potential for forecasting errors; (ii) they are circular in nature in that to estimate the required ROE for a particular company, the model itself first requires an estimate of the earned ROE; and (iii) its assumption that increasing retention ratios are associated with increasing future growth is empirically incorrect.[298] He also uses projected EPS growth rates—despite criticizing their use[299]—and he misapplies them. In his DCF analysis, Dr. Woolridge uses projected growth rates of 5.25% and 5.00%, based on an acceptable range of 5.00% to 5.50%, for his and Mr. D'Ascendis' proxy groups, respectively. Yet the range of growth rates based on the projected EPS growth rates from Value Line, Yahoo!, Zacks, and S&P Capital IQ, from pages 4 and 5 of Exhibit JRW-7, the ranges are 5.2% to 6.0%, and 4.8% to 5.9%, for Dr. Woolridge's and Mr. D'Ascendis' proxy groups, respectively. Taking the midpoint of those respective ranges results in corrected DCF results for Dr. Woolridge's and Mr. D'Ascendis' proxy groups of 9.53% and 9.37%.

The ALJs should also reject Dr. Woolridge's misleading assertion that SWEPCO is somehow less risky because it "has a higher common equity ratio" than the proxy group.[300] First, his comparison is not apples-to-apples. He relies on the capital structure of utility *holding* companies in his proxy group, not the capital structures of utility *operating* companies.[301] The operating company capital structure is a better measure of comparison because SWEPCO is an operating company. Further, Dr. Woolridge's reliance on a simple average of equity percentages is flawed because the average ignores important differences between SWEPCO and the other utility operating companies in the proxy group. Looking to the average and median common equity ratios for the operating utility company subsidiaries indicates that SWEPCO is slightly more leveraged than the operating utility subsidiaries in Dr. Woolridge's proxy group, meaning

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297 SWEPCO Ex. 38 at 109:4-111:2.

298 SWEPCO Ex. 38 at 55:15-59:20 and 123:17-21.

299 SWEPCO Ex. 38 at 115:3-14.

300 CARD Ex. 4 at 18:25-26.

301 CARD Ex. 4 at 18:23-19:9.

SWEPCO's capital structure does not make it less risky than the proxy group.[302]

ii. Staff witness Mr. Filarowicz

Mr. Filarowicz considered multiple models, including the DCF, the RPM, and the CAPM. Although his constant growth DCF produced a 9.35% which is similar to Mr. D'Ascendis' updated DCF model of 9.32%, his applications of the multi-stage DCF, RPM, and CAPM analyses are flawed.

Mr. Filarowicz's application of the RPM suffers from three key flaws. First, while Mr. D'Ascendis and Mr. Filarowicz appear to agree with using projected measures in a cost of capital analysis because "the cost of equity is a forward-looking concept,"[303] Mr. Filarowicz deviates from this principle in the application of his RPM by applying current interest rates.[304] Second, Mr. Filarowicz relies on an annual average of authorized returns and prospective Moody's bond yields in determining their relationship to each other. This methodology is less accurate than considering those variables on an individual basis for two reasons: (i) it gives undue weight to years in which there were fewer rate case decisions; and (ii) it fails to capture the fluctuation that occurs when market conditions change in a given year.[305] Third, Mr. Filarowicz uses corporate bond yields for both his regression and the return on equity comparison rather than public utility bond yields, which is less precise.[306] Correcting the inputs to Mr. Filarowicz's RPM analysis increases his indicated ROE by 50 basis points to 9.55%.[307]

With respect to the CAPM, Mr. Filarowicz's 7.26% result is unreasonable on its face, which Mr. Filarowicz recognizes by not directly considering his CAPM results in the determination of his final ROE recommendation.[308] His misapplication of the CAPM is the driving factor for its unreasonableness. Here again Mr. Filarowicz failed to rely on a prospective measure. Instead he relied on a historical bond-yield as his risk-free rate.[309] In addition, the bond he relied

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302 SWEPCO Ex. 38 at 100:17-101:2.

303 Direct Testimony of Mark Filarowicz, Staff Ex. 1 at 20:12-20 (using the page number in the upper right hand corner of the page).

304 SWEPCO Ex. 38 at 33:9-34:5.

305 SWEPCO Ex. 38 at 34:6-15.

306 SWEPCO Ex. 38 at 34:16-19.

307 SWEPCO Ex. 38 at 36:9-10.

308 Staff Ex. 1 at 25:12-15.

309 SWEPCO Ex. 38 at 37:3-5.

upon was a 20-year bond, which is too short to match the life of a utility investment.[310] Instead he should have relied on a 30-year bond, which more appropriately matches the average life of SWEPCO's utility plant.[311] Second, he incorrectly calculated the Market Risk Premium (MRP) by using the total return on long-term government bonds in his calculation, instead of the *income* return recommended by the source he relied on for the fact that the income return "represents the truly riskless portion of the return."[312] Third, Mr. Filarowicz did not incorporate an ECAPM analysis even though empirical evidence indicates that low-beta securities, such as utilities, earn returns higher than the CAPM predicts and high-beta securities earn less.[313] Notably, Mr. Filarowicz did not criticize Mr. D'Ascendis' application of the CAPM, even as he criticized other aspects of Mr. D'Ascendis' ROE analysis. Correcting Mr. Filarowicz's errors results in a range of indicated ROEs between 10.28% and 10.32%.[314]

Mr. Filarowicz further provides in his direct testimony that his 9.35% ROE recommendation is just one input to Staff's overall ROE recommendation of 9.225%.[315] Citing PURA § 36.052 and TAC § 25.52(b)(1), Staff witness John Poole recommends a $1.13 million dollar annual reduction to SWEPCO's authorized ROE due to a transmission outage on August 18, 2019.[316] Mr. Poole's recommendation is addressed at the end of this section of the brief.

iii. TIEC witness Mr. Gorman

TIEC witness Gorman recommends an indicated range of ROEs from 8.90 to 9.35% and within that range he recommends a point estimate of 9.15%.[317] Mr. Gorman applies three DCF models (constant growth, sustainable growth, and multi-stage), a CAPM analysis, and two RPM analyses.[318] Before addressing his analyses, Mr. Gorman argues generally in support of lower ROEs because, "national average authorized returns on equity for both electric and gas utilities

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310 SWEPCO Ex. 38 at 37:13-38:20.

311 SWEPCO Ex. 38 at 38:13-39:4.

312 SWEPCO Ex. 38 at 39:8-28.

313 SWEPCO Ex. 38 at 37:7-10 and 41:20-42:3.

314 SWEPCO Ex. 38 at 42:4-14.

315 Staff Ex. 1 at 28:14-29:19.

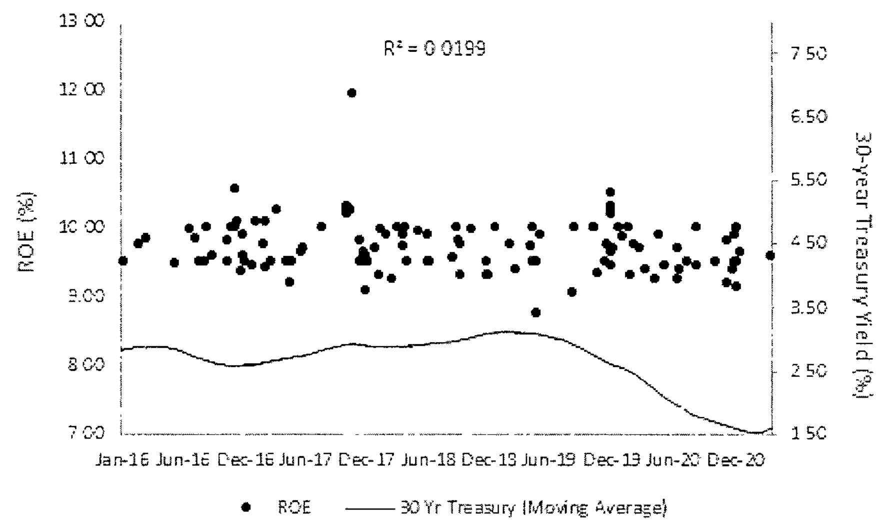
316 Direct Testimony of John Poole, Staff Ex. 5 at 12:9-12.

317 Direct Testimony of Michael Gorman, TIEC Ex. 3 at 5:15-22.

318 TIEC Ex. 3 at 47, 53-54, and Exhibits MPG-5, MPG-8, and MPG-10.

have declined over the last several years and have been reasonably stable around the mid 9% range for both electric and gas regulated utilities."[319] However, Mr. Gorman's analysis of these "trends" lacks context. Average annual data obscures variation in returns and does not address the number of cases or the jurisdictions issuing orders within a given year. For example, one year may have fewer cases decided, and a relatively large portion of those cases decided by a single jurisdiction. Moreover, using the authorized ROE average for 2020 (the COVID year) gives a false impression of a downward "trend," especially when Mr. Gorman himself agrees that 2020 was an outlier year for authorized returns.[320] As shown below, charting all authorized ROEs, rather than annual averages, shows that there is no meaningful trend since 2016. The majority of authorized ROEs since 2016 have been above the average cited by Mr. Gorman, as shown on the chart below.

Authorized Returns for Gas and Electric Utilities (2016-2021)[321]



If one considers all recently authorized ROEs, rather than simple annual averages, there is no discernible downward trend. There is no statistical difference in the averages over the past six

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[319] TIEC Ex. 3 at 7:5-7.

[320] Tr. at 1013:7-20 (Gorman Cross) (May 20, 2021).

[321] SWEPCO Ex. 38 at 54:1 (Source: Regulatory Research Associates. Excludes limited issue rate riders. Based on data through March 31, 2021. Note that the 30-year Treasury yield is based on a backwards-looking moving average that incorporates the previous 252 trading days (approximately one calendar year).

years.[322]

With respect to Mr. Gorman's DCF models, his constant growth (9.43% avg.) DCF is comparable to Mr. Filarowicz's and Mr. D'Ascendis' DCF models. However, Mr. Gorman's sustainable growth (8.44% avg.) and multi-stage (8.56% avg.) DCF model results are too low and as a consequence unreasonably lower his overall DCF recommendation. Citing Morin[323] and Financial Analysts Journal,[324] Mr. D'Ascendis testifies that the sustainable growth model has numerous flaws, including its reliance on a positive relationship between retention ratios and future earnings when the evidence suggests there is a negative relationship between the two.[325] Likewise, Mr. Gorman's multi-stage DCF produces unreasonably low results. As discussed above, the multi-stage DCF model is inapplicable to utilities because utilities are not in a growth stage, but a mature "steady-state" stage, which is characterized by limited, slightly attractive investment opportunities and steady earnings growth, dividend payout ratios, and ROEs.[326]

Mr. Gorman's RPM results (9.20% point est.) are too low because he relies on a short historical period (1986 – 2020) and he ignores the negative correlation between ERP and interest rates.[327] With respect to Mr. Gorman's use of a short historical period, Mr. D'Ascendis cites Duff and Phelps for the proposition that a proper equity risk premium requires a data series long enough to give reliable averages without undue influence by good or bad short-term returns.[328] Moreover, Mr. Gorman ignores the data supported by his own exhibits (MPG-12 and MPG-13), which show that as interest rates fall, the ERP increases.[329] Correcting this oversight and applying the correct risk-free rate and bond yield results in indicated ROEs of 9.44% and 9.57%, respectively.[330]

Mr. Gorman's CAPM results (9.5% point est.) are also too low because he fails to consider long-term projection of the risk-free rate published by Blue Chip (although he uses Blue Chip

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322 SWEPCO Ex. 38 at 53:6-12.

323 SWEPCO Ex. 38 at 56:5-57:1.

324 SWEPCO Ex. 38 at 58:6-12.

325 SWEPCO Ex. 38 at 58:10-59:20.

326 SWEPCO Ex. 38 at 60:3-12 and Tr. at 999:3-15 (Woolridge Cross) (May 24, 2021).

327 SWEPCO Ex. 38 at 64:4-9.

328 SWEPCO Ex. 38 at 65:18-31.

329 SWEPCO Ex. 38 at 68:14-20.

330 SWEPCO Ex. 38 at 70:3-5.

elsewhere in his analysis).[331] Moreover, Mr. Gorman's MRP calculation is flawed because it principally relies on the historical real market rate of return, which does not track investor sentiment or current market conditions.[332]

iv. Walmart witness Ms. Perry

Ms. Perry's recommendation for an ROE no higher than 9.6% is based on her review of authorized ROEs since 2017, both nationwide and in Texas.[333] Ms. Perry acknowledges that the Commission might find that a higher ROE is warranted "due to changes in circumstances since the Company's last rate case," but Ms. Perry did not perform any independent analysis of SWEPCO's ROE.[334] Ms. Perry also ignored the ongoing volatile financial and economic environment caused by COVID-19.[335]

v. Staff's Proposed ROE Penalty for Transmission Outage

Although no party filed testimony contesting SWEPCO's transmission-related O&M or capital expenditures, Staff witness Mr. John Poole proposed a $1.13 million reduction to the Company's return on equity and retention of an independent contractor based on a transmission outage that occurred August 18, 2019.[336] This recommendation should be rejected for at least two reasons:

1. Staff has not established any legal basis for such an ROE penalty or independent contractor and the evidence shows SWEPCO makes reasonable efforts to prevent interruption of service, consistent with 16 TAC § 25.52(b)(1); and
2. Staff's proposed ROE penalty would total approximately $4.5 million over the typical four-year span between rate cases, which vastly exceeds the Commission's authorized penalty authority of up to $25,000 per day of violation.

As an initial matter, Staff witness Mr. Poole's recommended ROE penalty seems to be premised on the fact that the August 18 outage occurred, rather than establishing any legal basis for such a large penalty. Although Mr. Poole cites PURA § 36.052(2) [quality of the utility's

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[331] SWEPCO Ex. 38 at 71:14-20.

[332] SWEPCO Ex. 38 at 73:8-20.

[333] Walmart Ex. 1 at 13:14-18; SWEPCO Ex. 38 at 137:12-14.

[334] Walmart Ex. 1 at 13:14-15; SWEPCO Ex. 38 at 6, n.1.

[335] SWEPCO Ex. 38 at 138:6-9.

[336] Staff Ex. 5 at 12:9-12.

service] and (4) [quality of utility's management] as well as 16 TAC § 25.52(b)(1) [reasonable efforts to prevent interruptions of service],[337] his testimony focuses on a single seven-hour outage, the likes of which has not occurred before or since on SWEPCO's system. He does not examine the overall quality of SWEPCO's service, the quality of its management, or its efforts to prevent service interruptions. In addition, while Mr. Poole asserts that "[i]t is my opinion that prudent vegetation management on the Knox-Pirkey Line and the Pirkney[sic]-to-Whitney 138-kV Line during 2010-2019 would have prevented the cascading interruptions,"[338] he agreed at hearing that he doesn't have any specific qualifications with respect to vegetation management.[339]

The evidence shows that SWEPCO satisfies the relevant outage prevention standard in 16 TAC § 25.52(b)(1) because the Company makes reasonable efforts to prevent interruptions of service. Some of those efforts were discussed in the attachments to Mr. Poole's testimony, such as the annual aerial vegetation inspection patrols for all lines less than 200kV and twice annual aerial patrols for lines greater than 200kV.[340] AEP Forestry uses the data from these inspections to determine reactive vegetation management strategies to remove immediate threats and proactive strategies to manage future work plans and determine frequency of maintenance.[341] SWEPCO's O&M programs to minimize and prevent interruptions are discussed in detail in Mr. Boezio's direct testimony and are based on industry standards.[342] SWEPCO's O&M expenditures for transmission vegetation management in Texas have increased significantly in recent years, from $2.85 million in 2016 to over $6 million in 2019 and 2020.[343]

In addition, SWEPCO has invested an average of $60 million per year since its last rate case on asset improvement projects to replace aging transmission infrastructure.[344] Mr. Poole agreed that it is normal for a utility to have a number of older lines that are being replaced over

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337 Staff Ex. 5 at 5:2-15.

338 Staff Ex. 5 at 9:13-15.

339 Tr. at 429:6-20 (Poole Cross) (May 20, 2021).

340 Rebuttal Testimony of Daniel R. Boezio, SWEPCO Ex. 41 at 3:6-9, citing the Direct Testimony of John Poole, CONFIDENTIAL Attachment JP-4 at 13-14 (Staff Ex. 5C).

341 SWEPCO Ex. 41 at 3:10-14.

342 SWEPCO Ex. 41 at 3:19-4:5, Direct Testimony of Daniel Boezio, SWEPCO Ex. 11 at 13:12-14:11.

343 SWEPCO Ex. 41 at 5:8-15.

344 SWEPCO Ex. 41 at 4:13-16, 5:16-19; Tr. at 438:1-4 (Poole Recross) (May 20, 2021).

time.[345] Neither Mr. Poole nor any other witness questions the reasonableness of this transmission asset replacement program, although Mr. Poole does assert that overall system reliability did not appreciably increase following the rebuilds, suggesting that not all issues have been addressed.[346] However, system reliability metrics can be affected by a number of factors, most notably weather, and it is undisputed that SWEPCO has a significant and ongoing program to replace aging transmission facilities as part of its reasonable efforts to prevent interruptions of service.

Mr. Poole largely dismisses the impact of weather in contributing to the August 18 outage, but the evidence shows that excessive rainfall was a major factor prior to the outage. Although Mr. Poole asserts that it would have taken a number of years for trees to grow to the height shown in SWEPCO's report to Staff and that annual rainfall over the previous decade was not unusual,[347] these conclusions are mistaken. As noted previously, Mr. Poole doesn't have any specific qualifications with respect to vegetation management.[348] His focus on annual rainfall over a decade is misplaced since the relevant evidence shows that the area received 32 inches of rain during the April-June growing season prior to the outage, 13.7 inches above average.[349] This rainfall not only contributed to abnormal levels of vegetation growth prior to the outage but also hindered the Company's efforts to access flooded or impassable rights-of-way to manage the growing vegetation.[350]

The initial vegetation contact for the August outage was a vine that had been specifically monitored in the aerial inspection several months earlier.[351] The inspection noted greater than 25 feet of clearance between the vine and the conductor, which is not considered to be a threat.[352] Mr. Poole acknowledged that he has no expertise in that specific type of vine and did not dispute the possibility that it could grow 25 feet in a period of a few months during heavy rainfall events.[353]

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[345] Tr. at 438:14-18 (Poole Cross) (May 20, 2021).

[346] Staff Ex. 5 at 10:13-17.

[347] Staff Ex. 5 at 9:10-13.

[348] Tr. at 429:6-20 (Poole Cross) (May 20, 2021).

[349] SWEPCO Ex. 41 at 6:11-12 (Figure 2).

[350] SWEPCO Ex. 41 at 6:13-7:2; Tr. at 433:2-7 (Poole Cross) (May 20, 2021).

[351] SWEPCO Ex. 41 at 7:4-6; Tr. at 430:15-431:24 (Poole Cross) (May 20, 2021).

[352] SWEPCO Ex. 41 at 7:6-7.

[353] Tr. at 431:18-24 (Poole Cross) (May 20, 2021).

The evidence also shows that the SWEPCO area has fast-growing trees that can grow as much as 10 feet in a single season and grew more than anticipated due to the abnormal rainfall.[354]

Finally, Mr. Poole's proposed ROE penalty is grossly disproportionate to the Commission's authority to impose administrative penalties. Under PURA § 15.023, the Commission is authorized to impose a penalty of up to $25,000 for each day a violation continues or occurs. By contrast, Mr. Poole's proposed ROE penalty is $1.13 million, which he acknowledges would apply each year until the Company's next rate case.[355] Under the standard Commission four-year schedule for rate cases, the proposed penalty would amount to more than $4.5 million.[356] This would be the equivalent of roughly 180 days at $25,000 per day, even though the outage lasted only seven hours.[357]

SWEPCO comprehensively investigated this outage in collaboration with the North American Electric Reliability Corporation (NERC) and SPP.[358] SWEPCO cooperated with an investigation by Commission Staff, responding to numerous RFIs including those attached as exhibits to Mr. Poole's testimony. SWEPCO met with the Commission in November 2019 and provided a detailed presentation and report of the event timelines, the affected stations and lines, and the Company's response.[359] Staff's recommendations related to the outage are unjustified and should not be adopted.

c. Conclusion

Company witness Mr. D'Ascendis conducted a series of analyses using well-known and commonly used methods to determine the Company's ROE. He used the DCF model; the RPM; and the CAPM.[360] Based on his analysis, Mr. D'Ascendis recommends an ROE range of 10.14% to 10.97% prior to any credit or size adjustment. Therefore, the Company's requested 10.35%

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[354] SWEPCO Ex. 41 at 7:10-17.

[355] Tr. at 433:14-434:9 (Poole Cross) (May 20, 2021).

[356] Tr. at 434:10-14 (Poole Cross) (May 20, 2021).

[357] Tr. at 434:21-435:8 (Poole Cross) (May 20, 2021); SWEPCO Ex. 41 at 2:11-16.

[358] SWEPCO Ex. 41 at 10: 1-12.

[359] SWEPCO Ex. 41 at 10: 13-21.

[360] SWEPCO Ex. 8 at 6:1-3.

ROE is a reasonable estimate of the investor required return for SWEPCO's level of risk and is appropriate for approval by the Commission.

2. Cost of Debt

Company witness Ms. Hawkins sponsors the Company's cost of debt in this proceeding. She explains in her direct testimony that SWEPCO's actual cost of debt at the end of Test Year was 4.18%.[361] She further testifies that the cost of debt calculation as shown on Schedule K-3 of the RFP was determined in accordance with Commission practices and is consistent with prior Texas rate cases.[362] With the exception of Commission Staff, the other witnesses that address rate of return issues in this case adopt the Company's proposed 4.18% cost of debt in their overall recommendations.[363]

Commission Staff witness Mr. Filarowicz recommends that SWEPCO's cost of debt should be reduced from 4.18% to 4.08%.[364] Mr. Filarowicz's recommendation is to remove the annual effects of the Series I Hedge Loss included in the Company's Schedule K-3.[365] Mr. Filarowicz argues that the hedge loss will be fully amortized in January 2022 and customers have already paid 93% of the loss. Thus, according to Mr. Filarowicz, the hedge loss amortization is not indicative of the Company's true cost of debt during the period in which rates will be in effect.[366]

In her rebuttal testimony, Ms. Hawkins responds that Mr. Filarowicz's recommendation is short sighted and an inappropriate known and measurable change.[367] She points out that the Test Year in this rate case ended March 31, 2020.[368] Mr. Filarowicz agrees.[369] Ms. Hawkins also points out that the rates set in this case will go into effect as of March 18, 2021.[370] Again, Mr. Filarowicz

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361 SWEPCO Ex. 9 at 4-5.

362 SWEPCO Ex. 9 at 4-5.

363 *See* TIEC Ex. 3 at Exhibit MPG-1; CARD Ex. 4 at 7 of 133 (Table 2 – CARD Rate of Return Recommendation); and Walmart Ex. 1 at Exhibit LVP-2.

364 Staff Ex. 1 at 8:21-25.

365 Staff Ex. 1 at 31:5-7.

366 Staff Ex. 1 at 31:8-15.

367 Rebuttal Testimony of Renee Hawkins, SWEPCO Ex. 39 at 3:1-16.

368 SWEPCO Ex. 39 at 3:1-16.

369 Tr. at 1059:16-18 (Filarowicz Cross) (May 24, 2021).

370 SWEPCO Ex. 39 at 2:17-19.

agrees.[371] Based on these facts, Ms. Hawkins testifies that the Series I Hedge Loss amortization occurs during both the Test Year and the period when new rates will be in effect.[372] The full amortization of the loss will not take place until almost two years after the end of the Test Year.[373] Moreover, Staff's recommendation pulls one distinct item out of the cost of debt without considering any other changes that may occur on or before February 2022.[374] Ms. Hawkins further explains that the Company's inclusion of the Series I Hedge Loss is reasonable and consistent with 16 TAC § 25.231(c)(2)(F).[375] Although removal of the Series I Hedge Loss may not be a rate base decrease, it was part of the debt and equity components connected to rate base at the Test Year end. Removing that one component without considering any other post-Test Year happenings disregards the scope and purpose of the Commission rule in evaluating rate base at Test Year end. The Series I Hedge Loss will not be fully amortized and removed from the Company's books until February 2022, after the Test Year and after the beginning of the rate year.[376]

Based on the foregoing, SWEPCO respectfully requests the adoption of the Company's actual cost of debt for the Test Year ended March 30, 2020, as reflected on Schedule K-3 of its RFP and in the testimony of Company witness Ms. Hawkins.

B. Capital Structure

As discussed above, Company witness Ms. Hawkins sponsors the Company's requested capital structure. Ms. Hawkins explains that the Company's actual capital structure as of the end of the test year – 50.63% long-term debt and 49.37% equity – when combined with the Company's 10.35% requested return on equity and its 4.18% cost of debt, results in an overall WACC of 7.22%.[377] The other parties did not raise any objections or offer any alternative recommendations with respect to the Company's requested capital structure. Accordingly, SWEPCO respectfully requests an authorized capital structure of 50.63% long-term debt and 49.37% equity in this proceeding.

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[371] Tr. at 1059:19-21 (Filarowicz Cross) (May 24, 2021).

[372] SWEPCO Ex. 39 at 2:17-19.

[373] SWEPCO Ex. 39 at 3:11-12.

[374] SWEPCO Ex. 39 at 3:12-15.

[375] SWEPCO Ex. 39 at 3:3-4.

[376] Tr. at 1059:22-1060:24 (Filarowicz Cross) (May 24, 2021).

[377] SWEPCO Ex. 9 at 3.

C. Financial Integrity, Including "Ring Fencing"

No Commission-imposed protections are necessary to safeguard SWEPCO's financial integrity and ability to provide reliable service at reasonable rates. The following segregation between SWEPCO and its AEP affiliates already occurs:

- SWEPCO does not share its credit facility with any unregulated affiliates;
- SWEPCO debt is not secured by non-SWEPCO assets;
- SWEPCO assets do not secure the debt of AEP or its non-SWEPCO affiliates; and
- SWEPCO has no assets pledged for any other entity.[378]

The Commission recently addressed ring-fencing measures recommended by Staff for SWEPCO affiliate AEP Texas in Docket No. 49494. In that proceeding, the Commission accepted the measures agreed to by AEP Texas in settlement without imposing further measures.[379]

In his direct testimony, Staff witness Mr. Filarowicz states that if the Commission determines it is appropriate to implement ring-fencing measures for SWEPCO in this case, he recommends fifteen such measures.[380]

He further recommends that to the extent SWEPCO already complies with any of his recommendations, the Commission should order SWEPCO to commit to continued compliance.[381]

Mr. Filarowicz does not provide any direct evidence regarding the specific need to build a ring-fence around SWEPCO.[382] Instead, he cites Oncor Electric Delivery Company (Docket No. 34077) as a successful example of ring-fencing measures protecting Oncor from the Energy Future Holdings Corporation bankruptcy.[383]

Ms. Hawkins responds to the ring-fencing recommendations as costly and generally unnecessary.[384] SWEPCO already adheres to the Texas affiliate rules and there are existing protections in place for SWEPCO's stand-alone credit rating.[385] Ms. Hawkins notes that SWEPCO already abides by most of the ring-fencing measures included in the Final Order for its affiliate

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378 SWEPCO Ex. 9 at 7:7-18.

379 *Application of AEP Texas for Authority to Change Rates*, Docket No. 49494, Final Order at 2 (Apr. 3, 2020).

380 Staff Ex. 1 at 44:12:15.

381 Staff Ex. 1 at 44:5-45:37.

382 SWEPCO Ex. 39 at 5:23-6:4.

383 Staff Ex. 1 at 46:1-47:12.

384 SWEPCO Ex. 39 at 3:18-4:7.

385 SWEPCO Ex. 39 at 5:19-22.

AEP Texas in Docket No. 49494, and confirms that SWEPCO is amenable to similar measures in this docket.[386] However, Ms. Hawkins disagrees with several of the recommendations offered by Mr. Filarowicz.

With respect to the first recommendation, it was originally unclear (due to the inadvertent inclusion of the word "dividend" in the title) whether Mr. Filarowicz intended to tie dividend restrictions to SWEPCO's credit rating.[387] During cross examination, Mr. Filarowicz confirmed that he does not recommend any dividend restrictions.[388] Therefore, that issue is no longer contested.

Ms. Hawkins also testifies against the third recommendation requiring that SWEPCO agree not to seek a higher ROE if its credit ratings fall below investment grade.[389] Ms. Hawkins points out that many unknown variables could impact SWEPCO's credit rating and it would be imprudent to restrict SWEPCO's ability to request a higher ROE.[390] Mr. D'Ascendis likewise testifies against this recommendation. He provides that ROE is related to risk and limiting SWEPCO's ability to seek a higher ROE commensurate with increased risk does not reflect the investor required return.[391] Quite simply, investors will not take on more risk without a higher potential return.

Ms. Hawkins further testifies that recommendations five and six regarding no cross-default provisions and rating agency triggers are unnecessary and would increase compliance costs for customers. SWEPCO already issues its own debt based on its stand-alone credit rating.[392] She further testifies that recommendation thirteen is too restrictive. Although Mr. Filarowicz excludes the utility money pool from his recommendation, there are other inter-company lending and borrowing programs that could be accessed by SWEPCO in certain circumstances that would benefit customers.[393]

Based on the foregoing, SWEPCO respectfully requests that any additional ring-fencing

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386 SWEPCO Ex. 39 at 8:8-14.

387 SWEPCO Ex. 39 at 5:5-11.

388 Tr. at 1062:5-15 (Filarowicz Cross) (May 24, 2021).

389 SWEPCO Ex. 39 at 8:20-9:3.

390 SWEPCO Ex. 39 at 8:20-9:3.

391 SWEPCO Ex. 38 at 50:9-14.

392 SWEPCO Ex. 39 at 9:3-6.

393 SWEPCO Ex. 39 at 9:7-21.

measures that unnecessarily increase compliance costs for SWEPCO and its customers be rejected. Moreover, SWEPCO specifically requests that Staff's ring-fencing recommendations three, five, six, and thirteen be rejected as unnecessary, overly burdensome, and prohibitive of SWEPCO's ability to provide reliable service and earn a reasonable return.

IV. Expenses

A. Transmission and Distribution O&M Expenses

1. Transmission O&M Expense

SWEPCO witness Dan Boezio's direct testimony addresses the Company's transmission O&M expenses. Mr. Boezio discusses the physical configuration, planning, and operation of both AEP's and SWEPCO's transmission systems, including how SWEPCO and AEPSC coordinate with respect to planning, construction, and O&M so that SWEPCO can benefit from economies of scale.[394] Mr. Boezio describes the services provided by the four primary functional units of the AEP Transmission organization and testifies that each of the services provided to SWEPCO are essential to ensure the system is well maintained, in good working order, and provides reliable service.[395] Mr. Boezio describes SWEPCO's programs to operate and maintain the reliability of its transmission system, which are divided into two major categories – Transmission Asset Management and Transmission Vegetation Management. He discusses the three broad functional areas within Transmission Asset Management – Station Programs, Transmission Line Programs, and Protection and Control – as well as the operation of the Transmission Vegetation Management Program.[396]

Mr. Boezio provides an overview of test year transmission operations and maintenance expenses incurred by SWEPCO. SWEPCO's Test Year transmission O&M expenses were $46,683,319, of which $8,636,052 were affiliate expenses.[397] He explains cost and staffing level trends and their significant underlying drivers, as well as the Company's use of contractors to supplement the Company's own workforce to respond to fluctuations in workload.[398] He also explains three benchmarking studies done under his supervision comparing SWEPCO's

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[394] SWEPCO Ex. 11 at 3:11-5:20.

[395] SWEPCO Ex. 11 at 7:1-10:15.

[396] SWEPCO Ex. 11 at 10:17-14:11.

[397] SWEPCO Ex. 11 at 14:13-15:6, 23:1-5, and Figure 4.

[398] SWEPCO Ex. 11 at 15:7-20:16.

transmission O&M expenditures to others in the industry and testifies that the studies indicate SWEPCO transmission O&M expenses are near or at the median values.[399]

Mr. Boezio also addresses the affiliate component of SWEPCO's O&M transmission expenses.[400] He confirms that the services do not duplicate those provided by personnel within SWEPCO or any other entity.[401] He describes recent trends in AEPSC billings to SWEPCO and in AEPSC's workforce and workload.[402] He testifies that his benchmarking studies support the reasonableness of SWEPCO's affiliate O&M transmission charges for the test year.[403]

No party filed testimony challenging the reasonableness of SWEPCO's transmission O&M expenses, although Staff witness Mr. Poole recommended an ROE penalty based on a transmission outage that occurred on the Company's system on August 18, 2019. That issue is addressed in the ROE section of this brief, *see supra* Section III.A.1.b.v.

2. Transmission Expense and Revenues under FERC-Approved Tariff

The SPP charges SWEPCO for the provision of transmission service to SWEPCO's customers. SWEPCO also receives payment from SPP for SPP members' use of SWEPCO's transmission facilities. These expenses and revenues are incurred and received pursuant to the FERC-approved SPP Open Access Transmission Tariff (OATT). The net amount that SWEPCO incurred under the SPP OATT during the Test Year is included in SWEPCO's requested cost of service in this proceeding.[404] Other than the challenge brought by Eastman Chemical Company (Eastman) and TIEC regarding SPP OATT charges incurred for Eastman's retail behind-the-meter load (addressed below in Section IV.A.6), the inclusion of the Test Year SPP OATT expenses and revenues in SWEPCO's requested cost of service is uncontested. Section IV.A.3, below, discusses SWEPCO's proposed deferral of changes in SPP OATT expenses and revenues.

3. Proposed Deferral of SPP Wholesale Transmission Costs

SPP is the sole provider of transmission service throughout the entire SPP footprint, including SWEPCO's three-state service territory. SPP charges SWEPCO for the provision of

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399 SWEPCO Ex. 11 at 20:17-22:20.

400 SWEPCO Ex. 11 at 23:6-24:4.

401 SWEPCO Ex. 11 at 9:26-30.

402 SWEPCO Ex. 11 at 24:5-26:5.

403 SWEPCO Ex. 11 at 26:6-22.

404 SWEPCO Ex. 4 at 12:7-15.

transmission service to SWEPCO's customers. SWEPCO also receives payment from SPP for SPP members' use of SWEPCO's transmission facilities. These payments (charges) and receipts (revenues) occur pursuant to the FERC-approved SPP OATT. The net amount that SWEPCO incurred under the SPP OATT during the test year is included in SWEPCO's requested cost of service in this proceeding. SWEPCO proposes that the portion of its ongoing net SPP OATT bill that is above or below the net test year level approved for recovery by the Commission be deferred into a regulatory asset or liability until it can be addressed in a future TCRF or base-rate proceeding. It is SWEPCO's intent that its proposal apply to the net SPP OATT bill, which nets costs incurred and revenues received pursuant to the SPP OATT.[405]

The nature of the SPP OATT charges being incurred by SWEPCO has been discussed extensively in prior Commission orders. The following conclusions were drawn by the Commission in a previous SWEPCO TCRF proceeding:

> 12. The Federal Power Act requires that all rates for transmission and sale of wholesale electricity be filed with FERC and published for public review.
>
> 13. The filed rate doctrine requires that interstate power rates filed with FERC or fixed by FERC must be given binding effect by the Commission when determining interstate rates.
>
> 14. Wholesale tariffs filed with and accepted by FERC are wholesale tariffs approved by a federal regulatory authority for purposes of PURA § 36.209 and P.U.C. SUBST. R. 25.239(c).
>
> 15. SPP may not charge rates for its services other than those included in its OATT, which has been properly filed with and accepted by FERC.
>
> 16. SWEPCO is obligated to pay SPP the charges SPP bills to SWEPCO pursuant to the SPP OATT for the provision of transmission services to SWEPCO.
>
> 17. The United States Supreme Court has held that, under the filed rate doctrine, "a state utility commission setting retail prices must allow, as reasonable operating expenses, costs incurred as a result of paying a FERC-determined wholesale price . . . ."
>
> 18. Under the filed rate doctrine, proof that the SPP charges included in the approved transmission charges were billed to and paid by SWEPCO pursuant to the SPP OATT demonstrates the reasonableness of the charges

[405] SWEPCO Ex. 33 at 2:14-3:2; *see also* SWEPCO Ex. 4 at 12:7-13:5.

for retail ratemaking purposes as a matter of law.[406]

Unlike the capital SWEPCO invests in transmission assets and the transmission operations and maintenance expenses incurred by SWEPCO to operate and maintain those assets, SWEPCO does not have direct control over the expenses incurred pursuant to the SPP OATT.[407]

TIEC witness Mr. Jeffry Pollock has stated that there is no precedent for a rate mechanism that allows full recovery of wholesale transmission costs for non-ERCOT utilities such as SWEPCO.[408] While it is true that no non-ERCOT utility has requested a cost recovery mechanism like the one proposed by SWEPCO in this proceeding, the TCRF rule for distribution service providers operating in ERCOT authorizes the distribution service provider to charge or credit its customers for the amount of wholesale transmission cost changes to the extent that such costs vary from the wholesale transmission service cost used to fix the base rates of the distribution service provider.[409] When amending that rule in Project No. 37909, the Commission observed that this recovery mechanism is appropriate because the ERCOT distribution service providers (DSPs) have no ability to avoid such costs or address and manage the regulatory lag that exists with respect to these costs.[410] In that project, the Commission found that ERCOT DSPs "essentially serve as billing and collection agents for passed-through TCRF costs and, under the commission's current rules, have no ability to avoid such costs or address and manage the regulatory lag that exists with respect to these costs" and that for "this type of cost passed on to a DSP, the traditional concept that regulatory lag serves as a means of incentivizing greater efficiency does not hold, because the DSP has no means of controlling or managing the cost."[411] SWEPCO is in the same position regarding the costs it incurs under the SPP OATT – SWEPCO has no ability to avoid SPP OATT costs that it incurs in procuring transmission service for its customers and the use of regulatory lag as a means of incentivizing greater efficiency does not hold in SWEPCO's circumstances. These

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406 *Application of Southwestern Electric Power Company for Approval of Transmission Cost Recovery Factor*, Docket No. 42448, Order at Conclusions of Law (CoL) Nos. 12-18 (Nov. 24, 2014).

407 SWEPCO Ex. 33 at 3:9-12.

408 Direct Testimony of Jeffry Pollock, TIEC Ex. 1 at 9:17-20.

409 16 TAC § 25.193(b)(1).

410 SWEPCO Ex. 33 at 4:14-5:5.

411 *Rulemaking Proceeding to Amend PUC SUBST Rule §25 193, Relating to Distribution Service Provider Transmission Cost Recovery Factors (TCRF)*, Project No. 37909, Order at 18 and 32 (Oct. 5, 2010).

facts were not contested and remain unaddressed by those that oppose SWEPCO's request.

SWEPCO acknowledges that the Commission, more than 13 years ago, adopted the TCRF rule for non-ERCOT utilities with its stated purpose of including the recovery of "changes in wholesale transmission charges to the electric utility under a tariff approved by a federal regulatory authority . . . ."[412] SWEPCO's proposal in this proceeding is not a substitute for the non-ERCOT TCRF rule but, rather, a proposal to complement that rule. The Commission has concluded that the "purpose of the TCRF mechanism is to reduce regulatory lag and provide for a more timely recovery of costs."[413] The purpose of SWEPCO's proposal in this proceeding is the same, and that proposal will work in tandem with the TCRF rule to achieve that purpose, consistent with the Commission's previous conclusion that proof that SPP OATT charges were billed to and paid by SWEPCO "demonstrates the reasonableness of the charges for retail ratemaking purposes as a matter of law."[414]

4. Distribution O&M Expense

SWEPCO's total company adjusted Test Year O&M expenses, including SWEPCO's own costs plus AEPSC charges, for distribution activities necessary to provide safe, reliable distribution services were $93,656,735.[415] These costs reflect the amount necessary to perform distribution functions—e.g., planning, construction, operation, and maintenance of the distribution system; and implementing SWEPCO's distribution system asset management programs, reliability programs, and the vegetation management program. The evidence supporting the necessity and reasonableness of these costs is presented by SWEPCO witness Mr. Seidel. This evidence:

- describes SWEPCO's distribution system in Texas, which encompasses 9,960 square miles and includes approximately 8,679 miles of overhead conductor and 832 miles of underground conductor;[416]
- explains that SWEPCO's Texas service territory has a low customer density, as SWEPCO customers are widely distributed over a large area, which complicates providing service and requires more line-miles to serve end-use customers than is

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[412] 16 TAC § 25.239(c).

[413] Docket No. 42448, Order at CoL No. 19.

[414] Docket No. 42448, Order at CoL No. 18.

[415] SWEPCO Ex. 10 at 21:22-22:2.

[416] SWEPCO Ex. 10 at 3:16-18.

required in more densely populated service territories;[417]

- details SWEPCO's distribution organization and the programs used to maintain reliability of SWEPCO's distribution system;[418]
- discusses SWEPCO's ongoing budgeting and cost-control initiatives employed to ensure costs are kept to the minimum reasonable level;[419]
- confirms that SWEPCO makes use of outsourcing in connection with the construction, operation, and maintenance of the SWEPCO distribution system when appropriate in order to control costs;[420] and
- presents benchmarking data demonstrating that SWEPCO's average total company distribution O&M costs compare favorably to the median level of expenditures and are well below the maximum amount of expenditures in each peer group for each year studied (2017-2019), which is notable given the particular challenges posed by SWEPCO's service area—e.g., hilly terrain, heavy vegetation, and the high amount of annual rainfall, which make vegetation management highly challenging in SWEPCO's northeast Texas service territory.[421]

Combined, this evidence demonstrates that: (1) SWEPCO's Test Year distribution activities and associated costs were necessary, reasonable, and prudent; and (2) SWEPCO effectively controls its operating costs while continuing to provide safe and reliable distribution service.

Aside from OPUC's and CARD's objection to SWEPCO's proposed increase in distribution vegetation management spend by $5 million over that incurred in the Test Year, which is discussed in the next section of this brief, SWEPCO's Test Year distribution O&M services and expenses are unchallenged.

5. Distribution Vegetation Management Expense & Program Expansion

SWEPCO witness Mr. Seidel confirms that a robust vegetation management program is critical to maintaining the reliability of SWEPCO's distribution system.[422] Mr. Seidel further explains that given SWEPCO's heavily forested service area, which requires substantial amounts of tree trimming and removal to prevent outages, it should be recognized that this program will

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417 SWEPCO Ex. 10 at 4:9-12.

418 SWEPCO Ex. 10 at 5:3-8:16.

419 SWEPCO Ex. 10 at 23:14-25:10, 32:11-33:9.

420 SWEPCO Ex. 10 at 25:12-27:4.

421 SWEPCO Ex. 10 at 27:16-28:2, Exhibits DWS-3 through DWS-5.

422 SWEPCO Ex. 10 at 16:17-19.

require increased vegetation management funding in order for SWEPCO to achieve improved reliability for customers.[423] One of the top causes of outages within SWEPCO's Texas service territory continues to be vegetation, both inside and outside of the right-of-way.[424] During the Test Year, vegetation accounted for 2,641 customer interruptions[425] in SWEPCO's Texas service territory, representing 40.1% and 49.1% of the Company's overall System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI), respectively.[426]

To address this reality, SWEPCO is proposing a total annual vegetation management spend of $14.57 million. This is an increase of $5.0 million over the $9.57 million in vegetation management expenses incurred in the Test Year.[427] The requested increase will be used solely for increased vegetation management.[428] SWEPCO is also open to continuing the periodic reporting to the Commission showing such information as the trimming is completed and the funds spent.[429]

SWEPCO's proposal is consistent with the Commission's decisions in the Company's last three rate cases, the last two of which were fully litigated.[430] For example, in SWEPCO's most recent rate case, the Commission found that an additional $2.0 million of spending over test year levels to be reasonable and necessary to carry forward SWEPCO's vegetation management program to improve overall reliability on targeted circuits and decrease outages caused by trees.[431] As it committed to do, SWEPCO has spent the entirety of the additional $2 million on distribution vegetation management.[432]

Mr. Seidel confirmed that the increased distribution vegetation management spending

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[423] SWEPCO Ex. 10 at 21:11-14.

[424] SWEPCO Ex. 10 at 19:7-8.

[425] SWEPCO Ex. 10 at 19, n.9 (sustained, non-major event customer service outages).

[426] SWEPCO Ex. 10 at 19:11-14.

[427] SWEPCO Ex. 10 at 18:10-19:1.

[428] SWEPCO Ex. 10 at 19:14-15.

[429] SWEPCO Ex. 10 at 21:15-17.

[430] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 37364, Order at FoF Nos. 17, 19, and 33 (Apr. 16, 2010); Docket No. 40443, Order on Rehearing at FoF Nos. 179-80 (Mar. 6, 2014); Docket No. 46449, Order on Rehearing at FoF Nos. 206-09.

[431] Docket No. 46449, Order on Rehearing at FoF No. 207.

[432] *See* Docket No. 46449, Order on Rehearing at FoF No. 208.

since Docket No. 46449 has improved the reliability for SWEPCO's customers on the targeted circuits. Specifically, as displayed in the table below, there has been a significant improvement in the performance of targeted distribution circuits that were trimmed in 2018 and 2019. There has been significant improvement in overall reliability on these circuits and a decrease in the number of outages attributed to trees inside the ROW. This represents 11 circuits with approximately 283 circuit miles that were fully cleared, representing approximately 3.3% of SWEPCO's Texas overhead distribution circuits.[433] The number of outages from trees in the ROW on circuits that were trimmed completely was reduced by as much as 90% in the years following the trimming, the number of total customers affected was reduced by as much as 99%, and the customer minutes of interruption (CMI) was reduced by as much as 99% through the end of the Test Year.

Customer Experience
Improvements Due to Distribution Vegetation Management[434]

Circuits Trimmed in 2018

	Twelve Months Ending December 2017	Twelve Months Ending March 2020	Difference	% Reduction
No. of Interruptions	47	7	40	85%
Customers Affected	1,334	53	1,281	96%
CMI	248,308	7,572	240,736	97%

Circuits Trimmed in 2019

	Twelve Months Ending December 2018	Twelve Months Ending March 2020	Difference	% Reduction
No. of Interruptions	30	3	27	90%
Customers Affected	4,452	24	4,428	99%
CMI	730,148	5,728	724,420	99%

Mr. Seidel testified that he expects the increased spending requested in this case to produce results similar to those shown in the above table.[435]

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433 SWEPCO Ex. 10 at 17:19-18:2.

434 SWEPCO Ex. 10 at 18.

435 SWEPCO Ex. 10 at 20:1-2.

Based on the Commission's decision in SWEPCO's last base-rate case (Docket No. 46449), Commission Staff witness Ramya Ramaswamy recommends that the Commission approve SWEPCO's request for an increase of $5.0 million over the $9.57 million in vegetation management expenses incurred in the Test Year, and the additional $5.0 million be used solely for distribution vegetation management.[436] Ms. Ramaswamy concludes that SWEPCO provided sufficient information to demonstrate that it should implement more distribution vegetation management than it did during the Test Year.[437]

In addition, Ms. Ramaswamy recommends the Commission order SWEPCO to implement a 4-year trim cycle within 12 months of the filing of the final order in this proceeding.[438] Ms. Ramaswamy, however, does not recommend that SWEPCO be allowed to recover the significant costs of implementing a 4-year trim cycle, which Mr. Seidel estimated to cost ***$38.35 million annually***.[439] Thus, Staff's recommendation is contrary to PURA's requirement that rates be set at a sufficient level to allow an opportunity to recover both the utility's reasonable and necessary expenses and a reasonable return.[440] Moreover, Staff offered the same recommendation in SWEPCO's last rate case.[441] It was rejected there as cost prohibitive.[442] It should be rejected here for the same reason.

SWEPCO appreciates Staff witness Ramaswamy's recognition that a cyclical vegetation management program would produce improved reliability benefits for customers.[443] Indeed, Mr. Seidel agrees that the best long-term solution for SWEPCO's vegetation management program is to implement a four-year vegetation management cycle.[444] And SWEPCO is willing to accept Staff's proposal if fully funded.[445] But because the full expense of implementing a four-year

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436 Direct Testimony of Ramya Ramaswamy, Staff Ex. 2 at 12:6-11, 14:15-17.

437 Staff Ex. 2 at 13:8-12.

438 Staff Ex. 2 at 14:8-11.

439 SWEPCO Ex. 10 at 20:9-11.

440 PURA § 36.051.

441 Docket No. 46449, PFD at 256 (Sept. 17, 2017).

442 Docket No. 46449, PFD at 257; Docket No. 46449, Order on Rehearing at FoF Nos. 206-09 (adopting PFD recommendation on SWEPCO's vegetation management proposal).

443 Rebuttal Testimony of Drew W. Seidel, SWEPCO Ex. 40 at 7:16-18.

444 SWEPCO Ex. 10 at 20:5-6; SWEPCO Ex. 40 at 7:18-20.

445 SWEPCO Ex. 40 at 7:21.

vegetation management cycle is estimated at $38.35 million annually, SWEPCO believes this approach would be too costly for customers to absorb all at once.[446]

OPUC witness Ms. Cannady and CARD witness Mark E. Garrett both recommend rejection of SWEPCO's proposal for a $5.0 million increase in base level O&M to perform vegetation management on SWEPCO's Texas distribution system. Mr. Garrett argues that the additional distribution management spend is unnecessary because SWEPCO's actual spending levels have remained close to the $9.93 million authorized for vegetation management in the Company's last rate case, Docket No. 46449.[447] Mr. Garrett also claims that SWEPCO has not improved its reliability measures since Docket No. 46449.[448] Similarly, Ms. Cannady contends that SWEPCO has not shown that it is necessary to spend an additional $5 million to achieve a significant difference in the overall impact to customers for vegetation-related outages.[449]

Contrary to Mr. Garrett's claims, Mr. Seidel confirmed that without additional funding, SWEPCO will likely see degradation in SAIDI and SAIFI.[450] Mr. Seidel also testified that Mr. Garrett's suggestion that SWEPCO has not improved its reliability measures since Docket No. 46449 fails to consider the other mitigating factors that have affected overall system reliability metrics.[451] Although Mr. Seidel acknowledged that overall system reliability metrics have not shown marked improvement since Docket No. 46449,[452] he explained that the additional vegetation management spend approved by the Commission in Docket No. 46449 has had a significant, positive effect on SAIDI and SAIFI for the cleared circuits.[453] As set forth in the table above, there has been a dramatic improvement in the performance on the targeted distribution circuits that were trimmed in 2018 and 2019. The improved reliability measures on the targeted distribution circuits are the direct result of the increased level of spending. Despite this, one of the top causes of outages within SWEPCO's Texas service territory continues to be vegetation, both inside and

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446 SWEPCO Ex. 10 at 20:9-11; SWEPCO Ex. 40 at 7:21-8:3.

447 CARD Ex. 2 at 39:16-41:16.

448 CARD Ex. 2 at 40:3-7.

449 Direct Testimony of Constance T. Cannady, OPUC Ex. 1 at 49:1-3.

450 SWEPCO Ex. 40 at 7:7-11.

451 SWEPCO Ex. 40 at 3:8-9.

452 SWEPCO Ex. 40 at 3:9-11.

453 SWEPCO Ex. 10 at 18, Figure 5; SWEPCO Ex. 40 at 3:14-17.

outside of the ROW.[454] These outages account for a significant percentage of the Company's overall system SAIFI and SAIDI.[455]

Ms. Cannady notes that reliability improved on the targeted circuits that were completely trimmed in 2018 and 2019.[456] However, she then claims a review of the Company's historical SAIFI and SAIDI does not demonstrate that a more than 50% increase in the level of annual vegetation management spending will produce similar reductions on a system-wide basis.[457] But to state the current levels of spending on vegetation management will not have an impact on SAIFI and SAIDI appears to say that customers should settle for less reliability. SWEPCO's proposal for an increased level of vegetation management funds, focused exclusively on the Company's Texas distribution system, will improve reliability on targeted circuits as demonstrated by the reduction in the number of tree-related outages on the circuits that were trimmed in 2018 and 2019.[458] Additionally, increased funding will reduce the CMI impacted on these circuits, which will in turn help system SAIDI.[459]

6. Allocated Transmission Expenses Related to Retail Behind-The-Meter Generation

SWEPCO has transferred functional control of its transmission facilities to the SPP RTO.[460] As part of SPP's Transmission System, SWEPCO's transmission facilities deliver power and energy from generators throughout the SPP RTO footprint to SWEPCO's transmission and distribution system loads as well as the transmission and distribution system loads of other utilities, cooperatives, and municipalities within the SWEPCO service area.[461] To serve its retail and wholesale customers, SWEPCO purchases Network Integration Transmission Service (NITS) from SPP in accordance with SPP's FERC-approved OATT.[462]

The cost for the use of the SPP Transmission System is allocated by SPP to NITS customers

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454 SWEPCO Ex. 40 at 3:17-19.

455 SWEPCO Ex. 40 at 3:19-20.

456 OPUC Ex. 1 at 49:10-12.

457 OPUC Ex. 1 at 49:14-17.

458 SWEPCO Ex. 10 at 21:7-11.

459 SWEPCO Ex. 40 at 7:2-3.

460 Rebuttal Testimony of C. Richard Ross, SWEPCO Ex. 52 at 4:12-13.

461 SWEPCO Ex. 52 at 4:13-17.

462 SWEPCO Ex. 52 at 4:18-20.

based on the load ratio share of each customer's monthly "Network Load"[463] to the total system load at the time of the monthly system peak.[464] SPP's standard NITS Agreement requires Network Customers, such as SWEPCO, to submit their monthly Network Load data to SPP.[465] SWEPCO witness Charles Locke—SPP's Director of Transmission Policy and Rates—explained that the SPP OATT: (1) provides no exception to exclude or "net" behind-the-meter generation (BTMG) from Network Load calculations; and (2) does not differentiate between retail and wholesale BTMG.[466] As a result, SPP has instructed all Network Customers to include loads served by BTMG in their monthly Network Load calculations.[467] SPP has confirmed this directive in multiple presentations to SPP members.[468] As directed by SPP, during the Test Year in this case, SWEPCO included retail BTMG in reporting its monthly Network Load data.[469]

As noted in Section IV.A.3. above, the Commission has concluded that "SWEPCO is obligated to pay SPP the charges SPP bills to SWEPCO pursuant to the SPP OATT for the provision of transmission services to SWEPCO."[470] There is no dispute that the transmission charges included in SWEPCO's application were actually charged by SPP and paid by SWEPCO. Nor is there any dispute that SPP's Test Year bills to SWEPCO included charges for SWEPCO's purchase of NITS from SPP. Further, SWEPCO has offered uncontroverted proof of the charges billed to SWEPCO by SPP pursuant to the SPP OATT.[471] Under Commission precedent, that alone

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[463] The SPP OATT defines "Network Load" as "The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load." Rebuttal Testimony of Charles J. Locke, SWEPCO Ex. 51 at 3:3-16.

[464] SWEPCO Ex. 52 at 5:18-20.

[465] SWEPCO Ex. 51 at 5:1-3.

[466] SWEPCO Ex. 51 at 5:10-13.

[467] SWEPCO Ex. 51 at 5:13-14.

[468] SWEPCO Ex. 52 at 7:20-8:2; *see also, e g ,* SWEPCO Ex. 52, Exhibit CRR-1R at 19-20, 42.

[469] SWEPCO Ex. 52 at 7:18-20.

[470] *See* Docket No. 42448, Order at CoL No. 16.

[471] Direct Testimony of John O. Aaron, SWEPCO Ex. 31 at Exhibit JOA-5 (identifying total amounts billed by SPP). The SPP charges associated with NITS are booked to FERC Accounts 561 and 565. This information is contained in Schedule P at P-2. *See* RFP Schedules & Workpapers, SWEPCO Ex. 1 at Schedule P-2.

is enough to establish reasonableness. The Commission has concluded: "Under the filed rate doctrine, proof that the SPP charges included in the approved transmission charges were billed to and paid by SWEPCO pursuant to the SPP OATT demonstrates the reasonableness of the charges for retail ratemaking purposes *as a matter of law*."[472]

In this case, a dispute has arisen concerning the inclusion of retail BTMG load in SWEPCO's monthly Network Load and the corresponding increase in SWEPCO's load ratio share for purposes of SPP's allocation of transmission costs to its members. TIEC witness Jeffry Pollock and Eastman witness Ali Al-Jabir argue that the inclusion of retail BTMG load in Network Customers' monthly Network Load is not required by the SPP OATT, and therefore, SWEPCO's inclusion of this load was a voluntary choice of the Company.[473] On this basis, they recommend a disallowance of $5.7 million of transmission expense.[474]

Despite Messrs. Pollock and Al-Jabir's claims, SWEPCO's inclusion of retail BTMG load in its monthly Network Load data reported to SPP is not the result of the Company's interpretation of the SPP OATT.[475] Further, SWEPCO is not "proposing" in this case, as Mr. Al-Jabir repeatedly suggests,[476] that it be allowed to include retail BTMG in its monthly load data reported to SPP.[477] Rather, as noted above, SWEPCO has been directed by SPP to do so.[478] The only possible exceptions that have been acknowledged by SPP are the instances where the generator and the load operate in a manner such that neither the load nor the generator are synchronized with the SPP Transmission System or where there is an assurance that the loss of the generation results in a simultaneous loss of load.[479] As far as the load served by Eastman's BTMG, neither of these exceptions apply.[480] Indeed, Eastman requires the use of the SPP Transmission System, via a

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472 Docket No. 42448, Order at CoL No. 18 (emphasis added) and n.15.

473 Direct Testimony of Jeffry Pollock, TIEC Ex. 1 at 25:17-18 (using the page number in the upper right hand corner of the page); Direct Testimony of Ali Al-Jabir, Eastman Ex. 1 at 3:20-22, 4:17-18, 11:12-19 (using the page number in the bottom center of page).

474 *See* Eastman Ex. 1 at 28:8-21; TIEC Ex. 1 at 25:14-18.

475 SWEPCO Ex. 52 at 8:14-16.

476 Eastman Ex. 1 at 3:17-28, and 4:15-23.

477 SWEPCO Ex. 52 at 8:16-18.

478 SWEPCO Ex. 52 at 8:17-18.

479 SWEPCO Ex. 52 at 10:6-10.

480 SWEPCO Ex. 52 at 10:12.

SWEPCO-owned transmission line, at all times to serve the entire load at its campus with its BTMG.[481]

At hearing, Messrs. Pollock and Al-Jabir agreed this issue boils down to a dispute between SPP, on the one hand, and TIEC and Eastman, on the other, over how to interpret and implement the SPP OATT—i.e., whether the tariff requires the inclusion of retail BTMG load in a Network Customer's Network Load calculations.[482] The record evidence confirms that this dispute predates this rate case. In response to a discovery request in this proceeding, TIEC provided communications between it and SPP regarding SPP's interpretation of the OATT as it relates to retail load served by BTMG.[483] In email communications sent in March and June of 2019, from counsel for TIEC to SPP General Counsel, Paul Suskie, and SPP Director of Transmission Policy and Rates, Charles Locke, TIEC expressed its opinion that the SPP OATT does not require the recognition of retail load that is served by BTMG in the calculation of monthly Network Load.[484] It appears that SPP was unpersuaded by TIEC's arguments given that SPP in January of 2021 released a presentation coming to the opposite conclusion.[485] These communications between TIEC and SPP, as well as SPP's January 2021 presentation, demonstrate that TIEC's, as well as Eastman's, disagreement over the interpretation and application of the SPP OATT is with SPP, not SWEPCO.[486]

Essentially, Messrs. Pollock and Al-Jabir are asking the Texas Commission to interpret the FERC – jurisdictional SPP OATT and conclude that their tariff interpretation is correct and SPP's directive regarding the inclusion of retail BTMG load in a Network Load violates the OATT's terms. But under the Federal Power Act (FPA), the FERC has exclusive jurisdiction of the wholesale sale or transmission of electricity in interstate commerce.[487] Thus, FERC is the

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[481] Tr. at 631:9-14 (Al-Jabir Cross) (May 21, 2021); SWEPCO Ex. 52 at 10:18-20.

[482] Tr. at 629:22-630:13 (Al-Jabir Cross) (May 21, 2021); Tr. at 646:24-25 (Pollock Cross) (May 21, 2021).

[483] SWEPCO Ex. 52 at 9:11-13.

[484] SWEPCO Ex. 52 at 9:13-17. Attached to Mr. Pollock's workpapers is a memo that was written on behalf of TIEC in 2019 on this very issue. *See* Pollock Direct Workpapers, TIEC Ex. 1A at 927-936. The testimonies filed by both Mr. Pollock and Mr. Al-Jabir align with and generally restate the arguments set forth therein.

[485] SWEPCO Ex. 52 at 9:17-19. A copy of that presentation is included Exhibit CRR-1R to Mr. Ross's rebuttal testimony, SWEPCO Ex. 52, Exhibit CRR-1R at 36-82.

[486] SWEPCO Ex. 52 at 9:20-22.

[487] *Entergy Louisiana, Inc. v. Louisiana Pub. Serv. Comm'n*, 539 U.S. 39, 41 (2003); *see also* 16 U.S.C. § 824(b).

exclusive arbiter of any disputes involving a tariff's interpretation.[488] Mr. Al-Jabir concedes that a binding interpretation of the SPP OATT must come through FERC.[489] And both Messrs. Al-Jabir and Pollock agree that FERC has exclusive jurisdiction to address violations of the SPP OATT.[490] The fact that FERC has not been asked to make a decision as to the proper treatment of retail BTMG under the SPP OATT, as Mr. Al-Jabir notes,[491] is immaterial. The U.S. Supreme Court has made clear that FERC jurisdiction does not turn on whether a particular matter was actually determined in the FERC proceedings.[492] TIEC or Eastman could raise the issue at FERC if they chose to do so.[493]

Messrs. Pollock and Al-Jabir raise a series of arguments in support of their primary position that the SPP OATT does not require Network Customers to include retail BTMG load when reporting their monthly Network Load calculations to SPP. As discussed above, these are FERC-jurisdictional issues. However, SWEPCO witnesses Richard Ross and Charles Locke address each of these arguments in their rebuttal testimonies.

a. Wholesale vs. Retail BTMG

Messrs. Pollock and Al-Jabir claim SWEPCO has failed to distinguish between retail and

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[488] *AEP Texas North Co. v Texas Indus Energy Consumers*, 473 F.3d 581, 585-86 (5th Cir. 2006).

[489] Supplemental Direct Testimony of Ali Al-Jabir, Eastman Ex. 2 at 12:8-10 (using the page number in the bottom center of the page).

[490] Tr. at 621:2-7 (Al-Jabir Cross) (May 21, 2021); Tr. at 644:10-15 (Pollock Cross) (May 21, 2021).

[491] Eastman Ex. 2 at 12:10-11.

[492] *Entergy Louisiana, Inc*, 539 U.S. at 50 ("It matters not whether FERC has spoken to the precise classification of ERS units, but only whether the FERC tariff dictates how and by whom that classification should be made.").

[493] 16 U.S.C. §§ 824e, 825e; 18 C.F.R. § 385.206(a) ("Any person may file a complaint seeking Commission action against any other person alleged to be in contravention or violation of any statute, rule, order, or other law administered by the Commission, or for any other alleged wrong over which the Commission may have jurisdiction."); *see also American Elec. Power Serv Corp*, 153 FERC ¶ 61167, at P 21 (FERC 2015) ("In sum, for the reasons explained above, the Commission concludes that: (1) retail ratepayers may file complaints and protest transmission rates and wholesale power sales rates before the Commission; and (2) allowing retail customers to challenge transmission and wholesale power sales rates does not violate principles of federalism."); *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys Op., Inc*, 149 FERC ¶ 61,049, at P 181 (2014) (finding complainants who are industrial customers within [Midcontinent Independent System Operator, Inc.] who either directly pay wholesale transmission rates or pay for transmission through bundled retail rates have standing per Rule 206); *Potomac-Appalachian Transmission Highline, LLC, et. al,* 140 FERC ¶ 61229, at P 106 (FERC 2012) ("A complaint regarding a transmission rate can, under Commission rules, be filed by any person, including an end-use customer that will pay that some portion of that rate when flowed through its retail bill.").

wholesale BTMG.[494] However, as Mr. Locke explains, the difference is irrelevant.[495] Mr. Locke testified that FERC policy, as well as the SPP OATT, require that Network Customer load, including load that may be served by BTMG, be included in the calculation of Network Load.[496] There is no differentiation between retail and wholesale BTMG in these requirements.[497] He further detailed why the operational considerations cited by Messrs. Pollock and Al-Jabir do not support differentiating between retail and wholesale BTMG for purposes of Network Load reporting.[498]

b. SPP Network Customer Reporting Practices

SPP has conducted two surveys related to the reporting of BTMG in Network Load.[499] The first, in 2017, was conducted to gain an understanding of the load reporting practices of its Network Customers.[500] The purpose of the second survey, conducted in 2019, was to gauge SPP stakeholder interest in changes to the existing Network Load reporting requirements.[501]

Messrs. Pollock and Al-Jabir note that in response to the surveys, some Network Customers indicated they do not include retail BTMG load in their Network Load calculations.[502] The suggestion is that it is reasonable for SWEPCO to ignore SPP's directives regarding the reporting of Network Load simply because other customers may be doing so. But SWEPCO's decision to comply with the SPP's load reporting instructions and express directives is not dependent on the practices or decisions of other SPP network customers. Moreover, what other network customers do and whatever their motivations might be are simply not relevant to whether SWEPCO has acted in compliance with SPP's directive.

c. Network Load Reporting in other RTOs

Messrs. Pollock and Al-Jabir contend that SPP's interpretation of its OATT is incorrect

494 TIEC Ex. 1 at 17:4-16; Eastman Ex. 1 at 6:13-7:2, 18:1-23.

495 SWEPCO Ex. 52 at 13:17; SWEPCO Ex. 51 at 23:20-22.

496 SWEPCO Ex. 51 at 12:1-4.

497 SWEPCO Ex. 51 at 12:4-5.

498 SWEPCO Ex. 51 at 18:8-20:23.

499 SWEPCO Ex. 51 at 22:3-4.

500 SWEPCO Ex. 51 at 22:4-5.

501 SWEPCO Ex. 51 at 22:5-7.

502 TIEC Ex. 1 at 18:1-9; Eastman Ex. 1 at 13:15-14-7.

because other RTOs either permit utilities to exclude the load served by retail BTMG from their monthly Network Load calculations as a matter of practice or they have explicit tariff provisions that exclude retail BTMG load from these calculations.[503] Their analogy is inapt for multiple reasons.

First, what other RTOs include in their tariffs is not relevant to or controlling in this case.[504] SWEPCO is a Network Customer of SPP and, as such, is bound by the FERC-approved SPP OATT's terms and conditions.[505]

Second, Mr. Locke testified that FERC has approved alternative proposals for netting BTMG load in the calculation of Network Load for at least two RTOs—the PJM Interconnection (PJM) and California Independent System Operator (CAISO).[506] But he explained that if FERC's general policy had been to exclude retail BTMG from Network Load, there would have been no need for PJM or CAISO to request the exception for retail.[507] And he noted that the PJM and CAISO exceptions do not apply under the SPP OATT.[508]

Third, Mr. Locke discussed why Mr. Pollock's and Mr. Al-Jabir's assertions regarding the treatment of Network Load in the MISO region do not hold up under scrutiny. To support their position, Mr. Pollock and Mr. Al-Jabir both refer to a FERC order in a complaint by Occidental Chemical Corporation against MISO.[509] This complaint was lodged in the context of Entergy's integration into MISO, and specifically concerned MISO's plans to handle Qualifying Facilities (QFs).[510] Therefore, FERC's orders in that case have limited applicability, which does not encompass either the SPP OATT or the establishment of national policy regarding BTMG.[511] Furthermore, FERC's orders in that case focused on rules for market integration and market price determination for QFs in MISO's Entergy footprint and did not specifically address rules for

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503 TIEC Ex. 1 at 20:6-19; Eastman Ex. 1 at 19:2-9.

504 SWEPCO Ex. 52 at 14:15-16; SWEPCO Ex. 51 at 14:16-17.

505 SWEPCO Ex. 52 at 14:18-19.

506 SWEPCO Ex. 51 at 8:10-11:15.

507 SWEPCO Ex. 51 at 9:19-10:1.

508 SWEPCO Ex. 51 at 14:20-21.

509 TIEC Ex. 1 at 20:11-19; Eastman Ex. 1 at 19:20-20:9.

510 SWEPCO Ex. 51 at 15:10-12.

511 SWEPCO Ex. 51 at 15:13-15.

transmission service or the establishment of transmission charges.[512] Eastman and TIEC, like Occidental, should pursue a remedy at FERC if they wish to change the treatment of BTMG by SPP.

d. SPP Revision Request (RR) 241

Messrs. Locke and Ross also address Mr. Pollock's misplaced reliance on RR 241 as proof that including load served by retail BTMG is not required under the SPP OATT.[513] RR 241 proposed to add an exception to the reporting requirement for Network Load.[514] Specifically, RR 241 proposed to exclude from Network Load any generation behind a retail meter of less than 1 MW, because the SPP OATT provided no exception to exclude or "net" BTMG from Network Load calculations.[515] RR 241 was not approved through the SPP stakeholder process and, therefore, was not filed at FERC for approval.[516] However, even if RR 241 had been approved, filed at FERC, and approved by FERC for incorporation into the SPP OATT it would not have provided an exception for the retail load served by Eastman's BTMG, which is greater than 1 MW.[517] As explained by Mr. Ross, the proposed revision required that generators with a combined rating greater than 1MW be included in BTMG reporting.[518]

e. Qualifying Facilities

Messrs. Pollock and Al-Jabir claim that the practice of including load served by retail BTMG is inconsistent with state and federal regulations concerning QFs.[519] The regulations that Messrs. Pollock and Al-Jabir rely on provide that "rates for sales of back-up power or maintenance power shall not be based upon an assumption . . . that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both."[520] But, as Mr. Ross confirms, SWEPCO does not make that

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[512] SWEPCO Ex. 51 at 15:15-18.

[513] TIEC Ex. 1 at 21:1-22:5.

[514] SWEPCO Ex. 51 at 21:5-6.

[515] SWEPCO Ex. 51 at 21:7-9.

[516] SWEPCO Ex. 51 at 21:9-11.

[517] Eastman Ex. 1 at 9:20-22 ("Eastman uses its retail BTMG to provide approximately 150 MW of power....").

[518] SWEPCO Ex. 52 at 14:7-8.

[519] TIEC Ex. 1 at 23:14-24:5 (citing 16 TAC § 25.242(k)(3)(A) and 18 C.F.R. 292.305(c)(1)); Eastman Ex. 1 at 24:16-25:7 (same).

[520] *See* 16 TAC § 25.242(k)(3)(A) and 18 C.F.R. 292.305(c)(1).

assumption in the calculation of its monthly peak load data reported to SPP.[521] And SPP's NITS charges to SWEPCO are based on actual loads, not anticipated loads, served with BTMG.[522] Moreover, the issue here is transmission service charges, not generating capacity and energy.[523]

f. SWEPCO's Network Load Reporting Practices

Messrs. Pollock and Al-Jabir correctly note that historically SWEPCO did not include retail BTMG load in its monthly Network Load data reported to SPP, but changed its practice in late 2018.[524] Mr. Ross explained that the change occurred at that time because, in the wake of SPP's 2017 survey of Network Customers' reporting practices, SPP began providing educational information to its stakeholders clarifying that FERC policy and the SPP OATT provide no exception to exclude or "net" BTMG from Network Load calculations.[525]

Mr. Ross noted that SWEPCO initiated the data reporting changes beginning with the loads served using the Eastman BTMG due to the size of the facility, its impact on day-to-day SPP real-time operations, and the fact that it is impossible for the Eastman BTMG to serve all of the load at the Eastman campus without the use of the SPP Transmission System.[526] Furthermore, the relative size of the Eastman facility makes it larger than all other potential BTMG combined in SWEPCO's Texas jurisdiction and, in fact, across its entire service territory.[527]

Mr. Ross further explained that, in some instances, SWEPCO has not included these loads because the generation and associated load are not synchronized to the SPP system or there is a concomitant loss of load with the loss of generation at the site.[528] And that SWEPCO has not included in its Network Load report to SPP the loads served by smaller-scale "roof-top solar" behind retail distribution system points of delivery.[529] He confirmed, however, that SWEPCO is continuing to review these situations and, as appropriate, will update its data reporting procedures

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521 SWEPCO Ex. 52 at 15:7-8.

522 SWEPCO Ex. 52 at 15:8-9.

523 SWEPCO Ex. 52 at 15:9-10.

524 TIEC Ex. 1 at 15:1-6, 15:19-16:1; Eastman Ex. 1 at 8:8-12.

525 SWEPCO Ex. 52 at 11:10-12; SWEPCO Ex. 51 at 23:3-5.

526 SWEPCO Ex. 52 at 12:15-19; Tr. at 631:9-14 (Al-Jabir Cross) (May 21, 2021).

527 SWEPCO Ex. 52 at 12:19-21.

528 SWEPCO Ex. 52 at 12:7-10.

529 SWEPCO Ex. 52 at 12:10-12.

for SPP transmission billing.[530]

g. Conclusion

In sum, TIEC and Eastman are asking the Commission to interpret the SPP OATT and penalize SWEPCO—i.e., disallow $5.7 million in transmission expenses that were indisputably incurred in the Test Year—for complying with SPP's tariff interpretation. Whether the SPP OATT is susceptible to Eastman's competing interpretation is a legal question properly raised before the FERC.[531] The Commission should decline their invitation to circumvent FERC's exclusive jurisdiction.

B. Generation O&M Expense

SWEPCO witness Monte McMahon's direct testimony addresses the Company's generation O&M expenses. He describes SWEPCO's power plant fleet and the O&M practices SWEPCO employs to prudently manage that fleet.[532] He also supports the reasonableness of SWEPCO's generation O&M practices and expenses and the generation-related billings to SWEPCO from its affiliate service company, AEPSC.[533]

Mr. McMahon describes the role of the SWEPCO and AEPSC organizations in the operation and management of SWEPCO's generation fleet[534] and the six groups within AEPSC that provide generation-related services to SWEPCO.[535] The division of responsibility prevents any overlap or duplication of services between SWEPCO and AEPSC generation employees.[536] He also testifies that SWEPCO uses multiple methods to ensure its generation O&M costs are reasonable, including budget controls, cost trends, and careful tracking of staffing levels at its power plants.[537]

Mr. McMahon also discusses the affiliate charges from the AEPSC Generation

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[530] SWEPCO Ex. 52 at 12:12-14.

[531] *AEP Texas North Co.*, 473 F.3d at 585-86; *see Roberts Exp., Inc v Expert Transp , Inc.*, 842 S.W.2d 766, 771 (Tex. App.—Dallas 1992, no writ) ("Like statutory interpretations, tariff interpretations involve mainly questions of law.").

[532] SWEPCO Ex. 7 at 2:15-16.

[533] SWEPCO Ex. 7 at 20:1-31:9.

[534] SWEPCO Ex. 7 at 12:13-15:12.

[535] SWEPCO Ex. 7 at 12:13-15:12, 15:13-16:36.

[536] SWEPCO Ex. 7 at 16:37-17:2.

[537] SWEPCO Ex. 7 at 21:1-26:20.

organization to SWEPCO, including how they are charged to SWEPCO and their trends. He explains the evidence supporting those charges and concludes that AEPSC controls costs effectively and that these charges are reasonable.[538]

Finally, Mr. McMahon describes the performance of SWEPCO's generation fleet, confirming the effectiveness of SWEPCO's O&M practices.[539] Using metrics such as Equivalent Availability Factor and Equivalent Forced Outage Rate, together with power plant performance information from the North American Electric Reliability Corporation's Generating Availability Data System, Mr. McMahon explains how the performance of SWEPCO's fleet is reasonable compared to industry performance.

CARD witness Scott Norwood was the only other witness to address SWEPCO's generation O&M expense, proposing to disallow select portions of the Company's Test Year level of O&M expense relating to the Dolet Hills plant and five recently-retired natural gas units.[540] These proposals are not supported by the evidence and should be rejected.

Mr. Norwood's proposed adjustment to Dolet Hills plant O&M costs should be rejected because the Test Year Dolet Hills plant O&M costs are reasonably representative of the costs the plant will incur in 2021. During the Test Year and until its retirement at the end of 2021, the plant has been and will continue to be offered into the energy market year round, incurring expenses required to ensure the unit is available to operate when called upon by SPP or MISO. SWEPCO expects the Dolet Hills plant will operate seasonally in 2021 much like it did during the Test Year and that, as a result, O&M expenses will also be similar. Mr. Norwood's adjustment would significantly under-recover the plant's O&M in 2021, following the March 2021 effective date of rates in this case.[541]

Mr. Norwood offers no legal basis for his proposed adjustment to the Dolet Hills plant O&M expense. No such basis exists. Although he argues the plant will be retired "only a few months after the Company's new base rates are placed into effect,"[542] the date new rates are placed into effect is not relevant. Under PURA § 36.211(b), the effective date of new rates in this case is

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[538] SWEPCO Ex. 7 at 27:1-30:8.

[539] SWEPCO Ex. 7 at 31:11-38:11.

[540] CARD Ex. 3 at 5:6-7:12.

[541] SWEPCO Ex. 37 at 2:3-10.

[542] CARD Ex. 3 at 5:25-26.

the 155^{th} day after the application was filed, i.e., March 18, 2021.[543] Mr. Norwood has offered no valid basis for his proposed adjustment to Test Year Dolet Hills plant O&M expense and it should be rejected.

Mr. Norwood's proposed adjustment related to the retirement of five natural gas units similarly lacks validity. As an initial matter, Mr. Norwood's testimony does not acknowledge that SWEPCO *already* made an O&M adjustment in its application to account for the natural gas units' retirement.[544] SWEPCO's requested level of generation O&M includes the removal of the retired units' Test Year expense ($616,316) in its entirety.[545] This reduction is a known and measurable adjustment, based on historic actual costs for these units.[546] SWEPCO maintains O&M expense records by "benefiting location," which identifies costs at the generating unit level.[547] Extracting Test Year O&M expense using this identifier ensured that the Company's adjustment of $616,316 accounted for all costs incurred for the retired units.[548]

In contrast, Mr. Norwood is recommending an additional $1,699,879 reduction to Test Year Generation O&M – nearly 3 times the historical Test Year amount of the retired units. He calculates his adjustments based on the percentage of capacity retired at each affected generation plant, which he adds to the amount already removed by the Company for the retired units.[549] Mr. Norwood's adjustment ignores the fact that when a generating facility has multiple units, there are often shared assets such as fuel delivery and water treatment systems, tools, buildings and infrastructure, and transformers.[550] When a unit retires, the expenses associated with those shared assets must now be distributed amongst fewer units.[551] Mr. Norwood's proposed adjustment of plant costs erroneously incorporates a reduction in shared asset costs at multi-unit plants that did not actually occur. His plant-level method of calculating the impact of the retired units on Test

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543 *See* SOAH Order No. 2 at 2 (showing relate-back date under PURA § 36.211 of March 18, 2021) (Nov. 23, 2020).

544 SWEPCO Ex. 37 at 2:16-3:11.

545 SWEPCO Ex. 37 at 6:6-7.

546 SWEPCO Ex. 37 at 6:7-9.

547 SWEPCO Ex. 37 at 3:3-5.

548 SWEPCO Ex. 37 at 3:5-7.

549 SWEPCO Ex. 37 at 3:21-4:3.

550 SWEPCO Ex. 37 at 5:15-17.

551 SWEPCO Ex. 37 at 5:17-18.

Year expense is not based on a known and measurable change and overstates the costs attributable to the retired units.[552] It should be rejected.

C. Labor Related Expenses

1. Payroll Expenses

In measuring the cost of providing service, the Commission's Cost of Service rule looks to those expenses incurred by the utility during its historical test year, "as adjusted for known and measurable changes."[553] In reflecting its payroll costs, SWEPCO made two known and measurable adjustments: (1) annualizing the base payroll to the salary rate in effect at the end of the test year and (2) recognizing the effect of the merit and general increases that were awarded in 2020 after the end of the Test Year. In other words, SWEPCO's requested payroll in this case is based on the salaries of its employees for the final pay period at the end of the Test Year (i.e., payroll was annualized). Further, the salaries of merit eligible employees were adjusted 3.0% and those of the hourly physical and craft employees were adjusted 2.5%, all of which was approved by the Company's Compensation Committee and implemented by October 2020.[554] Specifically, all pay increases were approved in February 2020 and implemented in April 2020 for nonunion employees and in September 2020 for hourly and physical craft employees.[555]

In making these two known and measurable adjustments, SWEPCO is implementing the same adjustments that were challenged, vetted, and found reasonable by the Commission in SWEPCO's previous two rate cases. In Docket No. 40443, the Commission found:

> 210. SWEPCO made two adjustments to its test year payroll. The Company updated payroll costs by annualizing the base payroll to the salary rates in effect at the end of the test year and by recognizing the effect of the merit and general increase that were awarded in 2012.
>
> 211. Because these payroll increases were awarded in 2012, they represent appropriate known and measurable adjustments to test year expenses.[556]

In Docket No. 46449, the Commission found:

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[552] SWEPCO Ex. 37 at 5:22-6:2.

[553] 16 TAC § 25.231(b).

[554] SWEPCO Ex. 36 at 31:1-15; *see also* SWEPCO Ex. 6 at 21:1-12. Please note that Mr. Baird's direct testimony inaccurately identified this latter adjustment as a 3.5% increase.

[555] SWEPCO Ex. 36 at 33:7-9.

[556] Docket No. 40443, Order on Rehearing at 38.

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 [sic] 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.[557]

CARD witness Mr. Mark Garrett opposes these adjustments. Mr. Garrett recycles the failed arguments he raised in SWEPCO's previous base rate case, Docket No. 46449. In fact, it appears that Mr. Garrett simply reproduced his Docket No. 46449 testimony in the current case. Below is an excerpt of the Docket No. 46449 PFD beginning at page 231 (footnotes omitted), with bracketed references to Mr. Garrett's testimony in this proceeding where he makes the exact same allegation:

> CARD opposes the 3.5% payroll increase. CARD witness Mark Garrett testified that setting rates based upon a nominal pay increase such as this is almost never appropriate because the actual payroll levels will never increase by the amount of the nominal increase. **[CARD Ex. 2 at 33:17-20.]** Mr. Garrett also testified that, in his opinion, the actual 3.5% increase does not constitute a known and measurable change to the test year amounts because there are too many other factors which impact the Company's overall payroll expense. **[CARD Ex. 2 at 33:22-23.]** These factors include:
>
> 1. Normal employee turnover that occurs on a regular basis with retiring employees taking higher salaries off the books and newer employees being hired at a lower pay scale;
> 2. Workforce reorganizations where significant workforce reductions are achieved through new technologies or other innovations;
> 3. Productivity gains where reductions in workforce levels are achieved on an ongoing basis through increased employee efficiencies; and
> 4. Capitalization ratio changes where more payroll costs are capitalized rather than expensed during a period of capital expansion such as SWEPCO is experiencing now. **[CARD Ex. 2 at 33:24-34:7.]**

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[557] Docket No. 46449, Order on Rehearing at 34.

> CARD maintains that each of these factors can impact overall payroll expense as much or more than pay raises and should be accounted for in determining the appropriate payroll expense for SWEPCO. **[CARD Ex. 2 at 34:7-8.]** CARD also asserts that, when rates are based on an historical test year, payroll expense should be annualized, such as SWEPCO has done, as long as the period that is annualized is representative of ongoing expense levels. However, contends Mr. Garrett, it is not appropriate to adhere to test year costs for other costs such as rate base investment, depreciation expense, taxes, and revenues, but to reach beyond the test year for the payroll expense adjustment. It is especially inappropriate to account for payroll expense in the piecemeal fashion that SWEPCO proposes, which does not account for the other factors listed above. **[CARD Ex. 2 at 34:12-18.]**

Because Mr. Garrett has chosen to reproduce the same allegations he made and the Commission rejected in Docket No. 46449, the result should also be the same. In Docket No. 46449, the ALJs wrote:

> CARD acknowledges in its Initial Brief that the Commission approved this same type of adjustment in SWEPCO Docket No. 40443, but asks that the Commission reconsider its precedent. However, the ALJs see no reason for the Commission to diverge from its past precedent because CARD did not present persuasive testimony that the Company's action in this case was markedly different from the procedure it followed in SWEPCO Docket No. 40443 or that ETI followed in ETI Docket No. 39896. The preponderance of evidence on this issue demonstrates that the Company followed the proper procedure to ensure that its payroll was properly annualized and updated with a known and measurable increase of 3.5%, to properly match the expenses it will incur following this rate case with the new rates the Commission approves in this docket.[558]

Both Staff witness Ms. Stark and OPUC witness Ms. Cannady recommend a departure from Commission precedent, as well. Instead of annualizing Test Year data and applying a known and measurable adjustment, these witness recommend departing from Test Year data altogether by annualizing payroll data from October 31, 2020.[559] This recommendation is contrary to the Commission's Cost of Service rule, which states, "In computing an electric utility's allowable expenses, only the electric utility's historical test year expenses as adjusted for known and measurable changes will be considered."[560] In departing from Commission precedent and Test Year data, both Ms. Stark and Ms. Cannady point to a retirement incentive package offered by

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[558] Docket No. 46449 PFD at 234 (footnotes omitted).

[559] *See* Staff Ex. 3 at 6:17-8:8; *see also* OPUC Ex. 1 at 31:5-34:7.

[560] 16 TAC § 25.231(b).

AEP and SWEPCO after the end of the Test Year. However, the impact of that program on SWEPCO's payroll costs is not known and measurable. As explained by SWEPCO, "[a]nnualization of base payroll after the final departure of employees who accepted the retirement incentive package cannot be done until all employees have departed and decisions on backfilling have been finalized for each of these positions."[561] SWEPCO witness Mr. Baird expanded on this explanation, "[w]hen vacancies occur, it is common practice to assess alternatives before replacing positions in-kind; in many instances associated reductions in payroll are offset in-part or in whole by increased spending in other cost categories, such as outside services when work is redirected to contingent labor or outsourced."[562] Further, as a practical matter, the recommendation of Ms. Stark and Ms. Cannady is also unworkable from a rate case filing perspective. SWEPCO filed this case on October 14, 2020 and would not have had access to October 31, 2020, payroll data at the time of filing. Ms. Stark's and Ms. Cannady's proposal to divorce payroll expense from test year data and to rely entirely on post-filing data is not workable from a rate case filing and processing perspective.

2. Incentive Compensation

a. Short-Term Incentive Compensation

Consistent with recent Commission precedent,[563] SWEPCO removed a portion of non-collectively bargained short-term incentive compensation (STI) expenses from its rate application as follows:

- first, the Company removed the financially-based portion of the target level of STI expense; and
- second, the Company excluded 50% of the financially-based funding mechanism.[564]

These adjustments are summarized in the following table from Mr. Baird's direct testimony:[565]

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[561] SWEPCO Response to OPUC RFI 6-2, OPUC Ex. 37.

[562] SWEPCO Ex. 36 at 35:3-7.

[563] *See* CARD Ex. 2 at 18:1-21 (explaining recent Commission precedent and acknowledging that "[i]t appears the Company attempted to follow the precedent for the most part . . . ."). Mr. Garrett's limited disagreement with the Company's approach is discussed later in this section of the brief.

[564] SWEPCO Ex. 6 at 21:13-22:6; Direct Testimony of Andrew Carlin, SWEPCO Ex. 21 at 38:25-30.

[565] SWEPCO Ex. 6 at 22.

Annual Incentive Plan		
Description	**SWEPCO**	**AEPSC**
Per Book Expense	$9,800,004	$8,942,256
Reduction to Target Level	(1,878,186)	(3,367,674)
Target Level Incentives	$7,921,818	$5,574,582
Remove Direct Financial	(429,050)	(662,984)
Target Less Financial	$7,492,768	$4,911,598
Remove 50% of Financial Funding of 70%, or 35%	(1,558,984)	(1,753,868)
Requested Amount	$5,933,784	$3,157,730

Company witness Andrew Carlin explained that SWEPCO does not agree with the Commission's policy of disallowing financially based incentive compensation but requested recovery of that excluded expense only in the event anticipated legislation was enacted that would require electric utility incentive compensation to be treated consistent with the law recently passed for gas utilities. However, that legislation was not enacted[566] and, as a result, SWEPCO's STI request is set out in the table above, consistent with recent Commission precedent.[567]

Mr. Carlin also explained that the 50% exclusion tied to the funding mechanism was applied to the 70% of the funding mechanism that was based on financial measures (i.e., earnings per share (EPS)) in the 2019 STI plan, resulting in a 35% exclusion of STI costs based on the funding mechanism (50% X 70% = 35%).[568] He noted that in 2020, which included the final 3 months of the test year, the funding mechanism was changed to 100% EPS due to the financial uncertainty caused by the COVID pandemic, but this was a one-time change and not representative of the Company's STI plan either before or after 2020.[569]

In addition, the Company included the full target value of STI compensation provided under a collective bargaining agreement, not just the portion related to non-financially based

566 *See* SWEPCO Ex. 21 at 3:22-4:10, 38:25-41:5; Rebuttal Testimony of Andrew Carlin, SWEPCO Ex. 46 at 10:14-19.

567 *See also* Staff Ex. 3 at 8:13-16 ("While disagreeing with the Commission's precedent of excluding financial based STI and 50% of the financial based funding mechanisms related to its STI plans, SWEPCO nonetheless quantifies and excludes these costs from its requested revenue requirement for its non-union represented employees.").

568 SWEPCO Ex. 21 at 31:10-14; *see also* SWEPCO Ex. 6 at 22.

569 SWEPCO Ex. 21 at 31:15-20.

measures, because that compensation is presumed reasonable under PURA § 14.006.[570]

Testimony addressing STI compensation expense was filed by Staff witness Ruth Stark, OPUC witness Constance Cannady, and CARD witness Mark Garrett. Ms. Stark's testimony recognizes that the Company excluded financial based STI and 50% of the financial based funding mechanism related to its STI plans from its requested revenue requirement for non-union employees.[571] She did not contest the Company's proposed STI expense except to recommend approximately $100,000 of adjustments based on errors identified by the Company in response to discovery.[572] SWEPCO agrees with Ms. Stark's proposed adjustments.

OPUC witness Cannady and CARD witness Mark Garrett propose more extensive STI adjustments that should be rejected. Ms. Cannady recommends: 1) replacing the Test Year target level of STI expense with the lower 2019 target level, and 2) disallowing financially based STI measures for collectively bargained employees despite the provisions of PURA § 14.006. Mr. Mark Garrett recommends using the 100% EPS financial funding mechanism established for 2020 in response to the COVID pandemic rather than the 70% used by the Company.

Ms. Cannady's proposal to replace the Test Year target level of STI expense with the lower 2019 target level lacks any valid basis and should not be adopted. The asserted basis for Ms. Cannady's proposal appears to be that the test year level is not based on known and measurable expenses.[573] She argues that using the 2020 portion of the test year STI target "assumes that all employees will receive 100% of the target for 2020 [and] was not based on a known and measurable STI compensation payout at the time of the filing, or even up until the STI compensation was actually awarded in 2021."[574] The problem with Ms. Cannady's analysis is that she, like SWEPCO and every other witness that addressed the issue, bases incentive compensation expense on the *target* amount rather than *actual* payments, consistent with Commission

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[570] SWEPCO Ex. 21 at 14:14-15:7. PURA § 14.006 establishes that "[a]n employee wage rate or benefit that is the product of . . . collective bargaining is presumed to be reasonable."

[571] Staff Ex. 3 at 8:13-16.

[572] Staff Ex. 3 at 9:15-10:6.

[573] OPUC Ex. 1 at 35:6-9, 36:10-12.

[574] OPUC Ex. 1 at 37:16-18.

precedent.[575] Her testimony notes that her calculation "begins with actual STI compensation awarded to SWEPCO employees in March 2020 *set at 100% of the target payout*."[576] Her Schedule CTC-8 confirms that her calculation starts with the incentive compensation *target*, not *actual* payouts.[577]

As a result, her argument that *actual* incentive compensation payouts for 2020 were not known until after the test year is misdirected because *actual* incentive compensation payouts are irrelevant to the calculation. Incentive compensation allowances in rate cases are based on *target* amounts, as Ms. Cannady recognizes. The target amount of incentive compensation is known and measurable at any given time and is generally lower than the actual amount of STI paid.[578] Use of the target amount of incentive compensation is in accord with consistent Commission precedent.[579] There is no valid basis for Ms. Cannady to exclude the target STI amount for 2020 that SWEPCO used for the last three months of the test year.

Ms. Cannady's second proposal – to remove incentive compensation expense for collectively bargained union employees – is inconsistent with both PURA § 14.006 and Commission precedent. PURA § 14.006 provides:

> The commission may not interfere with employee wages and benefits, working conditions, or other terms or conditions of employment that are the product of a collective bargaining agreement recognized under federal law. An employee wage rate or benefit that is the product of the collective bargaining is presumed to be reasonable.

Ms. Cannady's proposal to exclude collectively bargained STI expense violates both of PURA § 14.006's components:

- it disallows costs that are presumed reasonable by law; and

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[575] SWEPCO Ex. 46 at 4:11-14; Docket No. 46449, PFD at 237 (the Company's incentive compensation request was based on target levels); *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, PFD at 88 (Oct. 12, 2015) (SPS request based on target level of incentive compensation expenses).

[576] OPUC Ex. 1 at 38:3-4 (emphasis added).

[577] Schedule CTC-8, Recommended Adjustment to SWEPCO Direct STI Compensation, OPUC Ex. 16, (top line of calculation begins with SWEPCO Direct Test Year STI Compensation at 100% Target).

[578] SWEPCO Ex. 46 at 4:15-17, 5:11-13.

[579] SWEPCO Ex. 46 at 4:11-14; Docket No. 46449, PFD at 235, 237 (the Company's incentive compensation request was based on target levels); Docket No. 43695, PFD at 88-89, 93 (SPS request based on target level of incentive compensation expenses).

- it interferes with employee wages and benefits that are the product of a collective bargaining agreement.

Disallowing collectively bargained STI expenses on the grounds that it is unreasonable to include financial incentives in rates cannot be reconciled with PURA § 14.006's directive that such expenses are presumed reasonable. PURA § 14.006 has carved out collective bargaining agreements from the Commission's authority to find wages and benefit expenses unreasonable. Furthermore, if recovery of the target level of collectively bargained STI expense were denied, the Company would be motivated to renegotiate collective bargaining agreements to reduce or eliminate such STI expense in favor of additional base pay, which would interfere with collectively bargained compensation in violation of PURA § 14.006. Treating collectively bargained STI expense the same as STI expense for other employees would ignore the treatment of such wages provided under the law. SWEPCO's inclusion of collectively bargained STI expense is also consistent with its last rate case, where that treatment was not contested.[580]

Alone among the witnesses addressing incentive compensation, CARD witness Mark Garrett challenges SWEPCO's proposal to base the funding mechanism adjustment on the 2019 70% EPS amount rather than the anomalous COVID-driven 2020 100% EPS amount.[581] Staff witness Ms. Stark did not challenge the Company's use of 70% EPS and OPUC witness Ms. Cannady affirmatively used that amount in her recommendation.[582] However, Mr. Garrett asserts that the 100% EPS amount should be used because the Company changed to that amount for 2020, which included the last three months of the test year. Mr. Garrett's proposal should be rejected.

As an initial matter, the 100% EPS funding mechanism was only in place for the last three months of the test year which fell in 2020, so Mr. Garrett's recommendation to use only that funding mechanism would be substantially overstated even if it were otherwise reasonable.[583] But the recommendation is not reasonable because the 2020 100% EPS measure was clearly an anomalous, one-time reaction to the financial uncertainty caused by the COVID pandemic and did

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[580] Docket No. 46449, PFD at 235.

[581] CARD Ex. 2 at 18:23-19:1.

[582] Staff Ex. 3 at 8:9-10:6; OPUC Ex. 1 at 38:7-8.

[583] SWEPCO Ex. 46 at 7:15-18.

not reflect SWEPCO's STI funding mechanism either before or after that year. The funding mechanism was 70% EPS in 2019 and has now been established at 60% EPS for 2021.[584]

b. Long-Term Incentive Compensation

In accordance with the Commission's practice and past rate cases, the Company is requesting that the test year level of LTI compensation, excluding the portion tied to financial measures, be included in SWEPCO's cost of service and rate base. The included amount is the 25% portion of LTI compensation related to restricted stock units (RSUs), which are not tied to any performance measures (financial or otherwise) but are instead provided to foster employee retention over a longer period.[585] Consistent with the Commission's ruling in SWEPCO's previous rate case (Docket No. 46449), the Company adjusted test year LTI expense for both SWEPCO and AEPSC to remove the performance unit portion (75%).[586]

Only CARD witness Mark Garrett disagrees with the Company's treatment of LTI expenses, proposing to disallow the 25% of those expenses related to RSUs because, he asserts, "the value of the RSU is directly tied to the value of the Company's common stock."[587] This recommendation is squarely contrary to the Commission's decision in SWEPCO's last two rate cases, Docket Nos. 46449 and 40443. In Docket No. 46449, the Commission found that "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."[588] In Docket No. 40443, the Commission also approved recovery of RSU expense, upholding the ALJs' recommendation that:

> restricted stock units, while generally similar in value to shares of AEP common stock, are awarded based solely on an employee's satisfaction of certain vesting requirements. Restricted stock units have no associated financial performance target and are awards, in the words of SWEPCO's brief, 'paid because an employee sticks around long enough to earn them.'[589]

Mr. Garrett is seeking to overturn well-established Commission precedent on this issue.

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[584] SWEPCO Ex. 46 at 7:18-21.

[585] SWEPCO Ex. 21 at 41:21-42:6.

[586] SWEPCO Ex. 46 at 11:14-18.

[587] CARD Ex. 2 at 27:7-8.

[588] Docket No. 46449, Order on Rehearing at 35 (FoF No. 199).

[589] Docket No. 40443, PFD at 84.

Mr. Garrett's argument that RSUs are financially based is wrong, as the Commission has previously concluded. The Company's RSUs do not have any metrics, goals or measures of any sort, and, while they are denominated in AEP stock, the impact that management may have on a company's stock price is much attenuated. RSUs are designed to provide management continuity by vesting stock rights after a certain number of years of service.[590] In addition, SWEPCO's RSUs have not been changed in any material respect since the Commission approved them in previous rate cases.[591] Mr. Garrett has shown no basis for disallowing them.

3. Severance Costs

During the Test Year, SWEPCO incurred $1,460,876 in severance costs properly allocated to SWEPCO from AEPSC and $767,074 in severance costs incurred directly by SWEPCO.[592] AEPSC and SWEPCO prudently incur severance costs under a severance program that allows management to evaluate operations on a continuing basis to provide the most efficient and effective service at the lowest reasonable cost to customers.[593] Only OPUC witness Ms. Cannady challenges SWEPCO's Test Year severance costs. Ms. Cannady does not allege that any Test Year severance cost was imprudently incurred or that a severance program more generally is unreasonable. Instead, Ms. Cannady recommends a disallowance of a substantial amount of the costs incurred during the Test Year only because of her allegation that the Test Year costs do not "appear" to be a normal level of severance pay for inclusion in rates.[594] Ms. Cannady supports this false allegation by ignoring the fact that severance costs are a cost of doing business and relying on a cherry-picked and misleading set of historically incurred severance costs.

Regarding the severance costs experienced at AEPSC and properly allocated to SWEPCO, the average of the costs incurred for the three calendar years 2017-2019 is $1,313,281, which is consistent with the level incurred during the Test Year of $1,460,876.[595] Ms. Cannady manufactures her average by excluding calendar year 2019 and instead using 2017, 2018, and the Test Year, thereby excluding a significant portion of SWEPCO's recent cost experience in 2019.

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[590] SWEPCO Ex. 46 at 12:10-13.

[591] SWEPCO Ex. 46 at 12:14-17.

[592] SWEPCO's Response to Staff RFI 5-33, OPUC Ex. 41.

[593] SWEPCO Ex. 36 at 33:17-20.

[594] OPUC Ex. 1 at 43:10-14.

[595] SWEPCO Ex. 36 at 34:3-5.

By excluding calendar year 2019 in her average, she avoids the 2019 severance expense of $2,957,553 in favor of the significantly lower Test Year amount of $1,460,876.[596]

Regarding the severance costs experienced directly at SWEPCO, Ms. Cannady recommends that the entire Test Year amount be disallowed because SWEPCO did not directly incur severance costs in 2017 or 2018. Once again, Ms. Cannady ignores the costs incurred in 2019. Further, she ignores the fact that severance costs are a legitimate cost of providing service to customers and they should certainly be more than zero.[597] Ms. Cannady does not present a persuasive case to depart from the Commission's Cost of Service rule that requires reliance on "historical test year expenses as adjusted for known and measurable changes."[598]

4. Other Post-Retirement Benefits

a. Pension Expense

The requested cost of service pension expense reflects the costs being recorded by SWEPCO in 2020 as presented in the 2020 actuarial studies, which are the latest available actuarial studies performed by Willis Towers Watson, the Company's independent actuary. SWEPCO applies the Test Year actual payroll expense/capital ratio of 69.71% to these 2020 costs to determine the pro forma level of expense to include in the cost of service.[599] Staff witness Ms. Stark recommends the use of SWEPCO's loading ratio, which is based on estimates, instead of the actual payroll capitalization ratio from the Test Year. The actual payroll capitalization ratio for the Test Year reflects the costs actually incurred during the Test Year, is the superior allocation ratio, and is consistent with how this adjustment has been calculated in past cases, which has not been challenged.[600] Further, Ms. Stark does not challenge the aggregate amount of pension costs, only the allocation of a portion of those costs to expense. Ms. Stark does not recognize the offsetting increase to capitalized pension cost that would result from her recommendation.

b. OPEB Expense

The requested cost of service Other Post Retirement Benefits (OPEB) expense reflects the costs being recorded by SWEPCO in 2020 as presented in the 2020 actuarial studies, which are

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596 SWEPCO Ex. 36 at 34:1-3.

597 SWEPCO Ex. 36 at 33:14-22.

598 16 TAC § 25.231(b).

599 SWEPCO Ex. 6 at 25:12-26:4.

600 SWEPCO Ex. 36 at 35:21-36:5.

the latest available actuarial studies performed by Willis Towers Watson, the Company's independent actuary.[601] CARD witness Mr. Mark Garrett alleges he identified "a problem" with the calculation of OPEB expense.[602] However, Mr. Mark Garrett's allegation is based on inaccurate information. Mr. Garrett failed to recognize that the Company filed a corrected Adjustment 3.11 work paper in response to CARD 4-41 that is also provided at Exhibit MAB-3R to the rebuttal testimony of SWEPCO witness Michael Baird. If the proper Company adjustment from the corrected Adjustment 3.11 work paper had been included on line 6 of Mr. Garrett's MG 2.6, then no further adjustment is warranted. Exhibit MAB-4R to the rebuttal testimony of Mr. Baird is a corrected version of MG 2.6. Exhibit MAB-4R shows that if line 6 is adjusted to the Company's actual adjustment, then CARD's adjustment would be zero, not $5,406,303 as proposed by Mr. Garrett.[603]

D. Depreciation and Amortization Expense

In his direct testimony, Company witness Jason Cash recommends revised depreciation accrual rates for SWEPCO's electric utility plant in service at December 31, 2019 with adjustments for units retired in 2020.[604] Mr. Cash's direct testimony includes his depreciation report (Exhibit JAC-2).[605] He also testifies that the revised depreciation rates primarily result from increased investment since the last depreciation study dated December 31, 2015.[606] A comparison of the existing depreciation rates and accruals with the new, recommended rates and accruals is provided in Mr. Cash's direct testimony and re-stated below:[607]

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[601] SWEPCO Ex. 6 at 25:12-26:2.

[602] CARD Ex. 2 at 32:6-33:6.

[603] SWEPCO Ex. 36 at 39:20-40:6.

[604] SWEPCO Ex. 16 at 2:17-21.

[605] SWEPCO Ex. 16 at 2:17-21; *see also* Exhibit JAC-2.

[606] SWEPCO Ex. 16 at 3:3-7.

[607] SWEPCO Ex. 16 at 4.

Depreciation Rates and Accruals
Based on Plant In Service at December 31, 2019 (as adjusted)
(Total Company)

	Existing		Study		
Functional Plant Group	Rates	Accruals	Rates	Accruals	Difference
Production	2.33%	99,513,823	2.71%	115,877,699	16,363,876
Transmission	2.06%	42,285,974	2.33%	47,890,727	5,604,753
Distribution	2.33%	52,941,254	2.80%	63,573,769	10,632,515
General	3.52%	7,383,029	3.07%	6,441,093	(941,936)
Total Depreciable Plant	2.29%	202,124,080	2.65%	233,783,288	31,659,208

Note: The Dolet Hills Power Station was not included in the depreciation study and as a result is not included in the Production Plant function depreciation rates proposed in this case.

As shown above, the recommended revised depreciation rates produce an increase in annual depreciation expense of $31,659,208 on a total company basis. However, the depreciation accruals that SWEPCO requests in its cost of service for this proceeding are calculated and supported by Company witness Michael Baird and reflected in Adjustment A-3.4.[608]

In response to Mr. Cash's direct testimony and his depreciation study, only CARD witnesses David and Mark Garrett propose depreciation-related recommendations.[609] There are no recommendations from other parties regarding Mr. Cash's depreciation study.

The contested depreciation issues between SWEPCO and CARD in this case involve the following:

- Sargent and Lundy LLC's (S&L) use of a 10% contingency factor in its plant demolition cost study;
- Mr. Cash's application of a 2.22% escalation factor to the net salvage amounts provided by S&L to determine the future terminal net salvage amount at each plant's retirement year; and
- the recommended service life and Iowa curve for Account 353 (Transmission Station Equipment), Account 354 (Transmission Towers and Fixtures), Account 355

608 SWEPCO Ex. 6 at 22:7-23:4.

609 Mr. Steven D. Hunt, testifying on behalf of ETEC/NTEC, also addresses depreciation in the context of the Dolet Hills Power Station issue. Mr. Hunt's testimony is addressed in Section II.A.1 of this brief.

(Transmission Poles and Fixtures), Account 356 (Transmission Overhead Conductors and Devices), Account 364 (Distribution Poles, Towers and Fixtures), Account 366 (Distribution Underground Conduit), Account 367 (Distribution Underground Conductor), Account 369 (Distribution Services), and Account 370 (Distribution Meters).

10% Contingency Factor

Mr. Cash calculated his recommended depreciation rates using the Average Remaining Life method, which recovers the original cost of the plant, adjusted for net salvage, minus accumulated depreciation over the average remaining life of the plant.[610] For Production Plant, SWEPCO commissioned independent engineering firm S&L to update the conceptual dismantling costs at their estimated retirement dates.[611] The S&L dismantling or demolition study, which provided terminal net salvage amounts for Production Plant at 2020 prices, was used by Mr. Cash (after applying an inflation factor) to calculate the net salvage percentages in the depreciation study.[612]

Mr. David Garrett testifies that the S&L demolition study should not include a 10% contingency factor. He argues that the 10% contingency fee used by S&L is arbitrary and unsupported.[613] He further suggests that it is unfair and uncertain.[614] Company witness Paul Eiden with S&L responds that use of a 10% contingency factor is consistent with the precedent established in SWEPCO's last base case.[615] In particular, he notes that the Order on Rehearing in Docket No. 46449 provides as follows:

> [t]he 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.
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> * * *
>
> [i]t is common practice to include contingency amounts in cost estimates for contract work across all industries.[616]

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[610] SWEPCO Ex. 16 at 6:9-13.

[611] SWEPCO Ex. 16 at 7.

[612] SWEPCO Ex. 16 at 7

[613] Direct Testimony of David Garrett, CARD Ex. 1 at 7:23-8:4 (using the page number in the bottom center of the page).

[614] CARD Ex. 1 at 8:7-8.

[615] Rebuttal Testimony of Paul Eiden, SWEPCO Ex. 42 at 2:12-3:12.

[616] SWEPCO Ex. 42 at 2:1-7 (citing Docket No. 46449, Order on Rehearing at FoF Nos. 177 and 179).