Cause No. 45576
I&M Industrial Group
MPG Public WP 18

FILED
October 14, 2021
INDIANA UTILITY
REGULATORY COMMISSION

State Office of Administrative Hearings

Kristofer S. Monson
Chief Administrative Law Judge

August 27, 2021

TO: Stephen Journeay, Commission Counsel **VIA EFILE TEXAS**
Commission Advising and Docket Management
William B. Travis State Office Building
1701 N. Congress, 7th Floor
Austin, Texas 78701

RE: SOAH Docket No.473-21-0538
PUC Docket No.51415

Application of Southwestern Electric Power Company for Authority to Change Rates

Enclosed is the Proposal for Decision (PFD) in the above-referenced case. By copy of this letter, the parties to this proceeding are being served with the PFD.

Please place this case on an open meeting agenda for the Commissioners' consideration. The final order deadline is October 27, 2021. Please notify me and the parties of the open meeting date, as well as the deadlines for filing exceptions to the PFD, replies to the exceptions, and requests for oral argument.

Sincerely,

Steven H. Neinast
Administrative Law Judge/Mediator

Enclosure
xc: All Parties of Record

SOAH DOCKET NO. 473-21-0538

PUC DOCKET NO. 51415

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

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LIST OF ACRONYMS AND DEFINED TERMS

TERM	DEFINITION
1CP	1 Coincident Peak
4CP	4 Coincident Peak
12CP	12 Coincident Peak
A&E/4CP	Average and Excess/4 Coincident Peak
ADFIT	Accumulated Deferred Federal Income Taxes
AEP	American Electric Power Company
AEPSC	American Electric Power Service Company
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
ASC	Accounting Standards Codification
ATC	Approved Transmission Charges
BTMG	Behind-the-Meter Generation
CAISO	California Independent System Operator
CAPM	Capital Asset Pricing Model
CARD	Cities Advocating Reasonable Deregulation
CCOSS	Class Cost of Service Study
CLECO	Cleco Power LLC
CoL	Conclusion of Law
Commission	Public Utility Commission of Texas
Company	Southwestern Electric Power Company
CONE	Cost of New Entry
DCF	Discounted Cash Flow
DCRF	Distribution Cost Recovery Factor
DHLC	Dolet Hills Lignite Company
Dolet Hills	Dolet Hills Power Station
ECAPM	Empirical Capital Asset Pricing Model
ECOM	Investment that Exceeded Market
ERCOT	Electric Reliability Council of Texas
ETEC/NTEC	East Texas Electric Cooperative, Inc. and Northeast Texas Electric Cooperative, Inc.
ETSWD	East Texas Salt Water Disposal Company
FERC	Federal Energy Regulatory Commission
FoF	Finding of Fact
GAAP	Generally Accepted Accounting Principles
GCRR	Generation Cost Recovery Rider
GDP	Gross Domestic Product
GS	General Service
IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolt
kVAR	Kilovolt-Ampere Reactive
kW	Kilowatt

TERM	DEFINITION
kWh	Kilowatt-hour
LLP	Large Lighting and Power
LLP-T	Large Lighting and Power–Transmission
LP	Lighting and Power
LTI	Long Term Incentive
MDD	Maximum Diversified Demand
MISO	Midcontinent Independent System Operator, Inc.
MW	Megawatt
NITS	Network Integration Transmission Service
NOLC	Net Operating Loss Carry-forward
Nucor	Nucor Steel-Longview
O&M	Operations and Maintenance
OAG	Office of the Attorney General of Texas
OATT	Open Access Transmission Tariff
OLT	Observed Life Table
Oncor	Oncor Electric Delivery Company
OPEB	Other Post-Employment Benefits
OPUC	Office of Public Utility Counsel
PEV	Plug-in Electric Vehicle
PFD	Proposal for Decision
PJM	PJM Interconnection
PO	Preliminary Order
PRPM	Predictive Risk Premium Method
PUC	Public Utility Commission of Texas
PURA	Public Utility Regulatory Act
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility
RCE	Rate Case Expense
RCS	Rate Case Surcharge
REC	Renewable Energy Credit
RFI	Request for Information
RFP	Rate Filing Package
ROE	Return on Equity
RR	Revision Request
RSU	Restricted Stock Units
RTO	Regional Transmission Organization
S&L	Sargent & Lundy
S&P	Standard & Poor's
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SBMAA Tariff	Supplementary, Backup, Maintenance and As-Available Power Service Tariff

TERM	DEFINITION
SERP	Supplemental Executive Retirement Plan
Sierra Club	Sierra Club and Dr. Lawrence Brough
SOAH	State Office of Administrative Hearings
SPP	Southwest Power Pool
SPS	Southwestern Public Service Company
SSD	Sum of Squared Differences
SSGL	Synchronous Self-Generation Load
Staff	Staff of the Public Utility Commission of Texas
STI	Short Term Incentive
SWEPCO	Southwestern Electric Power Company
TAC	Texas Administrative Code
TCGA	Texas Cotton Ginners Association
TCJA	Tax Cuts and Jobs Act of 2017
TCRF	Transmission Cost Recovery Factor
TIEC	Texas Industrial Energy Consumers
USofA	FERC Uniform System of Accounts
Value Line	Value Line Investment Survey
WACC	Weighted Average Cost of Capital
Walmart	Walmart Inc.
Zacks	Zacks Investment Research

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PROPOSAL FOR DECISION

I. INTRODUCTION

Southwestern Electric Power Company (SWEPCO or the Company) is a wholly-owned subsidiary of American Electric Power Company (AEP). SWEPCO, as an electric utility providing service in Texas, is subject to the Texas Public Utility Regulatory Act (PURA) and the jurisdiction of the Public Utility Commission of Texas (PUC or Commission) thereunder.[1] On October 14, 2020, SWEPCO filed an application in this docket to change its base rates (Application).

SWEPCO is a fully integrated electric utility providing service to 543,400 retail customers and six wholesale customers in Texas, Arkansas, and Louisiana. Of those retail customers, 187,400 reside in Texas. Two of the Company's six Federal Energy Regulatory Commission (FERC)-approved wholesale customer contracts are with electric cooperatives in Texas. Through wholesale arrangements with these Texas cooperatives, SWEPCO supplies generation to cooperatives serving approximately 240,000 retail customers in Texas. SWEPCO's Texas service area generally includes the area between Waskom (on the eastern Texas border) and Sulphur Springs on the west, and Texarkana and Center on the north and south, with an additional five counties along the Texas border with Oklahoma in the Texas panhandle, running north of Childress to Wheeler.[2] The largest cities in SWEPCO's Texas service area include Longview, Texarkana, Marshall, Mount Pleasant, Kilgore, and Henderson.

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[1] Tex. Util. Code §§ 11.001-66.016 (PURA).

[2] Most of SWEPCO's service territory is in the northeast corner of Texas, well east of Dallas. But SWEPCO also serves customers in the Texas panhandle along Texas's eastern border with Oklahoma.

This service area is entirely in the Southwest Power Pool (SPP). The SPP maintains functional control of the SWEPCO transmission system and executes an organized wholesale market in which SWEPCO participates.[3]

In its Application, SWEPCO states that it will retire its Dolet Hills Power Station (Dolet Hills) on December 31, 2021, rather than extend operation of the plant through its original estimated life into 2046. SWEPCO proposes a number of rate treatments to address this early retirement, including using its excess deferred federal income taxes as an offsetting accounting entry. Other significant proposals in SWEPCO's Application include proposals to: (1) increase its vegetation management costs by $5 million over its recorded test year vegetation management expense; (2) establish a self-insurance reserve; (3) defer recovery of Hurricane Laura costs; (4) establish a mechanism to track certain costs it is billed by SPP; (5) establish baseline calculations to be used in the Company's future Transmission Cost Recovery Factor (TCRF), Distribution Cost Recovery Factor (DCRF), and Generation Cost Recovery Rider (GCRR) filings; and (5) new or revised rate schedule provisions.

The test year in this case is the 12 months ending March 31, 2020. In its Application, SWEPCO asks the Commission to approve a total Texas retail base rate revenue requirement of $534,165,103 and a base rate increase of $105,026,238, which is an increase of 30.31% over adjusted Texas retail test year base rate revenues exclusive of fuel and rider revenues. The proposed increase in annual Texas retail revenues will be offset by setting SWEPCO's current TCRF and DCRF to zero, which reduces its revenue deficiency by $14,826,502, resulting in a net proposed increase of $90,199,736. This is a 26.03% increase over adjusted Texas retail test-year base rate revenues exclusive of fuel and other rider revenues. The overall impact of the proposed revenue requirement increase, considering both fuel and non-fuel revenues, is a 15.57% increase. The impact of the rate change on various customer classes will vary from the overall impact.[4]

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[3] SWEPCO Ex. 3 (Smoak Dir.) at 3-4.

[4] SWEPCO Ex. 1 (Application) at 4.

SWEPCO calculated its proposed revenue requirement based on an overall weighted average cost of capital (WACC) of 7.22%. This WACC includes the Company's proposed return on equity (ROE) of 10.35%.[5]

In its rebuttal testimony filed on April 23, 2021, SWEPCO proposed a Texas retail base rate revenue requirement of $529,371,963, which is approximately $5 million less than its as-filed request.[6] After accounting for $82,905,762 in revenue credits, which offset the $529 million unadjusted requested Texas retail base rate revenue requirement, SWEPCO requests that the Commission approve a Texas retail base rate revenue requirement (also referred to as Texas retail cost of service) of $446,466,201.[7] SWEPCO's rebuttal Texas retail cost of service for its Residential rate class is $625,801 higher than the cost of service for the Residential rate class in the Company's as-filed case, while the other rate classes experienced a lower Texas retail cost of service as a result of the rebuttal revisions.[8]

II. JURISDICTION AND NOTICE

SWEPCO is a "public utility" as that term is defined in PURA § 11.004(1) and an "electric utility" as that term is defined in PURA § 31.002(6). The Commission exercises regulatory authority over SWEPCO, and jurisdiction over the subject matter of this application, pursuant to PURA §§ 14.001, 32.001, and 36.101. The State Office of Administrative Hearings (SOAH) has jurisdiction over the contested case hearing, including the preparation of the proposal for decision (PFD), pursuant to PURA § 14.053 and Texas Government Code § 2003.049(b).

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[5] SWEPCO updated its ROE analyses in its rebuttal testimony, but did not revise its requested 10.35% ROE. *See* SWEPCO Ex. 38 (D'Ascendis Reb.) at 6.

[6] SWEPCO Ex. 34 (Aaron Reb.), *e.g.*, JOA Workpapers, SWEPCO TX COS_Class TY 3_ 2020 Rebuttal, "TX Class" Schedule at line 827. SWEPCO's changes between its as-filed case and its rebuttal case are listed in this same workpaper at the schedule labeled "COS Changes-Rebuttal."

[7] SWEPCO Ex. 34 (Aaron Reb.) at 6, Table 1, and, *e.g.*, JOA Workpapers, SWEPCO TX COS_Class TY 3_ 2020 Rebuttal, "TX Class" Schedule at line 802.

[8] SWEPCO Ex. 34 (Aaron Reb.) at 6, Table 1. SWEPCO's rebuttal testimony does not indicate the percentage base rate increases that result from its rebuttal case, as compared to the 26% increase (exclusive of fuel and rider revenues) stated in its as-filed case.

Those municipalities in SWEPCO's service area that have not ceded jurisdiction to the Commission continue to have exclusive original jurisdiction over SWEPCO's rates, operations, and services in their respective municipalities, pursuant to PURA § 33.001. When SWEPCO filed the Application with the Commission, it also filed the Application with its original jurisdiction cities. Pursuant to PURA §§ 32.001(b), 33.051, and 33.053, SWEPCO appealed the actions of the original jurisdiction cities to the Commission and requested that those appeals be consolidated with this docket. All of the appeals were consolidated into this docket in a series of SOAH orders issued in 2021 prior to the hearing on the merits.

SWEPCO's notice of its application and notice of the hearing were not contested and, therefore, do not require further discussion but will be addressed in the proposed Findings of Fact (FoFs) and Conclusions of Law (CoLs) listed at the end of this PFD.

III. PROCEDURAL HISTORY

On October 30, 2020, the Commission referred this case to SOAH. On December 17, 2020, the Commission issued its Preliminary Order setting forth 85 issues to be addressed in this proceeding. The Preliminary Order also ruled that SWEPCO's request for a declaratory order related to battery storage would not be addressed in this proceeding.

Ten parties intervened, and Commission Staff (Staff) also participated:

Parties	Counsel
SWEPCO	William Coe, Kerry McGrath, Patrick Pearsall[9]
Cities Advocating Reasonable Deregulation (CARD)	Alfred Herrera, Brennan Foley, Sergio Herrera

[9] Several other attorneys appeared on behalf of SWEPCO.

Parties	Counsel
East Texas Electric Cooperative, Inc. and Northeast Texas Electric Cooperative, Inc. (ETEC/NTEC)	Adrianne Waddell, Jacob Lawler
East Texas Salt Water Disposal Company (ETSWD)	Todd Kimbrough, Dane McKaughan
Eastman Chemical Company (Eastman)	Andrew Kever, Katherine Mudge
Nucor Steel-Longview (Nucor)	Damon E. Xenopoulos, Laura Baker, Joseph Briscar
Office of Public Utility Counsel (OPUC)	Zachary Stephenson, Tucker Furlow, Chris Ekoh
Sierra Club and Dr. Lawrence Brough (Sierra Club)	Joshua Smith, Matthew Miller, Tony Mendoza
Texas Cotton Ginners' Association (TCGA)	Zachary Brady
Texas Industrial Energy Consumers (TIEC)	Rex VanMiddlesworth, Benjamin Hallmark, James Zhu
Walmart Inc. (Walmart)	Julie Clark
Staff	Rashmin Asher, Robert Parish, Justin Adkins

Between May 19 and 26, 2021, four SOAH Administrative Law Judges (ALJs)[10] held a hearing on the merits in this docket using the Zoom videoconferencing application.[11] Prior to the hearing on the merits, SWEPCO extended the final order deadline to October 27, 2021.[12]

The parties submitted initial post-hearing briefs on June 17, 2021, and reply briefs and proposed FoFs, CoLs, and Ordering Paragraphs on July 1, 2021. The record closed on July 1, 2021, except that SWEPCO, CARD, and Staff were authorized to continue to file updates to SWEPCO's

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[10] Administrative Law Judges (ALJs) Andrew Lutostanski, Steven Neinast, Robert Pemberton, and Cassandra Quinn.

[11] As authorized by SOAH Order No. 13, SWEPCO filed a motion for optional completeness of exhibits, offering additional pages that were not included within Staff Ex. 67. Staff Ex. 67 was admitted during the hearing on the merits. SWEPCO's optional completeness pages were offered as SWEPCO Ex. 88. No party objected to SWEPCO Ex. 88. Therefore, SWEPCO Ex. 88 is admitted into the record.

[12] *See* Agreed Motion to Adopt Procedural Schedule filed by SWEPCO on November 19, 2020.

and CARD's rate case expenses and supporting testimony through the end of July 2021.[13] Calculation of the numerical impacts of the ALJs' recommendations in this PFD (number-running) commenced on August 4, 2021, and concluded on August 12, 2021.

IV. EXECUTIVE SUMMARY

As shown in the schedules attached to this PFD, the ALJs recommend that SWEPCO's Texas retail base rate annual revenue requirement be set at $402,643,175, which is $43.8 million less than its Texas retail base rate revenue requested through its rebuttal testimony. The ALJs' primary recommendations on discrete issues are summarized below.

A. Rate Base

1. Retired Gas-Fired Generation Units

Consistent with the Commission's treatment of Welsh Unit 2 in Docket No. 46449, the ALJs recommend that the Commission remove from rate base (and, therefore, deny SWEPCO any return upon) the net book value of the now-retired Lieberman Unit 2, Lone Star Unit 1, and Knox Lee Units 2, 3, and 4, and place those values into a regulatory asset, to be amortized over the four-year period in which the rates adopted in this proceeding are anticipated to remain in effect.

2. Dolet Hills Power Station (Dolet Hills)

Also informed by Docket No. 46449, the ALJs recommend that the Commission address the upcoming retirement of Dolet Hills by removing from base rates all cost recovery for Dolet Hills, the plant's lignite inventory, SWEPCO's investment in the Oxbow mine reserves, and

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[13] The rate case expense reports or supplemental testimony filed by SWEPCO, CARD, and Staff on July 6, 20, and 27, 2021, in accordance with SOAH Order No. 13, were not subject ot objections and are hereby admitted into the record.

SWEPCO's return on equity and associated taxes concerning the Dolet Hills Lignite Company (DHLC), and address cost recovery for these items in a Dolet Hills Rate Recovery Rider, as follows:

- For the period between March 18, 2021 (the relate-back date for the rates to be approved in this proceeding) through December 31, 2021 (when Dolet Hills will be retired) (the Operational-Plant Phase):
  - Dolet Hills, its lignite inventory, and the Oxbow investment are treated as if in rate base, earning a return.
    - The ALJs also recommend that the Commission approve SWEPCO's requested test-year capital investment and operations and maintenance (O&M) expense at Dolet Hills.
    - The ALJs further recommend that the Commission approve the 45-day target lignite inventory level requested by SWEPCO for Dolet Hills.
  - Similarly, SWEPCO continues to recover the return on equity and associated taxes for DHLC.
  - SWEPCO continues to depreciate Dolet Hills in accord with the plant's previously established 2046 useful life.
  - Similarly, SWEPCO can continue to recover O&M and the other categories of expenses associated with the operation of a generating plant.
- For the period beginning January 1, 2022 (the Post-Retirement Phase):
  - The then-remaining net book value of Dolet Hills and the Oxbow investment will be placed in a regulatory asset, to be depreciated in accord with the plant's 2046 useful life.
  - All other cost recovery relating to Dolet Hills, including return and expenses, its lignite inventory, the Oxbow investment, or DHLC ends.

3. Coal and Lignite Inventories

In addition to the above recommendations concerning Dolet Hills, the ALJs recommend that the Commission approve SWEPCO's requested 30-day burn levels of inventory at the Flint Creek, Welsh, Turk, and Pirkey plants.

4. Test-Year Capital Spending and O&M

The ALJs recommend that the Commission approve SWEPCO's proposed test-year capital investment and O&M at the Flint Creek and Welsh plants, which Sierra Club has challenged.

5. Net Operating Loss Carry-Forward (NOLC) Adjustment

The ALJs recommend that the Commission disallow SWEPCO's requested $455,122,490 reduction of its accumulated deferred federal income taxes (ADFIT) balance to recognize a NOLC ADFIT asset.

6. Excess ADFIT/Surcharge Offset

The ALJs recommend that the Commission order SWEPCO to return its refundable excess ADFIT balance (unprotected ADFIT and accrued protected ADFIT) by: (1) crediting the balance against any surcharge owing from customers by virtue of the relate-back date; and (2) refunding any remaining balance over a six-month period, with carrying charges at the same WACC that the Commission approves in this proceeding.

7. Self-Insurance Reserve

Due to a failure in the proof of public interest required by Commission rule, the ALJs recommend that the Commission deny SWEPCO's request to establish a self-insurance reserve at this time.

B. Rate of Return

The ALJs recommend an ROE of 9.45%, a cost of debt of 4.18%, a capital structure comprised of 50.63% debt and 49.37% equity, and an overall rate of return of 6.79%. The ALJs' recommendation is a downward adjustment to SWEPCO's request for a 10.35% ROE, but adopts SWEPCO's proposed cost of debt, which only Staff opposed, and SWEPCO's proposed capital structure, which was unopposed.

C. Financial Integrity (Ring-Fencing Protections)

The ALJs recommend that the Commission require SWEPCO to implement most of the ring-fencing protections that Staff proposed, with the exception of four provisions that SWEPCO opposed.

D. Cost of Service

1. Transmission O&M Expense

The ALJs recommend approval of SWEPCO's transmission O&M expenses.

2. Transmission Expenses and Revenues under FERC-approved tariff

Other than Eastman and TIEC's challenge regarding SPP Open Access Transmission Tariff (OATT) charges incurred for Eastman's retail behind-the-meter load, the inclusion of the test year SPP OATT expenses and revenues in SWEPCO's requested cost of service is uncontested. The ALJs recommend that SWEPCO's SPP OATT expenses and revenues be approved except as otherwise stated.

3. Proposed Deferral of SPP Wholesale Transmission Costs

SWEPCO proposes that the portion of its ongoing SPP OATT bill that is above or below the net test year level approved by the Commission in this proceeding be deferred into a regulatory asset or liability until it can be addressed in a future TCRF or base rate proceeding. The ALJs recommend that SWEPCO's proposal be rejected.

4. Distribution O&M Expense

The ALJs recommend approval of SWEPCO's proposed distribution O&M expense.

5. Distribution Vegetation Management Expenses and Program Expansion

SWEPCO seeks an increase of $5 million over the $9.57 million in vegetation management expenses incurred in the test year. The ALJs recommend that an additional $5 million for vegetation management be approved. The ALJs also recommend that a compliance docket be opened to examine SWEPCO's vegetation management practices and spending. The ALJs decline to require SWEPCO to implement a four-year trim cycle.

6. Generation O&M Expense

SWEPCO proposes to include the O&M expense for Dolet Hills in its rates. The ALJs recommend that SWEPCO recover the test-year average monthly O&M expense for Dolet Hills until its retirement in December 2021 but not after.

SWEPCO proposes to include the O&M expense for five natural gas plants in its rates. The ALJs recommend that SWEPCO recover its requested O&M expenses for these units.

7. Payroll Expense

SWEPCO requested a payroll increase for employees. The ALJs recommend that Staff and OPUC's adjustment be adopted: a $544,331 increase for SWEPCO's direct payroll increase and a ($4,480,512) decrease for AEP Service Company's (AEPSC's) allocated payroll expense.

8. Incentive Compensation

The ALJs recommend that SWEPCO's incentive compensation expense be approved, with two small changes recommended by Staff and agreed to by SWEPCO.

9. Severance Costs

For SWEPCO's direct severance costs, the ALJs recommend a ($504,067) adjustment. For AEPSC's severance costs charged to SWEPCO, the ALJs recommend a ($636,576) adjustment.

10. Other Post-Retirement Benefits

The ALJs recommend that SWEPCO recover its other post-employment benefits expense.

11. Depreciation and Amortization Expense

The ALJs recommend the values proposed in SWEPCO's Application except for the following:

- <u>Remaining Net Book Value of Retired Gas-Fired Generating Units and Dolet Hills</u>: As summarized above, the remaining net book value of SWEPCO's five retired gas-fired generating units (Lieberman Unit 2, Lone Star Unit 1, and Knox Lee Units 2, 3, and 4) should be removed from base rates, placed in a regulatory asset, and amortized over four years. Further, the remaining net book value of Dolet Hills (and the associated Oxbow investment) should be removed from base rates and recovered through the Dolet Hills Rate Rider based on a 2046 useful life.

- Account 354 – Transmission Towers and Fixtures: adopt CARD's S1.5-74 curve life combination.

- Account 355 – Transmission Poles and Fixtures: adopt CARD's recommended L1.5- 9 curve life combination.

- Account 364 – Distribution Poles, Towers and Fixtures: adopt SWEPCO's rebuttal correction to use the S-.5-55 curve life combination.

- Account 366 – Distribution Underground Conduit: adopt CARD's recommended R4.0-80 curve life combination.

- Amortization: Adopt Staff's (unopposed) adjustment to intangible plant amortization.

12. Purchased Capacity Expense

SWEPCO purchases power under a contract with the Louisiana Generating Company (formerly Cajun Electric Power Cooperative). The ALJs recommend that SWEPCO continue to recover these costs through base rates.

SWEPCO purchased power from four wind projects. The ALJs recommend that the cost of the wind energy should continue to be collected through SWEPCO's fuel factor.

13. Affiliate Expenses

The ALJs recommend approval of Staff's adjustment of ($634,043) to affiliate expenses.

14. Federal Income Tax Expense

The ALJs recommend approval of SWEPCO's federal income tax expense as adjusted for flow-through matters (*e.g.*, invested capital and rate of return).

15. Ad Valorem (Property) Taxes

The ALJs recommend approval of Staff's adjustment to synchronize the effective ad valorem tax rate with the associated property subject to tax and the assets to which it is applied.

16. Payroll Taxes

The ALJs recommend approval of Staff's adjustment of ($258,162) to payroll tax expense.

17. Gross Margin Tax

SWEPCO's calculation of the cost-of-service margins was not contested. The ALJs recommend that revenue-related taxes should be updated and synchronized with the final revenue requirement set in this case.

E. Allocated Transmission Expenses Related to Retail Behind-the-Meter Generation

The ALJs conclude that SWEPCO's test-year charges from SPP for Network Integration Transmission Service are reasonable as a matter of law under the filed rate doctrine. The ALJs do not address whether SWEPCO's decision to report Eastman's retail behind-the-meter generation (BTMG) load to SPP for purposes of allocating such costs was required by SPP's OATT,because FERC has exclusive jurisdiction to resolve disputes involving the interpretation of a FERC-approved tariff, such as the OATT.

However, the ALJs recommend that SWEPCO's proposals to allocate transmission costs at both the jurisdictional and class levels by adding Eastman's BTMG load to the Texas jurisdiction and Large Lighting and Power–Transmission (LLP-T) class, respectively, should be rejected. Eastman's BTMG load should be removed when performing both allocations.

F. Billing Determinants

The ALJs recommend the Commission approve the adjusted test-year billing determinants proposed by SWEPCO, and that the billing determinants not be adjusted to attempt to account for the effects of the COVID-19 pandemic. The continuing effects of COVID-19 are transitory and unknown.

SWEPCO's use of estimated billing determinants to account for anticipated customer migration among existing rate schedules in between rate cases is acceptable.

G. Jurisdictional Cost Allocation

The underlying methodology and calculations of Staff's jurisdictional cost of service study are appropriate when the inputs addressed in this PFD are used to run the jurisdictional cost of service study.

SWEPCO properly removed its inadvertent assignment in Rate Filing Package Schedule P-3 of costs to the wholesale jurisdiction.

H. Class Cost Allocation

SWEPCO appropriately does not allocate major account representative-related costs to the Residential class. SWEPCO appropriately used a single coincident peak (1CP) system load factor to weight average demand in the class average and excess four coincident peak (A&E/4CP) allocation methodology.

In its next base rate case, SWEPCO should address why three classes—the Cotton Gin, Oilfield Secondary, and Public Street and Lighting classes—historically have been well under a unity (1.0) relative rate of return as a result of the class cost of service study, and what can and should be done to address these under-recoveries through methods other than gradualism.

I. Revenue Distribution and Rate Design

1. Revenue Distribution/Gradualism

The ALJs recommend that the Company's use of four rate groupings—the Residential, Commercial and Industrial, Municipal, and Lighting class Groups—to address revenue distribution/gradualism and rate design is appropriate. The Company's revenue distribution approach is a reasonable interpretation of the Commission's Orders in SWEPCO's two prior base rate cases. The ALJs therefore recommend that the Commission approve SWEPCO's revenue distribution/gradualism mechanism as proposed in SWEPCO's rebuttal case, as adjusted to reflect the class cost of service ultimately approved in this case.

2. Other Rate Design Issues

- <u>TCRF and DCRF Revenues</u>: SWEPCO must evaluate a class's present revenues inclusive of TCRF and DCRF revenues as required by Docket No. 46449.

- <u>Cotton Gin, Oilfield Secondary, and Public Street and Highway Lighting Classes</u>: The relative rates of return issue addressed in the class cost of service summary above may also be addressed in the context of rate design. That is, why are these three classes in particular well below a unity relative rate of return?

- <u>General Service (GS) Rate Design</u>: The ALJs recommend that the Commission reject SWEPCO's request to remove the 50 kilowatt (kW) maximum demand that applies to the GS rate schedule.

- <u>Migration Among Classes Between Rate Cases</u>: The ALJs recommend against Staff's proposal to require SWEPCO to revise many of its rate schedules to preclude customers from migrating among classes between rate cases. This issue, however, should be addressed in more detail in SWEPCO's next base rate case.

- <u>Lighting and Power (LP) Secondary Class</u>: SWEPCO should not collect fixed demand-related costs through energy charges in the LP Secondary rate class.

- Reactive Power Charge in the Large Lighting and Power (LLP) Rate Schedule: SWEPCO has not justified its proposal to increase the reactive demand charge in the LLP rate schedule. If SWEPCO proposes to increase this charge in its next base rate case, it should provide a more detailed explanation, or a study, that support the requested increase.

J. Riders

- Proposed Residential Service Plug-in Electric Vehicle (PEV) Rider: The Commission should approve SWEPCO's proposed PEV Rider.

- Renewable Energy Credit (REC) Rider: SWEPCO should revise the REC Rider to allow a customer to link its RECs to specific renewable resources. SWEPCO's REC opt-out credit applicable to transmission level customers that "opt out" of paying RECs should be allocated based on energy, not demand.

K. Retail Choice Pilot Project

ETSWD's request that the Commission implement a retail choice pilot project in SWEPCO's service territory is moot based on the Commission's rejection of that request in its declaratory order issued in Docket No. 51257.

L. Baselines

SWEPCO's proposals to reset the baselines for the components that are used for a subsequent implementation of the TCRF and DCRF, and to establish a baseline for the GCRR should be approved. The TCRF, DCRF, and GCRR baselines should be set in the compliance phase of this case.

M. Rate Case Expenses

SWEPCO should be authorized to recover its own and CARD's rate case expenses totallling $3,700,021 through its proposed Rate Case Surcharge (RCS) Rider. The Commission should deny SWEPCO's request to recover $65,167 attributable to the hourly fees charged by two attorneys in excess of $550 per hour. The total amount stated above includes $2,500 in CARD's rate case expenses finally incurred in Docket No. 47141.

V. RATE BASE/INVESTED CAPITAL
[PO Issues 4, 5, 10, 11, 12, 13, 14, 15, 16, 18, 19, 20, 21, 22, 23, 36, 37, 38, 39, 40, 41, 50, 67, 68, 69, 70, 71]

A. Transmission, Distribution, and Generation Capital Investment [PO Issues 4, 5, 10, 11, 13, 14, 15, 16]

SWEPCO presented for review approximately $636.7 million in capital additions to its transmission system, approximately $143.5 million in distribution capital additions, and approximately $320.9 million in capital additions to its generating plants, made between the June 30, 2016 conclusion of the historical test year used in SWEPCO's last base rate case—Docket No. 46449[14]—and the March 31, 2020 conclusion of the test year in the present case. The capital additions were discussed in the testimony and exhibits of SWEPCO witnesses Wayman Smith (transmission), Drew Seidel (distribution), and Monte McMahon (generation). No party challenged the capital additions or the costs thereof aside from a challenge by Sierra Club (addressed below) to spending at three solid-fuel-fired generating units. The ALJs recommend including the capital additions in setting rates in this case.

The more controversial issues in regard to capital investment, rather, concern the proper rate treatment of SWEPCO's investments in generating plants that have been retired or soon will be.

1. Retired Gas-Fired Generating Units [PO Issue 13]

Since the Commission's decision in Docket No. 46449, SWEPCO has retired five of its gas-fired generating units:

Unit	Year Entered Service	Date Retired
Knox Lee Unit 4	1956	January 1, 2019

[14] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 46449, Order on Rehearing, FoF No. 7 (Mar. 19, 2018) (Docket No. 46449).

Knox Lee Unit 2	1950	May 1, 2020
Knox Lee Unit 3	1952	May 1, 2020
Lieberman Unit 2	1949	May 1, 2020
Lone Star Unit 1	1954	May 1, 2020[15]

SWEPCO's vice-president over generating assets, Mr. McMahon, testified that the Company determined the retirements to be in its customers' best interests, considering the age and condition of the units' equipment, the significant capital investment required to keep them operating, and the units' relatively high cost to generate electricity compared to the forecasted market price of electricity.[16]

No party questions the plant retirements themselves, which occurred at or near the ends of the units' respective useful lives.[17] However, the retired units still had remaining undepreciated value, which gives rise to a dispute between SWEPCO and Staff concerning the appropriate rate treatment for that investment. Their respective positions distill to a disagreement over the extent to which SWEPCO's rate recovery relating to the retired units is, or should be, governed by the Commission's rate treatment of the retired Welsh Unit 2 in Docket No. 46449.

In 2016, 24 years before the end of the plant's previously projected useful life, SWEPCO had retired Welsh Unit 2, a coal-fired generating plant, pursuant to a broader strategy of SWEPCO and other AEP affiliates to respond to increasingly stringent federal air-quality regulations by retiring or retrofitting coal and lignite-fired plants across the AEP system.[18] In Docket No. 46449,

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[15] SWEPCO Ex. 7 (McMahon Dir.) at 9-10.

[16] SWEPCO Ex. 7 (McMahon Dir.) at 9.

[17] SWEPCO Ex. 7 (McMahon Dir.) at 9-10; *see* Staff Ex. 3 (Stark Dir.) at 19 (noting that the units "were retired at the end of their estimated useful lives as established in Docket No. 46449").

[18] Docket No. 46449, Order on Rehearing, FoF Nos. 21-23, 65 (Mar. 19, 2018); *see also* Docket No. 46449, PFD at 87 (Sep. 22, 2017); *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Order on Rehearing, FoF No. 199 (Mar. 6, 2014) (estimated useful life through 2040).

the Commission found that the Welch Unit 2 retirement was prudent.[19] The Commission also found, and there was no dispute, that SWEPCO was entitled to recover the undepreciated value of Welch Unit 2 remaining upon its retirement, roughly $75 million.[20] However, parties differed as to whether SWEPCO was also entitled to earn a return on that undepreciated value, which SWEPCO had sought to do, considering that PURA and Commission rules contemplate a return only on invested capital that is "used and useful" in providing service to the public.[21]

SWEPCO argued that it was entitled to earn this return by virtue of the accounting treatment prescribed by the FERC Uniform System of Accounts (USofA) and thus mandated by the Commission.[22] That accounting treatment, as the parties agreed and the Commission ultimately found, was to credit the relevant Plant in Service account (reflecting the original cost of electric utility plant) in the amount of Welsh Unit 2's original cost (thereby removing that value from the account) and debiting the corresponding Accumulated Depreciation account by the same amount, leaving a debit balance in Accumulated Depreciation equaling the plant's undepreciated balance.[23] But this adjustment, standing alone, would enable SWEPCO to earn a return on the undepreciated value of Welsh Unit 2 because that value (now reflected as a debit balance in Accumulated Depreciation) would also continue to be reflected in Net Plant in Service (the difference of subtracting Accumulated Depreciation from Plant in Service, *i.e.*, the plant's net book value, the figure that ultimately goes into rate base).[24] In SWEPCO's view, this accounting treatment served to remove Welsh Unit 2 from "invested capital" while also still enabling it to earn a return on the plant's undepreciated value.[25] SWEPCO further argued that this rate treatment was consistent with

[19] Docket No. 46449, Order on Rehearing, FoF Nos. 53-64 (Mar. 19, 2018).

[20] Docket No. 46449, Order on Rehearing, FoF No. 69 (Mar. 19, 2018); *see also* Docket No. 46449, PFD at 89 (Sep. 22, 2017).

[21] Docket No. 46449, PFD at 89-90 (Sep. 22, 2017); *see* PURA §§ 36.051, .053; 16 Tex. Admin. Code (TAC) § 25.231(c)(2)(A)).

[22] *See* 16 TAC § 25.72(c).

[23] Docket No. 46449, Order on Rehearing, FoF No. 67 (Mar. 19, 2018); *see also* Docket No. 46449, PFD at 87-89 (Sep. 22, 2017).

[24] *See* Docket No. 46449, PFD at 87-91 (Sep. 22, 2017); 16 TAC § 25.231(c)(2)(A).

[25] Docket No. 46449, PFD at 89-90 (Sep. 22, 2017).

Commission precedent and the principle that a utility be allowed to recover a return on its prudent investments.[26] Urging that a retired plant is not "used and useful" in providing service, Staff and various intervenors contended that the remaining undepreciated value should be cleared from Accumulated Depreciation and moved to a regulatory asset account, from which the value would be repaid to SWEPCO, but without a return.[27]

The Commission agreed with Staff and intervenors and rejected SWEPCO's approach, finding that: (1) "Welsh [U]nit 2 no longer generates electricity and is not used by and useful to SWEPCO in providing electric service to the public"; (2) "[b]ecause Welsh [U]nit 2 is no longer used and useful, SWEPCO may not include its investments associated with the plant in its rate base, and may not earn a return on that remaining investment"; (3) "[a]lowing SWEPCO a return of, but not on, its remaining investment in Welsh [U]nit 2 balances the interests of ratepayers and shareholders with respect to a plant that no longer provides service"; and (4) "[t]he appropriate accounting treatment that results in the appropriate ratemaking treatment was, as Staff and intervenors had urged, "to record the undepreciated balance of Welsh [U]nit 2 in a regulatory-asset account" rather than leaving it in Accumulated Depreciation.[28] The PFD, which the Commission adopted in material part, elaborated:

> This issue is actually quite simple. The FERC [USofA] requires a journal entry to account for retirement. But for an asset such as a power plant, the journal entry does not end as SWEPCO contends if the utility is not entitled to earn a return on the undepreciated balance of the asset remaining at retirement. So, the princip[al] question here is whether SWEPCO is entitled to earn a return on the undepreciated balance of Welsh Unit 2. If it is, then the journal entry proposed by SWEPCO should be approved; if not, then an additional clearing entry, moving the undepreciated balance to a regulatory asset where SWEPCO will receive only the return of the asset is allowed . . . .
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> The issue is fundamental to ratemaking. Accounting does not determine the appropriate ratemaking treatment. The statutory framework determines ratemaking treatment. To earn a return, an asset must be both used and useful. SWEPCO argues

[26] Docket No. 46449, PFD at 90-94 (Sep. 22, 2017).

[27] Docket No. 46449, PFD at 90 (Sep. 22, 2017).

[28] Docket No. 46449, Order on Rehearing, FoF Nos. 66, 68-69, 71 (Mar. 19, 2018).

> that the remaining value of Welsh Unit 2 continues to be used and useful, even after its retirement, but SWEPCO has failed to provide any evidence as to how a retired plant will still be useful in serving the public. There is no dispute that Welsh Unit 2 did serve the public in the past, but, to be included in rate base, an investment must be both used and useful. The plain meaning of "useful" is: being of use or service; serving some purpose; advantageous; of practical use, as for doing work; producing material results; supplying common needs. A retired plant does none of these things . . . .[29]

The Commission also found it reasonable for SWEPCO to recover Welsh Unit 2's remaining undepreciated balance over the 24-year remaining lives of Welsh Units 1 and 3,[30] an amortization schedule that also corresponded roughly to Welsh Unit 2's estimated remaining useful life as determined before retirement.[31]

As with Welsh Unit 2, professing adherence to the USofA, SWEPCO has credited the relevant Plant in Service accounts with the book values of the five retired plants, debited the relevant Accumulated Depreciation accounts by the same amounts, and made no additional adjustment to remove the remaining undepreciated values of the retired plants from rate base.[32] Citing Docket No. 46449 as governing "Commission precedent for the treatment of retired generating units," Staff proposes to adjust SWEPCO's requested rate base to remove the net book values of the retired plants and place those values in a regulatory asset.[33] Because the units were retired at or near the end of their estimated useful lives (unlike the "early" retirement of Welch Unit 2), Staff proposes to amortize payment of the units' remaining undepreciated value to SWEPCO over the four-year period in which rates in this case are expected to be in effect.[34] As explained by Staff witness Ruth Stark, "these adjustments provide for a return of, but not on,

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[29] Docket No. 46449, PFD at 93-94 (Sep. 22, 2017) (internal citations omitted).

[30] Docket No. 46449, Order on Rehearing, FoF No. 70 (Mar. 19, 2018).

[31] Docket No. 40443, Order on Rehearing, FoF No. 199 (Mar. 6, 2014).

[32] Staff Ex. 3 (Stark Dir.) at 18, Attachment RS-25, SWEPCO's response to CARD RFI 9-2 at 1; SWEPCO Ex. 36 (Baird Reb.) at 26.

[33] Staff Ex. 3 (Stark Dir.) at 18-19.

[34] Staff Ex. 3 (Stark Dir.) at 19; *see* 16 TAC § 25.246(c) (utility generally must initiate next base rate case "on or before the fourth anniversary of the date of the final order in the utility's most recent comprehensive base rate proceeding").

SWEPCO's remaining investment in these units[,] consistent with Commission precedent."[35] TIEC joins with Staff in advocating these adjustments.[36]

SWEPCO counters that "the Docket No. 46449 Welch Unit 2 rate treatment" was an unprecedented departure from the USofA and prior Commission practice that should not be applied categorically to all cases in which a power plant is retired with some undepreciated value.[37] According to SWEPCO witness Michael Baird, Managing Director of Accounting Policy and Research for SWEPCO's affiliate service company, AEPSC, it is not unusual that some undepreciated value remains upon the retirement of a gas plant at the end of its useful life. He added that the normal practice has been simply to include any under- or over-appreciated value in determining future depreciation rates for the remaining units. He further asserted that "the Commission has never singled out and addressed gas plants" in the manner of the retired Welsh Unit 2 coal-fired plant.[38] The "unique" circumstances of the Welch Unit 2 adjustment, SWEPCO maintains, were illustrated even within Docket No. 46449 itself, pointing out that it had retired another unit in 2015, Lieberman Unit 1, without the Commission requiring any adjustment to rate base and "[i]nstead . . . allow[ing] the ratemaking for Lieberman Unit 1 to follow the requirements of the FERC USofA."[39] SWEPCO insists that "Staff presents no compelling reason to depart from that practice with respect to these retired gas-fired generating units."[40]

"To apply the Docket No. 46449 Welsh Unit 2 rate treatment to the retirement of any generation unit independent of the circumstances," SWEPCO adds, would effectively penalize utilities who have prudently invested capital in generation plant by depriving them, upon a plant's retirement, of a return on any undepreciated portion of that investment, requiring that portion to be written off as expense, as well as creating the "perverse incentive" to imprudently continue

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35 Staff Ex. 3 (Stark Dir.) at 20.

36 Staff Initial Brief at 12-13; TIEC Initial Brief at 11-12.

37 SWEPCO Initial Brief at 13-14; SWEPCO Reply Brief at 10-12.

38 SWEPCO Ex. 36 (Baird Reb.) at 26.

39 SWEPCO Initial Brief at 14; SWEPCO Reply Brief at 10-11.

40 SWEPCO Initial Brief at 14.

running plants that should be retired.[41] Likewise, SWEPCO urges, its opportunity to earn a reasonable return on prudently invested capital will be made contingent on the depreciation rates the Commission is persuaded to adopt rather than its prudent management of its business, and will relatedly incent parties in rate cases to advocate extensions of plants' depreciable lives in order to leave undepreciated value upon retirement.[42]

In reply, Staff and TIEC observe that the Commission in Docket No. 46449 rejected similar arguments by SWEPCO that emphasized the USofA and SWEPCO's interest in recovering a return on its prudent capital investments.[43] They also dispute SWEPCO's premise that Docket No. 46449's rate treatment of Welsh Unit 2 represented a departure from Commission precedent.[44] Each notes that neither the Commission's Order nor the PFD in Docket No. 46449 addressed the retirement or ratemaking treatment of Lieberman Unit 1, whereas those issues were squarely presented and addressed with regard to Welsh Unit 2.[45] TIEC adds that, similarly, SWEPCO has not identified any case where the Commission has affirmatively held that a utility should earn a return on a retired plant, further suggesting that SWEPCO's invocation of professed policy concerns reflects tacit acknowledgment that it is seeking a departure from precedent.[46] Staff, on the other hand, points to a 1997 order in Docket No. 14965 that reflects the Commission's recognition of its authority to reduce or deny rate recovery of capital investment, including prudent capital investment, when such investment is not being used to provide service.[47]

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41 SWEPCO Reply Brief at 11-12; SWEPCO Ex. 36 (Baird Reb.) at 26.

42 SWEPCO Reply Brief at 11.

43 Staff Reply Brief at 9-10 (citing Docket No. 46449, Order on Rehearing, FoF Nos. 69, 72 (Mar. 19, 2018); PFD at 94 (Sep. 22, 2017)); TIEC Reply Brief at 6 (citing Docket No. 46449, PFD at 87-88, 93-94 (Sep. 22, 2017)).

44 Staff Reply Brief at 10-11; TIEC Reply Brief at 7-8.

45 Staff Reply Brief at 10 (citing Docket No. 46449, Order on Rehearing (Mar. 19, 2018), PFD (Sep. 22, 2017)); TIEC Reply Brief at 6-7 (citing same).

46 TIEC Reply Brief at 6-8.

47 Staff Reply Brief at 10-11 (citing *Application of Central Power and Light Company for Authority to Change Rates*, Docket No. 14965, Second Order on Rehearing at 2 (Oct. 16, 1997)).

In Docket No. 14965, in the context of addressing a utility's rate recovery of investment that exceeded market value (ECOM) (*i.e.*, that which was economically "unuseful" or "less useful" in rendering service), the Commission observed that it had the duty to set overall revenues at a level to provide a reasonable opportunity to earn a reasonable return on invested capital used and useful in rendering service. It further stated that "[u]nder the 'used' standard applied in past cases, the Commission [had] exercised its authority to balance equities by allowing recovery of capital costs while eliminating or reducing the return on those assets that have been found prudent, but that are not used to provide service."[48] "The same rationale," the Commission reasoned, "may be consistently applied when assets are unuseful," and it went on to balance the interests of the utility and its owners (in regard to potential under-recovery) versus current and future utility customers (in regard to paying for assets that are less "useful") in adjusting a proposed recovery of ECOM with return by reducing the recovery period but lowering the rate of return.[49]

The order in Docket No. 14965 could be read to imply a governing principle that is more nuanced than simply a categorical bar prohibiting a utility from ever recovering a return on the undepreciated value of a retired plant, one that perhaps leaves room for balancing the sorts of economic and policy interests SWEPCO invokes in determining the extent to which the utility should receive a return on that investment. Yet the ALJs must also be guided by the Commission's more recent order in Docket No. 46449. And the clear import of the Commission's holdings and reasoning there regarding Welsh Unit 2 is that "the interests of ratepayers and shareholders with respect to a plant that no longer provides service" are properly balanced by "[a]llowing [the utility] a return on, but not of, its remaining investment" in that plant. Moreover, and perhaps more critically, the Commission reasons that a retired plant is not considered a "used and useful" investment that would be included in rate base under PURA and Commission rules.[50] In the very least, Docket No. 46449 would stand for the proposition that utility customers should not be required to continue paying a return on a retired plant absent some unique and compelling

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[48] Docket No. 14965, Second Order on Rehearing at 2 (Oct. 16, 1997).

[49] Docket No. 14965, Second Order on Rehearing at 2-3 (Oct. 16, 1997).

[50] Docket No. 46449, Order on Rehearing, FoF Nos. 66, 68, 69, 71 (Mar. 19, 2018); Docket No. 46449, PFD at 94 (Sep. 22, 2017).

circumstance justifying that they do so, one that somehow amounts to the ongoing "use and usefulness" of the plant. Whether fairly characterized as consistent with prior precedent or a departure from it, the ALJs will follow this most recent authoritative pronouncement from the Commission, unless and until the Commission or the Legislature instructs otherwise.[51]

Although suggesting that the Commission's order in Docket No. 46449 should be distinguished from this case, SWEPCO offers no persuasive reason why it would not apply. The Commission's reasoning turned on the fact that Welch Unit 2 had been retired, not any specific circumstance relating to that plant *vis a vis* any other retired plant, the plant's fuel source, or the amount of net book value or remaining useful life. Nor does SWEPCO point to any circumstance unique to the five retired plants that might justify treating them differently. SWEPCO's appeals to economic or policy considerations implicate interests that would be present in regard to any plant retirement where some amount of prudently incurred but undepreciated value remains.

Accordingly, the ALJs recommend that the Commission, as Staff has proposed, adjust SWEPCO's requested rate base to remove the net book values of the five retired gas plants and place those values in a regulatory asset. The ALJs further conclude that Staff's proposal to amortize SWEPCO's recovery of those values over four years is reasonable and should be adopted.

2. Dolet Hills Power Station Retirement [PO Issues 67, 68, 69, 70, 71]

a. Background

Dolet Hills is a 650-net-megawatt (MW), single-unit, lignite-fueled generating plant, located southeast of Mansfield, Louisiana, that is owned jointly by Cleco Power LLC (CLECO), SWEPCO, NTEC (intervenor in this case), and Oklahoma Municipal Power Authority, with SWEPCO's ownership interest being 262 MW, approximately 40% of the unit's total capacity.[52]

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[51] *Cf.* PURA § 39.352 (providing an affirmative right to recover "stranded costs" resulting from transition to retail competition).

[52] SWEPCO Ex. 4 (Brice Dir.) at 5-6.

CLECO operates and manages Dolet Hills pursuant to the Dolet Hills Power Station Ownership, Construction and Operating Agreement between CLECO and SWEPCO, effective November 13, 1981.[53]

Dolet Hills has been in service since 1986,[54] although SWEPCO did not seek to include its share of the plant in its Texas rate base until Docket No. 37364, in which the Commission did so by order issued in 2010.[55] In the ensuing Docket No. 40443—SWEPCO's base rate case immediately preceding its most recent Docket No. 46449—the Commission established a 60-year estimated useful life for Dolet Hills (ending in 2046),[56] which was also maintained in Docket No. 46449.[57]

Dolet Hills is a "mine-mouth" plant, fueled by lignite mined in the area and transported by conveyor belt.[58] In 2009, SWEPCO acquired, with CLECO, additional area lignite reserves known as the Oxbow reserves and sought in Docket No. 40443 to include its share of the acquisition costs (its Oxbow investment) in rate base.[59] SWEPCO presented evidence that the Dolet Hills mine reserves on which it had heretofore relied were becoming depleted, that the investors had evaluated alternative means of fueling Dolet Hills, and that acquiring the Oxbow reserves and merging resources represented the least costly option for securing a reliable fuel supply sufficient to meet Dolet Hills' needs for the remainder of its economic life.[60] The Commission found that the Oxbow investment "was necessary to extend the life of the Dolet Hills power plant from 2016 through 2019 to at least 2026" and that it was reasonable to include the Oxbow investment (along with the

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53 SWEPCO Ex. 4 (Brice Dir.) at 6.

54 SWEPCO Ex. 7 (McMahon Dir.) at 5.

55 SWEPCO Ex. 33 (Brice Reb.) at 5-6; Docket No. 37364, Order, FoF No. 39 (Apr. 16, 2010).

56 Docket No. 40443, Order on Rehearing, FoF No. 198 (Mar. 6, 2014).

57 Tr. at 106.

58 SWEPCO Ex. 33 (Brice Reb.) at 6; Tr. at 108.

59 Docket No. 40443, PFD at 71-73 (May 20, 2013).

60 Docket No. 40443, PFD at 71-73 (May 20, 2013).

plant itself) in SWEPCO's rate base.[61] The Oxbow investment was also included in SWEPCO's rate base in Docket No. 46449, where the Commission further found that "[s]ince the Docket No. 40443 test year, the Dolet Hills lignite reserves have been depleted and all of the draglines and mining operations are moving to the Oxbow reserve."[62] Also included in SWEPCO's rate base in both Docket No. 40443 and Docket No. 46449 has been a return on equity SWEPCO contributed to DHLC—a subsidiary that performs the mining operations—as well as income taxes associated with that return.[63]

In Docket No. 49466, the Commission additionally found that SWEPCO had acted prudently in making—and thereby permitted rate recovery of—an investment of approximately $56.2 million in environmental-compliance retrofits to Dolet Hills.[64] Among other considerations noted by the Commission was SWEPCO's Oxbow investment a few years earlier.[65] The economic analysis presented by SWEPCO to justify the retrofits presumed the 2046 useful life for Dolet Hills.[66]

However, SWEPCO and CLECO have since determined to retire Dolet Hills in light of intervening developments. According to Thomas Brice, SWEPCO's Vice President for Regulatory and Finance, increases in lignite-production costs prompted SWEPCO and CLECO in 2019 to reduce mining operations and move Dolet Hills to seasonal operations, running the plant only in peak summer months but keeping it available in case called upon for reliability reasons by SWEPCO's or CLECO's respective Regional Transmission Organizations (RTOs) (for SWEPCO,

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[61] Docket No. 40443, FoF Nos. 140-41 (Mar. 6, 2014).

[62] Docket No. 46449, Order on Rehearing, FoF No. 139 (Mar. 19, 2018); Docket No. 46449, PFD, Attachment A, Schedule III (Sep. 22, 2017).

[63] Staff Ex. 3 (Stark Dir.), Attachment RS-28 (SWEPCO Response to Staff RFI 5-61).

[64] Docket No. 46449, Order on Rehearing at 2-5, FoF Nos. 24-36, CoL No. 18 (Mar. 19, 2018); *see* Docket No. 46449, PFD at 18 (Sept. 22, 2017) (noting that SWEPCO's share of the investment, for which it sought recovery through rates, was "approximately $56.2 million").

[65] Docket No. 46449, Order on Rehearing at 4, FoF Nos. 30P-30Q (Mar. 19, 2018).

[66] Tr. at 82.

SPP).[67] Despite attempts to reduce mining costs, including reducing mining operations from what were formerly three drag lines to only one, it was determined in early 2020 that the economically recoverable lignite reserves were depleted, that mining activity should cease, and that Dolet Hills should be retired by the end of 2021.[68]

Lignite production at the mine ceased in May 2020, although Dolet Hills has continued to run on previously-mined lignite that DHLC has delivered or will deliver to the plant, which will fuel the plant until its retirement.[69] At the hearing, SWEPCO's Mr. McMahon confirmed that the Dolet Hills retirement will occur on December 31, 2021.[70] In the meantime, SWEPCO plans to continue operating Dolet Hills seasonally while maintaining its availability in case called upon by SPP.[71]

While Mr. Brice testified that the decision to retire Dolet Hills was driven primarily by the economics of recovering the remaining lignite reserves,[72] SWEPCO's President and Chief Operating Officer, Malcolm Smoak, acknowledged that the plant's retirement is also a component of a broader strategy among AEP and its affiliates to transition away from lignite- and coal-fueled generation in favor of "cleaner" power sources.[73] Within the last decade, as Mr. Smoak explained, AEP has retired or sold nearly 13,500 MW of coal-fueled generation and expects to reduce coal capacity by another 5,600 MW by 2030.[74] And recently, citing concerns with climate change, AEP has announced a new goal of achieving net zero carbon emissions by 2050, with an 80% reduction in carbon emissions compared to 2000 levels by 2030, and to these ends plans to add 10,000 MW

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[67] SWEPCO Ex. 33 (Brice Reb.) at 6-7.

[68] SWEPCO Ex. 33 (Brice Reb.) at 6-7; Tr. at 101-03. A study was performed in aid of this decision, which is found at SWEPCO Ex. 4A (Brice workpapers).

[69] SWEPCO Ex. 4 (Brice Dir.) at 6.

[70] Tr. at 176.

[71] SWEPCO Ex. 37 (McMahon Reb.) at 2.

[72] Tr. at 100.

[73] Tr. at 52-57.

[74] Tr. at 52-53; TIEC Ex. 5 (AEP News Release Mar. 22, 2021) at 1.

of renewables by 2030.[75] Consistent with this strategy, SWEPCO is planning to retire another lignite-fueled plant, Pirkey, in 2023, and intends either to convert to gas or retire outright the currently coal-fired Welsh Units 1 and 2 in 2028.[76]

Although the retirement of Dolet Hills has not yet occurred, the Commission directed that the ALJs consider the prudence of SWEPCO's retirement decision in this proceeding.[77] No party has contested the prudence of that decision, and the evidence supports a finding that it was prudent. Of much greater controversy, however, is the appropriate rate treatment regarding Dolet Hills in light of that impending retirement.

b. SWEPCO's Proposal

SWEPCO's analytical starting point is the assertion that Generally Accepted Accounting Principles (GAAP) and "standard regulatory practice" would require it to depreciate Dolet Hills' remaining net book value over the asset's "expected useful life"—which, SWEPCO insists, has now become the plant's December 31, 2021 retirement date rather than the previously projected 2046 retirement date.[78] That is to say, SWEPCO would recover the entirety of the plant's Texas share of net book value from its Texas customers—approximately $45.4 million ($122.8 million on a total company basis)—during the roughly nine months between the new rates' March 18, 2021 effective date and the year's end.[79] But as Mr. Baird explained, SWEPCO "determined that recovery over the remaining life [of Dolet Hills] was not feasible, as it would have required a significant increase in revenue requirements due to the very large depreciation

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75 Tr. at 52; TIEC Ex. 5 (AEP News Release Mar. 22, 2021) at 1.

76 Tr. at 56, 73-74, 76-79, 109.

77 Preliminary Order at ¶ 67 (Dec. 17, 2020); *cf.* Docket No. 40443, Order on Rehearing, FoF Nos. 125-125A (Mar. 6, 2014) (deferring decision of whether then-anticipated Welsh Unit 2 retirement was prudent until "a future proceeding that addresses the actual retirement of the plant when it occurs").

78 SWEPCO Ex. 4 (Brice Dir.) at 7; SWEPCO Ex. 36 (Baird Reb.) at 8-9.

79 SWEPCO Ex. 36 (Baird Reb.) at 8.

expense."[80] Accordingly, SWEPCO proposes to "mitigate" this asserted rate impact through two means.[81]

First, SWEPCO would seize the "unique opportunity" afforded by the excess accumulated deferred federal income tax SWEPCO owes to its customers by virtue of the Tax Cut and Jobs Act of 2017 (TCJA).[82] Other aspects of SWEPCO's proposed treatment of ADFIT and "excess" ADFIT attributable to the TCJA (excess ADFIT) are addressed below, and the ALJs will reserve a more detailed explanation of both ADFIT and excess ADFIT until it becomes relevant to analysis of those other issues. For present purposes, the excess ADFIT can be understood as the portion of SWEPCO's projected future federal income tax payments it has collected from customers through its current rates that, due to the TCJA's intervening tax-rate cut that took effect beginning in 2018, now exceed the actual amount of taxes SWEPCO would ultimately pay the Internal Revenue Service (IRS) under the lower tax rate.[83] SWEPCO has recorded this excess ADFIT as a regulatory liability[84] and the Commission in Docket No. 46449 deferred its treatment until this proceeding.[85]

SWEPCO proposes to utilize its excess ADFIT accruing between January 1, 2018 (when the TCJA became effective) through April 1, 2021, to offset the remaining net book value of the Dolet Hills plant, which would leave approximately $6.4 million for Texas ($11.5 million total company) on the books.[86] This remaining balance is the focus of SWEPCO's second "mitigation"

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80 SWEPCO Ex. 36 (Baird Reb.) at 12-13.

81 SWEPCO Ex. 4 (Brice Dir.) at 7-8.

82 SWEPCO Ex. 4 (Brice Dir.) at 7-8; SWEPCO Ex. 36 (Baird Reb.) at 12-13.

83 SWEPCO Ex. 17 (Hodgson Dir.) at 21-22.

84 SWEPCO Ex. 17 (Hodgson Dir.) at 21.

85 Docket No. 46449, Order on Rehearing, Ordering Par. No. 10 (Mar. 19, 2018) ("The regulatory treatment of any excess deferred taxes resulting from the reduction in the federal-income-tax rate will be addressed in SWEPCO's next base-rate case.").

86 SWEPCO Ex. 6 (Baird Dir.) at 48-49; SWEPCO Ex. 17 (Hodgson Dir.) at 21; SWEPCO Ex. 36 (Baird Reb.) at 5-6, Exh. MAB-2R. SWEPCO quantifies its excess ADFIT as approximately $39 million for Texas ($111.3 million total company), although the amount is one of the disputed ADFIT-related issues addressed below. There are also some nuances regarding a distinction between "protected" and "unprotected" ADFIT that are best explained in the context of that discussion.

proposal—SWEPCO would amortize its recovery over the four years during which the rates are expected to remain in effect, as opposed to the months remaining before Dolet Hills' retirement.[87]

While acknowledging that SWEPCO benefits by "receiv[ing] immediate recovery of a portion of the Dolet Hills Power Plant"—indeed, 91% of its net book value—as well as a significantly shortened amortization period compared to the previous 2046 time frame, Mr. Baird termed the proposal a "win-win" for not only the utility but also its customers, given the rate impact that customers would otherwise absorb in SWEPCO's view.[88] He further asserted that the offset was "equitable" because it utilizes taxes overpaid by the same customers who also "have not paid enough of Dolet [Hills] depreciation in hindsight" to reduce the remaining balance.[89] He similarly reasoned that the four-year amortization of the remaining balance was "reasonable," as "a longer period . . . simply pushes depreciation costs to future customers."[90] In SWEPCO's view, spreading the costs of Dolet Hills to future customers "for decades," as with a 2046 useful life, is inequitable because those costs should properly be borne by the customers who were actually served by the plant, particularly including the customers to whom the excess ADFIT is owed.[91]

SWEPCO further contends that the offset is consistent with PURA and the Commission's Cost of Service Rule, which lists ADFIT as a required deduction from invested capital in determining rate base.[92] The Company also points to the Commission's order in Docket No. 48577, which approved a settlement whereby the parties agreed to offset AEP Texas's catastrophe-reserve regulatory asset with unprotected excess ADFIT.[93] While acknowledging that the order "does not constitute binding precedent" and that "the asset might be different," SWEPCO urges that the Commission's approval and incident finding that "[t]he Settlement Agreement's treatment of

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87 SWEPCO Ex. 6 (Baird Dir.) at 49.

88 SWEPCO Ex. 36 (Baird Reb.) at 6, 13.

89 Tr. at 475.

90 SWEPCO Ex. 36 (Baird Reb.) at 13.

91 SWEPCO Reply Brief at 7.

92 SWEPCO Initial Brief at 10-11; *see* 16 TAC § 25.231(c)(2)(C)(i).

93 SWEPCO Initial Brief at 11 (citing *Application of AEP Texas, Inc. for Determination of System Restoration Costs*, Docket No. 48577 (Feb. 28, 2019)).

ADFIT is appropriate" reflect 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."[94]

But because some undepreciated balance for Dolet Hills would remain on SWEPCO's books under any scenario suggested, a question arises—particularly given the Commission's treatment of Welsh Unit 2 in Docket No. 46449—regarding the extent to which that value should be included in SWEPCO's rate base, and thereby earn a return, for purposes of the rates set in this proceeding. SWEPCO urges that Docket No. 46449's treatment of Welsh Unit 2 has no application here because Dolet Hills provided service throughout the test year ending on March 31, 2020, whereas Welch Unit 2 had been retired before the end of the Docket No. 46449 test year.[95] The more applicable Commission precedent, according to Mr. Baird, is thus the preceding Docket No. 40443, in which Welsh Unit 2, still operating through the test year, was included in rate base despite SWEPCO's then-already-formulated plans to retire the plant while the rates would be in effect (although the Commission, unlike in this case, deferred deciding the prudence of that retirement).[96]

The Commission's Cost of Service Rule, 16 Texas Administrative Code (TAC) § 25.231, permits post-test-year adjustments for known and measurable rate-base decreases relative to test-year data (such as with the four May 2020 gas-unit retirements discussed above). However, as SWEPCO emphasizes, Section 25.231(c)(2)(F)(iii) of the rule prescribes that such adjustments can be made "*only when* . . . [t]he decrease represents . . . [p]lant that has been removed from service, mothballed, sold, or removed from the electric utility's books *prior to the rate year*."[97] The "rate year" in this case, as SWEPCO observes, begins on March 18, 2021, the relate-back date from

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94 SWEPCO Initial Brief at 11 (citing Docket No. 48577, Order, FoF No. 54 (Feb. 28, 2019)).

95 SWEPCO Ex. 36 (Baird Reb.) at 18; *see* Docket No. 46449, Order on Rehearing, FoF Nos. 7, 65 (findings that Welsh Unit 2 was retired in April 2016 and that the historical test year ended on June 30, 2016).

96 SWEPCO Ex. 36 (Baird Reb.) at 18; *see* Docket No. 40443, Order on Rehearing, FoF Nos. 119, 124, 125, 125A (Mar. 6, 2014).

97 SWEPCO Ex. 36 (Baird Reb.) at 7; 16 TAC § 25.231(c)(2)(F)(iii) (emphases added).

which the rates ultimately approved in this case will be effective.[98] As of that date, Dolet Hills was undisputedly still operating (unlike the gas units). Consequently, SWEPCO reasons, Dolet Hills must remain in rate base for purposes of the rates set in this proceeding, including paying a return on that investment to SWEPCO, for so long as those rates remain in effect, without regard to the plant's retirement in the meantime. As Mr. Baird put it, "[t]he Commission's rules are clear that a plant in service at the beginning of the rate year will be included in rate base and thus receive a full return."[99] (A corollary, according to SWEPCO, is that its excess-ADFIT-offset proposal would confer the further benefit to customers of significantly reducing the rate base on which they would otherwise have to pay a return).[100]

It follows, in SWEPCO's view, that its Oxbow mine investment should also be included in rate base for purposes of the rates set in this proceeding, and that it should likewise continue recovering return on equity and associated taxes for DHLC.[101] Although acknowledging that mining of additional lignite ceased in May 2020, SWEPCO argues that its Oxbow investment has not been removed from service but will continue providing benefit to customers through Dolet Hills' retirement, as previously mined lignite is burned to produce electricity.[102] Similarly, SWEPCO reasons that DHLC has continued to exist and to deliver previously-mined lignite to Dolet Hills, such that SWEPCO has continued to incur the associated non-eligible fuel expense.[103]

Staff, CARD, ETEC/NTEC, Nucor, OPUC, Sierra Club, and TIEC all oppose aspects of SWEPCO's proposal. Generally, these parties advocate one or more adjustments in reliance on, and similar in effect to, Docket No. 46449's rate treatment of the retired Welsh Unit 2, at least

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[98] SWEPCO Ex. 36 (Baird Reb.) at 6, 18; *see* 16 TAC § 25.5(101) (defining "rate year" under the Commission's rules, in relevant part, as "[t]he 12-month period beginning with the first date that rates become effective").

[99] SWEPCO Ex. 36 (Baird Reb.) at 7.

[100] SWEPCO Ex. 36 (Baird Reb.) at 14.

[101] SWEPCO Ex. 6 (Baird Dir.) at 37, 47.

[102] SWEPCO Reply Brief at 5-6; SWEPCO Ex. 36 (Baird Reb.) at 21.

[103] SWEPCO Reply Brief at 5-6; SWEPCO Ex. 36 (Baird Reb.) at 21.

with respect to the period after Dolet Hills' retirement.[104] However, they differ somewhat in their precise reasoning and the specific adjustments they propose.

c. Staff's Position

Staff argues that SWEPCO should be allowed to recover return and depreciation associated with the Dolet Hills plant only for the period between the rates' March 18, 2021 effective date through the plant's December 31, 2021 retirement.[105] This recovery would occur over the four-year period in which the rates are presumed to remain in effect.[106] But SWEPCO's recovery for periods following Dolet Hills' retirement would be limited—similar to Welsh Unit 2 in Docket No. 46449—to recovery *of* the remaining plant investment, but no return *on* it, amortized over the asset's 2046 useful life.[107] More specifically, upon Dolet Hills' retirement, Staff would remove from rate base the net book value of the plant then remaining, as well as that of the Oxbow investment, and place the plant balance in a regulatory asset whose value would be returned to SWEPCO in accord with the plant's previously established 2046 useful life.[108]

According to Ms. Stark, the Commission should in these ways follow the "early retirement" precedent of Welsh Unit 2 in Docket No. 46449.[109] Although she acknowledged "Welsh Unit 2 was retired prior to the end of the test year in Docket No. 46449 [whereas] the Dolet Hills plant is still in service," Ms. Stark pointed out that the Dolet Hills retirement also differs from the posture of the then-anticipated Welsh Unit 2 retirement as presented in the earlier Docket No. 40443, in that the Dolet Hills retirement will occur during the rate year associated with this proceeding.[110]

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[104] Staff, OPUC, CARD, ETEC/NTEC, and TIEC also propose adjustments to reduce O&M or other expenses related to Dolet Hills. Although these proposals overlap with or rely on much the same logic as with their arguments concerning capital investment, they are addressed below in connection with other expense-related issues.

[105] Staff Initial Brief at 5, 7; Staff Ex. 3 (Stark Dir.) at 25.

[106] Staff Ex. 3 (Stark Dir.) at 25.

[107] Staff Initial Brief at 7; Staff Ex. 3 (Stark Dir.) at 25.

[108] Staff Initial Brief at 7; Staff Ex. 3 (Stark Dir.) at 25.

[109] Staff Ex. 3 (Stark Dir.) at 24 ("While Welsh Unit 2 was retired prior to the end of the test year in Docket No. 46449, the Dolet Hills plant is still in service.").

[110] Staff Ex. 3 (Stark Dir.) at 24.

Moreover, she emphasized, the retirement will occur only about two months after the Commission is anticipated to issue its final order in this proceeding, meaning that the costs SWEPCO requests in its revenue requirement with respect to Dolet Hills will be "outdated" for most of the period in which the rates are expected to remain in effect.[111] "These circumstances," urged Ms. Stark, "suggest that the Commission should address the retirement of Dolet Hills in this case, not four years from now when SWEPCO would have recovered in excess of $138,000 million [by her calculation] from its ratepayers for a plant that did not provide service to them for the majority of that time period."[112] She further suggested that the additional anticipated retirement of the Pirkey plant in March 2023, also during the period in which the rates are expected to remain in effect, was an additional consideration warranting that the Commission address Dolet Hills in this proceeding.[113]

While tacitly acknowledging that Staff's proposed rate-base adjustments for Dolet Hills are inconsistent with the Cost of Service Rule's limitations on post-test-year rate-base reductions, Ms. Stark maintained that SWEPCO's proposal had itself deviated from Section 25.231(c)(2)(F)(iii)(II) by reducing the Dolet Hills end-of-test-year plant balance in rate base.[114] Consequently, she explained, she had "assum[ed] SWEPCO was requesting an exception [to the rule] by its own proposal," further observing that "[t]he Commission makes exceptions to its rules all the time."[115] In that context, Ms. Stark was "just responding to SWEPCO's proposal."[116]

Nor would a GAAP-prescribed accounting treatment be a bar to Staff's proposed amortization schedule, according to Ms. Stark, because the Commission's Cost of Service Rule explicitly authorizes "[o]ther means of depreciation . . . when it is determined that such

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[111] Staff Ex. 3 (Stark Dir.) at 24, 27.

[112] Staff Ex. 3 (Stark Dir.) at 24.

[113] Staff Ex. 3 (Stark Dir.) at 27.

[114] Staff Ex. 3 (Stark Dir.) at 24-25; Tr. at 409-10.

[115] Tr. at 417-18; *see* 16 TAC § 25.3(b) ("The commission may make exceptions to this chapter for good cause.").

[116] Tr. at 418.

depreciation methodology is a more equitable means of recovering the cost of the plant."[117] And considerations supporting the continued use of the 2046 projected useful life, in Ms. Stark's view, include the Commission's approval in Docket No. 46449 of SWEPCO's substantial investments in environmental retrofits to Dolet Hills—approximately 39% of the plant's test-year-end total book value—with the expectation that those costs would be recovered through 2046 and not the compressed time frame SWEPCO now seeks.[118]

Ms. Stark also criticized SWEPCO's offset proposal as "greatly benefit[ting] [SWEPCO] to the detriment of ratepayers."[119] She recommended instead that SWEPCO be made to refund the excess ADFIT to its customers, first by crediting the balance against any amount owed by the Company's customers because of the March 18, 2021 relate-back date in this proceeding, and then return the remainder over a six-month period with carrying charges at the same WACC that is determined in this proceeding.[120]

Although citing the anticipated 2023 Pirkey retirement as a justification for addressing the Dolet Hills retirement in this proceeding, Ms. Stark did not recommend making further cost-of-service adjustments based on that subsequent retirement, reasoning that the posture of the Pirkey retirement (unlike Dolet Hills') is materially similar to Welsh Unit 2 in Docket No. 40443 and that its projected retirement date is also much less certain.[121] Instead, she recommended that the Commission address the Pirkey retirement by ordering SWEPCO to file monthly earnings reports every six months following that unit's retirement until SWEPCO files its next base rate case, "to ensure that any potential overearnings related to the plant's early retirement are dealt with in a timely manner."[122] However, Ms. Stark also presented several potential alternatives to her

[117] Tr. at 415; *see* 16 TAC § 25.231(b)(1)(B).

[118] Staff Ex. 3 (Stark Dir.) at 26.

[119] Staff Ex. 3 (Stark Dir.) at 24-25, 29.

[120] Staff Ex. 3 (Stark Dir.) at 46-47. Ms. Stark also takes issue with SWEPCO's calculation of its excess ADFIT balances. Staff Ex. 3 (Stark Dir.) at 44. Those issues, again, are addressed below.

[121] Staff Ex. 3 (Stark Dir.) at 27-28.

[122] Staff Ex. 3 (Stark Dir.) at 28.

proposed treatments of Dolet Hills and Pirkey. The Commission could: (1) in its final order, require SWEPCO to file another rate case in June 2022 using a December 31, 2021 test-year-end, and then another in September 2023 using a March 31, 2023, to coincide with the Dolet Hills and Pirkey retirement dates[123]; (2) leave open the appropriate time for SWEPCO's next post-retirement rate case(s) and later act as warranted based on SWEPCO's monthly earnings monitoring reports; (3) require SWEPCO to begin recording regulatory liabilities for costs incurred in the revenue requirement associated with Dolet Hills and Pirkey beginning on the plants' respective retirement dates (a mechanism proposed by CARD and ETEC/NTEC, as discussed below); or (4) require a step-down of SWEPCO's rates in January 2022 and April 2023 to recognize the plants' early retirements.[124]

d. OPUC's Position

Similar to Staff, and likewise relying on Docket No. 46449's treatment of Welsh Unit 2, OPUC proposes that SWEPCO be allowed to recover a return on Dolet Hills only through the plant's retirement date and thereafter recover only the plant's remaining net book value, without a return or offset, with depreciation or amortization based on the asset's 2046 useful life.[125] OPUC would accomplish this, however, by removing the return on the plant from base rates altogether (although leaving in base rates the annual amortization of the plant's remaining net book value) and charging it through a rate rider that would be discontinued upon the plant's retirement.[126] According to OPUC witness Constance Cannady, the rate rider would have the advantage of allowing SWEPCO to recover costs related to the operation of the Dolet Hills plant during the period in which that asset continued to provide service, but not beyond, without need to revise

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123 While acknowledging that "these proceedings would necessitate the incurrence of rate-case expenses," Ms. Stark maintained that "those expenses should still be much less than the costs of Dolet Hills and Pirkey included in SWEPCO's requested revenue requirement in this case." Staff Ex. 3 (Stark Dir.) at 28.

124 Staff Ex. 3 (Stark Dir.) at 28.

125 OPUC Initial Brief at 3-6; OPUC Ex. 1 (Cannady Dir.) at 11-20.

126 OPUC Ex. 1 (Cannady Dir.) at 11-12, 20. Ms. Cannady similarly proposed that SWEPCO's lignite inventory for Dolet Hills be included in the rider. OPUC Ex. 1 (Cannady Dir.) at 13, 29-30. The ALJs address issues relating to the lignite inventory in the next subsection.

base rates upon the plant's retirement.[127] Ms. Cannady also urged that SWEPCO's return of the excess ADFIT "should be accomplished through a more transparent refund" than SWEPCO's proposed offset, one "that assures Texas retail customers receive the refund amounts resulting from the passage of the TCJA."[128]

OPUC also proposes similarly to remove SWEPCO's Oxbow mine investment from rate base and amortize recovery of its remaining net book value over the same period as with the Dolet Hills plant.[129] OPUC would also remove from base rates the expenses and associated taxes for DHLC.[130] These proposed adjustments, Ms. Cannady explained, reflected that: (1) the Commission had previously found SWEPCO's Oxbow mine investment to be prudent, such that SWEPCO should recover its value; but (2) mining operations had ceased, such that the Oxbow mine and DHLC, in her view, were no longer used and useful in providing service to SWEPCO's customers.[131]

Regarding Section 25.231(c)(2)(F)(iii)(II)'s time limitation on post-test-year adjustments, OPUC urges that this condition should not bar its proposed rate rider under the circumstances—in substance a request for a good-cause exception[132]—because SWEPCO manipulated the timing of the rate year (also the Section 25.231(c)(2)(F)(iii)(II) deadline) "to maximize its returns on Dolet Hills at the expense of its customers."[133] OPUC points out that: (1) SWEPCO had decided in early 2020 to retire the Dolet Hills plant at the end of 2021[134]; (2) SWEPCO was not required to file a

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[127] OPUC Ex. 1 (Cannady Dir.) at 20.

[128] OPUC Ex. 1 (Cannady Dir.) at 11.

[129] OPUC Initial Brief at 7-8; OPUC Ex. 1 (Cannady Dir.) at 21-27.

[130] OPUC Initial Brief at 8-9; OPUC Ex. 1 (Cannady Dir.) at 27-28.

[131] OPUC Ex. 1 (Cannady Dir.) at 22-28.

[132] *See* 16 TAC § 25.3(b) ("The commission may make exceptions to this chapter for good cause.").

[133] OPUC Initial Brief at 4-5; OPUC Reply Brief at 3.

[134] OPUC Initial Brief at 4 (citing SWEPCO Ex. 4 (Brice Dir.) at 6).

base-rate case until March 19, 2022[135]; and (3) SWEPCO (with awareness of its prior decision to retire Dolet Hills at the end of 2021) initiated the present base rate case roughly one-and-a-half years before the deadline,[136] which had the effect of commensurately accelerating the new rates' relate-back date (155 days after filing), and thus the beginning of the rate year, to a date that would precede the plant's retirement.[137] Had SWEPCO not accelerated the deadline in this way, OPUC observes, the Dolet Hills retirement would have preceded the test year and thereby been subject to post-test-year adjustment under Section 25.231(c)(2)(F)(iii)(II).[138] Under these circumstances, OPUC argues, SWEPCO "should not burden [its] ratepayers for three years with payments on Dolet Hills, especially when it is no longer used and useful in providing service to the public."[139]

Moreover, OPUC argues that its proposed adjustments regarding SWEPCO's Oxbow mine investment and DHLC independently comport with Section 25.231(c)(2)(F)(iii)(II), without need for the exception it advocates in regard to the Dolet Hills plant, because mining had ceased by May 2020, long before the rate year began in March 2021.[140]

e. CARD's Position

Similar to Staff and OPUC, CARD cites Docket No. 46449's rate treatment of the retired Welsh Unit 2 in arguing that SWEPCO should not earn a return on Dolet Hills after the plant's retirement.[141] However, in the view that Dolet Hills differs from Welsh Unit 2 in being retired between rate cases, CARD would address the Dolet Hills retirement by requiring SWEPCO to

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135 Docket No. 49449, Order on Rehearing (Mar. 19, 2018); *see* 16 TAC § 25.246(c)(1)(A) (general deadline of "on or before the fourth anniversary of the date of the final order in the utility's most recent comprehensive base rate proceeding").

136 SWEPCO Ex. 1 (rate filing package, filed October 14, 2020).

137 OPUC Initial Brief at 4-5; OPUC Reply Brief at 3.

138 OPUC Initial Brief at 5.

139 OPUC Initial Brief at 5.

140 OPUC Initial Brief at 7-9.

141 CARD Initial Brief at 5-6; CARD Ex. 2 (M. Garrett Dir.) at 15-16. CARD similarly argues that SWEPCO's requested level of lignite inventory for Dolet Hills should be eliminated to account for the plant's retirement. This issue is addressed below, in conjunction with a broader challenge CARD brings regarding SWEPCO's method of determining target lignite and coal inventories.

establish a regulatory liability that accrues the post-retirement return it receives on the plant and refund that balance to customers through the rates implemented in SWEPCO's next rate case.[142] CARD asserts that this proposed regulatory liability "is a commonplace mechanism used in utility rate-making," observing that SWEPCO's excess AFDIT balances are themselves a regulatory liability that the Commission ordered created to account for the effects of the TCJA's corporate tax rate reduction.[143] To the extent this regulatory liability or rate-base adjustments to account for the Dolet Hills retirement could arguably violate Section 25.231(c)(2)(F)(iii)(II), CARD suggests the adjustments would still be within the Commission's discretion in setting "just and reasonable" rates.[144]

Regarding the remaining plant balance, CARD again cites Docket No. 46449 in urging that SWEPCO should continue to depreciate or amortize it in accord with the plant's 2046 useful life.[145] According to CARD witness Mark Garrett, utilities nationwide are experiencing "abnormally high investment levels" to comply with environmental regulations, including "stranded costs that result from early plant retirements," and Docket No. 46449 is representative of many regulatory decisions, including cases involving AEP affiliates, that have rejected proposals to accelerate recovery of those stranded costs.[146] A key rationale underlying those decisions, Mr. Garrett testified, has been "generational equity—the recognition that the entire cost should not be borne by current ratepayers, but instead, that future ratepayers should share in the costs of achieving a cleaner, safer environment because those future ratepayers are the primary beneficiaries of the

[142] CARD Initial Brief at 5-6; CARD Ex. 2 (M. Garrett Dir.) at 15-16.

[143] CARD Reply Brief at 4.

[144] CARD Reply Brief at 8-9. CARD further contends that Section 25.231(c)(2)(F)(iii)(II) might be avoided entirely if the Commission's order in this case ultimately issues after the Dolet Hills retirement. This is so, CARD reasons, because the "rate year" actually begins on the date the Commission issues its final order, not on the March 18, 2021 relate-back date, leaving open the possibility that Dolet Hills might be retired before the order issues. CARD Reply Brief at 4, 8. However, the ALJs share the consensus view of SWEPCO, Staff, and other intervenors that the "rate year" in this case begins on the March 18, 2021 relate-back date, the date from which the rates to be implemented in this case become effective. *See* 16 TAC § 25.5(101) (defining "rate year" under Commission's rules, in relevant part, as "[t]he 12-month period beginning with the first date that rates become effective").

[145] CARD Initial Brief at 3-6; CARD Ex. 2 (M. Garrett Dir.) at 5-14.

[146] CARD Ex. 2 (M. Garrett Dir.) at 7 & n.3, 8-9, 13-14.

improvements."[147] Another rationale, he stated, has been a recognition "that by spreading the recovery of these costs into the future[,] opportunities arise to offset some of the costs with other savings" from "improved technologies, increased operating efficiencies, lower capital costs, or load growth," in addition to affording time for depreciation to reduce "rate bases that are currently inflated with environmental compliance costs . . . to more reasonable levels."[148] Mr. Garrett further asserted that SWEPCO's proposed offset and other acceleration of its recovery of "the Dolet Hills stranded costs" "would unduly increase costs for ratepayers at a time when it is least affordable," noting COVID-related financial distress and also the increased fuel costs resulting from the catastrophic winter weather events of February 2021.[149]

In Mr. Garrett's view, arguments that the useful life of an early-retiring plant should be the retirement date and depreciation recovered over the new shortened life, such as SWEPCO advances here, have "no merit."[150] Rather, he contended, both GAAP and "standard regulatory practice" would be to: (1) "move the unrecovered Dolet Hills balance to a regulatory asset account, to which "the depreciation rules no longer apply" because those rules "apply only to plant in service"; and (2) "recover that balance over whatever period the commission deems appropriate"—just as the Commission did with Welch Unit 2 in Docket No. 46449.[151]

f. ETEC/NTEC's Position

ETEC/NTEC argues that SWEPCO's recovery of Dolet Hills' remaining net book value should not be addressed until the plant is actually retired, in SWEPCO's next rate case, and ETEC/NTEC further specifically opposes accelerated or other special recovery of the plant's value while SWEPCO would also still be recovering ordinary depreciation and return on the plant.[152]

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[147] CARD Ex. 2 (M. Garrett Dir.) at 7.

[148] CARD Ex. 2 (M. Garrett Dir.) at 7-9.

[149] CARD Ex. 2 (M. Garrett Dir.) at 7-8.

[150] CARD Ex. 2 (M. Garrett Dir.) at 12-13.

[151] CARD Ex. 2 (M. Garrett Dir.) at 13-14 & n.13.

[152] ETEC/NTEC Initial Brief at 6-7.

However, to the extent the Commission "is inclined to grant special ratemaking treatment given the imminent retirement of Dolet Hills," ETEC/NTEC offers an "alternative proposal"—amortize Dolet Hills' remaining book value over 33 years, the average remaining life of the composite group of SWEPCO's coal and lignite-burning generating assets.[153] ETEC/NTEC further joins with other parties in urging that SWEPCO not be permitted to earn a return on that remaining investment.[154]

According to ETEC/NTEC witness Steven Hunt, a former FERC Chief Accountant and Director of the agency's Division of Audits and Accounting,[155] this rate treatment is consistent with both the USofA and Docket No. 46449's treatment of Welsh Unit 2.[156] He elaborated that a debit balance in Accumulated Depreciation resulting from the accounting entry following a plant retirement would be "incorporated in future determinations of depreciation on the composite group of assets over [the group's] average remaining life," which in Dolet Hills' case was 33 years.[157] Mr. Hunt further opined that while the USofA permitted "significant unrecovered costs of a prematurely retired asset . . . to be recorded as a regulatory asset when approved by the Commission," as SWEPCO was seeking to do, this "should not result in an acceleration of the amortization period compared to the rate effect of recording the unrecovered amount in accumulated depreciation."[158] To the extent FERC or Commission rules would require accelerated depreciation of a retiring plant, Mr. Hunt maintained that such requirements should yield to the overarching requirements that rates be just and reasonable and in the public interest.[159]

ETEC/NTEC likewise opposes SWEPCO's proposed offset of excess ADFIT, instead favoring refunding the amounts to customers over the four-year period in which the rates are

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[153] ETEC/NTEC Initial Brief at 6-9; ETEC/NTEC Ex. 1 (Hunt Dir.) at 9-11.

[154] ETEC/NTEC Reply Brief at 7.

[155] ETEC/NTEC Ex. 1 (Hunt Dir.) at 1-3.

[156] ETEC/NTEC Ex. 1 (Hunt Dir.) at 9-11.

[157] ETEC/NTEC Ex. 1 (Hunt Dir.) at 10-11.

[158] ETEC/NTEC Ex. 1 (Hunt Dir.) at 10.

[159] Tr. at 322-23.

expected to remain in effect.[160] In Mr. Hunt's view, the excess ADFIT owing to SWEPCO's customers and cost recovery for Dolet Hills present two separate and unrelated rate issues.[161]

ETEC/NTEC would also require SWEPCO to defer its actual Dolet Hills demolition and removal costs as a regulatory asset, to be addressed in SWEPCO's next rate proceeding, rather than factoring estimated costs into its calculation of net book value.[162]

g. TIEC's Position

Relying on the analysis of its witness Billie LaConte, TIEC argues that SWEPCO's proposal is "internally inconsistent" in seeking accelerated cost recovery and special ratemaking treatment for Dolet Hills based on the plant's impending retirement, yet also treating the plant as if fully operational by including a return on the plant.[163] Instead, urged Ms. LaConte, the rates "should either be based on the assumption that (1) Dolet Hills is an operational plant or (2) Dolet Hills has been retired."[164] Under either assumption, Ms. LaConte maintained, SWEPCO's proposal would be inconsistent with the Commission precedent addressing Welsh Unit 2.[165]

Regarding the operational-plant assumption, Ms. LaConte observed that in Docket No. 40443 the Commission refused SWEPCO's request to accelerate depreciation of the remaining undepreciated plant costs so as to recover them by the anticipated 2016 retirement date rather than the plant's original useful life through 2040. Instead, the Commission left the anticipated

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160 ETEC/NTEC Initial Brief at 10-11; ETEC/NTEC Ex. 1 (Hunt Dir.) at 7-8.

161 ETEC/NTEC Ex. 1 (Hunt Dir.) at 7-8.

162 ETEC/NTEC Initial Brief at 13; ETEC/ETEC Ex. 1 (Hunt Dir.) at 11-12. ETEC/NTEC also complains that SWEPCO has increased its depreciation rate and expense for Dolet Hills by 23% and urges that SWEPCO should continue using the rate approved in Docket No. 46449. ETEC/NTEC Initial Brief at 12-13; ETEC/NTEC Ex. 1 (Hunt Dir.) at 13-14. Informed by the rebuttal testimony of SWEPCO's Jason Cash, SWEPCO Ex. 43 (Cash Reb.) at 4-5, the ALJs understand ETEC/NTEC's argument to refer to an implication of the four-year amortization SWEPCO proposes, and thus do not address it separately.

163 TIEC Initial Brief at 3-5; TIEC Ex. 4 (LaConte Dir.) at 8.

164 TIEC Ex. 4 (LaConte Dir.) at 9.

165 TIEC Ex. 4 (LaConte Dir.) at 9-10.

retirement date unchanged until the Commission could evaluate the prudence of the retirement in a future rate proceeding.[166] Accordingly, she reasoned, a "reasonable alternative [under the operational-plant assumption] would be to include the plant in base rates in this case, using its current expected retirement date of 2046, and to address any subsequent cost recovery after the plant has been retired."[167] Alternatively, were Dolet Hills to be treated as if retired, she urged that the Docket No. 46449 precedent would require SWEPCO to remove the plant from rate base; place the plant's remaining undepreciated balance in a regulatory asset; and amortize SWEPCO's recovery of that balance, without a return, through 2046.[168] While either option is reasonable in its view, TIEC argues that the Commission should treat Dolet Hills as a retired plant under the circumstances presented.[169]

Ms. LaConte further opined that there would be good cause to remove Dolet Hills from rate base (*i.e.*, for an exception to Section 25.231(c)(2)(F)(iii)(II)) considering: (1) the "significant and unusual" dimensions of the plant's unamortized balance due to the 25-year acceleration of retirement date and the inclusion of the recent retrofits that were to be recovered over the asset's useful life ending in 2046; (2) that the plant will be in service for at most nine months after rates are effective in this case; (3) significant additional unrecovered fixed costs associated with the Oxbow and Dolet Hills mines; and (4) the approaching 2023 Pirkey retirement, or others that may follow, which will present similar early-retirement cost-recovery problems and issues.[170] Additionally, similar to OPUC, TIEC points to SWEPCO's choice to file its rate case with "timing [that] facilitates SWEPCO's central contention . . . that it is entitled to a return on the remaining balance of [Dolet Hills] because the plant will be operational during the rate year."[171]

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[166] TIEC Ex. 4 (LaConte Dir.) at 9-10 (citing Docket No. 40443, Order on Rehearing, FoF Nos. 198-199 (Mar. 6, 2014); Docket No. 40443, PFD at 176-77 (May 20, 2013)).

[167] TIEC Ex. 4 (LaConte Dir.) at 10, 13.

[168] TIEC Ex. 4 (LaConte Dir.) at 10-11, 13.

[169] TIEC Initial Brief at 3.

[170] TIEC Ex. 4 (LaConte Dir.) at 11-12.

[171] TIEC Initial Brief at 10-11.

Finally, Ms. LaConte recommended that the Commission reject SWEPCO's offset proposal, urging that the matter of TCJA excess ADFIT "is not related to the impending retirement of Dolet Hills," but is money over-collected from and owed to customers—since 2018—and would be so regardless how the Commission decides to treat the plant retirement.[172] She proposed that SWEPCO "promptly" refund the excess ADFIT to customers over one year, with carrying costs calculated using SWEPCO's regulated rate of return, on the balance from the relate-back date.[173]

h. Sierra Club's Position

Although Sierra Club did not file testimony in opposition to SWEPCO's proposed rate treatment of Dolet Hills,[174] in briefing it joins with other parties in opposing SWEPCO's recovery of a return on the remaining undepreciated value of that asset, citing the Commission's treatment of Welsh Unit 2 in Docket No. 46449.[175] Further, alluding to its opposition to the environmental retrofit costs that the Commission ultimately approved in that docket, Sierra Club urges that the Commission "should not allow [SWEPCO] to collect a 'return on' those ill-conceived (and soon-to-be-unused) retrofit investments," as "[d]oing so would serve only to further encourage risky and potentially unnecessary investments in marginally economical assets."[176]

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[172] TIEC Ex. 4 (LaConte Dir.) at 8, 14-15.

[173] TIEC Ex. 4 (LaConte Dir.) at 14-17; Tr. at 356-57.

[174] Sierra Club Ex. 2A (Glick Dir., redacted) at 11 (explaining that her testimony "focuse[d] solely on the economic performance and the operational and planning practices at the Flint Creek and Welsh units" and did not evaluate Dolet Hills).

[175] Sierra Club Initial Brief at 22.

[176] Sierra Club Initial Brief at 22-24. Sierra Club also seeks adjustments to eliminate or reduce SWEPCO's test-year new capital spending at Dolet Hills. Sierra Club Initial Brief at 16-19. This challenge is addressed separately below.

The remaining intervenor to oppose SWEPCO's proposal, Nucor, filed briefing supporting "the consensus of the testifying parties other than SWEPCO [that] the Commission should reject [SWEPCO's] proposed accelerated depreciation plan and instead require that SWEPCO recover the remaining costs over a longer period of time, such as the [previously established] useful life, through 2046," including rejecting SWEPCO's offset proposal. Nucor Initial Brief at 2-3. Accordingly, Nucor's position is not discussed separately.

i. SWEPCO's Responses

In addition to arguments noted previously, SWEPCO urges that all rival proposals that would directly or indirectly remove Dolet Hills or its Oxbow investment from rate base would violate Section 25.231(c)(2)(F)(iii)(II) because those assets, unlike Welsh Unit 2 in Docket No. 46449, were still providing service through the first day of the rate year.[177] Nor, SWEPCO insists, is there any justification for the Commission to depart from "the clear requirements of the Cost of Service rule."[178] SWEPCO disputes Ms. Stark's assertion that its offset proposal violates Section 25.231(c)(2)(F)(iii)(II), observing that other Cost of Service Rule provisions prescribe that ADFIT is to be deducted from invested capital when determining rate base.[179] SWEPCO acknowledges, however, that its proposal to offset the value of a single asset differs from the historically accepted deduction from rate base as a whole,[180] a distinction that CARD emphasizes in arguing that the Cost of Service Rule does not permit linkage to a specific rate-base item.[181] TIEC would also distinguish *excess* ADFIT, such as SWEPCO proposes to offset here, which represents taxes that customers have paid through rates yet which the utility will never have to pay, as contrasted with ADFIT resulting from mere timing differences between the utility's collection of taxes through rates and its tax payments.[182]

As for any strategic tailoring of its timing in filing this case, Mr. Brice acknowledged that SWEPCO's early filing had resulted in Dolet Hills operating during a portion of the rate year and that this fact is integral to the arguments it now makes regarding Section 25.231(c)(2)(F)(iii)(II).[183] However, he denied that this had been a consideration for SWEPCO when choosing when to file

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[177] SWEPCO Initial Brief at 7-10; SWEPCO Reply Brief at 1-4, 22.

[178] SWEPCO Reply Brief at 3.

[179] SWEPCO Reply Brief at 2-3; *see* 16 TAC § 25.231(c)(2)(C)(i).

[180] SWEPCO Reply Brief at 3.

[181] CARD Reply Brief at 5-6.

[182] TIEC Reply Brief at 3-4.

[183] Tr. at 70-71.

the case, insisting that the timing was a function of SWEPCO's inability to earn a reasonable return in excess of its operating costs.[184]

SWEPCO also emphasizes the concept that utility customers do not pay for any specific asset used to provide service, only for the service itself.[185] It follows, SWEPCO reasons, that its customers will not in any relevant sense be made to "pay for" Dolet Hills after its retirement any more that they could be said to receive service "free of charge" from generating assets that are not yet included in rate base.[186] In this regard, SWEPCO observes that the temporal cut-off in Section 25.231(c)(2)(F)(iii)(II) serves a sound regulatory purpose, as Mr. Brice testified:

> [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 changes 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.[187]

And if SWEPCO's rate base should be reduced based on Dolet Hills' retirement, Mr. Brice added, it follows logically that SWEPCO's rate base should likewise be increased for any new investment placed in service between the March 31, 2020 test-year end and that retirement.[188] Absent the corresponding increase, he argued, the effect of the "asymmetry" would be to deprive SWEPCO of its opportunity to earn a reasonable return on its invested capital, because "in [his] experience rate base tends to increase over time, not decrease."[189] In fact, SWEPCO points out, since the

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[184] Tr. at 71.

[185] SWEPCO Reply Brief at 1 (quoting *Board of Pub. Util. Comm'n v. New York Tel. Co.*, 271 U.S. 23, 32 (1926) ("Customers pay for service, not for the property used to render it.")).

[186] SWEPCO Reply Brief at 7-8; SWEPCO Ex. 33 (Brice Reb.) at 11. To emphasize the point, SWEPCO observes that the Dolet Hills plant was in service for approximately twenty-five years before SWEPCO sought and obtained a corresponding adjustment to its Texas base rates. SWEPCO Ex. 33 (Brice Reb.) at 5-6, 11. To the extent this would be an appeal for a corresponding inverse treatment of Dolet Hills, Staff urges that "[i]f SWEPCO felt that it was not earning a sufficient return without Dolet Hills included in rates, SWEPCO could have come in for a rate case at any time during those 25 years." Staff Reply Brief at 6-7.

[187] SWEPCO Ex. 33 (Brice Reb.) at 9.

[188] SWEPCO Ex. 33 (Brice Reb.) at 10.

[189] SWEPCO Ex. 33 (Brice Reb.) at 10.

March 31, 2021 test-year end, its gross plant has increased by $244 million while its net plant has increased by $88 million, increases that will continue through the time of the Dolet Hills retirement.[190]

Consequently, SWEPCO contends, there is "simply no evidence" or reason to assume that its overall cost of service to customers will necessarily decrease following the Dolet Hills retirement.[191] And regardless, it suggests, that risk would be one inherent to Texas cost-of-service ratemaking and shared by both a utility and its customers.[192] As Mr. Baird testified:

> The reality is, in Texas regulation, there is lag between rate cases. If the lag goes in [SWEPCO's] favor[,] that will show up in the annual Earnings Monitoring Report (EMR) via an actual return on equity that is higher than the approved return on equity, [and] then the Commission can call SWEPCO in for a rate case. If the lag goes in the customer's favor, that too will show up in the annual EMR via an actual return on equity that is lower that the approved return on equity. At that time, [SWEPCO] has the ability to file a base rate case.[193]

In fact, SWEPCO emphasizes, Ms. Stark suggested this very option—waiting and watching SWEPCO's earnings-monitoring reports, intervening only when and if warranted by SWEPCO's actual performance—as an alternative means by which the Commission could address any issues arising from the retirement of Dolet Hills, or the subsequent Pirkey retirement.[194]

Additionally, SWEPCO argues that denying it a return on its Dolet Hills and Oxbow investment, or its proposed means of accelerating recovery, would unfairly "penalize" it for its prudent decision to retire the plant, by leaving it with a large undepreciated balance—from investments that the Commission had also found prudent—on which it would lose its costs of

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[190] SWEPCO Reply Brief at 8 (citing SWEPCO Ex. 33 (Baird Reb.) at 17).

[191] SWEPCO Initial Brief at 10.

[192] SWEPCO Ex. 36 (Baird Reb.) at 17-18.

[193] SWEPCO Ex. 36 (Baird Reb.) at 17-18.

[194] SWEPCO Reply Brief at 3-4 (citing Staff Ex. 3 (Stark Dir.) at 28).

capital.[195] Nor would recovery over the 2046 useful life serve "intergenerational equity" in SWEPCO's view, reasoning that Dolet Hills' costs should properly be borne by the current customers who have been served by the plant (and from whom the excess ADFIT was collected) rather than future customers who will not be.[196] And Docket No. 40443 does not require that treatment here, SWEPCO argues, reasoning that the Commission made no change to Welsh Unit 2's depreciable service life in that case because the Commission deferred the prudence of the unit's retirement until SWEPCO's next base rate case.[197] By contrast, as SWEPCO emphasizes, the Commission's Preliminary Order in this case includes the prudence of Dolet Hills' retirement among the issues to be addressed.[198] Consequently, SWEPCO reasons, the Commission can (and should) allow SWEPCO a more expeditious recovery of its investment in Dolet Hills, given the plant's now-shortened useful life. It adds that the same treatment would also be appropriate in regard to Pirkey or the remaining Welsh Units, to the extent future changes involving those units are considered in this proceeding.[199]

j. ALJs' Analysis

i. Rate-Base Reduction

The most pivotal question presented here distills to whether or how the Commission's rate treatment of Welsh Unit 2 in Docket No. 46449 should also guide its treatment of Dolet Hills in light of that plant's imminent retirement. On one hand, the Dolet Hills retirement, once it occurs, will squarely implicate the substantive principles that guided the Commission in Docket No. 46449—namely, that a retired plant is not considered a "used and useful" investment properly included in rate base under PURA and Commission rules, and that "the interests of ratepayers and shareholders with respect to a plant that no longer provides service" are properly balanced by

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195 SWEPCO Reply Brief at 4-6, 9-10.

196 SWEPCO Reply Brief at 6-7.

197 SWEPCO Reply. Brief at 8-9 (citing Docket No. 40443, Order on Rehearing, FoF No. 125A (Mar. 4, 2014)).

198 SWEPCO Reply Brief at 9; *see* Preliminary Order ¶ 67.

199 SWEPCO Reply Brief at 9.

"[a]llowing [the utility] a return on, but not of, its remaining investment."[200] Yet the circumstances of the Dolet Hills retirement plainly differ from those of Welsh Unit 2 in Docket No. 46449, which had been retired before the test-year end (although they do not quite match the circumstances of Welsh Unit 2 in Docket No. 40443, either). It is likewise true that, as SWEPCO emphasizes, Section 25.231(c)(2)(F)(iii)(II) would preclude a rate-base reduction based on the Dolet Hills retirement because the plant has remained in service into the rate year. But the Commission has left itself discretion to make exceptions to Section 25.231(c)(2)(F)(iii)(II) or other Chapter 25 requirements where it finds "good cause."[201] So, is there "good cause" here for the Commission to make an exception and a post-test-year reduction to SWEPCO's rate base to reflect the Dolet Hills retirement? Or stated another way, which set of governing principles now in conflict—the substantive principles of Docket No. 46449 relating to retired generating plants, versus Section 25.231(c)(2)(F)(iii)(II)'s timing restriction—should prevail?

As SWEPCO points out, the Section 25.231(c)(2)(F)(iii)(II) timing restriction is no mere empty formalism, but serves important and beneficial regulatory purposes in the context of ratemaking founded principally on actual data from an historical test year. In such a regime, as Mr. Brice observed, the Commission must necessarily draw *some* temporal cut-off line for post-test-year rate-base adjustments, and it has done so in Section 25.231(c)(2)(F)(iii)(II)—the start of the rate year.[202] It is also true, as Mr. Brice pointed out, that rate base is somewhat a moving target and that one-sided (or "asymmetrical," as he termed it) rate-base reductions without corresponding increases for new capital can potentially distort a utility's earnings relative to cost of service.[203] Likewise, as Mr. Baird testified, a certain amount of regulatory lag is inherent in the system and, in theory, both utility and customers bear the risk that post-test-year events may not go their way.[204]

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[200] Docket No. 46449, Order on Rehearing, FoF Nos. 66, 68, 69, 71 (Mar. 19, 2018); PFD at 94 (Sep. 22, 2017).

[201] 16 TAC § 25.3(b).

[202] SWEPCO Ex. 33 (Brice Reb.) at 9.

[203] SWEPCO Ex. 33 (Brice Reb.) at 10.

[204] SWEPCO Ex. 36 (Baird Reb.) at 17-18.

Yet bright-line rules like Section 25.231(c)(2)(F)(iii)(II) bring the potential for arbitrary effect in a particular case, both with regard to the rule's own underlying purposes and broader fundamental policies of the surrounding regulatory scheme—like the principles that utility rates should include only assets and expenses that are used and useful in providing service and must ultimately be just and reasonable. In this case, Section 25.231(c)(2)(F)(iii)(II), applied as written, would bar the Commission from making a rate-base reduction to reflect a plant retirement occurring just over nine months past the rule's start-of-rate-year deadline, not to mention mere weeks (at most) after the Commission's final order issues. The consequence would be to leave a power plant in rate base for what is expected to be more than four years until SWEPCO's next base-rate case, with customers paying a return, as with a fully operational plant, even though the plant will be retired and thus not providing service for over three years of that period.

These outcomes are especially arbitrary considering that the Section 25.231(c)(2)(F)(iii)(II) deadline precedes the Dolet Hills retirement not because of mere random chance, the Commission's normal timetables for filing base-rate cases, or even the timing of the retirement in itself, but because SWEPCO chose to file this base rate case over one-and-a-half years before it was required to do so. Had SWEPCO waited until its March 19, 2022 deadline to file, or even until sometime after July 2021, the beginning of the rate year (the relate-back date, 155 days after filing) would have fallen after the December 31, 2021 Dolet Hills retirement date, such that a post-test-year rate-base reduction would undisputedly have been allowed under Section 25.231(c)(2)(F)(iii)(II). The ALJs will take Mr. Brice at his word in professing that SWEPCO did not time its filing to achieve any such tactical benefit, but was driven merely out of concern with the utility's perceived inability to earn a reasonable return in excess of its operating costs.[205] Even so, ascribing outsized significance to the Section 25.231(c)(2)(F)(iii)(II) deadline under these circumstances would invite such manipulation in the future by utilities anticipating retirements of generation units (and the implications of Docket No. 46449 upon retirement), particularly units being retired early or otherwise with substantial remaining net book value.

[205] Tr. at 71.

Which brings the ALJs to the next factor weighing in favor of finding good cause—the sheer size of the asset in question. While it may be true in theory that SWEPCO's customers pay for service and not the Dolet Hills plant itself or any other specific asset used to provide that service, they would still be paying a return on tens of millions in capital investment—approximately $122.8 million on a total company basis, or approximately $45.4 million Texas retail—that will not be providing them any of that service for the vast majority of the period in which the rates are expected to remain in effect. Although SWEPCO insists there is a possibility of offsetting new capital investment, it cites a figure ($88 million) that would be dwarfed by the effect of the Dolet Hills retirement.[206] Moreover, to the extent SWEPCO would have legitimate concerns about under-recovery following an "asymmetrical" rate-base reduction to account for the Dolet Hills retirement, Staff and CARD point out that SWEPCO now has resort to interim mechanisms through which it can update its rates to account for new capital investment—the GCRR, the TCRF, and the DCRF.[207]

As for SWEPCO being unfairly "penalized" by being denied recovery of its cost of prudently invested capital, this is less a justification for enforcing Section 25.231(c)(2)(F)(iii)(II) than a complaint about Docket No. 46449's holdings. As observed in regard to the retired gas units, the ALJs conclude they should follow Docket No. 46449 unless and until the Commission or the Legislature instructs otherwise. And as weighed against the policies reflected in Docket No. 46449 and PURA's broader directive of just and reasonable rates, the ALJs conclude that the timing requirement of Section 25.231(c)(2)(F)(iii)(II) should yield under the circumstances of this case. That is to say, the ALJs recommend that the Commission find good cause to make an exception to Section 25.231(c)(2)(F)(iii)(II), and in turn to make post-test-year adjustments to remove Dolet Hills from rate base in light of its retirement.

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[206] SWEPCO Reply Brief at 8 (citing SWEPCO Ex. 33 (Baird Reb.) at 17).

[207] Staff Reply Brief at 6 (citing 16 TAC §§ 25.239, .243, .248); CARD Reply Brief at 5 (citing same). As Staff notes, "it is unlikely that the GCRR would provide for an update to remove a retired Dolet Hills facility." Staff Reply Brief at 6.

But the logic of Docket No. 46449 also implies that, likewise, SWEPCO should be permitted to continue earning a return on Dolet Hills so long as it is used and useful in providing service to customers. Indeed, this was the prevailing view among Staff and most intervenors who briefed the issue, and the ALJs share it. Accordingly, the ALJs recommend that, essentially, Dolet Hills be treated for ratemaking purposes as an operational, used and useful, power plant, including earning a return on the plant's net book value, with respect to the period between March 18, 2021 (the rates' effective date) and December 31, 2021 (the plant's retirement), but not thereafter.

ii. Depreciation/Amortization Schedule

The next question to be addressed, also pivotal in resolving this case, concerns SWEPCO's recovery *of* (as opposed to the return *on*) Dolet Hills' remaining net book value. Consistent with the foregoing analysis and Docket No. 46449, SWEPCO should (1) continue ordinary depreciation of Dolet Hills with respect to the period between March 18, 2021, and the December 31, 2021 plant retirement, and (2) with respect to the period thereafter, place any remaining net book value into a regulatory asset, to be amortized over some period of time. The issue then becomes the period of time over which SWEPCO should recover Dolet Hills' net book value, whether as pre-retirement depreciation or post-retirement amortized recovery.

Even accepting SWEPCO's disputed premise of GAAP-required depreciation of Dolet Hills' entire net book value by the December 31, 2021 retirement date, any such requirement would not necessarily dictate the Commission's ratemaking treatment, as several parties point out. The Commission recognized in Docket No. 46449 that "[a]ccounting does not determine the appropriate ratemaking treatment," as ratemaking is instead a function of the Commission's regulatory authority.[208] And with regard to depreciation passed on in rates, the Commission's Cost of Service Rule directs that allowable depreciation expense is generally to be "based on original cost and computed on a straight line basis as approved by the commission," but provides that "[o]ther methods of depreciation may be used when it is determined that such depreciation

[208] Docket No. 46449, PFD at 94 (Sep. 22, 2017).

methodology is a more equitable means of recovering the cost of the plant."[209] As such, the Cost of Service Rule recognizes the Commission's discretion to depart from straight-line depreciation over a plant's expected useful life (however "expected useful life" might be defined) in favor of a different methodology that it deems "a more equitable means of recovering the cost of the plant."[210] SWEPCO essentially conceded this point during the hearing, as Mr. Baird acknowledged that the Commission could order a ratemaking treatment that differed from GAAP, that the Commission had done so in the past, and that SWEPCO's own proposed four-year amortization would depart from its view of GAAP's requirements.[211]

Consequently, the amortization question turns ultimately on what the Commission deems equitable, an inquiry that must necessarily weigh the respective interests of SWEPCO and its current or future customers. At first blush, Docket No. 46449 would seem to indicate the appropriate balancing of interests once again, as the Commission directed that Welsh Unit 2's remaining net book value would be amortized over the 24-year remaining lives of Welsh Units 1 and 3,[212] which also corresponded roughly to Welsh Unit 2's estimated remaining useful life as determined before retirement.[213] Yet the Commission did not analyze the specific amortization questions SWEPCO now presents because SWEPCO's arguments centered on whether Welsh Unit 2's net book value should remain in rate base post-retirement, in the form of a debit balance in Accumulated Depreciation, an accounting treatment that also effectively tied its amortization to that of the two remaining units.[214]

SWEPCO reasons that the equities favor placing the cost of its Dolet Hills investment upon the customers who have obtained or will obtain service during the plant's period of operation, first

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[209] 16 TAC § 25.231(b)(1)(B); *see also* 16 TAC § 25.231(c)(2)(A)(ii) (Accumulated depreciation (as deducted in determining rate base) "shall be computed on a straight line basis or by such other method approved under [the provision governing depreciation expense] over the expected useful life of the item or facility.").

[210] 16 TAC § 25.231(b)(1)(B).

[211] Tr. at 472-73.

[212] Docket No. 46449, Order on Rehearing, FoF No. 70 (Mar. 19, 2018).

[213] Docket No. 40443, Order on Rehearing, FoF No. 199 (Mar. 6, 2014).

[214] Docket No. 46449, PFD at 87-95 (Sep. 22, 2017).

by offsetting the refundable excess ADFIT, then amortizing the remaining balance over four years (if not by the December 31, 2021 retirement date). SWEPCO resists the notion that the cost should be carried into future decades and shifted (increasingly as time passes) onto future customers who will never have been served by Dolet Hills. But SWEPCO takes too narrow a view of the competing interests to be balanced.

As CARD's witness Mr. Garrett testified, the relevant interests concern not merely one soon-to-be-retired power plant viewed in isolation, but the broader context of a long-term shift by SWEPCO (like its AEP affiliates and other utilities) from reliance on solid-fuel-fired generation toward alternative, "cleaner" energy sources.[215] These changes have responded to seismic and often-rapid shifts in the legal and regulatory environment, as well as the marketplace, as solid-fuel-fired generation once permitted and thought prudent and acceptable has increasingly become popularly disfavored. A byproduct, as Mr. Garrett observed, has been early retirements of solid-fuel-fired plants that are replaced with other forms of generation, with attendant stranded costs.[216] But these stranded costs are not merely a problem for the customers formerly served by the retiring plants. As Mr. Garrett suggests, they amount to a type of investment being made—by the utility, its customers, and the governmental regulators that in theory serve all the citizenry—to ensure cleaner air going forward. And that resultantly cleaner air, as Mr. Garrett argues, benefits future customers, perhaps to a greater extent than current customers.[217] Consequently, as Mr. Garrett reasons, it is fair that those future customers bear a share of the costs.[218]

The ALJs also find persuasive other rationales Mr. Garrett offers for extending amortization of Dolet Hills over its 2046 useful life. In addition to the potential that the costs will decrease over time, Mr. Garrett observes that the amortization period chosen in Docket No. 46449 is consistent with regulatory decisions from other states that have addressed similar early

[215] CARD Ex. 2 (M. Garrett Dir.) at 7.

[216] CARD Ex. 2 (M. Garrett Dir.) at 7.

[217] CARD Ex. 2 (M. Garrett Dir.) at 7.

[218] CARD Ex. 2 (M. Garrett Dir.) at 7.

retirement issues.[219] Accordingly, the ALJs recommend that the Commission retain the same depreciation rates it previously approved for Dolet Hills, predicated on a useful life ending in 2046, and use this same schedule for both pre-retirement depreciation and post-retirement amortization of the regulatory asset.

It follows from this analysis that the ALJs also would reject SWEPCO's proposed offset utilizing refundable excess ADFIT, as this mechanism would achieve the contrary result of an immediate recovery of most of Dolet Hills' net book value. The ALJs address the ultimate disposition of the excess ADFIT below.

iii. Implementation

The ALJs next address the appropriate mechanism through which the foregoing recommendations should be implemented. The ALJs would follow the basic rate-rider model proposed by OPUC's Ms. Cannady,[220] but with some modifications. That is, cost recovery for Dolet Hills would be removed from rate base entirely and addressed instead through the rider, as follows:

- For the period between March 18, 2021 (when the rates are effective) and December 31, 2021 (the Dolet Hills retirement date), *i.e.*, while the plant is still used and useful in providing service (the Operational-Plant Phase):
    - SWEPCO will earn a return on Dolet Hills, as if in rate base.
    - SWEPCO will continue to depreciate Dolet Hills in accord with its useful life ending in 2046.
- For the period beginning January 1, 2022 (*i.e.*, after Dolet Hills is retired) (the Post-Retirement Phase):

[219] CARD Ex. 2 (M. Garrett Dir.) at 7-14.

[220] OPUC Ex. 1 (Cannady Dir.) at 11-28.

- o The then-remaining net book value of Dolet Hills will be placed in a regulatory asset, to be amortized in accordance with the estimated useful life ending in 2046.[221]

- o All other cost recovery relating to Dolet Hills, including return, will cease.

The ALJs recommend the rider mechanism because it has the dual benefits of (1) segregating and separately addressing the unique cost-recovery issues associated with Dolet Hills, (2) while also aligning the costs of the plant while still operating with the rates paid by SWEPCO customers who are receiving service at that time.

iv. Oxbow Investment and DHLC

The same logic underlying the above recommendations regarding Dolet Hills guides the ALJs' proposed rate treatment of SWEPCO's Oxbow investment and the equity return and associated taxes for DHLC. More specifically, the ALJs conclude that: (1) both the Oxbow investment and the DHLC equity return and taxes should be removed from base rates and addressed in the same rate rider with Dolet Hills; (2) during the Operative-Plant Phase, SWEPCO should continue to earn a return on the Oxbow investment and the DHLC equity return and taxes; but (3) during the Post-Retirement Phase, the Oxbow investment should be placed in a regulatory asset and amortized over the same useful life as with Dolet Hills.

These recommendations reflect the ALJs' conclusion that both the Oxbow investment and DHLC will cease to be used and useful in providing service to SWEPCO customers when Dolet Hills retires. However, the ALJs have rejected OPUC's argument that both assets already ceased to be used and useful in providing service when further lignite extraction ended in May 2020. As Mr. Baird testified, both the Oxbow mine and DHLC have continued to provide benefit and will do so through the plant's final operations, as DHLC delivers and Dolet Hills burns already-mined lignite in generating electricity.[222]

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[221] This aspect of the ALJs' recommendation differs from Ms. Cannady's proposal, as she would have the rate rider expire upon Dolet Hills' retirement and address amortization of the regulatory asset as part of base rates. OPUC Ex. 1 (Cannady Dir.) at 12.

[222] SWEPCO Ex. 36 (Baird Reb.) at 21-22.

Mr. Baird also pointed out that amortizing the Oxbow investment while Dolet Hills is still operating, as OPUC's Ms. Cannady proposed, would result in a double-recovery for SWEPCO.[223] He explained that as lignite has been mined, it is amortized and billed to SWEPCO, which records the billings as fuel inventory and recovers the cost through eligible fuel expense only when the lignite is burned.[224] The ALJs have addressed this overlap by recommending that amortized recovery of SWEPCO's remaining Oxbow investment begin only after the Dolet Hills retirement.

v. Demolition Costs

Through the testimony of its witness Jason Cash, Accounting Senior Manager with AEPSC,[225] SWEPCO presented evidence that its currently approved depreciation rates have included a component for each production plant's estimated final demolition costs in its calculation of net salvage, that it is normal to do so, and how these estimates were determined.[226] The ALJs find that SWEPCO's reliance on the estimated Dolet Hills demolition costs is reasonable and, accordingly, do not recommend adoption of ETEC/NTEC proposal to require SWEPCO to defer its actual demolition and removal costs for Dolet Hills into a regulatory asset.[227]

3. Coal and Lignite Inventories

SWEPCO's witness Mark Leskowitz submitted evidence concerning the fuel inventory levels maintained at the three coal plants at which the Company owns an interest—Flint Creek, Welsh, and Turk—and the two lignite-burning plants, Dolet Hills and Pirkey.[228] He testified that the purpose of maintaining solid fuel inventories is to assure a continuous supply of coal or lignite of the appropriate quality to all of AEP's solid-fuel generating stations, delivered at a reasonable

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[223] SWEPCO Ex. 36 (Baird Reb.) at 22.

[224] SWEPCO Ex. 36 (Baird Reb.) at 21-22.

[225] SWEPCO Ex. 16 (Cash Dir.) at 1.

[226] SWEPCO Ex. 16 (Cash Dir.) at 6-9; SWEPCO Ex. 43 (Cash Reb.) at 4.

[227] ETEC/NTEC Initial Brief at 13; ETEC/ETEC Ex. 1 (Hunt Dir.) at 11-12.

[228] Mr. Leskowitz adopted the direct testimony of SWEPCO witness Amy Jeffries and presented rebuttal testimony.

cost over a period of years.[229] Mr. Leskowitz indicated that solid fuel target inventory levels are determined based on the number of days that the respective plant can be expected to operate using only fuel inventory available at the plant site, expressed or quantified in terms of a “days-burn,” defined as the number of tons that the plant would burn in one day at full load.[230] This determination, he further explained, is made by initially allocating each plant a base level of days-burn inventory, then making additions based on criteria that include the probability of interruptions in the fuel supply (*e.g.*, extreme weather events, mining issues), how long such interruptions may last, how much fuel is necessary to provide for these contingencies, and plant-specific criteria (*e.g.*, fuel transportation and unloading options).[231] Mr. Leskowitz added that these targets are set annually for the three coal plants and the Pirkey lignite plant by AEPSC Fuel Procurement, Engineering, and SWEPCO power plant management, while CLECO, which manages Dolet Hills, sets the target for that plant.[232]

Based on these determinations of inventory target levels, SWEPCO proposes to include in rate base a 45-day level of fuel inventory at Dolet Hills and a 30-burn-day level at each of the other plants.[233] These levels, Mr. Leskowitz attested, were the same as approved in Docket No. 46449.[234] CARD witness Scott Norwood asserts that these levels are excessive in two ways.

First, Mr. Norwood observes that SWEPCO makes no adjustment for the Dolet Hills retirement, instead treating the plant as if it would continue to operate throughout the period in which the rates will remain in effect.[235] For this reason, Mr. Norwood recommends that the Commission disallow the entirety of SWEPCO’s requested inventory for Dolet Hills “because the

[229] SWEPCO Ex. 25 (Jeffries Dir., adopted by Leskowitz) at 13-14.

[230] SWEPCO Ex. 25 (Jeffries Dir., adopted by Leskowitz) at 15.

[231] SWEPCO Ex. 25 (Jeffries Dir., adopted by Leskowitz) at 14-15.

[232] SWEPCO Ex. 25 (Jeffries Dir., adopted by Leskowitz) at 14.

[233] SWEPCO Ex. 25 (Jeffries Dir., adopted by Leskowitz) at 16.

[234] SWEPCO Ex. 25 (Jeffries Dir., adopted by Leskowitz) at 16; *see also* Docket No. 46449, Order on Rehearing, FoF Nos. 136-140 (affirming continued use of 45-day inventory target that “has been in use for many years” at Dolet Hills).

[235] CARD Ex. 3 (Norwood Dir.) at 9.

plant is scheduled to be retired no later than two months after [SWEPCO's] new rates are put into effect and . . . will not require fuel inventory in the future.[236] In this regard, CARD also emphasizes that Dolet Hills has been operating only seasonally and points to the plant's equivalent available factors as provided by SWEPCO, which reflect that SWEPCO did not operate the plant between September and December 2017, in November and December 2018, nor in November and December 2019.[237] "Thus," CARD concludes, "it would neither be just nor reasonable to allow SWEPCO to include in rate base the fuel inventory for Dolet Hills when SWEPCO will almost certainly not operate Dolet Hills after September of 2021.[238] In the alternative, CARD requests the Commission to require SWEPCO to create a regulatory liability to track this component of its cost of service, similar to its proposal concerning return on the Dolet Hills plant.[239]

Mr. Norwood also criticizes SWEPCO's use of days-burn as the relevant unit of measure at not only Dolet Hills but the other four plants.[240] He maintains that the assumption underlying the target—the need for continuous operations at full load for 30 or more days—is unrealistic and unjustified compared to the actual average energy production at SWEPCO's coal and lignite plants, which decreased by 36.5% between 2014 and 2019.[241] And this trend will continue downward, Mr. Norwood insisted, emphasizing the retirements of Dolet Hills and the Pirkey plant.[242] CARD also points out the broader strategy of SWEPCO and AEP to transition away from carbon-based fuels.[243] In light of these considerations, Mr. Norwood recommended replacing the days-burn measure in SWEPCO's inventory calculation with the test-year average daily burn level

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[236] CARD Ex. 3 (Norwood Dir.) at 9.

[237] CARD Ex. 9 at 2, 9, 15.

[238] CARD Reply Brief at 9.

[239] CARD Reply Brief at 9.

[240] CARD Ex. 3 (Norwood Dir.) at 8.

[241] CARD Ex. 3 (Norwood Dir.) at 7-9.

[242] CARD Ex. 3 (Norwood Dir.) at 8.

[243] CARD Initial Brief at 9 (citing Tr. at 52).

at each plant, *i.e.*, a target inventory at Flint Creek, Welsh, Turk, and Pirkey of enough fuel to supply each plant for 30 days of operation at its respective test-year-average daily burn level.[244]

Mr. Leskowitz urged that the Commission reject Mr. Norwood's recommendation, reasoning that the proposed shift to an historical average burn level would negatively impact SWEPCO's ability to reliably serve its customers.[245] He asserted that reliance on historical average burn rates is problematic because future conditions can "easily" differ from the past conditions that underlie the averages (*e.g.*, weather events or unit outages), that the averages can likewise be skewed by such events, and that the averages fail to account for the peak coal inventories needed during heavier parts of the year.[246] In contrast, Mr. Leskowitz maintained, SWEPCO's reliance on full-load burn days avoids such issues, ensuring that adequate inventory will be on hand to provide necessary reliability. He emphasized that the Commission had approved this approach in Docket Nos. 46449 and 40443.[247]

Mr. Leskowitz further denied that any decline in energy production from SWEPCO's coal and lignite units over years impacted its present inventory needs, maintaining that SWEPCO still had to be prepared for periods in which coal generation is in high demand, a plant would be required to run at or near full capacity for an extended period, and unforeseen supply disruptions could require the plant to rely only on the fuel supply it has on hand.[248] The same is true of Dolet Hills through its retirement date, he argued, and added that the plant had to be available for seasonal burn and reliability year-round for SPP for SWEPCO and in the Midcontinent Independent System Operator, Inc. (MISO) market for CLECO.[249]

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[244] CARD Ex. 3 (Norwood Dir.) at 9, Attachment SN-7.

[245] SWEPCO Ex. 49 (Leskowitz Reb.) at 3.

[246] SWEPCO Ex. 49 (Leskowitz Reb.) at 4.

[247] SWEPCO Ex. 49 (Leskowitz Reb.) at 4.

[248] SWEPCO Ex. 49 (Leskowitz Reb.) at 5-6.

[249] SWEPCO Ex. 49 (Leskowitz Reb.) at 5-6.

CARD points out that SWEPCO has been required to offer each of its coal and lignite plants into the SPP market since 2014, and the aforementioned declines in average energy production have occurred notwithstanding.[250] Thus, CARD reasons, "the more credible evidence in the record is that it is no longer necessary for SWEPCO to maintain inventory sufficient to operate the units for 30 or 45 days of continuous operations at their full-rated output."[251] CARD further insists that reliance on averages squares with "normal ratemaking principles" that rates are set to reflect normal historical operating conditions.[252]

The ALJs conclude that SWEPCO presented sufficient evidence to demonstrate the prudence of setting inventory levels at its coal and lignite plants based on burn-days rather than the historical averages that CARD champions. As Mr. Leskowitz persuasively testified, if SWEPCO is to assure reliability for its customers, it must be prepared for instances in which each plant may need to be operated at peak capacity and with only the fuel then on hand. While perhaps reflective of longer-term or broader trends, historical averages (being averages) tend to obscure peak or extreme periods for which SWEPCO must be prepared. Likewise, reliance on historical averages presumes that materially the same underlying conditions will persist into the future—a risky assumption given the vicissitudes of weather and other factors that may impact both power demand and the supply chain. Finally, the ALJs note that SWEPCO's burn-day methodology, and indeed the same resulting inventory targets, were approved by the Commission in Docket No. 46449 and Docket No. 40443. Accordingly, the ALJs recommend that the Commission reject CARD's proposal to employ the averages instead.

With regard to Dolet Hills specifically, SWEPCO argues in part that Section 25.231(c)(2)(F)(iii)(II) bars a post-test-year adjustment to reduce its lignite inventories in light of the Dolet Hills retirement.[253] For the same reasons explained in regard to Dolet Hills, the ALJs recommend that the Commission find good cause to make a post-test-year adjustment removing

[250] CARD Initial Brief at 9.

[251] CARD Initial Brief at 9.

[252] CARD Reply Brief at 10.

[253] SWEPCO Reply Brief at 22.

the Dolet Hills lignite inventory from base rates, placing it in the Dolet Hills Rate Rider, allowing SWEPCO to earn a return on the inventory during the Operative-Plant Phase, and ceasing all cost recovery in the Post-Retirement Phase. However, the ALJs would likewise reject CARD's proposal to disallow the lignite inventory for Dolet Hills entirely. As Mr. Leskowitz testified, the inventories will continue to be needed at Dolet Hills through its retirement date, including during periods beyond seasonal usage, when the plant must remain available for reliability.[254]

4. New Generation Capital Investment

Sierra Club seeks adjustments to disallow or reduce SWEPCO's test-year new capital investment (and also test-year O&M) at Dolet Hills, and to disallow all test-year capital investment and O&M at three other units: Flint Creek and Welsh Units 1 and 3. Sierra Club also requests additional relief addressed to ongoing or future capital spending at Flint Creek and Welsh that SWEPCO did not present for review in this case.

a. Dolet Hills Test-Year Investment

Although it did not present direct evidence to contest the issue,[255] Sierra Club argues in its briefing that "SWEPCO failed to present *any* evidence" to support the prudence or reasonableness of its test-year capital investment or O&M at Dolet Hills.[256] As an initial observation, the ALJs would note that their preceding recommendations regarding Dolet Hills would bar SWEPCO from recovering either a return on any new capital spending or O&M with respect to the period beyond the December 31, 2021 plant retirement date. Consequently, Sierra Club's challenge to SWEPCO's Dolet Hills test-year spending (and O&M) implicates only cost of service with respect to the period between March 18, 2021, and December 31, 2021, and whether SWEPCO ultimately recovers the new capital investment as part of the plant's amortized remaining net book value.

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[254] SWEPCO Ex. 49 (Leskowitz Reb.) at 5-6.

[255] Sierra Club Ex. 2A (Glick Dir., redacted) at 11 (explaining that her testimony "focuses solely on the economic performance and the operational and planning practices at the Flint Creek and Welsh units" and does not evaluate Dolet Hills).

[256] Sierra Club Initial Brief at 17 (emphasis in original).

The legal standard for determining prudence is well established:

> Prudence is the exercise of that judgment and the choosing of one of that select range of options which a reasonable utility manager would exercise or choose in the same or similar circumstances given the information or alternatives available at the point in time such judgment is exercised or option is chosen.[257]

"The 'prudence' standard explicitly incorporates a utility's reasonableness and, by speaking in terms of available alternatives, implicitly recognizes that an expense must be necessary."[258] But "[w]hat is prudent, reasonable, and necessary depends on circumstances. The prudence standard does not require perfection."[259]

> There may be more than one prudent option within the range available to a utility in a given context. Any choice within the select range of reasonable options is prudent, and the Commission should not substitute its judgment for that of the utility. The reasonableness of an action or decision must be judged in light of the circumstances, information, and available options existing at the time, without benefit of hindsight.[260]

A utility seeking to raise its rates, as SWEPCO seeks to do here, bears the burden of proving that each dollar of cost was reasonably and prudently invested.[261] It enjoys no presumption that the expenditures reflected in its books have been prudently incurred merely by opening the books to inspection.[262] But while the ultimate burden of *persuasion* on the issue of prudence remains with the utility, its initial burden of *production* (*i.e.*, to come forward with evidence) is shifted to

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[257] Docket No. 46449, Order on Rehearing, CoL No. 15 (citing *Gulf States Utilities Co. v. Public Util. Comm'n*, 841 S.W.2d 459, 476 (Tex. App—Austin 1992, writ denied)).

[258] *Nucor Steel v. Public Util. Comm'n*, 26 S.W.3d 742, 748 (Tex. App.—Austin 2000, pet. denied).

[259] *Nucor*, 26 S.W.3d at 749.

[260] Docket No. 46449, Order on Rehearing, CoL No. 16 (citing Docket No. 40443 Order on Rehearing at 5 (Mar. 6, 2014) (citing *Nucor*, 26 S.W.3d at 752)).

[261] *See, e.g.*, *Entergy Gulf States, Inc. v. Public Util. Comm'n*, 112 S.W.3d 208, 214 (Tex. App.—Austin 2003, pet. denied) (citing *Public Util. Comm'n v. Houston Lighting & Power Co.*, 778 S.W.2d 195, 198 (Tex. App.—Austin 1989, no writ).

[262] *Entergy Gulf States, Inc.*, 112 S.W.3d at 214 (citing *Houston Lighting & Power Co.*, 778 S.W.2d at 198).

opponents if the utility establishes a *prima facie* case of prudence.[263] This is a "Commission-made" rule, intended "to aid in the trial of utility prudence reviews" and facilitate "efficient hearings," allowing the utility to establish prudence "by introducing evidence that is comprehensive, but short of proof of the prudence of every bolt, washer, pipe hanger, cable tray, I-beam, or concrete pour."[264]

While decrying "Sierra Club's tactics" in raising its "new claim" in a manner that has "denied SWEPCO the opportunity to provide testimony rebutting its specific allegations,"[265] SWEPCO points to evidence it presented to make a *prima facie* showing of the prudence of its requested test-year capital and O&M at all of its generating plants.[266] This included Schedule H-5.2b of SWEPCO's Rate Filing Package (RFP), which lists every capital project with a value of greater than $100,000 that SWEPCO placed in service at its generating plants (including Dolet Hills, Flint, and Welsh) since the test-year end in Docket No. 46449.[267] The schedule further indicates whether a cost-benefit analysis was performed for each project and classifies each project according to one or more of ten categories of purposes (*e.g.*, "Immediate Personnel Safety Requirement," "Regulatory Safety of Operations Requirement," "Reliability").[268] SWEPCO also presented testimony from Mr. McMahon describing SWEPCO's decisional process in determining whether to make a capital addition to a plant.[269] According to Mr. McMahon, the first step is to research alternatives that may exist and to perform a cost-benefit analysis when warranted to estimate a project's value.[270] Once the need for a capital project is determined, Mr. McMahon explained, the most efficient way to manage the project is selected, typically through competitive

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[263] *Entergy Gulf States, Inc.*, 112 S.W.3d at 214.

[264] *Entergy Gulf States, Inc.*, 112 S.W.3d at 214-15 & n.5.

[265] SWEPCO Reply Brief at 17-18.

[266] SWEPCO Reply Brief at 12-14.

[267] SWEPCO Ex. 1 (Application), Schedule H-5.2b.

[268] SWEPCO Ex. 1 (Application), Schedule H-5.2b.

[269] SWEPCO Ex. 7 (McMahon Dir.) at 17-18.

[270] SWEPCO Ex. 7 (McMahon Dir.) at 17.

bidding to ensure that a fair market price is paid, although projects may also be expedited or sole-sourced if there is a lack of competition for a given piece of equipment or service.[271]

Regarding O&M incurred at SWEPCO's generating plants during the test year, SWEPCO presented: (1) Schedule H-1.2, which provides a description of the O&M incurred by FERC account by plant for each month of the test year[272]; (2) Schedule H-3, which provides historical SWEPCO generation O&M, by FERC account, by year since 2015[273]; and (3) Schedule H-4, which lists the major O&M projects undertaken during the test year by plant.[274] Additionally, Mr. McMahon testified that SWEPCO uses multiple processes to ensure that its generation plant O&M expenses are reasonable, including scrutinizing budgets on an annual basis to ensure they are reasonable, tracking and projecting expenses on a monthly basis, using competitive bids when it is reasonable to do so, and comparing generation plant O&M to past years to ensure it is not unreasonably high or low.[275] Mr. McMahon further observed that SWEPCO's generation fleet O&M had decreased from approximately $136 million in 2017 to approximately $130 million during the test year.[276]

The gravamen of Sierra Club's arguments is that this evidence should be disregarded as incompetent with respect to Dolet Hills because "SWEPCO apparently deferred to the analyses and investments of the operator of the plant, Cleco Power."[277] It similarly argues that SWEPCO's proof of prudence falls short because it "unreasonably failed to evaluate opportunities for reducing its capital and O&M spending at the [Dolet Hills] plant to reflect its shortened useful life," reasoning that CLECO rather that SWEPCO would be making such decisions.[278] To support its

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[271] SWEPCO Ex. 7 (McMahon Dir.) at 17.

[272] SWEPCO Ex. 1 (Application), Schedule H-1.2.

[273] SWEPCO Ex. 1 (Application), Schedule H-3.

[274] SWEPCO Ex. 1 (Application), Schedule H-4.

[275] SWEPCO Ex. 7 (McMahon Dir.) at 21-22.

[276] SWEPCO Ex. 7 (McMahon Dir.) at 23-24.

[277] Sierra Club Initial Brief at 17-18; Sierra Club Reply Brief at 8-9.

[278] Sierra Club Initial Brief 18-19.

premise, Sierra Club emphasizes testimony from Mr. McMahon acknowledging that CLECO, as the plant's operator, handled day-to-day operation and maintenance of the plant and that SWEPCO, therefore, had no "direct role" in determining capital and O&M expenditures and could not override CLECO's decisions regarding them.[279] However, SWEPCO disputes the insinuation that SWEPCO has merely deferred blindly to potentially imprudent investment decisions by CLECO,[280] and indeed the evidence belies that notion. When read in proper context, Mr. McMahon also made clear that SWEPCO management provides "input and feedback" to CLECO regarding its investment decisions and that based on "communications with plant management and others at CLECO," he believed that CLECO had acted prudently in making capital and O&M investment decisions that would get the plant safely and reliably to the end of its life.[281]

Nor is there anything inherently wrong with SWEPCO's reliance on CLECO in its decision-making processes at Dolet Hills, as SWEPCO points out. It notes that the Commission addressed this relationship in Docket No. 46449, in the context of determining that retrofitting Dolet Hills was prudent at the time of that decision, as was SWEPCO's reliance on CLECO in the decision-making process:

> In particular, the Commission finds it important that Mr. Franklin relied upon the study performed for the majority owner of the power plant, Cleco Power LLC (Cleco). SWEPCO and Cleco had a long and ongoing professional relationship related to Dolet Hills. Cleco owns 50% of the Dolet Hills power plant and is responsible for the operations and maintenance of the plant. As such, Cleco has the obligation to make all repairs, replacements, and capital additions to the plant. However, Cleco is required to consult with SWEPCO's operating committee representative in making major decisions, and the operating committee is required to unanimously approve such decisions. Further, the business relationship between Cleco and SWEPCO related to Dolet Hills had been ongoing since at least 1981, or for more than 30 years, at the time of the decision to retrofit the power plant. Over those years, SWEPCO had collaborated with Cleco in its management role on the operations and maintenance of the power plant and all capital improvements. The

279 SWEPCO Ex. 7 (McMahon Dir.) at 5; Tr. at 159-60.

280 SWEPCO Reply Brief at 18.

281 Tr. at 159-60.

> Commission finds it is reasonable for SWEPCO to have had confidence in this longstanding relationship as part of its decision-making process as to the retrofits.[282]

Sierra Club further suggests that the approaching Dolet Hills retirement or the plant's seasonal operation in themselves raise an inference that SWEPCO's test-year capital spending and O&M was wholly unsupported or at least inflated.[283] A "commensurate reduction," in Sierra Club's view, would be to allow SWEPCO only one-third of its requested test-year capital and O&M expenditures, or "[a]t a minimum" a one-third reduction to reflect that the plant will likely not be operating during the last three months of 2021.[284] The ALJs conclude, however, that it would be unreasonable to infer that the Dolet Hills retirement or seasonal operation automatically equals imprudence or unreasonableness in the test-year capital investment and O&M amounts presented by Mr. McMahon, let alone by any specific ratio or percentage of excessiveness.

As both Mr. Brice and Mr. McMahon testified during the hearing while being cross-examined by Sierra Club, SWEPCO necessarily had to spend both capital and O&M at Dolet Hills to ensure that the plant could operate reliably and safely through its retirement date.[285] Mr. McMahon further explained that an approaching retirement did not automatically translate to a reduced need for capital spending, but would depend upon the circumstances.[286] As he put it, SWEPCO was "not going to go out and build training facilities, office buildings, things that we know are absolutely not necessary, but we will deploy the appropriate level of capital to get those plants safely to the end of life."[287] Similarly, with regard to seasonal operations, Mr. McMahon

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[282] Docket No. 46449, Order on Rehearing at 2 (Mar. 19, 2018).

[283] Sierra Club Initial Brief 18-21.

[284] Sierra Club Reply Brief at 12-13. Sierra Club further reasons that these post-test-year adjustments would be permissible under Cost of Service Rule Section 25.231(c)(2)(F)(iii)(II) because, "as a practical and regulatory matter" SWEPCO had "seasonally mothballed" Dolet Hills prior to the rate year that began March 18, 2021, thereby satisfying that rule's temporal limitation. Sierra Club Reply Brief at 11-12.

[285] Tr. at 90, 159-61.

[286] Tr. at 165.

[287] Tr. at 165-66.

noted that the plant had to remain available for the entire year, and had recently been called into operation during the February 2021 winter storm event.[288] Additionally, Mr. McMahon, as noted previously, attested to his belief that CLECO had aligned the capital and O&M spending at Dolet Hills with the plant's needs through retirement.[289]

In sum, contrary to Sierra Club's assertions, SWEPCO has presented evidence to make a *prima facie* showing of the prudence of its test-year capital investment at Dolet Hills, and otherwise met its burden as to that issue and the reasonableness of its test-year O&M spent at that plant.

b. Flint Creek and Welsh Test-Year Investment

Similar to its challenge to test-year capital investment and O&M at Dolet Hills, Sierra Club contends that SWEPCO has failed to prove that any of its test-year capital spending or O&M at Flint Creek or Welsh Units 1 and 3 is prudent or reasonable. This is so, Sierra Club reasons, because SWEPCO failed to demonstrate that it is economically rational to continue operating the units rather than retiring them. In support of that proposition, Sierra Club advances two arguments.

First, Sierra Club posits that SWEPCO's initial burden includes not only presenting the evidence regarding capital spending and O&M described in the preceding section, but also providing economic modeling, a unit-disposition study, or other "quantified analysis" to justify continuing to operate the Flint Creek and Welsh units instead of retiring them.[290] The ALJs disagree that SWEPCO was required to make any such showing in the first instance. Aside from referencing the general concept that SWEPCO must prove that "every dollar of its revenue requirement is reasonable and necessary,"[291] Sierra Club points to no authority for its premise, which would imply that a utility must, as a component of its *prima facie* showing in every rate case, continually re-justify the prudence of the entire generation fleet that the Commission has

[288] Tr. at 163.

[289] Tr. at 159.

[290] Sierra Club Initial Brief at 2-3, 6, 8-9.

[291] Sierra Club Initial Brief at 8 (citing PURA § 36.006(1)).

previously deemed prudent and placed in rates. The ALJs add that Flint Creek has been in service since 1978, the two Welsh units since 1977 and 1982,[292] and in SWEPCO's most recent rate case, Docket No. 46449, the Commission found prudent SWEPCO's decisions to retrofit those three units (and others) to comply with emerging environmental regulations, thereby enabling their continued operation in lieu of retiring them.[293] The Commission cited a "robust" series of monthly economic analyses of unit-disposition alternatives that had informed the decision, which had taken account of "the projected operating and capital costs of the alternatives studied, as well as varying assumptions on the timing and amount of retrofit capital that reasonably reflected uncertainties regarding the timing and evolution of the various environmental programs in play," and "[m]ultiple commodity-price forecasts . . . include[ing] sensitivities for future gas prices, market energy prices, carbon dioxide prices, and other commodity inputs."[294] Given this historical context—which, contrary to Sierra Club's assertions, is not "irrelevant"[295]—SWEPCO has made a sufficient initial showing of the prudence and reasonableness of its test-year capital investment and O&M at Flint Creek and Welsh.

Sierra Club's second argument relies on the opinions of its expert, Devi Glick.[296] According to calculations prepared by Ms. Glick, SWEPCO incurred losses of $153 million and $144 million at Flint Creek and Welch respectively during the past six years (2015-2020).[297] She further concluded that Flint Creek and Welch will continue to incur losses of $161 million and $266 million respectively during the next decade.[298] SWEPCO contends that Ms. Glick's analyses are flawed in three chief ways.

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292 SWEPCO Ex. 7 (McMahon Dir.) at 4-5.

293 Docket No. 46449, Order on Rehearing, FoF Nos. 40-52, CoL No. 18 (Mar. 19, 2018).

294 Docket No. 46449, Order on Rehearing, FoF Nos. 42-44, 48 (Mar. 19, 2018).

295 Sierra Club Reply Brief at 5.

296 Sierra Club Initial Brief at 10-16.

297 Sierra Club Ex. 2A (Glick Dir., redacted) at 12-19.

298 Sierra Club Ex. 2A (Glick Dir., redacted) at 19-28.

First, SWEPCO witnesses Jason Stegall (AEPSC's Manager of Regulatory Pricing and Analysis)[299] and Mark Becker (AEPSC Manager of Resource Planning)[300] opined that Ms. Glick conflated two concepts—the prospective evaluation of a capital investment (such as was done with the retrofits in Docket No. 46449) and the historical evaluation of a generating unit's performance.[301] A generating unit's performance, they maintained, properly compares the unit's market revenues to the incremental variable costs of generating the power being sold.[302] This is so, Mr. Stegall explained, because the measure corresponds to the way that SWEPCO's generating units are offered into the SPP Integrated Marketplace (IM), using "offer curves" derived from the unit's incremental variable costs.[303] He further observed that the Commission in Docket No. 46449 found that SWEPCO had correctly bid its solid-fueled generating units into the SPP Integrated Marketplace based on the offer curves that represented the incremental cost of dispatch.[304] And looking to this measure, according to Mr. Stegall, that SWEPCO's revenues from sales from the Flint Creek and Welsh units between 2016 through 2020 had exceeded their variable costs by $196 million.[305]

In contrast, Mr. Stegall observed, Ms. Glick's calculations were not based on the incremental cost of dispatching the units, but incorporated fixed costs, creating what he termed "an apples to oranges comparison that is misleading and inaccurate."[306] Mr. Becker further noted that much of the capital investment that Ms. Glick had included in her historical loss calculations had been reviewed by the Commission, found to be prudent, and placed in SWEPCO's rate base in Docket No. 46449.[307] A related criticism, and one that extended also to Ms. Glick's projections

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[299] SWEPCO Ex. 47 (Stegall Reb.) at 1.

[300] SWEPCO Ex. 48 (Becker Reb.) at 1.

[301] SWEPCO Ex. 47 (Stegall Reb.) at 5; SWEPCO Ex. 48 (Becker Reb.) at 3.

[302] SWEPCO Ex. 47 (Stegall Reb.) at 3-5; SWEPCO Ex. 48 (Becker Reb.) at 3.

[303] SWEPCO Ex. 47 (Stegall Reb.) at 3-4.

[304] SWEPCO Ex. 47 (Stegall Reb.) at 4-5; *see* Docket No. 46449, Order on Rehearing, FoF Nos. 343-346 (Mar. 19, 2018).

[305] SWEPCO Ex. 47 (Stegall Reb.) at 4.

[306] SWEPCO Ex. 47 (Stegall Reb.) at 5; *see* Sierra Club Ex. 2A (Glick Dir., redacted) at 12-19.

[307] SWEPCO Ex. 48 (Becker Reb.) at 5-6.

of future losses, was that she had "manufacture[d]" the losses by recognizing multi-million-dollar SWEPCO capital investments as expenditures made entirely during the year of the investment rather than expensing them (as SWEPCO would normally do) over the life of each asset.[308]

A third critique, one that Mr. Becker termed "most important[]," was that Ms. Glick's analysis "considers only one side of the analysis—where the plant continues to operate—and fails to consider the cost to customers . . . where the plant is retired and replacement energy and capacity costs are incurred."[309] These costs would include, according to Mr. Becker, $150 million in transmission-system upgrades that would become necessary to maintain system reliability in northwest Arkansas were Flint Creek retired.[310] Ms. Glick's analysis, in other words, was not in Mr. Becker's view a proper "unit disposition analysis that studies the costs to serve consumers with a unit's retirement versus the costs to serve customers with a unit's . . . continued operation."[311]

Sierra Club counters that Ms. Glick's analysis is (or is intended to be) a unit-disposition analysis (also termed a "going-forward analysis" by Sierra Club), which must necessarily take account of fixed and capital costs and not merely variable or incremental costs.[312] It emphasizes Mr. Becker's agreement during the hearing that a unit-disposition analysis would include fixed and capital costs (albeit without conceding that Ms. Glick's analysis was a proper unit-disposition analysis).[313] Consequently, Sierra Club urges, SWEPCO's emphasis on the units' net revenues over the units' incremental variable costs is "irrelevant" and "not resource planning evidence."[314]

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[308] SWEPCO Ex. 48 (Becker Reb.) at 3-7.

[309] SWEPCO Ex. 48 (Becker Reb.) at 7.

[310] SWEPCO Ex. 48 (Becker Reb.) at 8.

[311] SWEPCO Ex. 48 (Becker Reb.) at 7.

[312] Sierra Club Reply Brief at 7-8.

[313] Sierra Club Reply Brief at 7-8; *see* Tr. at 689-90, 694-97.

[314] Sierra Club Reply Brief at 5-6.

As for SWEPCO's criticism that Ms. Glick presented only "one side" of a unit-disposition analysis, Sierra Club argues that SWEPCO is "simply wrong" that Ms. Glick failed to account for the costs of replacing the Flint Creek or Welch units.[315] Sierra Club points out that Ms. Glick included in her analysis, alongside the energy and ancillary market revenues that SWEPCO had obtained from sales into the SPP market, a capacity value.[316] Because SPP does not have a capacity market (and thus no actual capacity market revenues for SWEPCO), Ms. Glick calculated a capacity value based on SWEPCO's forward capacity price forecast between the years 2016-19.[317] Ms. Glick also ran a "conservative sensitivity" using SPP's Cost of New Entry (CONE) as a proxy for the value of capacity in the region.[318] CONE, according to Ms. Glick, is "calculated based on the revenue needed to cover the capital and fixed costs of a hypothetical gas-burning peaking facilities," and is thus "conservative" because "unless a region is capacity constrained (which it is not, as evident by SWEPCO's incredibly low capacity price forecast), then capacity can generally be procured for less than the cost of building an entirely new plant."[319]

Thus, Sierra Club concludes, "Ms. Glick did, in fact, include an energy generation alternative—replacing both Flint Creek and Welsh with energy market purchases" and/or constructing a new gas-fired resource at the CONE value.[320] And with regard to any additional transmission infrastructure required if Flint Creek is retired, Sierra Club asserts that these costs would be much less than losses Ms. Glick has projected for that unit, and would not be incurred at all if SWEPCO converted the unit to gas.[321]

Finally, concerning the timing of Ms. Glick's recognition of fixed and capital costs at the three units, Sierra Club acknowledges the witness's reliance on the "assumption that all fixed and

[315] Sierra Club Reply Brief at 7.

[316] Sierra Club Ex. 2A (Glick Dir., redacted) at 18.

[317] Sierra Club Ex. 2A (Glick Dir., redacted) at 13, 16 & n.21, 18.

[318] Sierra Club Ex. 2A (Glick Dir., redacted) at 13.

[319] Sierra Club Ex. 2A (Glick Dir., redacted) at 13 & n.15.

[320] Sierra Club Reply Brief at 7.

[321] Sierra Club Initial Brief at 15-16.

capital costs are expensed in the year those costs are incurred, rather than depreciating the costs over the life of the unit."[322] But "Ms. Glick's analysis presents a reasonable forecast of the [units'] forward-looking economics," Sierra Club insists, because as Mr. Becker acknowledged, that analysis "is dependent on the assumed useful life of the plant" and "a plant generally cannot recover costs through market revenues after it has ceased operations."[323] And the assumption of a reduced useful life is "not unreasonable" in the case of Welsh and Flint Creek, Sierra Club urges, given that the Welsh units will be retired or converted to gas in 2028, "the declining economics at Flint Creek and coal generation generally," and the broader SWEPCO and AEP strategy entailing early coal-plant retirements.[324]

Yet Sierra Club does not bridge a more fundamental disconnect between Ms. Glick's assumption of same-year expensing of fixed and capital costs and the manner in which SWEPCO actually has been expensing those investments. So long as that gap remains, Ms. Glick's assertions of historical or projected losses amount to mere unsupported conclusions rather than competent evidence of losses.[325] Nor should the witness's analysis be considered a probative unit-disposition analysis merely by virtue of incorporating some capacity value. As Mr. Becker explained, a proper unit-disposition analysis, such as that approved by the Commission in Docket No. 46449, would ordinarily entail consideration of multiple alternative resources and not merely a single resource or CONE input.[326]

In short, Sierra Club has not presented any evidence for disallowing the test-year capital and O&M spending at the Flint Creek and Welsh units.

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[322] Sierra Club Initial Brief at 14.

[323] Sierra Club Initial Brief at 14; *see* Tr. at 703-05.

[324] Sierra Club Initial Brief at 14-15.

[325] *See, e.g., Houston Unlimited, Inc. v. Mel Acres Ranch*, 443 S.W.3d 820, 832-33 (Tex. 2014) ("If an expert's opinion is unreliable because it is based on assumed facts that vary from the actual facts, the opinion is not probative evidence. . . . [and] if the record contains no evidence supporting an expert's material factual assumptions . . . opinion testimony founded on those assumptions is not competent evidence" (internal citations and quotations omitted)).

[326] Tr. at 742-43.

c. Additional Investment

In addition to the above challenges to test-year spending at Dolet Hills, Flint Creek, and Welsh, Sierra Club requests that the Commission address ongoing spending on environmental retrofits at Flint Creek that—as confirmed by multiple SWEPCO witnesses during the hearing[327]—SWEPCO is *not* seeking to include in the rates to be approved in this proceeding.[328] Nonetheless, Sierra Club has sought to challenge the prudence of the retrofits in this case, in the view that the spending "is likely to harm customers and saddle them with paying back the costs of stranded assets in the future."[329] The propriety of Sierra Club attempt to challenge spending that SWEPCO has not yet sought to include in rates was litigated prior to the hearing, principally through a SWEPCO motion to strike the corresponding portion of Ms. Glick's testimony, which the ALJs granted,[330] and a Sierra Club motion for reconsideration of that ruling, which the ALJs denied.[331] In the alternative to reconsideration, Sierra Club appealed the ALJs' ruling to the Commission, but no Commissioner voted to add it to an open-meeting agenda.[332]

Sierra Club has again urged the Commission to reverse the ALJs' ruling, reach the prudence of the Flint Creek retrofits, and disallow them.[333] The ALJs remain of the view that the earlier rulings were correct.[334] As the ALJs have explained, the appropriate forum and time for Sierra Club's challenge will occur "[i]f and when SWEPCO seeks to recover the costs of retrofitting Flint Creek in a future rate case," at which time "the prudence of those expenditures will be subject to Commission scrutiny."[335] Those investments will be passed on to consumers

[327] Tr. at 84-85, 123-24, 156-58.

[328] SWEPCO Initial Brief at 27-29.

[329] Sierra Club Initial Brief at 27.

[330] SOAH Order No. 7 at 1-6 (Apr. 27, 2021).

[331] SOAH Order No. 12 at 1-3 (May 17, 2021).

[332] Commission Advisory (May 13, 2021).

[333] Sierra Club Initial Brief at 27.

[334] Both of the earlier orders were signed by ALJs Neinast and Pemberton, prior to the assignments of ALJs Lutostanski and Quinn.

[335] SOAH Order No. 12 at 3.

only to the extent SWEPCO can then show them to be prudent.[336] Accordingly, the ALJs recommend that the Commission again decline Sierra Club's request to address ongoing spending that is beyond the scope of this case.[337]

The same logic extends to a request by Sierra Club for the Commission to "supervise" SWEPCO's resource-planning decisions, including requiring an advance prudence determination of any future decision to convert Welsh to gas, to protect consumers in light of the utility's "recent history of undertaking costly environmental retrofits and then retiring units soon thereafter."[338] As Sierra Club's witness Ms. Glick observed, Texas, unlike some other states, "does not have an official resource planning process," making it "especially important for the Commission to address resource planning concerns through rate cases in test year spending."[339] Only if and when SWEPCO requests to include those costs in rates through a future rate case, can those costs ever be passed on to consumers—and only if and to the extent the Commission, in that proceeding, finds the investments to be prudent.[340]

B. Prepaid Pension and OPEB Assets [PO Issue 41]

SWEPCO's Mr. Baird testified that SWEPCO has recorded an additional cash investment in its pension trust fund as a prepaid pension asset in accordance with GAAP under Accounting

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[336] SOAH Order No. 12 at 3. The supplemental Kentucky authority submitted by Sierra Club, which was submitted well after the close of the record in this case, does not compel any contrary result. Among other considerations, the regulatory body addressed the environmental-compliance costs in the context of a utility's request to recover them through a surcharge. *See In the Matter of: Electronic Application of Kentucky Power Co. for Approval of a Certificate of Public Convenience and Necessity for Environmental Project Construction at the Mitchell Generating Station, an Amended Environmental Compliance Plan, and Revised Environmental Surcharge Tariff Sheets*, Docket No. 2021-00004, Order at 4 (July 15, 2021).

[337] In the alternative, Sierra Club urges the Commission to "make clear" that SWEPCO cannot recover the retrofit costs in its Texas rates. Sierra Club Initial Brief at 27-29. That proposition is already inherent in the preceding analysis and recommendations.

[338] Sierra Club Initial Brief at 25-26.

[339] Sierra Club Ex. 2A (Glick Dir., redacted) at 12.

[340] SOAH Order No. 12 at 3.

Standards Codification (ASC) 715-30.[341] He maintained that the prepaid pension asset represents the cumulative additional pension cash contributions beyond the amount of pension cost and that, accordingly, an additional cash investment recorded as a prepaid pension asset should be included in rate base under PURA § 36.065.[342] No party has contested SWEPCO's inclusion of the prepaid pension asset in rate base, and the ALJs recommend its inclusion.

C. Accumulated Deferred Federal Income Taxes [PO Issue 20]

As noted previously, SWEPCO's proposed offset of the Dolet Hills' remaining net book value is not the only subject of dispute concerning ADFIT or "excess" ADFIT presented in this case. Staff raises additional challenges to SWEPCO's proposed treatment of both items, and there also remains the question of how, in lieu of SWEPCO's proposed offset, the excess ADFIT should be refunded to SWEPCO customers. Before turning to these issues, some additional background regarding the nature of ADFIT is helpful.

As applicable here, ADFIT derives from temporary timing differences in a public utility's recognition of income or expenses for tax purposes versus the "book" purposes of financial or regulatory reporting.[343] A primary example of such temporary differences arises when a utility avails itself of accelerated depreciation of assets for tax purposes while using straight-line depreciation for book purposes.[344] While both methods will recognize the same total amount of depreciation over the asset's useful life, accelerated depreciation will initially yield larger deductions (and lower taxes) than will straight-line depreciation, but the difference will eventually reverse itself as straight-line depreciation yields larger deductions in later years.[345]

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341 SWEPCO Ex. 6 (Baird Dir.) at 15.

342 SWEPCO Ex. 6 (Baird Dir.) at 15-16.

343 SWEPCO Ex. 17 (Hodgson Dir.) at 7-8; SWEPCO Ex. 45 (Hodgson Reb.) at 7.

344 SWEPCO Ex. 17 (Hodgson Dir.) at 9.

345 SWEPCO Ex. 17 (Hodgson Dir.) at 9-10.

Federal law requires that regulated public utilities use "normalized" accounting in determining tax expense in order to take advantage of accelerated depreciation of their property.[346] Commission rules likewise require that federal-income-tax expense be calculated "on a normalized basis."[347] Normalization requires a utility, when computing its tax expense for establishing cost of service for ratemaking purposes and reflecting operating results for book purposes, to use a method of depreciation for property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for establishing its cost of service for ratemaking purposes.[348] With respect to any temporary timing differences in deductions for accelerated versus book depreciation, the utility must also distinguish between (1) the portion of tax expense that is actually payable to the IRS during the current year, which is recorded as a current liability, and (2) the portion for which payment has been effectively "deferred" through use of accelerated depreciation, which is reflected through adjustments to a reserve account—ADFIT—that is calculated with reference to the applicable corporate tax rate.[349] To the extent a utility's future or deferred taxes exceed its currently payable taxes, the ADFIT balance is adjusted upward.[350] Conversely, as the utility pays its taxes year after year over a depreciating asset's usable life, the difference between the taxes it has collected from customers and what it has paid to the IRS will shrink, causing the ADFIT balance to decrease.[351] A further aspect of normalization, known as the consistency rule, requires a utility, when determining for rate making purposes its tax expense, depreciation expense, and ADFIT, to use consistent estimates or projections with respect to all of the items and to rate base.[352]

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346 SWEPCO Ex. 17 (Hodgson Dir.) at 11-12; Rev. Proc. 2020-39 at 1.

347 16 TAC § 25.231(b)(1)(D).

348 SWEPCO Ex. 17 (Hodgson Dir.) at 11-12 (quoting 26 U.S.C. § 168(i)(9)(A)(i)); Rev. Proc. 2020-39 at 2.

349 SWEPCO Ex. 17 (Hodgson Dir.) at 7-8, 11-12 (quoting 26 U.S.C. § 168(i)(9)(A)(ii)); SWEPCO Ex. 45 (Hodgson Reb.) at 7; Rev. Proc. 2020-39 at 2. *Accord* Staff Ex. 3 (Stark Dir.) at 30 (summarizing these aspects of normalization rules as requiring SWEPCO "to compute the federal income tax expense recovered in rates using a period no shorter than the period used to compute depreciation expense and the same method used to compute depreciation expense in setting rates," with ADFIT representing "the temporary difference between the amount of federal income tax collected through rates and the actual federal income tax paid because of the use of accelerated depreciation").

350 SWEPCO Ex. 17 (Hodgson Dir.) at 7; SWEPCO Ex. 45 (Hodgson Reb) at 7; Rev. Proc. 2020-39 at 2-3.

351 SWEPCO Ex. 45 (Hodgson Reb.) at 6.

352 Rev. Proc. 2017-47 at 3-4 (discussing 26 U.S.C. § 168(i)(9)(B)); Tr. at 402-03.

Under both normalization requirements and Commission rules, the ADFIT balance offsets, and thereby reduces, rate base.[353] This relationship reflects the concept that the utility has, by virtue of having its tax payments deferred temporarily through use of accelerated depreciation, effectively received an interest-free "loan" of that capital until those tax payments come due, such that the amount of the "loan" should in fairness be excluded from rate base and not earn a return.[354] Likewise, because the lower rate base will result in lower utility rates, the utility is made to share the benefits it receives from accelerated depreciation with its customers ratably over the regulatory useful life of the assets being depreciated.[355] Thus, as Staff observes, normalization of the "tax savings derived from liberalized depreciation" ensures that those benefits are "balanced equitably between present and future ratepayers and between ratepayers and the utility," which is also a PURA requirement.[356]

The consequences of a utility's depreciation-related normalization violation include losing the right to accelerate depreciation on property used to provide regulated service in the jurisdiction where the violation occurred, as well as quicker required payment of the taxes that had been deferred by virtue of the accelerated depreciation.[357] This would mean both that the utility would lose "loaned" cost-free capital (as ADFIT would be reduced) and that customers would lose the corresponding benefit of lower rates (as the loss of ADFIT would mean higher rate base).[358]

With this background in mind, the ALJs now turn to the remaining ADFIT-related issues.

[353] SWEPCO Ex. 45 (Hodgson Reb) at 7; 16 TAC § 25.231(c)(2)(C)(i).

[354] SWEPCO Ex. 45 (Hodgson Reb) at 7-8.

[355] SWEPCO Ex. 17 (Hodgson Dir.) at 8; Rev. Proc. 2020-39 at 1-2.

[356] Staff Initial Brief at 26; PURA § 36.059(a).

[357] SWEPCO Ex. 17 (Hodgson Dir.) at 15 (citing 26 U.S.C. § 168(f)(2)).

[358] SWEPCO Ex. 17 (Hodgson Dir.) at 16.

1. NOLC ADFIT

The first issue concerns a proposed adjustment by SWEPCO to reduce its ADFIT balance by $455,122,490 to reflect the effects of a net operating loss, attributable to accelerated depreciation that exceeded taxable revenues, as calculated on a stand-alone basis as of the end of the test year.[359] Neither SWEPCO's stand-alone loss calculation nor the type of adjustment it proposes, in itself, is controversial. SWEPCO and Staff agree, at least in concept, that SWEPCO is required to calculate its income-tax expense (including ADFIT) on a stand-alone basis—*i.e.*, reflecting only SWEPCO's own benefits and burdens in providing service to its customers, without commingling any tax benefits obtained by its affiliates—and that this is the basic import of PURA § 36.060, which states in pertinent part:

> If an expense is allowed to be included in utility rates or an investment is included in utility rate base, the related income tax benefit must be included in the computation of income tax expense to reduce the rates. If an expense is not allowed to be included in utility rates or an investment is not included in the utility rate base, the related income tax benefit may not be included in the computation of income tax expense to reduce the rates.[360]

In this respect, Section 36.060 in its current form differs from a prior version of that statute, in effect until September 1, 2013, which had provided instead that "[u]nless it is shown . . . that it was reasonable to choose not to consolidate returns, an electric utility's income taxes shall be computed as though a consolidated return had been filed and the utility had realized its fair share of the savings resulting from that return."[361]

It is likewise undisputed that federal tax law allows SWEPCO to carry its net operating losses forward to future years (known as a net operating loss carry-forward, or NOLC) to use in offsetting otherwise taxable income produced in those future years.[362] More specifically, where

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[359] SWEPCO Ex. 17 (Hodgson Dir.) at 27.

[360] PURA § 36.060(a); *see* SWEPCO Ex. 45 (Hodgson Reb.) at 2-3; Tr. at 389, 395, 423-24.

[361] *See* Act of May 25, 2013, 83rd Leg., R.S., ch. 787 (S.B. 1364).

[362] SWEPCO Ex. 17 (Hodgson Dir.) at 11; Staff Ex. 3 (Stark Dir.) at 30.

the use of accelerated depreciation creates tax-purpose losses that cannot be used to offset taxable income in a given year, the amount of taxes not being offset (*i.e.*, the amount of the NOLC times the tax rate) is recorded as a "NOLC ADFIT" asset, offsetting the ADFIT liability. This treatment reflects that this amount of depreciation-related ADFIT has not provided the "loan" of interest-free deferred tax payments to the utility and that, correspondingly, the NOLC (rather than the deferral of tax payment) will benefit customers in future years, by offsetting the taxes as they come due.[363] In fact, as both SWEPCO and Staff recognize, a series of IRS private letter rulings (not precedential as a formal matter, but often relied upon) have determined that to the extent an NOLC ADFIT asset is attributable to accelerated depreciation, it must be included in rate base in order to comply with normalization requirements.[364] The basic reasoning, as Staff's Ms. Stark acknowledged, is that the customer benefit associated with ADFIT (lower utility rates) should occur no faster than when the deferred taxes actually come due (as opposed to being offset by a NOLC) over the life of the associated assets.[365]

It is in this legal context that SWEPCO proposes its adjustment, which more specifically entails the deduction of a $455,122,490 NOLC ADFIT asset from its ADFIT balance, thereby increasing rate base by the same amount.[366] While having no quarrel with the proposed adjustment otherwise, Staff contends it is improper, and should be disallowed, in light of some additional circumstances relating to the NOLC ADFIT asset.[367] Namely, it is undisputed that SWEPCO was paid for the NOLC ADFIT asset—apparently the same total amount of $455,122,490[368]—and that its financial books at test-year end accordingly reflected a zero balance for NOLC ADFIT assets.[369]

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363 SWEPCO Ex. 17 (Hodgson Dir.) at 12-14; Staff Ex. 3 (Stark Dir.) at 30-31; Tr. at 391-92.

364 SWEPCO Ex. 17 (Hodgson Dir.) at 12-14; SWEPCO Ex. 45 (Hodgson Reb) at 12; Staff Ex. 3 (Stark Dir.) at 30-31.

365 Tr. at 401-02.

366 SWEPCO Ex. 17 (Hodgson Dir.) at 27.

367 SWEPCO Initial Brief at 19-22; Tr. at 392-95; Staff Ex. 3 (Stark Dir.) at 31.

368 Tr. at 268-73; Staff Ex. 42 (SWEPCO Response to Staff RFI 9-20); Staff Ex. 3 (Stark Dir.) at 37-38, Attachment RS-38.

369 Tr. at 272-73; Staff Ex. 40 (SWEPCO Response to Staff RFI 9-15).

The payments were made to SWEPCO pursuant to a tax-allocation agreement among SWEPCO and other members of a consolidated group for which AEP files federal income tax returns.[370] The agreement states that "[a] member with net positive tax allocation shall pay the holding company the net amount allocated, while a tax loss member with a net negative tax allocation shall receive current payment from the holding company in the amount of its negative allocation."[371] It further provides that "[t]he payment made to a member with a tax loss should equal the amount by which the consolidated tax is reduced by including the member's net corporate tax loss in the consolidated tax return."[372] Thus, pursuant to this agreement, SWEPCO was paid for the use of its NOLC ADFIT asset in offsetting otherwise-taxable income earned by other AEP affiliates, thereby reducing the taxable income of the consolidated group as a whole.

Staff argues that SWEPCO cannot use the NOLC ADFIT asset to offset ADFIT (and increase rate base) because SWEPCO has already sold the asset and taken it off its books, which Ms. Stark thought akin to the effects of selling accounts receivable to obtain cash more quickly than if it waited for customers to pay.[373] Ms. Stark also pointed out that SWEPCO's proposed accounting treatment of its NOLC ADFIT differed from the Company's approach, later approved by the Commission, in Docket No. 46449.[374] In that earlier rate case, she observed, SWEPCO's financial books at test-year end reflected, as in this case, an NOLC ADFIT balance of zero as a result of SWEPCO's participation in the AEP consolidated tax-allocation agreement. Yet in that case, SWEPCO did not propose or make any adjustments to recognize NOLC ADFIT again and thereby include it in rate base, as it seeks to do now.[375] Staff further touts this aspect of Docket No. 46449 as reflecting the Commission's "established" and "accepted" method of interpreting PURA § 36.060 and making a stand-alone tax calculation.[376] However, Staff does not identify any

[370] SWEPCO Ex. 45 (Hodgson Reb.) at 2; Staff Ex. 41 (SWEPCO Response to Staff RFI 9-17), Attachment 1 at 2. To be precise, SWEPCO apparently received the total amount through a series of payments. Tr. at 272.

[371] Staff Ex. 41 (SWEPCO Response to Staff RFI 9-17), Attachment 1 at 2.

[372] Staff Ex. 41 (SWEPCO Response to Staff RFI 9-17), Attachment 1 at 2.

[373] Staff Ex. 3 (Stark Dir.) at 31, 39-40.

[374] Staff Ex. 3 (Stark Dir.) at 33-34.

[375] Staff Ex. 3 (Stark Dir.) at 34-35; Staff Ex. 43 (SWEPCO response to Staff RFI 9-21).

[376] Staff Initial Brief at 29; Staff Reply Brief at 16.

other case in which the Commission applied the statute's current version, let alone had occasion to address the specific contentions SWEPCO makes now.

SWEPCO counters that the Commission cannot validly recognize the payments SWEPCO received for the NOLC ADFIT asset or the corresponding zero book balance in determining SWEPCO's tax expense. This is so, SWEPCO reasons, because PURA § 36.060 requires a "stand-alone" calculation reflecting SWEPCO's own benefits and burdens in serving its customers, whereas the payment was a product of the activities and attendant tax consequences of other affiliates within the AEP consolidated group.[377] In fact, in the view of SWEPCO witness David Hodgson—AEPSC's Tax Accounting and Regulatory Support Manager, who presented SWEPCO's tax schedules and federal income tax-expense calculations[378]—the Commission would, by recognizing the payments and disallowing SWEPCO's adjustment, make the "exact type of consolidated tax adjustment" made under the former version of PURA § 36.060 and that the Texas Legislature prohibited through its 2013 amendments to that statute.[379]

Staff disputes that current PURA § 36.060 would bar the Commission from following the same approach as in Docket No. 46449 and recognizing the tax-allocation payments, the resultant zero balance for NOLC ADFIT, and thus no offset.[380] Staff observes that Section 36.060 (aside from a heading, "Consolidated Income Tax Returns," which cannot singularly expand or limit the statute's meaning[381]) does not mention consolidated income tax returns or any special status conferred on payments made incident thereto. Instead, Section 36.060 merely prohibits the lowering of a utility's income-tax expense based on an income-tax benefit related to "an expense not allowed to be included in utility rates or an investment . . . not included in the utility rate base."[382] This language, in Staff's view, reflects an underlying concern with a mathematically

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[377] SWEPCO Initial Brief at 23-24; SWEPCO Reply Brief at 23-28.

[378] SWEPCO Ex. 17 (Hodgson Dir.) at 2-7.

[379] SWEPCO Ex. 45 (Hodgson Reb.) at 3.

[380] Staff Initial Brief at 14-15.

[381] *See* Tex. Gov't Code § 311.024.

[382] Staff Initial Brief at 16.

imputed form of "consolidated tax savings adjustment" that the Commission would impose under the prior version.[383] The situation here is different, Staff urges, involving "actual financial transactions with true economic substance," "actual operating results of SWEPCO as recognized by GAAP and FERC accounting," and "true economic costs of the utility."[384] Staff disputes that Section 36.060 requires the Commission to "ignore" these attributes merely because "those transactions are the result of a consolidated tax return."[385]

Nor does SWEPCO's "stand-alone" calculation take account of all of the effects of the tax-allocation payments, Staff insists. As Ms. Stark articulated this concern, she urged that SWEPCO is "cherry-picking" one item of a stand-alone tax calculation—seeking to add the NOLC ADFIT asset of $455,122,490 (rather than zero) into rate base—yet not correspondingly removing from rate base assets that were funded by the $455,122,490 tax-allocation payments.[386] The result, she maintained, would be that SWEPCO includes in rate base both (1) the $455,122,490 NOLC ADFIT asset and (2) $455,122,490 in other assets that are now in its rate base, financed by the tax-allocation payments, thereby enabling SWEPCO to earn a return on the same $455,122,490 twice.[387] And this net addition of $455,122,490 to rate base, Ms. Stark added, would occur "just because of the filing of the consolidated tax return and for no other reason," by virtue of the tax attributes of SWEPCO's affiliates. She further contends that he correspondingly higher rates charged to SWEPCO customers would effectively be subsidizing the operations of those affiliates by lowering their taxes.[388]

To support Staff's premise that SWEPCO would effectively be earning a return on the amount of the tax-allocation payments, in addition to the NOLC ADFIT, Ms. Stark referenced

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[383] Staff Initial Brief at 16.

[384] Staff Initial Brief at 17.

[385] Staff Initial Brief at 17.

[386] Tr. at 392-94, 396, 419-20.

[387] Tr. at 393-94, 419-20.

[388] Tr. at 394, 420; Staff Ex. 3 (Stark Dir.) at 40-41.

rebuttal testimony from Mr. Hodgson acknowledging that SWEPCO would have used the payment to invest in plant assets.[389] Mr. Hodgson's specific testimony on this point is the following:

> Staff has pointed out in its testimony, and [SWEPCO] has acknowledged, that [SWEPCO] has received cash as a result of its tax allocation agreement. Being a rate regulated utility, [SWEPCO] must prudently invest its capital into plant that is to the benefit of providing service to its customers. The Commission reviews the prudency of those investments when approving [SWEPCO's] rates. To the extent that [SWEPCO] received cash through its tax allocation agreement, [SWEPCO] would not use that additional capital to build plant beyond what would be prudent in serving its customers. Instead, the cash received by [SWEPCO] through the tax allocation agreement would reduce the otherwise needed capital to fund those prudent investments. As a result, [SWEPCO] would need less capital through debt and equity than it would absent the cash received through the tax allocation agreement.[390]

Or as the argument is restated in SWEPCO's briefing:

> The consolidated tax sharing agreement payments did not result in any incremental spend[ing] on capital investments that would not have otherwise occurred. The only thing that changes was that SWEPCO did not have to increase its debt and equity to fund the projects. As a result, customers received the benefit of the reduced cost of capital (i.e., an equity investment with no assigned cost). . . . The consolidated tax sharing agreement payments are not added to the debt/equity included in rates.[391]

In short, SWEPCO maintains that the tax-allocation payments should not be considered to increase rate base, as Staff assumes. This view, in turn, was a key premise in a larger analysis in which Mr. Hodgson sought to establish that Staff, in its expressed concerns about the rate impact of the NOLC ADFIT, has overlooked a "rate impact" from the tax-allocation payments (or, more

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389 Tr. at 394, 419-20.

390 SWEPCO Ex. 45 (Hodgson Reb.) at 14-15.

391 SWEPCO Reply Brief at 27-28.

precisely, the absence of a rate impact, assuming the payments does not increase rate base), such that recognizing the NOLC ADFIT would have a neutral impact on SWEPCO's rates.[392]

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[392] SWEPCO Ex. 45 (Hodgson Reb.) at 14-19. To illustrate his claims of a rate-neutral impact, Mr. Hopkins offered examples involving two hypothetical utilities, one with a tax-allocation agreement, the other with no such agreement. The starting points for both were pre-tax book income of $10,000 and an $11,000 deduction for accelerated depreciation, which would yield a $1,000 NOL and—all other things being equal—$2,310 in ADFIT (21% corporate tax rate times $11,000), and NOLC ADFIT of $210 (21% tax rate times the $1,000 NOL). He assumed a basic capital structure of $100,000 each in debt and equity, and a ratio of 4% for the debt component and 10% for the equity component, for respective WACC of 2% and 5%, for a total WACC of 7%.

For Mr. Hodgson's first hypothetical, involving a utility with no tax-allocation agreement, he posited that the ADFIT would reduce the debt and equity capital necessary to finance the plant as follows:

	Initial Capital	ADFIT	Adjusted Capital
Debt	100,000	<1,050>	98,950
Equity	100,000	<1,050>	98,950
Total	200,000	<2,100>	197,900

and that net rate base, factoring in the NOLC ADFIT offset of ADFIT, would be:

Plant	$200,000
ADFIT	<2,310>
NOLC ADFIT	210
Net Rate Base	$197,900

Multiplying the net rate base by the 7% WACC yielded a revenue requirement of $13,853.

For Mr. Hodgson's second hypothetical, involving a utility with a tax-allocation agreement, he added to the first hypothetical the element of a $210 cash payment to the utility for its $210 NOLC. Assuming the utility would use this additional cash, as with ADFIT, to reduce debt or equity capital otherwise needed to finance the plant, and in a manner maintaining the same capital ratios, Mr. Hodgson calculated the following new adjusted capital amount:

	Initial Capital	ADFIT	Tax-Alloc. Cash Pymt.	Adjusted Capital
Debt	100,000	<1,050>	<105>	98,845
Equity	100,000	<1,050>	<105>	98,845
Total	200,000	<2,100>	<210>	197,690

He then assumed—with intent to illustrate the effects of Staff's recommendations—that the NOLC ADFIT was reduced to zero by virtue of the tax-allocation payment:

Plant	$200,000
ADFIT	<2,310>
NOLC ADFIT	0
Net Rate Base	$197,690

Multiplying this net rate base by the 7% WACC yielded a revenue requirement of $13,838, less than the $13,853 revenue requirement in the first hypothetical.

Mr. Hodgson then modified the second hypothetical by adding a further adjustment, intended to represent SWEPCO's proposal, that removed the effect of the $210 tax-allocation payment on debt and equity requirements:

It followed from this conclusion that excluding the NOLC ADFIT from rate base, as Mr. Hodgson testified, would “break the connection between the tax expenses in the cost of service and the ADFIT in rate base,” violating “the consistency requirements of the normalization rules.”[393] The two are “inextricably linked,” he elaborated, noting that:

> rate base is reduced by ADFIT because it represents the cumulative amount of deferred tax expense that customers have paid [SWEPCO] in excess of income [SWEPCO] is currently obligated to pay the federal government. . . . [I]n order to achieve a balance between the rate base reduction and the amount of cash provided through rates for deferred tax expense, it is necessary to include the [NOLC ADFIT] asset in the overall ADFIT balance. To exclude the [NOCL ADFIT] asset would result in rate base being reduced by an amount greater than the deferred taxes [SWEPCO] received through rates.[394]

Mr. Hodgson further opined that Staff’s rationale for excluding the NOLC ADFIT from rate base based on the tax-allocation payments “results in the cross-subsidization of costs/benefits from [SWEPCO’s] affiliate companies,” as the customers of affiliate companies are effectively funding a portion of rate-base reduction otherwise based on the deferred taxes funded by SWEPCO customers.[395]

	Initial Capital	ADFIT	Tax-Alloc. Cash Pymt.	Proforma Adjustment	Adjusted Capital
Debt	100,000	<1,050>	<105>	105	98,950
Equity	100,000	<1,050>	<105>	105	98,950
Total	200,000	<2,100>	<210>	210	197,900

Plant	$200,000
ADFIT	<2,310>
NOLC ADFIT	210
Net Rate Base	$197,900

Multiplying the $197,900 net rate base by the 7% WACC yielded a revenue requirement of $13,853—the same revenue requirement as in the original hypothetical.

393 SWEPCO Ex. 45 (Hodgson Reb.) at 5.

394 SWEPCO Ex. 45 (Hodgson Reb.) at 12.

395 SWEPCO Ex. 45 (Hodgson Reb.) at 12.

SWEPCO presented additional testimony on the normalization issue from tax attorney Bradley Seltzer. He opined that the consistency requirement "implicitly and effectively require[s] use of the stand-alone approach to focus exclusively on the utility when computing the four related cost of service ratemaking items implicated by the normalization rules, namely regulatory depreciation expense, regulatory tax expense, [ADFIT], and rate base."[396] He echoed Mr. Hodgson's basic assessment that Staff, not SWEPCO, was seeking to "cherry pick[] one element of the inextricably tied four prongs of normalization," creating a "substantial risk of a violation of the normalization consistency rules" and a likelihood that the IRS would so conclude.[397]

Mr. Seltzer added that intercompany payments under tax-sharing agreements, such as with SWEPCO and other AEP affiliates, "may affect basis and/or earnings or profits, but the payments themselves are a nonevent for tax purposes," as the common parent of the group is the relevant "taxpayer" and group members are jointly and severally liable for the consolidated tax liability.[398] "Thus," he concluded, "since normalization is based on the extension of a loan <u>from the Federal Government</u> for the deferred taxes, the IRS is entirely indifferent to whether and how the group allocates liabilities amongst its members," and "[a]ny payments made or received by SWEPCO pursuant to the tax sharing agreement are simply irrelevant to the normalization issue."[399]

Nor, SWEPCO adds, should Docket No. 46449 be viewed as any sort of precedent barring its proposed adjustment.[400] Mr. Hodgson observed that the Commission never had occasion in Docket No. 46449 to rule on the proper treatment of SWEPCO's NOLC ADFIT, as the issue was never raised.[401] He further testified that SWEPCO first came to the opinion that the adjustment was warranted in light of normalization rules and PURA § 36.060 while preparing its rate filing in

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[396] SWEPCO Ex. 44 (Seltzer Reb.) at 6.

[397] SWEPCO Ex. 44 (Seltzer Reb.) at 9.

[398] SWEPCO Ex. 44 (Seltzer Reb.) at 7.

[399] SWEPCO Ex. 44 (Seltzer Reb.) at 7 (emphasis in original).

[400] SWEPCO Initial Brief at 24-25; SWEPCO Reply Brief at 23-24.

[401] SWEPCO Ex. 45 (Hodgson Reb.) at 19-20.

this case.[402] Mr. Seltzer added that "it is not uncommon for utilities to utilize procedures and adjustments that create potential normalization concerns that are only discovered and evaluated after one or more dockets have concluded," sometimes after decades and multiple cases in which they have been incorrectly computing deferred taxes.[403] In fact, he observed, the IRS had provided a safe harbor for taxpayers to correct their respective violations, provided they did so in their first available next rate case.[404] Accordingly, he explained, SWEPCO is raising its concerns in the context of its first next available rate case—this docket.[405]

The key weakness in SWEPCO's argument, as Staff argues, is the premise that the tax-allocation payments should be deemed to have no impact on its rate base despite Mr. Hodgson's acknowledgment that SWEPCO's rate base now includes assets that were funded by the payments.[406] While SWEPCO insists that there is no *net* change to rate base because the payments essentially substituted for debt and equity capital that otherwise would have financed the assets, the payments have still impacted rate base by financing assets that either would have been financed through other means or would not have been in rate base.

SWEPCO suggests a parallel between the tax-allocation payments and the cost-free capital represented by ADFIT.[407] Even if both are used similarly in financing rate base assets, SWEPCO's ADFIT differs from its tax-allocation payments in that the amount of depreciation-related ADFIT is specifically excluded from rate base under special rules founded on the notion that the ADFIT is effectively a loan from the federal government whose benefits should be shared with customers over the life of the associated assets. The tax-allocation payments, in contrast, represent cash from SWEPCO's affiliates (and, in turn, the affiliates' customers) exchanged for the use of SWEPCO's NOLC ADFIT in reducing the affiliates' taxes and their customers' cost of service. The rationales

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402 SWEPCO Ex. 45 (Hodgson Reb.) at 19; Tr. at 275-76.

403 SWEPCO Ex. 44 (Seltzer Reb.) at 7-8.

404 SWEPCO Ex. 44 (Seltzer Reb.) at 8.

405 SWEPCO Ex. 44 (Seltzer Reb.) at 8.

406 Staff Reply Brief at 13-16.

407 SWEPCO Reply Brief at 27.

that require exclusion of ADFIT from rate base do not extend to the rate-base assets SWEPCO has financed with its tax-allocation payments.

Thus, because the amount of the tax-allocation payments is now part of SWEPCO's rate base, it follows that SWEPCO's NOLC ADFIT adjustment would duplicate rather than preserve the rate impact of the NOLC ADFIT. In addition to the $455,122,490 now in rate base that SWEPCO received in exchange for the NOLC ADFIT, SWEPCO's rate base would be increased by $455,122,490 again, through the adjustment's offsetting of ADFIT by that amount. Nothing in PURA § 36.060 requires this double-counting, and allowing it would also violate normalization principles by doubling the rate impact of the NOLC ADFIT. Staff's proposal preserves the correct rate impact of the NOLC AFDIT now that the tax-allocation payments are in rate base.

In the very least, disallowing SWEPCO's proposed adjustment does not "clearly violate" normalization requirements. Although insisting that disallowance risks a violation finding, Mr. Seltzer ultimately acknowledged that the IRS has not directly addressed the fact pattern presented in this case.[408] Moreover, as Staff points out,[409] the IRS has recently issued guidance stating, with regard to determining the portion of NOLC attributable to depreciation, "[r]egulating commissions have expertise in this area, and any reasonable method . . . should generally be respected provided such method does not clearly violate normalization requirements."[410] Disallowing the adjustment to prevent a doubling of the NOLC ADFIT's rate-base impact is well within these bounds of reasonableness.

Accordingly, the ALJs recommend that the Commission disallow SWEPCO's proposed adjustment to deduct the $455,122,490 NOLC ADFIT asset from its ADFIT balance.[411]

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[408] SWEPCO Ex. 44 (Seltzer Reb.) at 9.

[409] Staff Reply Brief at 23.

[410] Rev. Proc. 2020-39 at 8.

[411] In light of this recommendation, the ALJs would not adopt Staff's alternative proposals to limit the adjustment solely to NOLC ADFIT accruing since Docket No. 46449, to reduce the amount of the adjustment in light of the TCJA rate cut, or to make the adjustment contingent on SWEPCO obtaining an IRS private-letter ruling. *See* Staff Initial Brief at 29-30; Staff Reply Brief at 18, 23; Staff Ex. 3 (Stark Dir.) at 35, 41-42.

2. Excess ADFIT

In contrast to ADFIT generally, which is a product of normalization and timing differences in the recognition of income and expenses for tax versus book purposes, the excess ADFIT is also a product of the TCJA's reduction of the corporate federal tax rate from 35% to 21%, effective January 1, 2018, and SWEPCO's current rates, which were predicated on the former 35% tax rate and thus collected more ADFIT from customers than the utility would ultimately pay the IRS at the 21% tax rate.[412] As SWEPCO acknowledges, it is obligated to return excess ADFIT to its customers and, per Docket No. 46449, it has been tracking the amount as a regulatory liability.[413] More specifically, SWEPCO has been tracking and must return two types of TCJA excess ADFIT to its customers: (1) "protected" or "normalized" excess ADFIT, which relates to temporary differences from depreciation and must be amortized over the remaining useful lives of the associated assets; and (2) "unprotected" excess ADFIT, which is not subject to the normalization limitations.[414] SWEPCO and Staff agree that the refund amount should thus include both (1) the accrued protected excess ADFIT amortization amounts for years 2018-2021, and (2) the unprotected excess ADFIT balance for all years.[415] The protected excess ADFIT amortization amounts for years 2022 going forward will be amortized through the income tax expense calculation over the associated assets' useful lives.[416]

Two disputes arose between SWEPCO and Staff concerning the utility's calculation of the excess ADFIT to be refunded to customers. The first concerns SWEPCO's proposed adjustment for NOLC ADFIT, discussed in the preceding section, which impacted both ADFIT generally and

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[412] SWEPCO Ex. 17 (Hodgson Dir.) at 21-22; Staff Ex. 3 (Stark Dir.) at 42.

[413] SWEPCO Initial Brief at 29; SWEPCO Ex. 17 (Hodgson Dir.) at 21-22; Staff Ex. 3 (Stark Dir.) at 42.

[414] SWEPCO Ex. 17 (Hodgson Dir.) at 22; Staff Ex. 3 (Stark Dir.) at 43, 45.

[415] SWEPCO Initial Brief at 29-30; SWEPCO Ex. 17 (Hodgson Dir.) at 22-23; Tr. at 403-05.

[416] SWEPCO Initial Brief at 29-30; SWEPCO Ex. 17 (Hodgson Dir.) at 22-23; Tr. at 403-05; Staff Ex. 3 (Stark Dir.) at 45.

excess ADFIT.[417] SWEPCO acknowledges that both of these facets of the NOLC ADFIT issue are controlled by the same analysis.[418]

The second dispute concerns what both SWEPCO and Staff now describe as confusion regarding the Texas Retail allocation factor and corresponding calculation of excess ADFIT provided by SWEPCO in its Application.[419] Staff recommended several adjustments based on its understanding of the allocation factor and resulting calculation.[420] In rebuttal, 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 TCJA's tax-rate change took effect.[421] SWEPCO also revised some sub-ledger information that updated the excess ADFIT amount to be returned to customers.[422] Staff acknowledges that SWEPCO's rebuttal testimony "cleared up this specific issue" and "does not oppose the use of the 35.01% Texas Retail allocation factor that was in effect when the tax laws were changed."[423]

In briefing, however, OPUC advocates the "updated" Texas jurisdictional factor of 36.94%, reasoning that the 35.01% factor "only captures the jurisdictional allocation as a snapshot in time when the TCJA was passed."[424] The ALJs agree with the assessment of SWEPCO's Mr. Hodgson that the 35.01% factor is appropriate, as it represented the Texas Retail allocation that was in effect when the TCJA's tax-rate cut took effect, thereby represents the proportion of the total company deferred taxes that were included in the rates of Texas consumers, and therefore is the proportion of excess ADFIT that should be returned to Texas customers.[425]

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[417] SWEPCO Ex. 45 (Hodgson Dir.) at 21-26; Staff Ex. 3 (Stark Dir.) at 44.

[418] SWEPCO Initial Brief at 30-31.

[419] SWEPCO Initial Brief at 30; Staff Reply Brief at 24.

[420] Staff Ex. 3 (Stark Dir.) at 42-47.

[421] SWEPCO Ex. 45 (Hodgson Reb.) at 25-26.

[422] Tr. at 564-65; SWEPCO Ex. 17B (Errata to Hodgson Dir.) at 24.

[423] Staff Reply Brief at 24.

[424] OPUC Initial Brief at 10.

[425] SWEPCO Ex. 45 (Hodgson Reb.) at 25.

Finally, there remains the question of how the excess ADFIT refund amount should be paid to customers. As discussed previously, SWEPCO proposes to use the entire excess ADFIT refund amount to offset the net book value of Dolet Hills, effecting an immediate recovery of most of the plant's remaining value. The ALJs have recommended instead that SWEPCO recover that value under its current amortization schedule, first as depreciation on the plant (alongside return and other costs of service) through the plant's retirement on December 31, 2021, and thereafter through amortized recovery from a regulatory asset. Thus, the ALJs must now address alternative methods or means by which SWEPCO should return the excess ADFIT refund amount. The parties addressing that issue have proposed four alternative options:

- Staff would have SWEPCO credit the balance against any amount owed by customers because of the March 18, 2021 relate-back date in this proceeding, and then return the remainder over a six-month period, with carrying charges at the same WACC that is determined in this proceeding.[426]

- ETEC/NTEC would require SWEPCO to refund the balance over the four-year period in which the rates are expected to remain in effect, with the balance offsetting rate base (and thereby lowering rates) in the meantime.[427]

- TIEC would require SWEPCO to refund the balance over one year, with carrying costs calculated using SWEPCO's regulated rate of return, on the balance from the relate-back date.[428]

- OPUC would require: (1) the eligible protected excess ADFIT to be returned through a one-time refund on SWEPCO customers' electricity bills within sixty days of the final order in this case; and (2) the unprotected excess ADFIT to be returned to customers through a separate tax-return rider, effective for two years from the effective dates of the rates approved in this proceeding.[429] OPUC further recommends that this tax-return rider include an additional monthly carrying charge equal to the monthly WACC approved by the Commission in this proceeding.[430]

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[426] Staff Ex. 3 (Stark Dir.) at 46-47.

[427] ETEC/NTEC Initial Brief at 10-11; ETEC/NTEC Ex. 1 (Hunt Dir.) at 7-8.

[428] TIEC Ex. 4 (LaConte Dir.) at 14-17; Tr. at 356-57.

[429] OPUC Initial Brief at 9-10; OPUC Ex. 1 (Cannady Dir.) at 53-54.

[430] OPUC Initial Brief at 10.

The ALJs find it most reasonable to return the currently refundable excess ADFIT to customers promptly, as opposed to extending those refunds over a period of years. As TIEC witness LaConte observed, SWEPCO had been accruing and owing excess ADFIT for three years.[431] Moreover, prompt refund is more likely to return the excess ADFIT to the same customers who overpaid the taxes. As to specific method, the ALJs recommend Staff's approach, as it would accomplish the refunds in no more than six months while having the added benefit of eliminating or offsetting any surcharges that customers would owe due to the relate-back date, in effect an immediate refund of the offsetting amount. Until the excess ADFIT is fully refunded, the balance should accrue carrying costs equal to SWEPCO's WACC, as Staff and other parties also advocated.

In the event the Commission rejects SWEPCO's proposal to offset the refundable excess ADFIT against Dolet Hills' net book value, SWEPCO's Mr. Baird proposed that the Commission adopt Staff's recommendation and that any refunds after offsetting the relate-back surcharge be handled through a rate rider.[432] He observed that "a separate rider makes more sense," as "[t]he two components of the [excess] ADFIT are fixed, and not ongoing, so they should not be included in base rates," and would also "allow for an exact refund, including applicable carrying costs."[433] The ALJs agree and recommend that a rider be used.

D. Accumulated Depreciation [PO Issue 12]

SWEPCO's witness Cash and also Mr. Baird testified concerning SWEPCO's calculations of depreciation rates and accumulated depreciation amounts.[434] They explained that because SWEPCO operates in multiple jurisdictions—FERC, Arkansas, and Louisiana, in addition to Texas—the Company records depreciation expense based on a composite rate that results in a

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[431] TIEC Ex. 4 (LaConte Dir.) at 17.

[432] SWEPCO Ex. 36 (Baird Reb.) at 24.

[433] SWEPCO Ex. 36 (Baird Reb.) at 24.

[434] SWEPCO Ex. 6 (Baird Dir.) at 43-44, SWEPCO Ex. 16 (Cash Dir.) at 8.

blended accumulated depreciation balance, necessitating adjustments to reflect the amount of accumulated depreciation as if SWEPCO had applied the Commission-approved rates to all of its depreciable plant.[435] No party has contested SWEPCO's accumulated-depreciation calculation or adjustments, which the ALJs recommend be approved.

E. Regulatory Assets and Liabilities [PO Issues 19, 21, 22, 41, 50]

1. Self-Insurance Reserve [PO Issues 19, 40]

In its Application, SWEPCO requests to establish a self-insurance reserve under PURA § 36.064.[436] Through that provision, the Texas Legislature has authorized an electric utility to self-insure all or part of a utility's potential liability or catastrophic property loss that could not have been reasonably anticipated and included under operating and maintenance expenses.[437] The Commission "shall approve a self-insurance plan under [PURA § 36.064] if [it] finds that: (1) the coverage is in the public interest; (2) the plan, considering all costs, is a lower cost alternative to purchasing commercial insurance; and (3) ratepayers will receive the benefits of the savings."[438] The Commission's Cost of Service Rule describes a "self-insurance plan" as "a plan providing for accruals to be credited to reserve accounts," which "are to be charged with property and liability losses which occur, and which could not have been reasonably anticipated and included in operating and maintenance expenses, and are not paid or reimbursed by commercial insurance."[439] The rule specifies that the Commission shall consider approving a self-insurance plan in a rate case in which expenses or rate-base treatment is requested for such a plan. The Commission will

[435] SWEPCO Ex. 6 (Baird Dir.) at 43-44, SWEPCO Ex. 16 (Cash Dir.) at 8.

[436] SWEPCO Ex. 4 (Brice Dir.) at 10-12.

[437] PURA § 36.064(a).

[438] PURA § 36.064(b).

[439] 16 TAC § 25.231(b)(1)(G); *see also* PURA § 36.064(g) (Commission "shall adopt rules governing self-insurance under this section").

approve such a plan "to the extent it finds it to be in the public interest."[440] The rule further prescribes the following requirements regarding the finding of "public interest":

> In order to establish that the plan is in the public interest, the electric utility must present a cost benefit analysis performed by a qualified independent insurance consultant who demonstrates that, with consideration of all costs, self-insurance is a lower-cost alternative than commercial insurance and the ratepayers will receive the benefits of the self insurance plan. The cost benefit analysis shall present a detailed analysis of the appropriate limits of self insurance, an analysis of the appropriate annual accruals to build a reserve account for self insurance, and the level at which further accruals should be decreased or terminated.[441]

SWEPCO's Mr. Brice testified that the idea of a self-insurance reserve was that "customers pay a representative amount each year toward the reserve and that the variability of losses will be averaged out over time through use of the reserve," which in his view was "the fairest means of ensuring over time that customers pay for only actual costs incurred and that [SWEPCO] recovers only its actual costs," and therefore in the best interests of both.[442] As for the particulars of SWEPCO's proposed self-insurance reserve, Mr. Baird testified that SWEPCO's proposal is patterned after a catastrophe reserve approved by the Commission for AEP Texas in various rate cases.[443] He explained that SWEPCO will utilize the reserve for a major storm for which incremental expenses exceed $500,000 for a single event (as opposed to "small storms") and relate to SWEPCO's Texas operations (*i.e.*, a $1 million storm in East Texas but not one occurring in Arkansas).[444] Mr. Baird opined that this self-insurance reserve was warranted because major storm costs are beyond SWEPCO's control or ability to predict.[445]

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[440] 16 TAC § 25.231(b)(1)(G); *see also* PURA § 36.064(g) (Commission "shall adopt rules governing self-insurance under this section").

[441] 16 TAC § 25.231(b)(1)(G).

[442] SWEPCO Ex. 4 (Brice Dir.) at 11.

[443] SWEPCO Ex. 6 (Baird Dir.) at 12-13.

[444] SWEPCO Ex. 6 (Baird Dir.) at 13.

[445] SWEPCO Ex. 6 (Baird Dir.) at 13.

Mr. Baird also described the accounting SWEPCO would implement for the reserve. He explained that SWEPCO would fund the reserve through monthly charges against its O&M expense and charge against the reserve when an eligible major storm event caused more than $500,000 in incremental O&M losses, which would include costs and charges incurred in restoration work in response to the storm but excluding capitalized costs and regular labor.[446] Mr. Baird added that in future rate filings, SWEPCO would treat the reserve amount as a reduction to its Texas jurisdictional rate base if the amounts credited to the reserve exceed the charges against it (*i.e.*, there is an excess or regulatory liability) and add the reserve amount to rate base if charges exceed credits (*i.e.*, there is a shortage or regulatory asset).[447]

In further support of its proposal, SWEPCO presented the testimony of Gregory Wilson, a consulting actuary specializing in property-casualty actuarial matters.[448] Mr. Wilson proposed an annual accrual of $1,689,700 to fund the reserve and a target reserve level of $3,560,000.[449] He explained that the annual accrual figure included two components, the first of which was $799,700 to provide for average annual expected losses from storms with transmission and distribution losses of at least $500,000.[450] Mr. Wilson stated that $799,700 represented the expected value of the annual losses incurred from all storm damage, calculated by running the loss history from 2000 through March 2021 through a "Monte Carlo simulation" (a statistical technique incorporating a computer program to simulate loss experience over a longer period of time), then adjusted to reflect current conditions and current cost levels.[451]

But because this figure represented only the average annual expected loss from storm damage, Mr. Wilson added, additional reserves needed to be built up to account for extreme or catastrophic storm events that could occur in a given year and vary significantly from the average

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[446] SWEPCO Ex. 6 (Baird Dir.) at 13-14.

[447] SWEPCO Ex. 6 (Baird Dir.) at 14.

[448] SWEPCO Ex. 28 (Wilson Dir.) at 1-2.

[449] SWEPCO Ex. 28 (Wilson Dir.) at 4.

[450] SWEPCO Ex. 28 (Wilson Dir.) at 4.

[451] SWEPCO Ex. 28 (Wilson Dir.) at 5-6.

losses.[452] According to Mr. Wilson, his recommended target reserve level of $3,560,000 represented the amount of O&M expense expected to result from a 25-year storm with total losses of at least $500,000, calculated through a Monte Carlo simulation.[453] He opined that this reserve level should be carried by SWEPCO to make an actuarially sound provision for coverage of self-insured losses.[454] Mr. Wilson further proposed that this reserve level be built up over four years (corresponding to SWEPCO's anticipated rate-filing schedule), with one-fourth of the total paid in each year ($890,000).[455] This figure represented the second component of Mr. Wilson's recommended annual accrual, and with the $799,700 for average annual expected losses comprised the $1,689,700 total annual accrual.[456]

Three intervenors oppose some aspect of SWEPCO's self-insurance reserve proposal. TIEC and OPUC contend that SWEPCO's target reserve and annual accrual should be smaller than SWEPCO proposes.[457] CARD, later joined by TIEC, argue that SWEPCO's proposal should be disallowed altogether because SWEPCO failed to present a valid or sufficient cost-benefit analysis as required by Commission rule.[458] The ALJs agree with CARD and TIEC that SWEPCO's proof falls short of this requirement.

Under the Commission's rule, SWEPCO was required to "present a cost benefit analysis performed by a qualified independent insurance consultant" who, among other things, "demonstrates that, with consideration of all costs, self-insurance is a lower-cost alternative than commercial insurance and the ratepayers will receive the benefits of the self insurance plan."[459] To meet this requirement and others under the rule, SWEPCO relied on the testimony of

[452] SWEPCO Ex. 28 (Wilson Dir.) at 5, 7-8.

[453] SWEPCO Ex. 28 (Wilson Dir.) at 8.

[454] SWEPCO Ex. 28 (Wilson Dir.) at 8.

[455] SWEPCO Ex. 28 (Wilson Dir.) at 9.

[456] SWEPCO Ex. 28 (Wilson Dir.) at 9.

[457] OPUC Initial Brief at 5-6; OPUC Ex. 1 (Cannady Dir.) at 45-47; TIEC Initial Brief at 15-16; TIEC Ex. 4 (LaConte Dir.) at 18-22.

[458] CARD Initial Brief at 11-12; CARD Ex. 2 (M. Garrett Dir.) at 37-39; TIEC Initial Brief at 13-15.

[459] 16 TAC § 25.231(b)(1)(G).

Mr. Wilson, and there is no dispute that he is a "qualified independent insurance consultant." To demonstrate that, with consideration of all costs, self-insurance is a lower-cost alternative than commercial insurance and the ratepayers will receive the benefits of the self-insurance plan, Mr. Wilson evaluated (1) "the manner in which insurance companies set premiums" and (2) "an actual comparison to estimated insurance premiums for the self-insurance coverage."[460] Regarding the first consideration, Mr. Wilson testified that a self-insurance reserve would avoid incurring costs incurred by insurance companies beyond those merely for losses and loss-related expenses, such as premium taxes and other state-imposed fees, a profit, commission payments to insurance agents or brokers who placed the business, underwriting costs, marketing, and overhead.[461] As for "an actual comparison to estimated insurance premiums for the self-insurance coverage," Mr. Wilson's testimony consisted of the following:

> Comparing the cost of self-insurance versus the cost of buying insurance is another way to establish that it is more cost effective for SWEPCO to self-insure. My understanding is that private coverage continues to be prohibitively expensive. As a result, the only conclusion is that commercial insurance is not economically available and the only way to protect SWEPCO's assets is through self-insurance.[462]

During the hearing, Mr. Wilson acknowledged that he had not "present[ed] a number" to quantify the cost of commercial insurance.[463] However, he stated his belief that commercial insurance would *always* be more expensive than self-insurance for a Texas utility with respect to the type of coverage for transmission and distribution lines that SWEPCO's proposal would address.[464] As for the basis for this belief, he testified that "I think the last time I remember getting a quote is probably three or four years ago," but he could not remember which insurance company had provided it, and believed it would have been for a utility other than SWEPCO.[465] On this

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[460] SWEPCO Ex. 28 (Wilson Dir.) at 10.

[461] SWEPCO Ex. 28 (Wilson Dir.) at 11.

[462] SWEPCO Ex. 28 (Wilson Dir.) at 12.

[463] Tr. at 284, 290, 292.

[464] Tr. at 286-87.

[465] Tr. at 289-90.

occasion, according to Mr. Wilson, he "was told that the deductible alone was worth more than the self-insurance cost, and the premium was even higher."[466] He added that "[s]ince then I've had a lot of problems getting companies to [give] quotes because the brokers don't want to give the quotes knowing that it's going to be very expensive and knowing that people aren't going to buy it."[467] Within a month of his testimony, Mr. Wilson added, he had communicated with someone with SWEPCO (he couldn't recall whom) to form his "understanding that private coverage continues to be prohibitively expensive."[468] However, he did not know whether SWEPCO had conducted a study, survey, or any analysis about the cost of commercial insurance and acknowledged that he had not identified any specific insurance companies or how much more expensive their insurance would have been.[469]

SWEPCO maintains that it is enough for Mr. Wilson to state that commercial insurance would always be more expensive than self-insuring, further insisting that "[t]here is simply no contested fact issue whether self-insurance is lower cost than commercial insurance."[470] Yet even if this testimony, founded as it is on anecdotal accounts and consisting only of broad generality, would suffice as competent evidence that commercial insurance is more expensive than self-insurance, the ALJs cannot conclude that it "present[s] *a cost benefit analysis* performed by a qualified independent insurance consultant who *demonstrates that, with consideration of all costs, self-insurance is a lower-cost alternative than commercial insurance*," as the Commission has required. In the very least, the analysis would need to demonstrate why or how the cost of commercial insurance would exceed the specific costs of SWEPCO's proposal, which are not inconsiderable and include establishing a reserve that more than doubles the annual cost levels.[471] There is simply nothing in the analysis to show why or how SWEPCO's specific costs, or any

[466] Tr. at 289-90.

[467] Tr. at 291.

[468] Tr. at 289-90.

[469] Tr. at 289-90.

[470] SWEPCO Reply Brief at 34.

[471] CARD Ex. 2 (M. Garrett Dir.) at 38.

other specific cost amount, would compare to commercial insurance alternatives.[472] Nor is there any demonstration that "the ratepayers will receive the benefits of the self insurance plan," also a requirement of the Commission's rule.

Because the cost-benefit analysis is made a prerequisite to the Commission's finding that a self-insurance plan is in the public interest,[473] and PURA requires that public-interest finding as a condition of plan approval,[474] the ALJs recommend that the Commission deny approval to SWEPCO's self-insurance plan.

2. Hurricane Laura Costs [PO Issues 36, 37, 38, 39]

SWEPCO requests authorization to charge its Texas jurisdictional Hurricane Laura restoration costs against the self-insurance reserve for which it is seeking approval.[475] No party has opposed this proposal, aside from the challenges brought by CARD and TIEC to the self-insurance reserve's approval. Because the ALJs have recommended that the Commission deny such approval due to the absence of the required cost-benefit analysis, the ALJs also recommend denial of SWEPCO's requested authorization to charge Hurricane Laura costs against that reserve.

VI. RATE OF RETURN [PO ISSUES 4, 5, 7, 8, 9]

A. Return on Equity [PO Issue 8]

The ROE is the return that investors require to make an equity investment in a firm. For regulated public utilities, regulation acts as a substitute for market competition in setting the

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472 The ALJs are required to rely only on the evidence and matters officially noticed, *see* Tex. Gov't Code § 2001.141(c), and both are lacking here with regard to the relative pricing.

473 16 TAC § 25.231(b)(1)(G).

474 PURA § 36.064(b).

475 SWEPCO Ex. 4 (Brice Dir.) at 11-12.

utility's ROE. The U.S. Supreme Court has set forth a minimum constitutional standard governing equity returns for utility investors:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[476]

Thus, a utility must have a reasonable opportunity to earn a return that is: (1) commensurate with returns on equity investments in enterprises having comparable risks; (2) sufficient to assure confidence in the financial soundness of the utility's operations; and (3) adequate to attract capital at reasonable rates, thereby enabling it to provide safe, reliable service. The allowed ROE should enable the utility to finance capital expenditures at reasonable rates and maintain its financial flexibility during the period in which the rates are expected to remain in effect.

SWEPCO, Staff, CARD, and TIEC presented experts who testified as to the appropriate ROE for SWEPCO given the current market conditions and SWEPCO's current financial situation. They used similar mathematical methodologies to estimate the appropriate ROE for SWEPCO, including the constant growth discounted cash flow (DCF) methodology, the multi-stage DCF methodology, versions of the risk premium approach, and the capital asset pricing model (CAPM). Each of these experts also addressed recent economic conditions and how they affect the mathematically derived recommendations.

[476] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944); *see also Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692-93 (1923) ("A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.").

Applying these analytical techniques resulted in varying ROE recommendations from the experts, as shown in the table below.

Summary of Witnesses' ROE Recommendations[477]

WITNESS	ROE RANGE		ROE RECOMMENDATION
	LOW	HIGH	
J. Randall Woolridge (CARD)	7.60%	9.15%	9.00%
Michael Gorman (TIEC)	8.90%	9.35%	9.15%
Mark Filarowicz (Staff)[478]	9.05%	9.35%	9.225%
Dylan D'Ascendis (SWEPCO)[479]	10.32%	11.43%	10.35%

In addition, Walmart presented testimony regarding recent ROEs approved in Texas and nationally, and recommended an ROE "no higher than 9.60%."[480] It is with this backdrop that the ALJs discuss the appropriate ROE for SWEPCO on a going forward basis, which the ALJs find is 9.45%.

1. Proxy Group

Because SWEPCO is not a publicly traded company, it is necessary to establish a group of companies that are publicly traded and comparable to SWEPCO in certain fundamental business and financial respects to serve as its "proxy" in the ROE estimation process. Both financial theory and legal precedent support the use of comparable companies within a proxy group to determine a

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[477] Staff Ex. 1 (Filarowicz Dir.) at 28; TIEC Ex. 3 (Gorman Dir.) at 54; CARD Ex. 4 (Woolridge Dir.) at 54; SWEPCO Ex. 8 (D'Ascendis Dir.) at Schedule DWD-1 at 2. OPUC and Nucor support the recommendations of intervenors and Staff. OPUC Initial Brief at 12-14; Nucor Initial Brief at 3-4.

[478] As discussed below, Mr. Filarowicz's recommended ROE includes a 12.5 basis point downward adjustment under PURA § 36.052 due to SWEPCO's alleged poor quality of service and management. Mr. Filarowicz's unadjusted ROE recommendation is 9.35%.

[479] In rebuttal, Mr. D'Ascendis updated his analysis, which resulted in a revised ROE range of 10.43% to 11.26%, but his overall ROE recommendation of 10.35% remained unchanged. SWEPCO Ex. 38 (D'Ascendis Reb.) at 9-10, Schedule DWD-1R at 2.

[480] Walmart Ex. 1 (Perry) at 4.

utility's ROE, and all of the ROE witnesses in this case who conducted mathematical analyses relied on proxy groups to estimate a required ROE for SWEPCO.

SWEPCO witness D'Ascendis performed his analyses using two proxy groups. First, the "Utility Proxy Group," which consisted of certain vertically integrated electric utilities in the Value Line Investment Survey (Value Line) that met a number of screening criteria.[481] His Utility Proxy Group included 14 companies, the makeup of which changed slightly on rebuttal because Mr. D'Ascendis removed one company, PNM Resources, Inc., that had agreed to a strategic merger, and added one company, Evergy, Inc., that at the time of his direct testimony was subject to rumors of a possible merger that did not materialize.[482]

Mr. D'Ascendis's second proxy group is the "Non-Price Regulated Proxy Group," which consisted of 45 domestic, non-price regulated firms that he concluded were comparable in total risk to the Utility Proxy Group.[483] To determine the comparable risk of the companies, he used two screening criteria: (1) their Beta coefficients (a measure of risk) must lie within plus or minus two standard deviations of the average unadjusted Beta coefficients of the Utility Proxy Group; and (2) the residual standard errors of the Value Line regressions which gave rise to the unadjusted Beta coefficients must lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.

In contrast, CARD, TIEC, and Staff used proxy groups composed only of electric utility companies. CARD witness Woolridge used two proxy groups. The first was based on different screening criteria than those used by Mr. D'Ascendis for his Utility Proxy Group and produced a proxy group of 27 publicly held electric utility companies. Dr. Woolridge's second proxy group is the same as Mr. D'Ascendis's initial Utility Proxy Group.[484] TIEC witness Gorman also used the

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[481] SWEPCO Ex. 8 (D'Ascendis Dir.) at 19-20.

[482] SWEPCO Ex. 38 (D'Ascendis Reb.) at 8.

[483] SWEPCO Ex. 8 (D'Ascendis Dir.) at 48-49.

[484] CARD Ex. 4 (Woolridge Dir.) at 18. Mr. Woolridge's testimony states that he used Mr. D'Ascendis's Utility Proxy Group, but he appears to have excluded PNM Resources, Inc. *See id.*, Exh. JRW-3.

same companies as in Mr. D'Ascendis's initial Utility Proxy Group, but with one exception—he removed PNM Resources, Inc. due to its reported merger.[485] Finally, Staff witness Filarowicz developed his proxy group by starting with all the electric utility companies covered by Value Line's Ratings and Reports and then applying slightly different screening criteria than those employed by Mr. D'Ascendis.[486] He arrived at a proxy group of 20 companies, which had some overlap with Mr. D'Ascendis's Utility Proxy Group.

There was little dispute among the parties about the composition of the proxy groups comprised of electric utility companies. However, CARD and TIEC urge rejection of Mr. D'Ascendis's Non-Price Regulated Proxy Group.[487] According to CARD, the companies in the group are not truly comparable to SWEPCO, and Mr. D'Ascendis used this separate group solely to inflate his recommendation regarding SWEPCO's ROE. CARD witness Woolridge identified two fundamental flaws with the group: (1) while many of the companies are large and successful, their lines of business are vastly different from the regulated electric utility business and they do not operate in a highly regulated environment; and (2) the DCF equity cost rate estimates are overstated due to an alleged upward bias in the earnings-per-share growth-rate forecasts of Wall Street analysts, which is particularly severe for non-utility companies.[488]

TIEC points out that Mr. D'Ascendis conducted the same analyses for both of his proxy groups, but the Non-Price Regulated Proxy Group produced higher ROE results.[489] In addition, Mr. D'Ascendis selected the companies in his Non-Price Regulated Proxy Group based solely on two quantitative measures—the Betas and the residual standard error of the regression—but when viewed from a qualitative perspective, the group includes many companies that simply are not comparable. For example, TIEC witness Gorman testified that the Non-Price Regulated Proxy

[485] TIEC Ex. 3 (Gorman Dir.) at 25.

[486] Staff Ex. 1 (Filarowicz Dir.) at 13-15.

[487] TIEC Initial Brief at 39-40; CARD Initial Brief at 20, 37-38. Staff also concurs with CARD's analysis of why Mr. D'Ascendis's Non-Price Regulated Proxy Group is inappropriate for estimating cost of equity. Staff Reply Brief at 29-30.

[488] CARD Ex. 4 (Woolridge Dir.) at 79.

[489] TIEC Initial Brief at 39.

Group contained large technology firms such as Apple and Alphabet, and that it is not credible to believe these firms have a similar operating and business risk as SWEPCO.[490] At the hearing, Mr. D'Ascendis acknowledged that the companies in his Non-Price Regulated Proxy Group operate in a competitive marketplace and do not provide essential services,[491] which, according to TIEC, makes them significantly more risky than regulated utilities.

Further, TIEC witness Gorman testified that to draw a valid comparison between SWEPCO and the Non-Price Regulated Proxy Group requires more than similar Betas; rather, it is necessary to show that the companies have comparable risk factors that are commonly used by investment professionals to compare risk between different investment alternatives.[492] TIEC asserts that Mr. D'Ascendis's use of a non-price-regulated proxy group has been rejected by other regulatory commissions, including the Public Service Commission of Maryland and the Pennsylvania Public Utility Commission,[493] and should similarly be rejected here.

However, SWEPCO contends that, because 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.[494] SWEPCO points out that Dr. Woolridge agreed that SWEPCO must compete with non-price-regulated companies for equity investment.[495] Thus, while these companies provide different products than SWEPCO, they represent SWEPCO's competition for equity investment. SWEPCO asserts that both of Mr. D'Ascendis's proxy groups have a comparable, though not identical, risk profile to SWEPCO.

490 TIEC Ex. 3 (Gorman Dir.) at 78.

491 Tr. at 903, 933.

492 TIEC Ex. 3 (Gorman Dir.) at 78.

493 TIEC Ex. 51, Pennsylvania Public Utility Commission Order dated April 16, 2020, at Bates 026; TIEC Ex. 52, Public Service Commission of Maryland Order dated March 22, 2019, at Bates 029-030.

494 SWEPCO Initial Brief at 37.

495 SWEPCO Reply Brief at 44 (citing Tr. at 1006).

2. DCF Analysis

a. Constant Growth DCF Analysis

To analyze SWEPCO's cost of equity capital, each of the ROE witnesses performed a DCF analysis. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_n}{(1+k)^n}$$

Where P_0 represents the current stock price; D_1, D_2, and D_n are the dividends in (respectively) years 1, 2, and future years (n); and k is the expected discount rate, or required ROE. If it is reasonable to assume that earnings and dividends will grow at a constant rate, the equation can be simplified and rearranged to ascertain the required ROE:

$$k = \frac{D_1}{P_0} + g$$

This is commonly referred to as the "constant growth DCF" model in which the first term (D_1/P_0) is the expected dividend yield and the second term (g) is the expected long-term growth rate.

For his DCF analysis, SWEPCO witness D'Ascendis calculated the dividend yield using his 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.[496] For the growth rate, Mr. D'Ascendis used analysts' five-year forecasts of earnings-per-share growth from Value Line, Zacks Investment Research (Zacks), and Yahoo! Finance (Yahoo!).[497] He explained that using analysts' earnings-

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[496] SWEPCO Ex. 8 (D'Ascendis Dir.) at 26.

[497] SWEPCO Ex. 8 (D'Ascendis Dir.) at 27.

per-share forecasts is appropriate because over the long run, there can be no growth in dividends per share without growth in earnings per share. The mean result of applying his constant growth DCF model to his Utility Proxy Group was 8.63%, the median result was 8.82%, and the average of the two was 8.73%.[498] In rebuttal, Mr. D'Ascendis updated his DCF analysis to reflect more current conditions, resulting in 9.32% as the average of his mean and median results.[499] Mr. D'Ascendis applied his constant growth DCF model in an identical manner to the Non-Price Regulated Proxy Group, which resulted in a common equity cost rate of 11.50% (updated to 11.62% on rebuttal).[500]

CARD witness Woolridge relied primarily on his DCF analysis to estimate SWEPCO's cost of equity.[501] He calculated the dividend yields for the companies in his proxy groups using the current annual dividend and the 30-day, 90-day, and 180-day average stock prices.[502] Dr. Woolridge next adjusted the dividend yield by one-half (1/2) of the expected growth to reflect growth over the coming year.[503] For his growth rate, Dr. Woolridge considered several sources. He reviewed Value Line's five- and ten-year historical and projected growth rate estimates for earnings per share, dividends per share, and book value per share.[504] He also used the average earnings-per-share growth-rate forecasts of Wall Street analysts as provided by Yahoo!, Zacks, and S&P Cap IQ.[505] Lastly, he assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.[506]

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[498] SWEPCO Ex. 8 (D'Ascendis Dir.) at 27.

[499] SWEPCO Ex. 38 (D'Ascendis Reb.) at 9, Table 1.

[500] SWEPCO Ex. 8 (D'Ascendis Dir.) at 49-50; SWEPCO Ex. 8 (D'Ascendis Reb.) at Schedule DWD-1R at 36.

[501] CARD Ex. 4 (Woolridge Dir.) at 28, 54.

[502] CARD Ex. 4 (Woolridge Dir.) at 29.

[503] CARD Ex. 4 (Woolridge Dir.) at 32-33.

[504] CARD Ex. 4 (Woolridge Dir.) at 33, 38-39.

[505] CARD Ex. 4 (Woolridge Dir.) at 33-34.

[506] CARD Ex. 4 (Woolridge Dir.) at 34.

Although he incorporates them in his analysis, Dr. Woolridge warned against relying exclusively on earnings-per-share forecasts prepared by Wall Street analysts in identifying a DCF growth rate, as they are upwardly biased.[507] According to Dr. Woolridge, this upward bias has been demonstrated by a number of academic studies, and was confirmed by a study he performed of forecasted versus actual long-term earnings-per-share growth rates for electric utilities over the 1985 to 2019 time period.[508] In that study, he found that the mean forecasted earnings-per-share growth rate was over 200 basis points above the actual earnings-per-share growth rate for utilities. To account for this bias, Dr. Woolridge adjusted his DCF growth rate downward.[509]

After considering these factors, Dr. Woolridge concluded that, for his proxy group, the appropriate projected growth rate is in the range of 5.0% to 5.5%, and he used the midpoint, 5.25%, as his DCF growth rate.[510] For Mr. D'Ascendis's Utility Proxy Group, Dr. Woolridge determined that the appropriate growth rate is 5.00%, which is the value he used in his DCF analysis for that group. Overall, Dr. Woolridge concluded that his DCF analysis suggested a cost of equity of 9.15% for his proxy group and 9.00% for Mr. D'Ascendis's Utility Proxy Group.[511]

TIEC witness Gorman's constant growth DCF model used his proxy group's 13-week average stock price and most recently reported quarterly dividends, along with a 5.46% growth rate, which was based on the mean of professional securities analysts' growth estimates for those companies.[512] The resulting average and median constant growth DCF returns for the proxy group were 9.43% and 9.35%, respectively.[513]

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[507] CARD Ex. 4 (Woolridge Dir.) at 36. CARD clarifies that Dr. Woolridge does not eschew the use of projected growth in earnings per share, but instead cautions against blind reliance on such projections because it leads to inflated ROEs. CARD Reply Brief at 14.

[508] CARD Ex. 4 (Woolridge Dir.) at 36-37.

[509] CARD Ex. 4 (Woolridge Dir.) at 38.

[510] CARD Ex. 4 (Woolridge Dir.) at 40.

[511] CARD Ex. 4 (Woolridge Dir.) at 41.

[512] TIEC Ex. 3 (Gorman Dir.) at 28-30, Exh. MPG-4.

[513] TIEC Ex. 3 (Gorman Dir.) at 30, Exh. MPG-5.

Mr. Gorman also ran a sustainable growth DCF model. This model is based on the principle that a utility's earnings will grow over time as it invests in additional utility plant and equipment, which enables it to earn its authorized return on a larger total rate base.[514] To estimate the sustainable growth in SWEPCO's rate base, Mr. Gorman looked to the proportion of total earnings that his proxy group retained for reinvestment rather than paying out in dividends.[515] He found that, on average, the sustainable growth rate for SWEPCO's proxy group is 4.50%.[516] Performing a DCF analysis using this sustainable growth rate resulted in average and median ROE results of 8.44% and 8.45%, respectively.[517]

Staff witness Filarowicz testified that the purpose of a DCF method is not to measure the rate at which SWEPCO will actually grow (which is primarily a function of economic conditions, management ability, regulatory actions, etc.), but rather the growth expectations that investors have embodied in the current price of the stock.[518] Because of the relationship between earnings growth and dividends growth, the growth rates Mr. Filarowicz used in his constant growth DCF analysis were the projected earnings growth rates for each of the proxy companies as forecasted by Value Line and Zacks.[519] Over the entire period Mr. Filarowicz modeled for his constant growth DCF analysis, he used the average of analysts' estimates for the proxy group's earnings growth over the next five years.[520] His constant growth DCF analysis produced ROE estimates ranging from 6.59% to 12.00%, with a 75th percentile of 9.38%.[521]

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514 TIEC Ex. 3 (Gorman Dir.) at 31.

515 TIEC Ex. 3 (Gorman Dir.) at 31, Exh. MPG-6.

516 TIEC Ex. 3 (Gorman Dir.) at 32, Exh. MPG-7

517 TIEC Ex. 3 (Gorman Dir.) at 32, Exh. MPG-8

518 Staff Ex. 1 (Filarowicz Dir.) at 19.

519 Staff Ex. 1 (Filarowicz Dir.) at 19.

520 Staff Ex. 1 (Filarowicz Dir.) at 18.

521 Staff Ex. 1 (Filarowicz Dir.) at 21, 28. For his DCF analyses, Mr. Filarowicz used the 75th percentile results in light of the current low interest rate environment, the proxy group he selected, and the nature of SWEPCO's operations. *Id.* at 21-22. He noted that the 75th percentile results are in accordance with recent trends in authorized ROEs approved by the Commission and across the country.

Of the intervenor and Staff ROE experts, only CARD witness Woolridge raised significant concerns with Mr. D'Ascendis's DCF analysis. In contrast, TIEC specifically notes that Mr. D'Ascendis's DCF analysis produces a reasonable estimate of SWEPCO's cost of equity (ranging from 8.73% in his direct testimony to 9.32% in his rebuttal testimony).[522]

CARD criticizes Mr. D'Ascendis for seemingly giving very little, if any, weight to his DCF results, pointing out that his mean DCF result for his proxy group is 8.73%, yet his overall recommendation is 167 basis points higher at 10.35%.[523] Had Mr. D'Ascendis given his resulting 8.73% any weight, CARD contends he would have arrived at a much lower recommendation for his estimated cost of equity. Additionally, CARD notes that Mr. D'Ascendis relied exclusively on Wall Street analysts' and Value Line's forecasts of growth rates in earnings per share, which Dr. Woolridge testified produce overly optimistic and upwardly biased results.[524] According to CARD, it is not likely that investors rely exclusively on such forecasts to the exclusion of other growth-rate measures in arriving at their expected growth rates for equity investments. Further, as Dr. Woolridge testified, the appropriate growth rate in the DCF model is the dividend growth rate rather than the earnings growth rate. Thus, in determining SWEPCO's ROE, and serving as a substitute for competition, it is necessary to give consideration to other indicators of growth, including historical and prospective dividend growth, internal growth, and projected earnings growth. And, in light of their inaccuracy, CARD urges that limited weight be given to analysts' projected earnings-per-share growth rates.

However, SWEPCO disagrees with CARD's contentions regarding analyst bias. As Mr. D'Ascendis explained, the bias of analyst-projected earnings-per-share growth rates for companies comparable in size to the average company in Dr. Woolridge's and Mr. D'Ascendis's proxy groups is very small, -0.009 (mean) and -0.003 (median).[525] Moreover, the forecast errors for analyst-projected earnings-per-share growth rates for the average company in the S&P 500 are

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[522] TIEC Initial Brief at 32; TIEC Ex. 3 (Gorman Dir.) at 64.

[523] CARD Initial Brief at 30.

[524] CARD Ex. 4 (Woolridge Dir.) at 60.

[525] SWEPCO Ex. 38 (D'Ascendis Reb.) at 121-22.

also small, -0.015 (mean) and 0.007 (median). Thus, the growth rates used by Mr. D'Ascendis are highly accurate and have a low "bias."

SWEPCO also critiqued CARD's and TIEC's DCF analyses.[526] As to CARD, SWEPCO asserts that Dr. Woolridge's primary reliance on his DCF results is problematic because current market conditions cause the DCF model to understate investors' expected return.[527] Additionally, according to SWEPCO, Dr. Woolridge misapplied his DCF. In particular, he used retention growth rates (also called sustainable growth rates), which are inappropriate because: (1) they introduce increased potential for forecasting errors; (2) 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 (3) they assume that increasing retention ratios are associated with increasing future growth, which is empirically incorrect.[528]

SWEPCO further contends that Dr. Woolridge used projected earnings-per-share growth rates—despite criticizing their use—and misapplied them.[529] Dr. Woolridge used 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's proxy groups, respectively. Yet the range of growth rates based on the projected earnings-per-share growth rates from his sources of Value Line, Yahoo!, Zacks, and S&P Capital IQ are 5.2% to 6.0%, and 4.8% to 5.9%, for the two proxy groups, respectively.[530] Taking the midpoint of those respective ranges results in corrected DCF results for Dr. Woolridge's and Mr. D'Ascendis's proxy groups of 9.53% and 9.37%, according to SWEPCO.[531]

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[526] SWEPCO witness D'Ascendis testified that, while he disagrees with Staff witness Filarowicz's use of the *multi-stage* DCF model (discussed below), Mr. Filarowicz's indicated ROE using the DCF model of 9.35% is comparable to Mr. D'Ascendis's updated DCF model result of 9.32%. SWEPCO Ex. 38 (D'Ascendis Reb.) at 32.

[527] SWEPCO Initial Brief at 46-47; SWEPCO Ex. 38 (D'Ascendis Reb.) at 109-11.

[528] SWEPCO Ex. 38 (D'Ascendis Reb.) at 55-59, 123.

[529] SWEPCO Initial Brief at 47.

[530] *See* CARD Ex. 4 (Woolridge Dir.), Exh. JRW-7 at 4-5.

[531] SWEPCO Initial Brief at 47.

With respect to TIEC, SWEPCO notes that Mr. Gorman's constant growth DCF results (9.43% average) are comparable to Mr. D'Ascendis's DCF results.[532] However, Mr. Gorman's sustainable growth DCF results (8.44% average) are too low and as a consequence unreasonably lower his overall DCF recommendation. Citing Morin and Financial Analysts Journal, Mr. D'Ascendis testified 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.[533]

b. Multi-Stage DCF Analysis

TIEC witness Gorman and Staff witness Filarowicz also performed a multi-stage DCF analysis. The multi-stage DCF model is an extension of the constant growth version and reflects the possibility of non-constant growth for a company over time.[534] The multi-stage DCF model enables the analyst to specify different growth rates over two or three distinct stages.

Mr. Gorman's multi-stage DCF model used three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (years six through ten); and (3) a long-term growth period starting in year eleven through perpetuity.[535] His multi-stage DCF model reflected that, while a utility may experience periods of high or low short-term growth, its growth rate will eventually regress toward a long-term sustainable rate.[536] To model this expectation, Mr. Gorman's analysis started with the consensus economists' growth rate projections he used in his constant growth DCF (5.46%), which represent reasonable investor expectations for the next five years. Then, for years six through ten, he adjusted the proxy group's growth rates halfway toward the long-term sustainable growth rate of 4.35%, based on economists' projections for total gross domestic product (GDP) growth. For years eleven

[532] SWEPCO Initial Brief at 51.

[533] SWEPCO Ex. 38 (D'Ascendis Reb.) at 56-57.

[534] TIEC Ex. 3 (Gorman Dir.) at 33.

[535] TIEC Ex. 3 (Gorman Dir.) at 33.

[536] TIEC Initial Brief at 24-25.

and after, Mr. Gorman projected growth at the long-term sustainable rate of 4.35%. Mr. Gorman testified that the GDP growth rate is a conservative proxy for the long-term growth rate because the long-term growth of a utility cannot exceed the growth rate of the economy in which it sells goods and services.[537] His resulting multi-stage DCF analysis produced average and median ROEs of 8.56% and 8.72%, respectively.[538]

Staff witness Filarowicz's multi-stage DCF analysis used two stages.[539] The first stage covered five years and used the same analysts' estimates he used in his constant growth analysis. The second stage, which covered years six through the end of the period studied (year 150), used an expected long-run nominal growth rate of 5.13%, consisting of the 3.13% per year average real growth-rate of GDP for the period 1950 through 2020 as calculated from data reported by the U.S. Bureau of Economic Analysis, and the 2.00% rate of inflation forecast by the Board of Governors of the Federal Reserve System.[540] Mr. Filarowicz's multi-stage DCF analysis produced ROE estimates ranging from 7.26% to 9.99%, with a 75th percentile of 9.31%.[541]

Mr. D'Ascendis criticized the use of the multi-stage DCF for utilities.[542] He testified that the multi-stage DCF model is inapplicable to utilities because they 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.[543] Mr. Filarowicz's multi-stage DCF analysis produced results comparable to Mr. D'Ascendis's updated constant growth DCF model result of 9.32%.[544] However, SWEPCO contends Mr. Gorman's multi-stage

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537 TIEC Ex. 3 (Gorman Dir.) at 34-37.

538 TIEC Ex. 3 (Gorman Dir.) at 40.

539 Staff Ex. 1 (Filarowicz Dir.) at 19-20.

540 Staff Ex. 1 (Filarowicz Dir.) at 20.

541 Staff Ex. 1 (Filarowicz Dir.) at 21, 28.

542 SWEPCO Ex. 38 (D'Ascendis Reb.) at 60-61.

543 SWEPCO Initial Brief at 51; SWEPCO Ex. 38 (D'Ascendis Reb.) at 60-61.

544 SWEPCO Ex. 38 (D'Ascendis Reb.) at 32.

DCF produced unreasonably low results, and consequently, unreasonably lowered his overall DCF recommendation.[545]

TIEC responded that, while utilities may not have the explosive growth of less mature industries, they do experience periods of relatively higher growth.[546] As Mr. Gorman explained, when utilities undertake large capital expenditure programs, their rate base grows rapidly, which accelerates earnings growth.[547] Once a major construction cycle levels off, rate base growth slows, and earnings growth also drops to a lower sustainable rate. Currently, as reported by Standard and Poor's (S&P), utilities are in a period of high capital investment that is expected to taper off.[548] Thus, the current average projected growth rate of 5.46% is not expected to be sustained over the long term.[549] That utilities are a relatively mature industry experiencing only modestly high growth is captured by the limited difference between the short-term and long-term growth rates that Mr. Gorman used.[550]

3. Risk Premium Analysis

The risk premium approach is based on the basic financial tenet that investors require greater returns for bearing greater risk. Common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. To compensate for bearing that additional risk, equity investors require a premium over the return they would have earned as a bondholder. Risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. The equity risk premium is not directly observable, so it typically is estimated using a variety of approaches.

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[545] SWEPCO Initial Brief at 51.

[546] TIEC Reply Brief at 16.

[547] TIEC Ex. 3 (Gorman Dir.) at 33.

[548] TIEC Ex. 3B (Gorman Conf. Workpapers) at MPG Confidential WP 8 at 1.

[549] TIEC Ex. 3 (Gorman Dir.) at 33-34.

[550] TIEC Reply Brief at 17.

Mr. D'Ascendis used two risk premium methods to derive an estimated ROE for SWEPCO.[551] First, he used the Predictive Risk Premium Model (PRPM), which estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk.[552] The PRPM is based on the variance of historical equity risk premiums. The inputs to 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. 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%. Averaging the mean and median results of the Utility Proxy Group resulted in an ROE of 10.27%.[553]

Second, Mr. D'Ascendis used the "total market approach."[554] In this form of the risk premium model, he added 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.[555]

The first step in the total market approach is to determine the appropriate bond yield.[556] Mr. D'Ascendis testified that, because setting the cost of capital is prospective, it is essential to use a prospective (not historical) yield. In determining the bond yield, he relied on a consensus forecast of 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the fourth quarter of 2021 and Blue Chip's long-term projections for 2022-2026 and 2027-2031. He then adjusted that rate slightly upward to reflect the riskier bond

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551 SWEPCO Initial Brief at 38-41.

552 SWEPCO Ex. 8 (D'Ascendis Dir.) at 29-30.

553 SWEPCO Ex. 8 (D'Ascendis Dir.) at 30.

554 SWEPCO Ex. 8 (D'Ascendis Dir.) at 30-40.

555 SWEPCO Ex. 8 (D'Ascendis Dir.) at 30.

556 SWEPCO Ex. 8 (D'Ascendis Dir.) at 30-31.

rating of the Utility Proxy Group, resulting in an expected bond yield for that proxy group of 3.78%.[557]

The components of the Beta-adjusted total market equity risk premium are: (1) an expected market equity risk premium over corporate bonds; and (2) the Beta coefficient.[558] The total Beta-derived equity risk premium that Mr. D'Ascendis applied is based on an average of six equity risk premiums, three that are historical in nature and three that are prospective. These six equity risk premiums are: (1) Ibbotson Equity Risk Premium (5.78%); (2) Regression on Ibbotson Risk Premium Data (9.34%); (3) Ibbotson Equity Risk Premium Based on PRPM (9.55%); (4) Equity Risk Premium Based on Value Line Summary and Index (13.50%); (5) Equity Risk Premium Based on Value Line S&P 500 Companies (10.63%); and (6) Equity Risk Premium Based on Bloomberg S&P 500 Companies (10.72%).[559] 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%.[560]

Mr. D'Ascendis also estimated three equity risk premiums based on the S&P Utilities 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.[561] 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%.[562]

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

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[557] SWEPCO Ex. 8 (D'Ascendis Dir.) at 31.

[558] SWEPCO Ex. 8 (D'Ascendis Dir.) at 32.

[559] SWEPCO Ex. 8 (D'Ascendis Dir.) at Schedule DWD-4 at 8.

[560] SWEPCO Ex. 8 (D'Ascendis Dir.) at 37.

[561] SWEPCO Ex. 8 (D'Ascendis Dir.) at 38.

[562] SWEPCO Ex. 8 (D'Ascendis Dir.) at 38.

public utility bonds for 1,167 fully litigated electric utility rate cases from 1980 to 2019.[563] The results of this analysis 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.[564] According to SWEPCO, the inverse relationship between the equity risk premium and interest rates is supported by multiple academic studies and is recognized by Staff witness Filarowicz. And although TIEC witness Gorman criticized Mr. D'Ascendis's observation of the inverse relationship, SWEPCO claims that Mr. Gorman's own data demonstrates the very inverse relationship that his testimony denies exists.[565]

Averaging the equity risk premium from these three methodologies resulted in an equity risk premium of 7.02% for Mr. D'Ascendis's total market approach.[566] 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%.[567]

When considering both of his risk premium approaches, Mr. D'Ascendis estimated a risk premium return of 10.54% for the Utility Proxy Group, which is the average of his PRPM risk premium (10.27%) and his total market approach risk premium (10.80%).[568] Mr. D'Ascendis applied nearly identical approaches to his Non-Price Regulated Proxy Group, except that he did not use public-utility-specific equity risk premiums, nor did he apply the PRPM to the individual non-price regulated companies.[569] For that proxy group, he concluded that the indicated common equity cost rate is 12.86%.[570]

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563 SWEPCO Ex. 8 (D'Ascendis Dir.) at 39.

564 SWEPCO Ex. 8 (D'Ascendis Dir.) at 39.

565 SWEPCO Ex. 38 (D'Ascendis Reb.) at 85-87.

566 SWEPCO Ex. 8 (D'Ascendis Dir.) at 40.

567 SWEPCO Ex. 8 (D'Ascendis Dir.) at 40.

568 SWEPCO Ex. 8 (D'Ascendis Dir.) at 41.

569 SWEPCO Ex. 8 (D'Ascendis Dir.) at 49-50.

570 SWEPCO Ex. 8 (D'Ascendis Dir.) at 50.

TIEC witness Gorman conducted a Bond Yield Plus Risk Premium analysis that estimated the additional return that investors will require to hold utility stock instead of Treasury bonds and A-rated utility bonds.[571] His analyses are based on a comparison of historically awarded utility ROEs to 30-year Treasury yields and A-rated utility bond yields, respectively, from 1986 through 2020.[572] To reflect the dynamic nature of utility risk premiums and mitigate the impact of anomalous market conditions, Mr. Gorman calculated five- and ten-year rolling average risk premiums. The average indicated risk premium over 30-year Treasury yields and A-rated utility bond yields was 5.65% and 4.28%, respectively.[573]

However, after comparing historical and recent yield spreads for utility bonds and general corporate bonds, Mr. Gorman concluded that the market is currently paying a premium for access to lower-risk utility securities.[574] As a result, Mr. Gorman took a conservative approach and applied risk premiums based solely on the high end of his ranges. This resulted in an equity risk premium over Treasury bonds of 7.02%, which is considerably higher than the 5.65% historical average premium.[575] Combined with a 2.4% projected U.S. Treasury bond yield, this resulted in a risk premium ROE estimate of 9.42%. Similarly, his equity risk premium over utility bonds was 5.77%, compared to the historical average of 4.28%. Adding this equity risk premium to current Baa-rated utility bond yields of 3.21% resulted in a risk premium ROE estimate of 8.98%.[576] Thus, after rounding, Mr. Gorman's risk premium analysis indicated an ROE in the range of 9.00% to 9.40%, with a midpoint of 9.20%.[577]

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[571] TIEC Ex. 3 (Gorman Dir.) at 50-51.

[572] TIEC Ex. 3 (Gorman Dir.) at 41.

[573] TIEC Ex. 3 (Gorman Dir.) at 42, Exhs. MPG-12, MPG-13.

[574] TIEC Ex. 3 (Gorman Dir.) at 44-46.

[575] TIEC Ex. 3 (Gorman Dir.) at 46-47.

[576] TIEC Ex. 3 (Gorman Dir.) at 47.

[577] TIEC Ex. 3 (Gorman Dir.) at 47.

Staff witness Filarowicz performed a "conventional" risk premium approach.[578] His analysis estimated the cost of SWEPCO's equity by comparing the costs of equity authorized for electric utilities across the United States to the yields of large-company corporate bonds that are rated Baa by Moody's Mergent Bond Data.[579] Mr. Filarowicz subtracted the bond yields from the historical authorized costs of equity to determine a risk premium for the riskier equity.[580] He then tested the data for correlation by performing a regression analysis, which showed the existence of an inverse trend in the relationship between risk premiums and bond yields with high confidence.[581] That is, as risk premiums increase, bond yields decrease. On average, from 1980 to 2020, risk premiums increased 0.4457% for every 1.00% that bond yields decreased. The results of Mr. Filarowicz's risk premium analysis produced a cost of equity of 9.05%.[582]

TIEC and CARD each identify alleged flaws in Mr. D'Ascendis's risk premium analyses. TIEC argues the PRPM approach should be rejected outright, as it is "an opaque, idiosyncratic, and biased model."[583] TIEC notes that the PRPM, which was developed by three of Mr. D'Ascendis's former colleagues at AUS Consultants, requires proprietary statistical software and produces inflated ROE results. In a follow-up article to the original article presenting the PRPM, Mr. D'Ascendis and the original three authors touted that the PRPM "produces a higher average indicated ROE than both the DCF and the CAPM."[584] While Mr. D'Ascendis claims the PRPM has never been rebutted in the academic literature, the article first setting forth the PRPM is behind a paywall and has rarely been accessed or cited.[585] As the Pennsylvania Public Utility Commission noted in rejecting Mr. D'Ascendis's use of the PRPM, the PRPM is a specialized

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578 Staff Ex. 1 (Filarowicz Dir.) at 24-25. Mr. Filarowicz refers to his approach as a "conventional" risk premium to distinguish it from the concept of risk premiums in general and to denote that it is the primary risk-premium method on which Staff has relied for many years. *Id.* at 24.

579 Staff Ex. 1 (Filarowicz Dir.) at 24.

580 Staff Ex. 1 (Filarowicz Dir.) at 24.

581 Staff Ex. 1 (Filarowicz Dir.) at 24-25.

582 Staff Ex. 1 (Filarowicz Dir.) at 25.

583 TIEC Initial Brief at 33.

584 SWEPCO Ex. 38A (D'Ascendis Reb. Workpapers) at 1177.

585 Tr. at 886-87; TIEC Ex. 48, SWEPCO's response to TIEC RFI 15-8.

form of the risk premium method that is not commonly used.[586] Further, according to TIEC, the PRPM overestimates the equity risk premium by failing to account for the volatility of bonds.[587]

TIEC also contends that Mr. D'Ascendis's "total market approach" risk premium analysis is flawed.[588] As described above, as part of this approach, Mr. D'Ascendis averaged three estimates of equity risk premium. TIEC focuses its criticisms on the first estimate—the Beta-adjusted total market equity risk premium (8.46%)—noting that the other two estimates (5.77% and 5.78%) were reasonable.[589] To determine his Beta-adjusted total market equity risk premium, Mr. D'Ascendis used the average of six equity risk premiums he calculated.[590] TIEC contends that three of these—specifically, Ibbotson Equity Risk Premium Based on PRPM (9.74%), Equity Risk Premium Based on Value Line S&P 500 Companies (10.77%), and Equity Risk Premium Based on Bloomberg S&P 500 Companies (12.17%)—are based on flawed methodologies that bias the resulting equity risk premium upward.[591]

The PRPM estimate should be rejected, according to TIEC, because it is based on the biased PRPM methodology as explained above. The remaining two results were calculated using a constant growth DCF model based on analysts' earnings growth expectations from Value Line and Bloomberg for every company in the S&P 500. However, Mr. D'Ascendis used three- to five-year growth rates from Value Line and Bloomberg, in direct contravention of the fundamental assumption of the constant growth DCF model that growth rates are in perpetuity. TIEC points out that, for many of the companies in the S&P 500, analysts are projecting three- to five-year growth rates that are much higher than what would be reasonably expected in perpetuity. For example,

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[586] TIEC Ex. 51, Pennsylvania Public Utility Commission Opinion and Order dated April 16, 2020, at Bates 025; Tr. at 916-17.

[587] TIEC Initial Brief at 33-34.

[588] TIEC Initial Brief at 34-38.

[589] TIEC Initial Brief at 34. TIEC's briefing used the updated percentages provided in Mr. D'Ascendis's rebuttal testimony, so they vary from those listed above, which were from his direct testimony.

[590] SWEPCO Ex. 8 (D'Ascendis Dir.), Exh. DWD-4 at 8.

[591] TIEC Initial Brief at 35. Again, the percentages here are based on Mr. D'Ascendis's updated analysis in his rebuttal testimony, and therefore, they vary from those listed above.

Amazon's growth rate was projected to be 32.3% and 33.5% by Value Line and Bloomberg, respectively.[592] It is unreasonable to project that any company will grow at a 33% growth rate, or any growth rate that is significantly higher than the long-term GDP growth rate of 4.35%, in perpetuity. The impact of using unreasonably high growth rates is shown by Mr. D'Ascendis's estimates of the total market return, which are 14.21% and 15.61%, and are unreasonably high when compared with historical returns on the market, which ranged from 6.1% to 7.9% between 1926 and 2019.[593] Mr. D'Ascendis's estimated returns are also nearly double what Value Line projects the return on the overall market to be.[594]

If the PRPM and the two S&P 500 estimates of the equity risk premium are ignored, TIEC contends the total market approach would result in an equity risk premium of 6.36%.[595] However, TIEC asserts this figure is still too high because, while Mr. D'Ascendis used an A3-rated utility bond as the starting point in his analysis, he calculated the spread between Aaa-rated corporate bonds and the total market,[596] resulting in an apples-to-oranges comparison. TIEC further contends that Mr. D'Ascendis's analysis is inflated because it uses a projected utility bond yield that exceeds currently observable utility bond yields.[597] As Dr. Woolridge testified, interest rate projections are extremely inaccurate.[598] Using the most recent observable Baa-rated utility bond yields (3.42%) and a corrected version of Mr. D'Ascendis's equity risk premium (5.8%) results in an ROE of 9.22%, which is similar to the result of Mr. Gorman's risk premium study of 9.2%.

CARD criticizes Mr. D'Ascendis's PRPM and the first three inputs to his Beta-adjusted total market equity risk premium for being based on historic stock and bond returns/yields.[599] As

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[592] TIEC Ex. 3 (Gorman Dir.) at 44-46.

[593] TIEC Ex. 3 (Gorman Dir.) at 73.

[594] Tr. at 892-93.

[595] TIEC Initial Brief at 36-37.

[596] Tr. at 900.

[597] TIEC Initial Brief at 37.

[598] Tr. at 1005-06.

[599] CARD Initial Brief at 31-33.

Dr. Woolridge testified, using historical returns to measure an *ex ante* equity risk premium is erroneous and overstates the true market or equity risk premium.[600] This approach can produce differing results depending on several factors, including the measure of central tendency used, the time period evaluated, and the stock-market index employed.[601] Dr. Woolridge also noted several empirical problems in the approach that result in inflated estimates of expected risk premiums.[602] Further, Duff & Phelps, which Mr. D'Ascendis relied on,[603] cautioned against using historical returns to compute an equity risk premium.[604] Duff & Phelps publishes its recommended U.S. equity risk premium, which decreased from 6.00% to 5.50%, as of December 9, 2020.[605]

CARD further contends the variability in returns included in Mr. D'Ascendis's PRPM study—ranging from a low of 7.62% for Ameren to a high of 13.38% for Entergy—makes his analyses suspect because it suggests the companies he uses are not similar to each other or SWEPCO.[606] According to CARD, one would expect that similar-risk companies would display a closer range in equity costs, and thus, the wide range in results indicates the data do not provide reliable estimates.

In addition, CARD contends the remaining three inputs to Mr. D'Ascendis's Beta-adjusted total market equity risk premium are based on unrealistic assumptions about future earnings.[607] Dr. Woolridge calculated that the implied earnings-per-share growth rates for the three approaches are 14.33%, 11.46%, and 11.55%, respectively, with an average of 12.45%, which is nearly triple the long-term projected growth rate of the economy as measured by GDP.[608] In comparison,

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600 CARD Ex. 4 (Woolridge Dir.) at 63.

601 CARD Ex. 4 (Woolridge Dir.) at 63.

602 CARD Ex. 4 (Woolridge Dir.) at 63-64.

603 Mr. D'Ascendis used studies of returns published by Ibbotson. However, the compilation of historical returns is now compiled and published by the investment advisory firm Duff & Phelps. CARD Ex. 4 (Woolridge Dir.) at 64.

604 CARD Ex. 4 (Woolridge Dir.) at 64-65.

605 CARD Ex. 4 (Woolridge Dir.) at 65.

606 CARD Ex. 4 (Woolridge Dir.) at 63.

607 CARD Initial Brief at 33-37.

608 CARD Ex. 4 (Woolridge Dir.) at 58, 66.

Dr. Woolridge's study of growth in nominal GDP, S&P stock-price appreciation, and S&P growth in earnings per share and dividends per share since 1960 showed historical long-run growth rates in the 6% to 7% range.[609] Dr. Woolridge further testified that there is a direct link between long-term earnings per share and GDP growth, and that GDP growth has slowed in recent decades and is projected to slow in the future.[610]

In response to TIEC, SWEPCO notes that the PRPM is based on the research of Dr. Robert F. Engle dating back to the early 1980s, has been published six times in peer-reviewed journals, has not been rebutted in the academic literature, and has been accepted by utility industry groups and regulators.[611] Mr. D'Ascendis also explained that his PRPM does not overestimate the equity risk premium.[612] He charted the predicted market risk premiums with the actual market risk premiums from 1936 to 2019, and the volatility patterns are nearly identical, showing the PRPM accurately reflects volatility. SWEPCO further contends that the critiques regarding use of the total market approach and projected utility bond yields are unwarranted.[613] Mr. D'Ascendis testified that, because estimating the common equity cost rate is a forward-looking exercise (which multiple witnesses acknowledged), he reasonably relied on a consensus forecast of about 50 economists as well as Blue Chip's long-term projections for 2022 through 2031.[614] He then made several adjustments to reflect the credit spread between Aaa-rated corporate bonds and the issuer rating of the proxy group.

As to CARD's critiques, SWEPCO states that Dr. Woolridge's concern about using the historical relationship between stock and bond returns is not an issue here because it does not apply to the individual electric company PRPM-derived equity risk premiums and ROEs, which are

609 CARD Ex. 4 (Woolridge Dir.) at 70.

610 CARD Ex. 4 (Woolridge Dir.) at 71-73.

611 SWEPCO Reply Brief at 45; SWEPCO Ex. 38 (D'Ascendis Reb.) at 89-93.

612 SWEPCO Ex. 38 (D'Ascendis Reb.) at 91-92.

613 SWEPCO Reply Brief at 45-46.

614 SWEPCO Ex. 38 (D'Ascendis Reb.) at 30-32.

based on the individual company, not a broad-based index.[615] In addition, SWEPCO contends CARD is inconsistent by criticizing the variable range of Mr. D'Ascendis's PRPM results while also arguing that Mr. D'Ascendis should give more weight to his DCF model, which also produced a wide range of results.[616]

SWEPCO also raised concerns with TIEC's and Staff's risk premium analyses. SWEPCO contends Mr. Gorman's risk premium results are too low because he relies on a short historical period (1986-2020) and ignores the negative correlation between equity risk premiums and interest rates.[617] Staff witness Filarowicz's risk premium analysis is also flawed, according to SWEPCO, because he: (1) used current interest rates even though the cost of equity is a forward-looking concept; (2) relied on an annual average of authorized returns and prospective Moody's bond yields in determining their relationship to each other, which is less accurate than considering those variables on an individual basis; and (3) used corporate bond yields for both his regression and ROE comparison rather than public utility bond yields, which is less precise.[618]

4. CAPM Analysis

The CAPM is a risk premium approach that estimates the ROE for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable, or systematic, risk of that security. The traditional CAPM formula is as follows:

$$K = R_f + \beta(R_m - R_f)$$

Where K equals the required market ROE; β equals the Beta (a measure of risk) of an individual security; R_f equals the risk-free rate of return; and R_m equals the required return on the market as a whole. In this equation, $(R_m - R_f)$ represents the market risk premium. Thus, the inputs to the

615 SWEPCO Reply Brief at 43; SWEPCO Ex. 38 (D'Ascendis Reb.) at 131-33.

616 SWEPCO Ex. 38 (D'Ascendis Reb.) at 133.

617 SWEPCO Ex. 38 (D'Ascendis Reb.) at 64.

618 SWEPCO Ex. 8 (D'Ascendis Dir.) at 33-34.

CAPM are the Beta, a risk-free rate of return, and a risk premium. The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. The CAPM presumes that investors only require compensation for systematic risk, which is measured by a stock's Beta. A Beta coefficient less than 1.0 indicates lower variability than the market as a whole, while a Beta coefficient greater than 1.0 indicates greater variability than the market.[619]

Mr. D'Ascendis undertook two CAPM analyses—a traditional CAPM (described above) and the empirical CAPM (ECAPM). According to Mr. D'Ascendis, 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.[620] 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. In view of this theory and the practical research, Mr. D'Ascendis applied both models and averaged the results.[621]

In performing both analyses, Mr. D'Ascendis used Beta coefficients from Value Line and Bloomberg Professional Services.[622] For the risk-free rate, Mr. D'Ascendis used 2.09%, which 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.[623] The yield on long-term U.S. Treasury bonds is appropriate because it is virtually risk free and its term is consistent with: (1) the long-term cost of capital to public utilities measured by the yields on Moody's A-rated public utility bonds; (2) the long-term investment horizon inherent in utilities' common stocks; and (3) 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, Mr. D'Ascendis testified that short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve

[619] SWEPCO Ex. 8 (D'Ascendis Dir.) at 41.

[620] SWEPCO Ex. 8 (D'Ascendis Dir.) at 42-43.

[621] SWEPCO Ex. 8 (D'Ascendis Dir.) at 44.

[622] SWEPCO Ex. 8 (D'Ascendis Dir.) at 44-45.

[623] SWEPCO Ex. 8 (D'Ascendis Dir.) at 45.

monetary policy.[624] Mr. D'Ascendis's market risk premium is derived from an average of three historical data-based market risk premiums and three prospective market-risk premiums, which are the same six measures he used in his risk premium analysis described above.[625] When averaged, these six measures result in an average total market equity risk premium of 10.92%.[626]

Using these inputs for the Utility Proxy Group, the mean result of Mr. D'Ascendis's CAPM/ECAPM is 12.61%, the median is 12.30%, and the average of the two is 12.46%.[627] Consistent with Mr. D'Ascendis's reliance on the average of mean and median DCF results, the indicated ROE for SWEPCO using these models is 12.46%. Mr. D'Ascendis also performed the same CAPM/ECAPM analyses for his Non-Price Regulated Proxy Group, which indicated a common equity cost rate of 12.09%.[628]

CARD's, TIEC's, and Staff's witnesses each conducted a traditional CAPM analysis. Staff witness Filarowicz, however, did not incorporate the results of his CAPM analysis into his ROE recommendation because it yielded a markedly lower ROE (7.26%) than his other estimates.[629] Instead, he used the CAPM result as a qualitative check on his other analyses.

CARD witness Woolridge's CAPM analysis used a risk-free rate of 2.5%, which is toward the middle of the range of recent yields on 30-year U.S. Treasury bonds.[630] He also used a Beta of 0.85, which is the median Beta for his proxy group.[631] To determine the market risk premium, Dr. Woolridge reviewed a series of studies that calculate the market risk premium using different methodologies. Based on his analysis of these studies, he concluded that the appropriate market

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[624] SWEPCO Ex. 8 (D'Ascendis Dir.) at 45.

[625] SWEPCO Ex. 8 (D'Ascendis Dir.) at 46.

[626] SWEPCO Ex. 8 (D'Ascendis Dir.) at 46-47.

[627] SWEPCO Ex. 8 (D'Ascendis Dir.) at 47.

[628] SWEPCO Ex. 8 (D'Ascendis Dir.) at 50.

[629] Staff Ex. 1 (Filarowicz Dir.) at 25-28.

[630] CARD Ex. 4 (Woolridge Dir.) at 43.

[631] CARD Ex. 4 (Woolridge Dir.) at 47.

risk premium in the United States is in the 4.0% to 6.0% range.[632] Dr. Woolridge used the upper end of the range, 6.0%, as his market risk premium. With these inputs, Dr. Woolridge's CAPM analysis for both his proxy group and Mr. D'Ascendis's Utility Proxy Group resulted in a cost of equity of 7.6%.[633] However, Dr. Woolridge relied primarily on the DCF model and less on the CAPM.[634]

TIEC witness Gorman used a risk-free rate of both current and projected 30-year Treasury yields of 1.85% and 2.40%, respectively.[635] He then reviewed data from Value Line to determine the current average Beta for his proxy group of 0.89.[636] Mr. Gorman explained that current published Betas are extremely elevated relative to their historical levels, which has generally ranged from 0.6 to 0.8, and that forward-looking Beta estimates have consistently been around 0.7.[637] Accordingly, Mr. Gorman conducted two CAPM analyses: (1) a current CAPM analysis that used current 30-year Treasury yields (1.85%) and current estimates of Beta (0.89); and (2) a normalized CAPM analysis that used projected 30-year Treasury yields (2.4%) and normalized estimates of Beta (0.7).[638]

For the final component of his CAPM analysis, Mr. Gorman derived two market risk premium estimates. His forward-looking estimate projected the returns of the S&P 500 into the future by adding an expected inflation rate to the long-term arithmetic average real return on the market (as determined by Duff & Phelps), which represents the market's achieved return above inflation.[639] This forward-looking method produced an expected market return of 11.29%. Subtracting the estimated projected risk-free rate of 2.4% resulted in a forward-looking market

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[632] CARD Ex. 4 (Woolridge Dir.) at 53.

[633] CARD Ex. 4 (Woolridge Dir.) at 53-54.

[634] CARD Reply Brief at 14; CARD Ex. 4 (Woolridge Dir.) at 54.

[635] TIEC Ex. 3 (Gorman Dir.) at 47.

[636] TIEC Ex. 3 (Gorman Dir.) at 49, Exh. MPG-16.

[637] TIEC Ex. 3 (Gorman Dir.) at 49.

[638] TIEC Ex. 3 (Gorman Dir.) at 53.

[639] TIEC Ex. 3 (Gorman Dir.) at 51.

risk premium of 8.89%, and subtracting the current risk-free rate of 1.85% resulted in a current market risk premium of 9.44%.[640]

Mr. Gorman also determined a historical estimate of the market risk premium by reviewing data from Duff & Phelps, which showed that the historical arithmetic average of the achieved total return on the S&P 500 was 12.1%.[641] By subtracting the historical total return on long-term Treasury bonds of 6.0%, he determined that the historical market risk premium was 6.1%. Based on this analysis, Mr. Gorman found that his market risk premium fell in the range of 6.1% to 9.44%, which is consistent with (though toward the higher end of the range of) market risk premium estimates made by Duff & Phelps, which are in the range of 5.5% to 7.2%.[642]

Using these inputs, Mr. Gorman's CAPM analysis resulted in an expected ROE of 8.65% to 10.24%.[643] Mr. Gorman recommended the midpoint of his CAPM indicated ROE range (9.45%, rounded up to 9.5%) as his CAPM return.[644]

Both CARD and TIEC raise concerns with Mr. D'Ascendis's CAPM and ECAPM analyses.[645] They each contend that his CAPM results are inflated because he generally used the same six methodologies for determining the market risk premium as in his risk premium analysis discussed above.[646] CARD states that Mr. D'Ascendis's market risk premium of 10.92% is markedly higher than published market risk premiums, and was developed using unrealistic assumptions of future earnings growth and stock market returns.[647] In addition, TIEC notes that if the PRPM and the two S&P 500 DCF results are excluded, then the resulting market risk premium

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[640] TIEC Ex. 3 (Gorman Dir.) at 50.

[641] TIEC Ex. 3 (Gorman Dir.) at 50-51.

[642] TIEC Ex. 3 (Gorman Dir.) at 52-53.

[643] TIEC Ex. 3 (Gorman Dir.) at 53.

[644] TIEC Ex. 3 (Gorman Dir.) at 53.

[645] CARD Initial Brief at 37; TIEC Initial Brief at 38-39.

[646] The one exception is that instead of taking the spread between Aaa-rated corporate bonds and the return on the market, Mr. D'Ascendis took the spread between 30-year Treasury yields and the return on the market. Tr. at 902.

[647] CARD Ex. 4 (Woolridge Dir.) at 73, 78.

goes down from 9.59% (the market risk premium Mr. D'Ascendis used in rebuttal) to 7.44%, which is in the middle of Mr. Gorman's range of estimates of the market risk premium.[648] TIEC also asserts that Mr. D'Ascendis's CAPM analysis contains the same faulty assumption regarding projected interest rates as his risk premium analysis because he used a forecast of the 30-year Treasury yield that goes out to 2031.[649]

CARD and TIEC also urge rejection of Mr. D'Ascendis's ECAPM analysis.[650] Mr. Gorman explained that the ECAPM model flattens the security market line by adjusting up Betas that are less than one and adjusting down Betas that are greater than one. However, because utility Betas are currently at 0.97 (and extremely high relative to their historical levels), the impact of the ECAPM is minimal. Nevertheless, according to TIEC, Mr. D'Ascendis's ECAPM should be rejected because the Betas reported by Value Line are already adjusted, meaning that the ECAPM results in a double adjustment. Additionally, TIEC contends that regulatory commissions generally disregard the use of the ECAPM, particularly when an adjusted Beta is used in the model.[651]

CARD asserts that the ECAPM has not been theoretically or empirically validated in refereed journals.[652] The ECAPM provides for weights that are used to adjust the risk-free rate and market risk premium in applying the ECAPM. According to CARD, Mr. D'Ascendis used 0.25 and 0.75 factors to boost the equity risk premium measure, but provided no empirical justification for those figures.[653] Then, Mr. D'Ascendis took his analysis a step further and used adjusted Betas to produce his ECAPM results, a practice CARD describes as at best untested. Therefore, CARD concludes his ECAPM produces unreliable outputs.

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648 TIEC Ex. 3 (Gorman Dir.) at 53.

649 TIEC Initial Brief at 38.

650 CARD Initial Brief at 37; TIEC Initial Brief at 39.

651 *See, e.g.*, TIEC Ex. 52, Public Service Commission of Maryland Order dated March 22, 2019, at Bates 030 (stating that "the ECAPM is not widely accepted by the financial community in determining ROEs.").

652 CARD Ex. 4 (Woolridge Dir.) at 79.

653 CARD Ex. 4 (Woolridge Dir.) at 79.

SWEPCO responds that Mr. D'Ascendis explained that financial theory and practical research support the use of the ECAPM as an appropriate tool in estimating the cost of equity.[654] In addition, as with his risk premium analyses, Mr. D'Ascendis demonstrated that his expected market returns are not inflated. The market risk premiums he uses, 10.92% (direct) and 9.59% (rebuttal), occur approximately 44% to 49% of the time looking at actual returns observed from 1926 to 2019.[655]

SWEPCO also had critiques of the CAPM analyses by CARD, TIEC, and Staff. As to CARD, SWEPCO dismisses Dr. Woolridge's CAPM results because he relied primarily on the DCF model and essentially "dismissed his own CAPM analysis."[656] In response to Mr. Gorman's CAPM, SWEPCO contends his results are too low because he fails to consider long-term projection of the risk-free rate published by Blue Chip (although he uses Blue Chip elsewhere in his analysis).[657] Moreover, Mr. Gorman's market risk premium 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.[658] With respect to Staff, SWEPCO contends Mr. Filarowicz's 7.26% result is unreasonable on its face, which he recognizes by not directly incorporating his CAPM results in his ROE determination.[659] According to SWEPCO, the driving factor for its unreasonableness is Mr. Filarowicz's misapplication of the CAPM by relying on historical, *i.e.*, recent, 20-year Treasury bond yield as his risk-free rate, using the total return on long-term government bonds in calculating his market risk premium, and not performing an ECAPM.[660]

[654] SWEPCO Ex. 38 (D'Ascendis Reb.) at 75-77.

[655] SWEPCO Ex. 38 (D'Ascendis Reb.) at 94-95.

[656] SWEPCO Initial Brief at 46; SWEPCO Ex. 38 (D'Ascendis Reb.) at 125.

[657] SWEPCO Initial Brief at 51-52; SWEPCO Ex. 38 (D'Ascendis Reb.) at 71.

[658] SWEPCO Ex. 38 (D'Ascendis Reb.) at 73.

[659] SWEPCO Initial Brief at 48.

[660] SWEPCO Initial Brief at 48-49; SWEPCO Ex. 38 (D'Ascendis Reb.) at 36-42.

5. Economic and Market Considerations

Intervenors identify two economic and market considerations that they claim support a lower ROE for SWEPCO: (1) low interest rates; and (2) a declining trend in authorized ROEs. In particular, CARD and TIEC note that interest rates are at historically low levels, which they contend results in lower capital costs.[661] According to TIEC, the cost of capital has declined significantly since SWEPCO's last rate case, as both 30-year Treasury yields and Aaa-rated corporate bond yields are more than 100 basis points lower than they were during the pendency of that case.[662] CARD argues that Mr. D'Ascendis's analyses and ROE results do not reflect this reality, as they are based on assumptions of *higher* interest rates and capital costs that have not occurred. As Dr. Woolridge testified, while economists continue to forecast higher interest rates, as does Mr. D'Ascendis, the predictions continue to be inaccurate.[663]

CARD, TIEC, and Walmart also point to a declining trend in authorized ROEs for utilities across the United States.[664] CARD witness Woolridge testified that from 2012 to 2020, the average authorized ROE for electric utilities declined from 10.01% to 9.39%.[665] As to Texas, Walmart notes that since 2017 the Commission has issued orders with stated ROEs in seven cases for investor owned utilities with an average approved ROE of 9.56%.[666] Yet, despite declines in awarded ROEs, TIEC contends that regulatory commissions have lagged behind the steep decline in interest rates.[667] Interest rates have declined by over 100 basis points since 2017, but average authorized ROEs have only dropped by approximately 20 basis points.[668] The result is that the spread between authorized ROEs and interest rates (or the implied equity risk premium) is higher

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[661] CARD Initial Brief at 17-19; TIEC Initial Brief at 18-19.

[662] TIEC Ex. 46, SWEPCO's response to TIEC RFI 12-1.

[663] Tr. at 1004-06.

[664] CARD Initial Brief at 16-17; TIEC Initial Brief at 19-22; Walmart Initial Brief at 4-6.

[665] CARD Ex. 4 (Woolridge Dir.) at 13; *see also* TIEC Ex. 3 (Gorman Dir.) at 7.

[666] Walmart Ex. 1 (Perry Dir.), Exh. LVP-3.

[667] TIEC Initial Brief at 19-20.

[668] TIEC Ex. 3 (Gorman Dir) at 7.

than it has ever been,[669] which according to TIEC, is due to the fact that regulators, due to structural factors, are often slower to lower ROEs than what market conditions dictate.[670]

TIEC also criticizes Mr. D'Ascendis for ignoring the decline in the cost of capital since SWEPCO's last rate case and instead narrowly focusing on increased volatility, which has been largely due to the COVID-19 pandemic. TIEC notes that the economy has started to recover, and the utility industry performed well during the pandemic. As S&P stated in a 2021 credit report:

> Encouragingly, the [utility] industry has generally performed well throughout the pandemic. Lower electric and gas deliveries to C&I customers were mostly offset by higher residential deliveries, the industry generally worked well with regulators to defer COVID-19-related costs for future recovery, market returns improved, and the industry generally had consistent access to the capital markets.[671]

Indeed, while Mr. D'Ascendis noted the risk of utilities lowering dividends during a prolonged economic downturn in his direct testimony, he acknowledged at the hearing that only two utility companies lowered dividends, and that other utility companies increased dividends in 2020, including AEP.[672]

SWEPCO responds that CARD and TIEC take a narrow view of the capital markets by focusing on interest rates.[673] In contrast, Mr. D'Ascendis takes a broader view by looking at interest rates, volatility indices, the impact of COVID-19 on the economy, and both near-term and long-term economic projections.[674] Notably, COVID-19 impacted the market through both declining interest rates and increased volatility.[675] As Mr. D'Ascendis testified, sudden and

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669 TIEC Ex. 3B (Gorman Conf. Workpapers) at MPG Confidential WP 15, Moody's Investors Service, *2021 Outlook Stable on Strong Regulatory Support and Robust Residential Demand* (Oct. 29, 2020) at 5.

670 TIEC Ex. 3A (Gorman Dir. Workpapers) at WP 11, *When "What Goes Up" Does Not Come Down: Recent Trends in Utility Returns*, Charles S. Griffey (Feb. 15, 2017) at Bates 335-36.

671 TIEC Ex. 3 (Gorman Dir) at 19-20.

672 Tr. at 875-77; TIEC Ex. 6, SWEPCO's response to TIEC RFI 1-32 at Bates 010.

673 SWEPCO Reply Brief at 36-39.

674 SWEPCO Ex. 8 (D'Ascendis Dir.) at 8-13.

675 SWEPCO Ex. 38 (D'Ascendis Reb.) at 11-12.

significant drops in interest rates are associated with increased volatility in the market. When this happens, risk-averse investors move to Treasury securities, which even Dr. Woolridge agreed happened in 2020.[676] Those investors that remain in the market require a higher return in response to the increased risk.[677] As instances of extreme volatility subside, interest rates begin to recover (move up). That is, there is an inverse relationship between extreme changes in volatility and extreme changes in interest rates.[678]

SWEPCO further disagrees with TIEC that the increased spread between interest rates and authorized returns is due to regulatory lag in setting ROEs, rather than an inverse relationship between interest rates and volatility, as argued by Mr. D'Ascendis.[679] According to SWEPCO, TIEC's argument is short-sighted and ignores the investor-required return on a forward-looking basis as the market recovers from the COVID-19 pandemic.

Further, SWEPCO claims that TIEC and CARD discount the fact that interest rates are on the rise.[680] Dr. Woolridge acknowledged at the hearing that the 30-year Treasury yield had climbed from 1.25% in mid-2020 to 2.29% at the hearing.[681] Mr. D'Ascendis noted that projected interest rates mirror this real-time rise and show a continued steady climb.[682] In addition, SWEPCO asserts that TIEC and CARD tie low interest rates to lower authorized ROEs during a declining trend, but fail to apply that same approach when interest rates are increasing. For example, since the Commission authorized an ROE of 9.45% for Southwestern Public Service Company (SPS) in 2020, the 30-year Treasury yield increased from about 1.45% to approximately 2.29% at the time of SWEPCO's hearing.[683] It follows then that SWEPCO's ROE would be higher than SPS's, but

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676 Tr. at 1002.

677 SWEPCO Ex. 38 (D'Ascendis Reb.) at 11-12.

678 SWEPCO Ex. 38 (D'Ascendis Reb.) at 12.

679 SWEPCO Reply Brief at 37-38.

680 SWEPCO Reply Brief at 38.

681 Tr. at 984.

682 SWEPCO Ex. 38 (D'Ascendis Reb.) at 13, Table 2.

683 Tr. at 993, 996-97.

Dr. Woolridge testified that there was not a one-to-one relationship between interest rates and Commission-authorized ROEs.[684]

As to the "trend" in authorized ROEs, SWEPCO states that, taking out 2020, which both Mr. Gorman and Dr. Woolridge agreed is an outlier year,[685] there is no discernible trend downward in authorized ROEs approved by regulatory agencies. On cross-examination, several ROE witnesses admitted that authorized ROEs have been stable from 2014 to 2019.[686] Further, as Mr. D'Ascendis pointed 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.[687] If one considers all recently authorized ROEs, rather than simple annual averages, there is no discernible downward trend. Moreover, there is no statistical difference in the averages over the past six years.[688]

6. SWEPCO's Proposed ROE Adjustments for Size and Credit Risk

Because no proxy group can be identical in risk to any single company, SWEPCO contends 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.[689] According to SWEPCO, it is relatively riskier than the companies in the proxy groups in two areas that warrant a small upward adjustment: smaller size and credit quality.

SWEPCO notes that size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues, and earnings.[690] For example,

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[684] Tr. at 993, 996-97.

[685] Tr. at 987 (Woolridge), 1013 (Gorman).

[686] Tr. at 989 (Woolridge), 1013 (Gorman), 1054-55 (Filarowicz).

[687] SWEPCO Ex. 38 (D'Ascendis Reb.) at 53-54.

[688] SWEPCO Ex. 38 (D'Ascendis Reb.) at 53.

[689] SWEPCO Initial Brief at 42-43.

[690] SWEPCO Initial Brief at 42.

smaller companies face 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.[691] SWEPCO witness D'Ascendis testified that neither S&P nor Moody's has minimum company size requirements for any given rating level, which means, all else equal, a relative size analysis must be conducted for equity investments in companies with similar bond ratings.[692]

The average company in Mr. D'Ascendis's Utility Proxy Group has a market capitalization 8.7 times the size of SWEPCO's estimated market capitalization.[693] To calculate his proposed size 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 to 2019 period, which he concluded indicated a 0.84% adjustment.[694] However, to be conservative, Mr. D'Ascendis recommended a size premium of 0.20%.

SWEPCO also contends a credit risk adjustment is warranted to reflect the lower credit rating of SWEPCO compared to the Utility Proxy Group.[695] Mr. D'Ascendis explained that his credit risk adjustment reflects both Moody's and S&P's bond ratings for SWEPCO compared to the proxy groups.[696] SWEPCO's Moody's bond rating is two notches below the average Moody's bond rating of the proxy group and SWEPCO's S&P bond rating is one notch above the average S&P bond rating of the proxy group.[697] Thus, SWEPCO is net one credit rating notch below the

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[691] SWEPCO Ex. 8 (D'Ascendis Dir.) at 52.

[692] SWEPCO Ex. 8 (D'Ascendis Dir.) at 17.

[693] SWEPCO Ex. 8 (D'Ascendis Dir.) at 55.

[694] SWEPCO Ex. 8 (D'Ascendis Dir.) at 55.

[695] SWEPCO Initial Brief at 43.

[696] SWEPCO Ex. 38 (D'Ascendis Reb.) at 48.

[697] SWEPCO Ex. 38 (D'Ascendis Reb.) at 48.

proxy group. To reflect the credit spread between SWEPCO and the proxy group, Mr. D'Ascendis proposed a 0.09% upward adjustment to SWEPCO's ROE.[698]

CARD, TIEC, and Staff disagree that either a size or credit risk adjustment is warranted for SWEPCO. As to the size adjustment, they each note that Mr. D'Ascendis could only identify three cases where a size adjustment had been adopted, all of which were utilities in rural Pennsylvania with rate bases in the range of $17 million,[699] several orders of magnitude smaller than SWEPCO's rate-base request in this proceeding of $5.4 billion.[700] Mr. D'Ascendis could not point to any precedent in which the Commission had approved an adjustment to an electric utility's ROE based on its size.[701] CARD's and Staff's witnesses further testified that it is questionable whether a small-size premium is appropriate at all for regulated public utilities.[702]

TIEC also argues that Mr. D'Ascendis ignores the fact that SWEPCO is a wholly owned subsidiary of AEP, one of the largest publicly traded utility holding companies in the United States.[703] AEP has a market capitalization of $38 billion, more than double the average market capitalization of the proxy group of $15 billion.[704] As Mr. Gorman testified, being part of AEP's system reduces SWEPCO's standalone investment risk, as SWEPCO receives equity capital through AEP and accesses the debt markets with its credit standing affiliation with AEP.[705] Additionally, SWEPCO is entitled to services from AEP through affiliate service contracts that provide SWEPCO benefits—such as being able to attract larger management and allowing

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698 Mr. D'Ascendis initially recommended an upward adjustment of 0.27%, but he adjusted his recommendation in rebuttal to reflect the credit ratings of both Moody's and S&P. *See* SWEPCO Ex. 8 (D'Ascendis Dir.) at 56-57; SWEPCO Ex. 38 (D'Ascendis Reb.) at 48.

699 TIEC Ex. 57, SWEPCO's response to Staff RFI 6-5; TIEC Ex. 51, Pennsylvania Public Utility Commission Opinion and Order dated April 16, 2020; Tr. at 913-16, 927-29.

700 SWEPCO Ex. 1 (Application), Schedule B-1.

701 Tr. at 926.

702 CARD Ex. 4 (Woolridge Dir.) at 80-83; Staff Ex. 1 (Filarowicz) at 34-35; Tr. at 1051.

703 TIEC Initial Brief at 40-41.

704 TIEC Ex. 3 (Gorman Dir.) at 62.

705 TIEC Ex. 3 (Gorman Dir.) at 63.

SWEPCO to rely on AEP services including executive, treasury, accounting, legal, and engineering—that also reduce SWEPCO's business risk.

Additionally, Staff contends a size premium is not justified because Mr. D'Ascendis's recommended ROE is far higher than the average nationwide authorized ROE of 9.44%.[706]

As to SWEPCO's proposed credit risk adjustment, CARD, TIEC, and Staff criticize Mr. D'Ascendis's analysis for ignoring SWEPCO's S&P credit rating, which is one notch *higher* than the Utility Proxy Group's average.[707] When considering both the Moody's and S&P ratings, they argue that SWEPCO's investment risk level is similar to the proxy group and therefore no credit risk adjustment is necessary.

CARD also argues that Mr. D'Ascendis's analysis is flawed because he considered the credit ratings for the operating subsidiaries of the proxy companies, rather than the parent holding companies that are represented in the proxy groups.[708] The operating companies, like SWEPCO, do not have common stock outstanding, so they cannot be used to estimate an equity cost rate. Therefore, the correct comparison is between SWEPCO and the proxy holding companies.

Staff adds that, because of the incommensurately high range for ROE recommended by Mr. D'Ascendis, as well as the general principle that a utility is responsible for managing its own creditworthiness, the Commission should not reward SWEPCO with a higher ROE based on its credit rating.[709] Staff asserts that it is not the Commission's role to serve as guarantor of SWEPCO's creditworthiness.

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[706] Staff Ex. 1 (Filarowicz Dir.) at 35.

[707] CARD Initial Brief at 39; TIEC Initial Brief at 42; Staff Initial Brief at 42.

[708] CARD Initial Brief at 39; CARD Ex. 4 (Woolridge Dir.) at 84.

[709] Staff Initial Brief at 42.

7. Staff's Proposed ROE Adjustment and Independent Consultant for Transmission Outage

PURA § 36.052 requires the Commission to consider the following factors in establishing a reasonable return on invested capital: (1) the efforts and achievements of the utility in conserving resources; (2) the quality of the utility's services; (3) the efficiency of the utility's operations; and (4) the quality of the utility's management.

In this proceeding, Staff recommends a downward adjustment to SWEPCO's ROE under subsections (2) and (4) for the alleged poor quality of SWEPCO's service and management as evidenced by a cascading outage on SWEPCO's system in 2019.[710] Staff witness John Poole testified that a major outage on SWEPCO's system occurred on August 18-19, 2019, resulting in multiple cascading interruptions on SWEPCO's transmission grid and affecting electric cooperatives directly connected to SWEPCO's transmission system.[711] Vegetation contact with SWEPCO's transmission lines initially caused the outage, resulting in SWEPCO spending $1.13 million to perform additional vegetation management and transmission line, substation, and protection work.[712]

According to Staff, the outage is indicative of SWEPCO's failure to adequately perform necessary vegetation management and maintain its transmission system so as to avoid unnecessary service interruptions. Staff points out that post-outage photographs provided by SWEPCO on November 14, 2019, showed significantly developed vegetation, including mature trees reaching transmission lines involved in the outage.[713] Furthermore, Staff notes that multiple transmission lines in SWEPCO's transmission system had been in service for 50 or more years, with some lines having been in service since the 1930s and 40s. In addition, system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) information submitted by

[710] Staff Initial Brief at 40-41.

[711] Staff Ex. 5 (Poole Dir.) at 6.

[712] Staff Ex. 5 (Poole Dir.) at 6.

[713] Staff Ex. 5 (Poole Dir.) at 6; Staff Ex. 5C (Poole Dir. Conf.), Attachment JP-4 at 12-13.

SWEPCO illustrates, according to Staff, that reliability did not appreciably increase following the in-service dates of certain rebuilt transmission lines.

For these reasons, Staff proposes to decrease SWEPCO's return by $1.13 million. This amount is approximately equal to the costs incurred by SWEPCO in response to the outage, which were largely for vegetation management.[714] Using Staff's recommended rate base and SWEPCO's requested capital structure, Staff witness Filarowicz calculated the $1.13 million downward adjustment as an approximate 12.5 basis point reduction to SWEPCO's ROE.[715]

Additionally, Staff recommends that the Commission require SWEPCO to hire an independent consultant to promptly conduct a comprehensive review of SWEPCO's transmission system and make recommendations regarding SWEPCO's vegetation management practices, facilities replacement, and transmission system protection.[716] As part of this requirement, Staff proposes that the Commission open a compliance docket and require SWEPCO to file reports regarding its hiring and use of the independent consultant, including the request for proposals to perform the related work, a notification of the independent consultant selection, a timeline for the consultant's work, as well as the consultant's reports and recommendations. Staff notes that the Commission previously ordered that an electric utility contract with an independent consultant due to the utility's poor reliability and management.[717] Thus, requiring SWEPCO to contract with an independent consultant to review its transmission system is in accordance with Commission precedent.

According to SWEPCO, Staff's recommendations should be rejected for at least two reasons:

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[714] Staff Ex. 5 (Poole Dir.) at 11.

[715] Staff Ex. 1 (Filarowicz Dir.) at 29-30.

[716] Staff Initial Brief at 43; Staff Ex. 5 (Poole Dir.) at 11-12.

[717] *See Entergy Gulf States, Inc. Service Quality Issues*, Docket No. 18249, Order on Rehearing at 28-29, 37 (Apr. 22, 1998); *Application of Entergy Texas for Approval of Its Transition to Competition Plan and the Tariffs Implementing the Plan and for the Authority to Reconcile Fuel Costs to Set Revised Fuel Factors and to Recover a Surcharge for Underrecovered Fuel Costs*, Docket No. 16705, Second Order on Rehearing at 18-19 (Jul. 22, 1998).

(1) Staff has not established any legal basis for such an ROE penalty or independent consultant 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.[718]

SWEPCO contends that Mr. Poole's recommended ROE penalty seems to be premised on the fact that the outage occurred, rather than establishing any legal basis for such a large penalty.[719] His testimony focuses on a single seven-hour outage,[720] the likes of which has not occurred before or since on SWEPCO's system, but 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 opined that prudent vegetation management on the Knox-Pirkey Line and the Pirkey-to-Whitney 138-kilovolt (kV) Line during 2010-2019 would have prevented the cascading interruptions,[721] he agreed at hearing that he does not have any specific qualifications with respect to vegetation management.[722]

SWEPCO also contends the evidence shows it satisfies the relevant outage prevention standard in 16 TAC § 25.52(b)(1) because it makes reasonable efforts to prevent interruptions of service.[723] These efforts include annual aerial vegetation inspection patrols for all lines less than 200 kV and twice annual aerial patrols for lines greater than 200 kV. The data from these inspections is used to determine reactive vegetation management strategies to remove immediate

[718] SWEPCO Initial Brief at 52.

[719] SWEPCO Initial Brief at 52-53.

[720] SWEPCO notes that Staff incorrectly refers to the outage as a two-day event, when instead, the evidence shows that the outage lasted seven hours and power was restored to all load by 11:00 p.m. on August 18. SWEPCO Reply Brief at 49; SWEPCO Ex. 41 (Boezio Reb.) at 2.

[721] Staff Ex. 5 (Poole Dir.) at 9.

[722] Tr. at 429.

[723] SWEPCO Initial Brief at 53.

threats and proactive strategies to manage future work plans and determine frequency of maintenance. SWEPCO witness Daniel Boezio testified that the Company's O&M programs to minimize and prevent interruptions are based on industry standards.[724] 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.[725] 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.[726] While the Company's overall system reliability did not appreciably increase following the rebuilds, SWEPCO notes that system reliability metrics can be affected by a number of factors, most notably weather.[727]

SWEPCO criticizes Mr. Poole for largely dismissing the impact of weather, specifically excessive rainfall, in contributing to the August 18, 2019 outage.[728] Although Mr. Poole asserted that it would have taken a number of years for trees to grow to the height shown in SWEPCO's post-outage report to Staff and that annual rainfall over the previous decade was not unusual,[729] SWEPCO contends these conclusions are mistaken. Mr. Poole's 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.[730] 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.

SWEPCO emphasizes that the initial vegetation contact for the August outage was a vine that had been specifically monitored in the aerial inspection several months earlier. The inspection

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[724] SWEPCO Ex. 11 (Boezio Dir.) at 13-14.

[725] SWEPCO Ex. 41 (Boezio Reb.) at 5.

[726] SWEPCO Ex. 41 (Boezio Reb.) at 4-5.

[727] SWEPCO Initial Brief at 54.

[728] SWEPCO Initial Brief at 54-55.

[729] Staff Ex. 5 (Poole Dir.) at 9.

[730] SWEPCO Ex. 41 (Boezio Reb.) at 6, Figure 2.

noted greater than 25 feet of clearance between the vine and the conductor, which is not considered to be a threat.[731] At the hearing, 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.[732] In addition, SWEPCO notes that its service area has fast-growing trees that can grow as much as 10 feet in a single season, and they grew more than anticipated due to the abnormal rainfall.[733]

Finally, according to SWEPCO, 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, under the standard Commission four-year schedule for rate cases, would amount to more than $4.5 million. This would be the equivalent of roughly 180 days at $25,000 per day,[734] even though the outage lasted only seven hours.

In response, Staff disagrees that Mr. Poole's recommended ROE reduction is predicated solely on the fact that the outage occurred.[735] Instead, Staff contends SWEPCO failed to perform diligent vegetation management over a multi-year period, which is shown by the lack of any vegetation management activities for approximately five years immediately preceding 2019 for three of the four lines that sustained vegetation contact during the outage.[736] According to Staff, the failure to perform adequate vegetation management is also reflected in SWEPCO's worsening SAIDI and SAIFI scores. Higher scores indicate longer and more frequent interruptions, and therefore, worse reliability. Since 2018, SWEPCO's transmission SAIFI score rose from 45.68 to

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[731] SWEPCO Ex. 41 (Boezio Reb.) at 7.

[732] Tr. at 431.

[733] SWEPCO Ex. 41 (Boezio Reb.) at 7.

[734] Tr. at 434-35.

[735] Staff Reply Brief at 30-31.

[736] Tr. at 528.

105.83, and its 2020 SAIFI score is SWEPCO's highest since 2011.[737] Similarly, SWEPCO's transmission SAIDI scores have increased since 2017, from 22.22 to 60.41, with the 2020 score being SWEPCO's highest since 2011.[738]

In addition, Staff argues that SWEPCO has mischaracterized the proposed ROE adjustment as a "penalty" that would be limited by PURA § 15.023.[739] Instead, Staff states that the adjustment is pursuant to the Commission's authority under PURA § 36.052, which authorizes a reduction to SWEPCO's ROE, and is consistent with Commission precedent, including Docket No. 18249.[740]

8. ALJs' Analysis

The ALJs begin by addressing certain analyses and adjustments they excluded when setting SWEPCO's ROE because these determinations narrow the range of reasonable ROEs considered.

First, the ALJs conclude that SWEPCO did not demonstrate that either a size or credit risk adjustment was appropriate in setting its ROE. As to the size adjustment, much of the potential risk Mr. D'Ascendis identified is ameliorated by SWEPCO's status as a wholly owned subsidiary of AEP. In addition, the few instances that Mr. D'Ascendis cited where a size adjustment had been adopted involved utilities orders of magnitude smaller than SWEPCO and that were not located in Texas. With regard to the credit risk adjustment, Mr. D'Ascendis noted that SWEPCO is net one credit rating lower than the Utility Proxy Group after considering both its Moody's and S&P bond ratings; however, the ALJs are persuaded by intervenors and Staff that SWEPCO's investment risk level is sufficiently similar to the proxy group that an adjustment is not justified. Therefore, neither of SWEPCO's proposed adjustments is adopted.

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[737] Staff Ex. 56, SWEPCO's response to CARD RFI 9-20; Tr. at 535.

[738] Staff Ex. 57, SWEPCO's response to CARD RFI 9-21; Tr. at 536-37.

[739] Staff Reply Brief at 33.

[740] Docket No. 18249, Order on Rehearing at 28-29, 37 (Apr. 22, 1998);

The ALJs also conclude that Staff failed to demonstrate that an ROE penalty is warranted. The August 18, 2019 outage was a one-time event, albeit a serious one. While this outage was caused by vegetation contact, Staff did not demonstrate that SWEPCO was negligent in its vegetation management practices. Notably, the vine that initially sparked the cascading outage was aerially examined in April, just months before the outage, and at that time, had a clearance of 25 feet from the conductor.[741] While SWEPCO's worsening SAIFI and SAIDI scores are troubling, the evidence is insufficient to show that these changing metrics warrant an ROE penalty under PURA § 36.052(2) and (4) due to the quality of SWEPCO's services and management. Instead, as addressed in Section VII below, the ALJs find these concerns are more appropriately addressed by adjusting SWEPCO's vegetation management expense. Accordingly, Staff's recommended ROE penalty is not adopted. For the same reasons, SWEPCO should not be required to retain an independent consultant to review its transmission system.

In addition, the ALJs exclude from consideration the results of Mr. D'Ascendis's analyses that used the Non-Price Regulated Proxy Group. SWEPCO failed to demonstrate that the companies in this proxy group were comparable in risk to SWEPCO. Accordingly, the ALJs give no weight to the 12.12% (11.81% rebuttal) equity cost rate that Mr. D'Ascendis calculated for this group and used in his analysis.[742]

The parties' remaining analyses were factored into the ALJs' recommended ROE. As discussed at the outset of this section, the experts presenting testimony on the appropriate ROE for SWEPCO employed both mathematical analyses and empirical data. The results of their analyses and examinations were predictably grouped: Staff and the intervenors at one end with a relatively tight grouping of recommended ROEs in the range of 9.0% to 9.225%, and SWEPCO at the opposite end recommending an ROE of 10.35%.[743]

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[741] SWEPCO Ex. 41 (Boezio Reb.) at 7.

[742] *See* SWEPCO Ex. 8 (D'Ascendis Dir.), Exh. DWD-7 at 1; SWEPCO Ex. 38 (D'Ascendis Reb.), Exh. DWD-1R at 36.

[743] The exception is Walmart's recommendation of "no higher than 9.6%," which was based on a review of approved ROEs nationwide and in Texas, rather than mathematical analyses.

Despite these variations, the ROE experts' constant growth DCF analyses produced relatively similar results—notably, with SWEPCO at 8.73% (direct) and 9.42% (rebuttal)—and the parties had few criticisms of each other's inputs and results. However, as Mr. D'Ascendis pointed out, the use of multiple models adds reliability to the estimation of the common equity cost rate and is supported in both the financial literature and regulatory precedent.[744] Even so, the ALJs find it is appropriate to give the constant growth DCF analyses more weight, as Mr. D'Ascendis did himself.[745] In contrast, the ALJs find that CARD and TIEC raised sufficient concerns with Mr. D'Ascendis's use of the PRPM risk premium approach that it should be given less weight in the analysis.

The economic metrics raised by the parties are not singularly aligned. Some of the metrics argue in favor of a lower ROE, while others argue for a higher ROE. It appears to the ALJs that there is no clearly dispositive factor on the subjective side of the analysis.

Taking these analyses into consideration, weighted as described, a reasonable range for SWEPCO's ROE would be from 9.0% on the low end to 9.9% on the high end. Given that there is no clear indicator within the economic, subjective group of factors, the ALJs conclude that a mid-point of this range is the best approximation of the appropriate ROE for SWEPCO. In this case, the point would be 9.45%, which the ALJs recommend the Commission adopt.

B. Cost of Debt [PO Issue 8]

SWEPCO requests adoption of its actual cost of debt at the end of the test year of 4.18%.[746] SWEPCO witness Renee Hawkins testified that the Company's cost of debt was calculated in accordance with Commission practices and is consistent with prior Texas rate cases.[747]

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[744] SWEPCO Ex. 38 (D'Ascendis Reb.) at 106.

[745] *See* SWEPCO Reply Brief at 42-43 (explaining that Mr. D'Ascendis gave 62.5% weight to his DCF result).

[746] SWEPCO Ex. 9 (Hawkins Dir.) at 4-5.

[747] SWEPCO Ex. 9 (Hawkins Dir.) at 4-5.

The only party to challenge SWEPCO's requested cost of debt was Staff, which proposes that it be reduced to 4.08%.[748] This reduction results from Staff witness Filarowicz's recommendation to adjust the cost of debt to remove the annual amortization of a Series I Hedge Loss sustained by SWEPCO in February 2012.[749] He testified that the Series I Hedge Loss will be fully amortized in January 2022, and SWEPCO customers have already paid 93% of this amortization as of the filing of his testimony in April 2021.[750] By the time new rates from this docket go into effect, there will be only approximately six months of amortization remaining. As such, Staff contends it is inappropriate to set new rates based on the hedge loss because the annual amortization is not indicative of SWEPCO's current annual cost of debt.

SWEPCO responds that Mr. Filarowicz's recommendation is shortsighted and an inappropriate known and measurable change.[751] SWEPCO points out that the test year ended March 31, 2020, and the rates set in this case will go into effect as of March 18, 2021. Based on these facts, Ms. Hawkins testified that the Series I Hedge Loss amortization occurs during both the test year and the period when new rates will be in effect. The full amortization of the loss will not take place until almost two years after the end of the test year.

SWEPCO further argues that 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. Ms. Hawkins explained that the Company's inclusion of the Series I Hedge Loss is reasonable and consistent with 16 TAC § 25.231(c)(2)(F), the Commission's rule regarding post-test-year adjustments to rate base. She testified that, 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. According to SWEPCO, removing that one component without considering any other

[748] Staff Initial Brief at 43-44.

[749] Staff Ex. 1 (Filarowicz) at 31.

[750] Staff Ex. 1 (Filarowicz) at 31.

[751] SWEPCO Initial Brief at 56-57.

post-test-year happenings disregards the scope and purpose of the Commission rule in evaluating rate base at test year end.

There is no dispute that SWEPCO's actual cost of debt at the end of the test year was 4.18%. The sole issue is whether the timing of the Series I Hedge Loss amortization supports an adjustment. However, because the effective date for rates set in this proceeding will relate back to March 18, 2021, the Series I Hedge Loss will remain on SWEPCO's books for the vast majority of the rate year. Thus, even though most of the loss has been amortized as Staff points out, the amount remaining is not insubstantial. In addition, Staff's adjustment would remove one item from the cost of debt without considering other potential changes that could occur during that time period. For these reasons, the ALJs find it is not appropriate to remove the effect of the amortization when setting SWEPCO's cost of debt. Accordingly, the ALJs recommend that the Commission adopt SWEPCO's actual cost of debt at the end of the test year of 4.18%.

C. Capital Structure [PO Issue 7]

SWEPCO presented testimony showing that its capital structure was composed of 50.63% long-term debt and 49.37% equity.[752] No party contested the reasonableness of this capital structure; therefore, the ALJs recommend that the Commission adopt that structure.

D. Overall Rate of Return [PO Issue 8]

The overall rate of return is a product of the capital structure, ROE, and cost of debt. Based on the discussion set forth above, the ALJs recommend that the Commission adopt the following overall rate of return for SWEPCO:

Component	**Cost**	**Weighting**	**Weighted Cost**
Debt	4.18%	50.63%	2.12%
Equity	9.45%	49.37%	4.67%
Overall			6.79%

752 SWEPCO Ex. 9 (Hawkins Dir.) at 3.

E. Financial Integrity, Including "Ring Fencing" [PO Issue 9]

To protect SWEPCO's financial integrity and ensure reliable service at just and reasonable rates, Staff recommends the implementation of certain financial protections to insulate SWEPCO from its parent company, AEP, and AEP's other subsidiaries.[753] Staff notes that AEP, with $81 billion of assets,[754] is a large corporation that includes not only SWEPCO as a subsidiary, but several other entities, including:

- Vertically Integrated Utilities: AEP Generating Company, Appalachian Power Company, Indiana Michigan Power Company, Kingsport Power Company, Kentucky Power Company, Public Service Company of Oklahoma, SWEPCO, and Wheeling Power Company, whose business activities consist of owning and operating assets for the generation, transmission, and distribution of electricity for sale to retail and wholesale customers;

- Transmission and Distribution Utilities: AEP Texas and Ohio Power Company, which own and operate assets for the transmission and distribution of electricity for sale to retail and wholesale customers. Ohio Power Company purchases energy and capacity at auction to serve standard service offer customers and provides transmission and distribution services for all connected load;

- AEP Transmission Holdco: a company that develops, constructs, and operates transmission facilities through investments in AEP Transmission Company. AEP Transmission Holdco also develops, constructs, and operates transmission facilities through investments in AEP's transmission-only joint ventures; and

- Generation and Marketing: AEP also has business: (1) owning competitive generation in PJM Interconnection (PJM); (2) performing marketing, risk management, and retail activities in the Electric Reliability Council of Texas (ERCOT), MISO, PJM, and SPP; and (3) holding contracted renewable energy investments and management services.[755]

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753 SWEPCO Initial Brief at 44-48.

754 Staff Ex. 1 (Filarowicz Dir.) at 38.

755 Staff Ex. 1 (Filarowicz Dir.) at 39-40.

The effects of financial instability or weakness in one entity, according to Staff, could affect not only AEP as the parent company, but other subsidiaries as well.[756] In an extreme case, an event that causes severe financial distress for AEP could lead to its bankruptcy—a situation that, absent the presence of protective measures, could impact subsidiaries like SWEPCO and drag them into the bankruptcy process.

To address these concerns, Staff recommends that the Commission order SWEPCO to implement certain "ring-fencing" provisions designed to create a degree of insulation between SWEPCO and its parent company AEP, as well as other AEP affiliates. In particular, Staff witness Filarowicz proposed the financial protections listed below.[757] To the extent that SWEPCO's existing policies comply with these provisions, he recommended that the Commission require SWEPCO to commit to maintaining those policies.[758]

Staff Proposed Financial Protections
1. SWEPCO Credit Ratings. SWEPCO will work to ensure that its credit ratings at S&P and Moody's remain at or above SWEPCO's current credit ratings. 2. Notification of Less-than-Investment-Grade Rating. SWEPCO will notify the Commission if its credit issuer rating or corporate rating as rated by either S&P or Moody's falls below investment-grade level. 3. ROE Commitment. If SWEPCO's issuer credit rating is not maintained as investment grade by S&P or Moody's, SWEPCO will not use its below-investment-grade ratings to justify an argument in favor of a higher regulatory ROE. 4. Stand-Alone Credit Rating. SWEPCO will take the actions necessary to ensure the existence of a SWEPCO stand-alone credit rating. 5. No Cross-Default Provisions. SWEPCO's credit agreements and indentures will not contain cross-default provisions by which a default by AEP or its other affiliates would cause a default by SWEPCO.

[756] Staff Ex. 1 (Filarowicz Dir.) at 40.

[757] Staff Ex. 1 (Filarowicz Dir.) at 44-45. TIEC generally supports the adoption of standardized ring-fencing measures for all Texas utilities and also the specific recommendations of Mr. Filarowicz in this case. TIEC Initial Brief at 43.

[758] Staff Ex. 1 (Filarowicz Dir.) at 44.

6. No Financial Covenants or Rating-Agency Triggers Related to Another Entity. The financial covenant in SWEPCO's credit agreement will not be related to any entity other than SWEPCO. SWEPCO will not include in its debt or credit agreements any financial covenants or rating-agency triggers related to any entity other than SWEPCO.

7. No Sharing of a Credit Facility. SWEPCO will not share a credit facility with any unregulated affiliates.

8. No SWEPCO Debt Secured by Non-SWEPCO Assets. SWEPCO's debt will not be secured by non-SWEPCO assets.

9. No SWEPCO Assets Pledged for Other Entities' Debt. SWEPCO's assets will not secure the debt of AEP or its non-SWEPCO affiliates. SWEPCO's assets will not be pledged for any other entity.

10. No Credit for Affiliate Debt. SWEPCO will not hold out its credit as being available to pay the debt of any AEP affiliates.

11. No Commingling of Assets. Except for access to the utility money pool and the use of shared assets governed by the Commission's affiliate rules, SWEPCO will not commingle its assets with those of other AEP affiliates.

12. Affiliate Asset Transfer Commitment. SWEPCO will not transfer any material assets or facilities to any affiliates, other than a transfer that is on an arm's-length basis in accordance with the Commission's affiliate standards applicable to SWEPCO, regardless of whether such affiliate standards would apply to the particular transaction.

13. No Inter-Company Lending and Borrowing Commitment. Except for any participation in an affiliate money pool, SWEPCO will not lend money to or borrow money from AEP affiliates.

14. No Debt Disproportionally Dependent on SWEPCO. Without prior approval of the Commission, neither AEP nor any affiliate of AEP (excluding SWEPCO) will incur, guaranty, or pledge assets in respect of any incremental new debt that is dependent on: (1) the revenues of SWEPCO in more than a proportionate degree than the other revenues of AEP; or (2) the stock of SWEPCO.

15. No Bankruptcy Cost Commitment. SWEPCO will not seek to recover from customers any costs incurred as a result of a bankruptcy of AEP or any of its affiliates.

In support of these proposed financial protections, Staff notes that the Commission has previously required ring-fencing provisions in several other dockets, including recent rate cases.[759] The ring-fencing provisions in the final orders in those cases are identical or similar to the provisions Staff suggests in this proceeding.[760] Mr. Filarowicz noted that ring-fencing protections have been proven to work, most notably, for Oncor Electric Delivery Company (Oncor).[761] In that instance, the Commission had ordered ring-fencing provisions in Docket No. 34077 that later effectively insulated Oncor from its parent company's 2014 multi-billion-dollar bankruptcy.[762]

SWEPCO disagrees, however, that Commission-imposed protections are necessary to safeguard its financial integrity and ability to provide reliable service at reasonable rates.[763] SWEPCO notes that 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.

In addition, SWEPCO contends Mr. Filarowicz did not provide any direct evidence regarding the specific need to build a ring-fence around SWEPCO, but instead, cites Oncor as a successful example of ring-fencing measures.

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759 *See, e.g., Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 49831, Order at FoF Nos. 75-91 (Aug. 27, 2020); *Application of AEP Texas Inc. for Authority to Change Rates,* Docket No. 49494, Order at FoF Nos. 108-121 (Apr. 6, 2020); *Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates*, Docket No. 49421, Order at FoF Nos. 71-87 (Mar. 9, 2020).

760 Staff Ex. 1 (Filarowicz Dir.) at 43.

761 Staff Ex. 1 (Filarowicz Dir.) at 46.

762 Staff Ex. 1 (Filarowicz Dir.) at 46-47 (citing *Joint Report and Application of Oncor Electric Delivery Company and Texas Energy Future Holdings Limited Partnership Pursuant to PURA § 14.101*, Docket No. 34077, Order on Rehearing (Apr. 24, 2008)).

763 SWEPCO Initial Brief at 58-60.

SWEPCO witness Hawkins testified that the proposed ring-fencing recommendations are costly and generally unnecessary.[764] SWEPCO already adheres to the Texas affiliate rules and there are existing protections in place for SWEPCO's stand-alone credit rating. SWEPCO notes that the Commission recently addressed ring-fencing measures recommended by Staff for SWEPCO affiliate AEP Texas in Docket No. 49494.[765] In that proceeding, however, the Commission only imposed those measures agreed to by AEP Texas in settlement. Ms. Hawkins noted that SWEPCO already abides by most of the ring-fencing measures included in the final order in Docket No. 49494, and confirmed that SWEPCO is amenable to similar measures in this docket. However, Ms. Hawkins disagreed with several of Mr. Filarowicz's recommendations.[766]

Specifically, Ms. Hawkins testified against Recommendation No. 3, which requires that SWEPCO agree not to seek a higher ROE if its credit ratings fall below investment grade.[767] She pointed 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. Mr. D'Ascendis likewise testified against this recommendation.[768] He maintained 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. Quite simply, investors will not take on more risk without a higher potential return.

Ms. Hawkins further testified that Recommendation Nos. 5 and 6 regarding no cross-default provisions and rating agency triggers are unnecessary and would increase compliance costs for customers.[769] SWEPCO already issues its own debt based on its stand-alone credit rating.

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764 SWEPCO Ex. 39 (Hawkins Reb.) at 3-4.

765 Docket No. 49494, Order at FoF Nos. 108-121 (Apr. 6, 2020).

766 Ms. Hawkins initially raised concerns with Staff's Recommendation No. 1 because it was 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. SWEPCO Ex. 39 (Hawkins Reb.) at 5. However, on cross-examination, Mr. Filarowicz confirmed he did not recommend any dividend restrictions. Tr. at 1062. Therefore, that issue is no longer contested. SWEPCO Initial Brief at 59.

767 SWEPCO Ex. 39 (Hawkins Reb.) at 8-9.

768 SWEPCO Ex. 38 (D'Ascendis Reb.) at 50.

769 SWEPCO Ex. 39 (Hawkins Reb.) at 9.

In addition, she testified that Recommendation No. 13 is too restrictive.[770] Although Mr. Filarowicz excluded 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.

Based on the foregoing, SWEPCO requests that any additional ring-fencing measures that unnecessarily increase compliance costs for SWEPCO and its customers be rejected. Moreover, SWEPCO specifically requests that Staff's ring-fencing Recommendation Nos. 3, 5, 6, and 13 be rejected as unnecessary, overly burdensome, and prohibitive of SWEPCO's ability to provide reliable service and earn a reasonable return.

In response, Staff argues the ring-fencing provisions should be adopted because the benefits to SWEPCO's ratepayers far outweigh the costs involved in implementation.[771] Given that SWEPCO admitted it already abides by most of the ring-fencing measures ordered in Docket No. 49494, Staff calls into question SWEPCO's claim that instituting Recommendation Nos. 5 and 6 will unnecessarily increase compliance costs for customers. Moreover, to the extent compliance costs will increase, Staff emphasizes it is important to keep in mind the end goal of ensuring SWEPCO's financial integrity and proper insulation from AEP. As such, Staff concludes that SWEPCO's contention that the proposed ring-fencing provisions "unnecessarily increase compliance costs for SWEPCO and its customers" should be rejected in favor of the recommended provisions.

Staff demonstrated that ring-fencing provisions serve a valuable purpose and have proven effective in Texas specifically in the case of Oncor. Ring-fencing provisions have also been ordered in three recent rate cases, although each involved a settlement among the parties.[772] As both SWEPCO and Staff note, one of those settlements involved SWEPCO's affiliate, AEP Texas,

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[770] SWEPCO Ex. 39 (Hawkins Reb.) at 9.

[771] Staff Reply Brief at 34.

[772] Docket No. 49831, Order at FoF Nos. 75-91 (Aug. 27, 2020); Docket No. 49494, Order at FoF Nos. 108-121 (Apr. 6, 2020); Docket No. 49421, Order at FoF Nos. 71-87 (Mar. 9, 2020).

and SWEPCO confirmed it is amenable to similar measures in this docket.[773] However, Staff's proposed ring-fencing provisions go beyond those ordered for AEP Texas, specifically as to Recommendation Nos. 3, 5, 6, and 13, which SWEPCO opposes. Staff did not explain why the specific provisions it recommends were appropriate for SWEPCO. Instead, Staff's primary support for its ring-fencing recommendations is that they were adopted in other cases for other utilities.

Yet, given the demonstrated value of ring-fencing protections and SWEPCO's non-opposition to measures similar to those adopted for AEP Texas, the ALJs conclude that the essentially uncontested provisions (Recommendation Nos. 1-2, 4, 7-12, and 14-15) should be adopted. While SWEPCO raises an overall concern regarding increased compliance costs of adopting ring-fencing provisions in general, the Company acknowledges that it is already abiding by most of these measures. Thus, any increase in compliance costs is likely outweighed by the benefit to SWEPCO and its customers of having the ring-fencing protections in place. As to the remaining contested provisions (Recommendation Nos. 3, 5, 6, and 13), the ALJs find that the evidence does not show they are reasonable and necessary for SWEPCO.

Accordingly, the ALJs recommend that the Commission adopt Staff's proposed ring-fencing provisions listed above, with the exception of Recommendation Nos. 3, 5, 6, and 13, which should not be adopted.

VII. EXPENSES [PO Issues 1, 14, 24, 25, 27, 29, 30, 32, 33, 34, 35, 40, 41, 42, 44, 45, 46, 49, 72, 73, 74]

A. Transmission and Distribution O&M Expenses

1. Transmission O&M Expense [PO Issue 24]

No party challenged the reasonableness of SWEPCO's transmission O&M expenses, and SWEPCO provided evidence in support of its expenses. SWEPCO witness Dan Boezio discussed AEP's and SWEPCO's transmission systems, the services provided to ensure the system is

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[773] SWEPCO Initial Brief at 58-59.

maintained and provides reliable service, and cost and staffing level trends and their underlying drivers.[774] He also discussed the affiliate component of SWEPCO's O&M transmission expenses, recent AEPSC billings to SWEPCO, and benchmarking studies used to gauge the reasonableness of SWEPCO's affiliate O&M transmission charges for the test year.[775]

2. Transmission Expenses and Revenues under FERC-approved Tariff [PO Issue 46]

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.[776] Other than Eastman and TIEC's challenge regarding SPP OATT charges incurred for Eastman's retail behind-the-meter load, the inclusion of the test year SPP OATT expenses and revenues in SWEPCO's requested cost of service is uncontested.[777]

3. Proposed Deferral of SPP Wholesale Transmission Costs [PO Issues 72, 73, 74]

SWEPCO proposes that the portion of its ongoing SPP OATT bill that is above or below the net test year level approved by the Commission in this proceeding be deferred into a regulatory asset or liability until it can be addressed in a future TCRF or base-rate proceeding. Net ATC (Approved Transmission Charges) is the difference between the charges that SWEPCO is assessed for its use of the SPP transmission system that qualify as ATC under 16 TAC § 25.239(b)(1) and the payments that SWEPCO receives for the use of its transmission system.[778] In short, SWEPCO seeks an ATC tracker. TIEC, Staff, and ETWSD oppose SWEPCO's request.

SWEPCO argues that its request is authorized by statute, serves as a complement to an administrative rule, and is appropriate here to reconcile costs and avoid regulatory lag. SWEPCO

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774 SWEPCO Ex. 11 (Boezio Dir.) at 3, 7, 11.

775 SWEPCO Ex. 11 (Boezio Dir.) at 23, 24, 26.

776 SWEPCO Ex. 4 (Brice Dir.) at 12.

777 SWEPCO Initial Brief at 61.

778 Staff Ex. 4A (Narvaez Dir.) at 7.

asserts that its request falls under PURA § 36.209(b), which allows for the recovery of changes in wholesale transmission charges to the electric utility under a tariff approved by a federal regulatory authority to the extent that the costs or charges have not otherwise been recovered.[779] SWEPCO states that the net charges and revenues that are subject to its proposal are incurred and received under the FERC-approved SPP OATT, and SWEPCO proposes to record a regulatory asset or liability only to the extent that those net charges and revenues vary from the net amount being recovered in base rates. Thus, SWEPCO asserts, the Commission has the authority to implement an ATC tracker under PURA § 36.209, and implementing one would be consistent with the law's legislative history, which indicates the law was intended to allow non-ERCOT utilities cost recovery opportunities similar to those available to ERCOT utilities.[780] SWEPCO argues that 16 TAC § 25.239 (the TCRF rule which applies to Distribution Service Providers in ERCOT) supports its request because that rule allows ERCOT Distribution Service Providers to track certain costs. SWEPCO explains that its proposal is similar and not a substitute for but a complement to 16 TAC § 25.239 (the Commission's non-ERCOT TCRF rule). SWEPCO states its proposal is an effective way to reduce regulatory lag by providing for more timely cost recovery.

The parties that oppose SWEPCO's request argue that it is contrary to statute, administrative rule, and Commission precedent. First, they distinguish PURA § 35.004(d) for ERCOT utilities from PURA § 36.209, which applies to non-ERCOT utilities like SWEPCO. They argue that Section 36.201 prohibits automatic adjustments with one exception not applicable here.[781] PURA § 35.004(d) (for ERCOT utilities) specifically makes Section 36.201 inapplicable and allows the Commission to "approve wholesale rates that may be periodically adjusted to ensure timely recovery of transmission investment."[782] But the non-ERCOT provision, PURA § 36.209, lacks this authorizing language.[783]

779 PURA § 36.209(b).

780 House Research Org., Bill Analysis, Tex. C.S.H.B. 989, 79th Leg., R.S. (Apr. 15, 2005).

781 PURA § 36.201.

782 PURA § 35.004.

783 PURA § 36.209.

Second, these parties argue that SWEPCO's request is inconsistent with 16 TAC § 25.239—the non-ERCOT TCRF rule. They state that the ERCOT TCRF rule is based on a different statute,[784] and the ERCOT rule implements a tracking mechanism, unlike the non-ERCOT rule.[785] They also argue that the non-ERCOT rule limits amendments to TCRFs to once per calendar year, and the proposed ATC tracker would circumvent this limitation by providing for contemporaneous rather than annual cost recovery of the ATC component of transmission costs.[786] They contend that, rather than an ATC tracker in a base rate case, § 25.239(b) provides the mechanism to account for changes in ATC outside of a base rate case.[787] These parties also argue that the proposed ATC tracker goes beyond the historical test year construct used by the Commission.[788] Moreover, the Commission previously denied a request by SWEPCO to make a post-test year adjustment for SPP expenses, stating that the TCRF "must be based on the unadjusted costs that were actually incurred during a historical test year."[789]

Third, these parties assert that SWEPCO's request is contrary to Commission precedent. In Docket No. 46449, SWEPCO proposed to defer certain SPP expenses, but the Commission denied the request.[790] The Commission also found that such deferred accounting treatment is an extraordinary remedy warranted only under special circumstances.[791] The parties opposed to the request argue that SWEPCO has not demonstrated special circumstances here, where its SPP

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784 *Rulemaking Proceeding to Amend PUC Subst R. 25.193 Relating to Distribution Service Provider Transmission Recovery Factor (TCRF)*, Project No. 37909, Order Adopting Amendments to § 25.193 as Approved at the September 29, 2010 Open Meeting at 33-35 (Oct. 4, 2010) (explaining amendment was adopted under PURA § 35.004); PURA § 35.004(d).

785 *Compare* 16 TAC § 25.193(b)(2)(B) *with* 16 TAC § 25.239.

786 TIEC Initial Brief at 44; 16 TAC § 25.193(b)(2)(B); TIEC Ex. 1 (Pollack Dir.) at 10.

787 Staff Initial Brief at 50; Staff Ex. 4A (Narvaez Dir.) at 9.

788 16 TAC §§ 25.231(a)-(b), .239; TIEC Initial Brief at 22; TIEC Reply Brief at 22.

789 *Application of Southwestern Electric Power Company for Approval of a Transmission Cost Recovery Factor*, Docket No. 42448, Order at FoF Nos. 32-45 and CoL No. 8 (Nov. 24, 2014).

790 Docket No. 46449, Order on Rehearing, FoF Nos. 238-244 (Mar. 19, 2018).

791 Docket No. 46449, PFD at 278-79 (Sep. 22, 2017).

OATT revenues have increased more than its SPP OATT charges since SWEPCO's last rate case and its last TCRF proceeding.[792]

Finally, TIEC, Staff, and ETSWD contend that a ATC tracker is unnecessary. They argue that, if rates are cost-based, increased revenues resulting from load growth should more or less match increases in base rate revenue recovery from customers.[793] SWEPCO responds that load growth would match increases in SPP OATT charges only if SPP OATT transmission rates are static, but they are not—SPP OATT charges can change as often as every month.[794] And Staff witness Adrian Narvaez admits that, if SWEPCO's rates are not sufficiently cost-based, then it is possible SWEPCO could recover either more or less than the amount of costs included in the test year ATC component of the TCRF baseline.[795] Those opposing the request emphasize the same evidence, arguing that SWEPCO's proposal could result in an over-recovery of transmission charges—which PURA § 36.209(b) and 16 TAC § 25.239 prohibit.[796] Those opposing the request also give a second reason a ATC tracker is unnecessary here: SWEPCO's SPP revenues have increased more than SWEPCO's charges since SWEPCO's last rate case and last TCRF proceeding.[797] They add that SWEPCO's request is piecemeal ratemaking because it only tracks changes to a single part of rates (ATC), not changes in other costs and revenues.[798]

The ALJs recommend rejecting SWEPCO's proposed ATC tracker. SWEPCO's comparison to the ERCOT TCRF rule is misplaced because here 16 TAC § 25.239 applies, rather than PURA § 35.004(d). As Staff, TIEC, and ETSWD argue, an ATC tracker is contrary to and not specified in 16 TAC § 25.239. Additionally, SWEPCO has not shown that deferred accounting

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[792] TIEC Ex. 1 (Pollock Dir.) at 11.

[793] Staff Ex. 4A (Narvaez Dir.) at 8.

[794] *See* Docket No. 42448, Order at FoF No. 37 (Nov. 24, 2014) (finding SWEPCO's charges under SPP's schedules 9 and 11 can change as often as every month).

[795] Staff Ex. 4A (Narvaez Dir.) at 8.

[796] Staff Ex. 4A (Narvaez Dir.) at 10-11.

[797] TIEC Ex. 1 (Pollock Dir.) at 11.

[798] TIEC Ex. 1 (Pollock Dir.) at 10.

is appropriate in this situation or that the proposed recovery mechanism is needed here, where its SPP revenues have increased more than its charges.

4. Distribution O&M Expense [PO Issue 24]

SWEPCO states that its total company adjusted test year O&M expenses for distribution activities was approximately $93.65 million.[799] No party contests this amount.

SWEPCO provided evidence in support of the necessity and reasonableness of its distribution O&M expense. SWEPCO explained its distribution system—over 9,960 square miles, comprising approximately 8,769 miles of overhead conductor, and 832 miles of underground conductor to a low-density customer group distributed over a large area.[800] SWEPCO discussed its budgeting and cost-control initiatives to keep costs at the minimal reasonable level and confirmed that it outsources work where appropriate to control costs.[801] SWEPCO also provided benchmarking data showing that its average total company distribution O&M costs compare favorably to the median level of expenditures for peer groups for each year studied.[802]

The ALJs recommend approval of SWEPCO's proposed distribution O&M expense.

5. Distribution Vegetation Management Expenses and Program Expansion [PO Issue 27]

SWEPCO seeks an annual vegetation management spend of $14.57 million.[803] This is an increase of $5 million over the $9.57 million in vegetation management expenses incurred in the test year.[804] SWEPCO states that the requested increase will be used solely for increased vegetation

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[799] SWEPCO Ex. 10 (Seidel Dir.) at 21.

[800] SWEPCO Ex. 10 (Seidel Dir.) at 3-4.

[801] SWEPCO Ex. 10 (Seidel Dir.) at 25.

[802] SWEPCO Ex. 10 (Seidel Dir.) at 27-28.

[803] SWEPCO Ex. 3 (Smoak Dir.) at 6.

[804] SWEPCO Ex. 3 (Smoak Dir.) at 6.

management.[805] SWEPCO also agrees to periodic reporting to the Commission about the vegetation management and the funds spent.[806]

a. SWEPCO's Position

SWEPCO argues that additional vegetation management is needed for the reliability of its distribution system.[807] SWEPCO notes that its overhead distribution lines are in rural areas with heavy vegetation and some of the heaviest levels of precipitation in the state.[808] One of the top causes of outages within its territory is vegetation.[809] During the test year, for example, vegetation accounted for 2,641 customer service interruptions—40.1% and 49.1% of its overall SAIFI and SAIDI, respectively.[810] SWEPCO states that additional funds should be spent to address this.[811]

SWEPCO argues that additional spending on vegetation management will improve system reliability.[812] SWEPCO relies on past experience in 2018 and 2019 where 11 circuits with approximately 283 circuit miles (about 3.3% of SWEPCO's overhead distribution circuits) were fully cleared, resulting in improved reliability—fewer outages, a reduced number of customers affected, and reduced customer minutes of interruption.[813] SWEPCO witness Drew Seidel testified that he expects the additional spending to produce similar improvements.[814]

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[805] SWEPCO Initial Brief at 66.

[806] SWEPCO Initial Brief at 66.

[807] SWEPCO Ex. 10 (Seidel Dir.) at 16.

[808] SWEPCO Ex. 10 (Seidel Dir.) at 4.

[809] SWEPCO Ex. 10 (Seidel Dir.) at 19.

[810] SWEPCO Ex. 10 (Seidel Dir.) at 19.

[811] SWEPCO Initial Brief at 66.

[812] SWEPCO Initial Brief at 66-67.

[813] SWEPCO Ex. 10 (Seidel Dir.) at 17-18.

[814] SWEPCO Ex. 10 (Seidel Dir.) at 18, 20.

SWEPCO agrees that implementing a four-year trim cycle would produce improved reliability benefits for customers.[815] And SWEPCO is willing to accept Staff's proposal of a four-year trim cycle if fully funded.[816] But SWEPCO argues that because the four-year trim cycle is estimated to cost $38.35 million annually, the cost is too much for customers to absorb at once.[817]

SWEPCO emphasizes that additional vegetation management is needed because without it there will likely be degradation in SAIDI and SAIFI.[818] SWEPCO also notes that the additional vegetation management spend authorized in a prior case had a significant positive effect on SAIDI and SAIFI for the cleared circuits.[819]

b. Staff's Position

Staff argues that SWEPCO's request for an additional $5 million for vegetation management should be approved with conditions: (1) SWEPCO should be required to file periodic reports in a compliance docket related to additional vegetation management funds and report on the effect of the additional spending in a manner consistent with another case; and (2) SWEPCO should implement a four-year trim cycle within twelve months of the filing of the final order in this proceeding.[820]

Staff contends that SWEPCO should receive the proposed increase in vegetation management expense to help improve service reliability. Staff notes that SWEPCO's service reliability has failed to meet the Commission's standards. In the test year ending in March 2020, SWEPCO slightly failed the Commission's SAIFI standard.[821] And over the past nine years,

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815 SWEPCO Initial Brief at 68; SWEPCO Ex. 10 (Seidel Dir.) at 20.

816 SWEPCO Initial Brief at 68.

817 SWEPCO Initial Brief at 68-69; SWEPCO Ex. 10 (Seidel Dir.) at 20.

818 SWEPCO Ex. 40 (Seidel Reb.) at 7.

819 SWEPCO Ex. 10 (Seidel Dir.) at 18.

820 Staff Initial Brief at 50.

821 Staff Ex. 2 (Ramaswamy Dir.) at 5.

SWEPCO has consistently failed to meet the Commission's SAIDI standard.[822] To address service reliability, Staff recommends that SWEPCO's vegetation management request be approved and that the additional $5 million be spent on distribution vegetation management on SWEPCO's targeted circuit list.[823] Staff states that this recommendation is consistent with the treatment of a similar disputed request in SWEPCO's last base-rate case, where the Commission approved the request but required periodic status reports.[824]

Staff also argues that a four-year trim cycle should be implemented. Staff notes that utilities must make reasonable efforts to prevent interruptions of service.[825] SWEPCO witness Seidel agrees that a four-year trim cycle would be the best long-term solution for vegetation management.[826] Staff argues that, although SWEPCO protests that a four-year trim cycle is too expensive, SWEPCO should not be allowed to fail to meet reliability standards.[827] And Staff states that even though the amount of money needed to implement a four-year trim cycle is not known and measurable and therefore cannot be recovered in rates in this case, SWEPCO must improve its reliability and can seek recovery of increased vegetation management expenses in its next rate case after implementing a four-year trim cycle.[828]

c. OPUC's Position

OPUC opposes SWEPCO's proposed increase in vegetation management expense.[829] OPUC argues that, although SWEPCO provided data about particular circuits and identified improvements for 11 circuits with approximately 283 miles, the SAIFI and SAIDI scores do not

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822 Staff Ex. 2 (Ramaswamy Dir.) at 5.

823 Staff Ex. 2 (Ramaswamy Dir.) at 12.

824 Staff Ex. 2 (Ramaswamy Dir.) at 13; *Compliance Report on Southwestern Electric Power Company in Accordance with the Order on Rehearing in Docket No. 46449*, Docket No. 50052, Order No. 8 at 1 (Jun. 9, 2020).

825 16 TAC § 25.52.

826 *See* SWEPCO Ex. 10 (Seidel) at 20.

827 Staff Initial Brief at 54.

828 Staff Initial Brief at 54.

829 OPUC Ex. 1 (Cannady Dir.) at 48.

show that the proposed increase in spending will produce similar improvements on a system-wide basis.[830] Relying on past spending and data, OPUC witness Cannady noted that changes in spending do not necessarily result in corresponding improvements to the SAIFI for the distribution system.[831] She added that SWEPCO's SAIDI has significantly increased.[832] And the SAIDI increase, according to SWEPCO, was in part due to new policies on tree trimming, and SWEPCO has not shown how additional vegetation management spending will impact the duration time of outages under its new trimming policy.[833] Thus, OPUC argues, SWEPCO's request for additional vegetation management expense should be denied because SWEPCO has failed to show a positive correlation between additional spending and better customer service.[834]

d. CARD's Position

CARD opposes SWEPCO's proposed $5 million increase in vegetation management expense. CARD argues that the additional spending is unjustified. CARD witness M. Garrett explained that in its previous rate case SWEPCO received a $2 million increase in funding over its 2016 test year level—authorizing SWEPCO to recover approximately $9.93 million per year.[835] But, although spending more money since 2016, SWEPCO reported a SAIFI of 1.73 for 2016 and 1.79 for the test year—not a meaningful improvement.[836] And after the last rate case, in 2017 SWEPCO did not "follow through" on vegetation management spending—spending approximately $6 million in 2017, $13 million in 2018, and $9.5 million in 2019.[837] Mr. Garrett stated that a company is not required to spend the amount authorized for vegetation management expense, but when a company indicates a certain expenditure is necessary and yet fails to spend it,

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[830] OPUC Ex. 1 (Cannady Dir.) at 49.

[831] OPUC Ex. 1 (Cannady Dir.) at 50.

[832] OPUC Ex. 1 (Cannady Dir.) at 50.

[833] OPUC Ex. 1 (Cannady Dir.) at 50-51.

[834] OPUC Initial Brief at 15.

[835] CARD Ex. 2 (M. Garrett Dir.) at 39.

[836] CARD Ex. 2 (M. Garrett Dir.) at 40.

[837] CARD Ex. 2 (M. Garrett Dir.) at 40.

that "raises questions" about whether the cost level is essential.[838] Overall, CARD's point is that SWEPCO's previous vegetation management expenses have not produced sufficient results to justify additional spending.[839] CARD adds that SWEPCO can spend more money on vegetation management if needed and in fact is required to do so to provide safe and reliable service to customers.[840] Thus, CARD asserts, there is no need to increase SWEPCO's vegetation management expense.[841]

e. Texas Cotton Ginners' Position

TCGA opposes SWEPCO's request for increased vegetation management expenses. In addition to joining OPUC's and CARD's arguments, TCGA argues that additional vegetation management spending is not reasonable or prudent in regard to the Cotton Gin class. TCGA has five member gins in rural counties in the Texas Panhandle.[842] That service territory in the Texas Panhandle is over 300 miles from the rest of SWEPCO's service territory. The Texas Panhandle area is mostly flat, treeless, grassy plains with little rainfall. The rest of SWEPCO's service territory in Texas has heavy vegetation and high precipitation.[843] TCGA points out that almost all of SWEPCO's vegetation management costs are incurred outside the Texas Panhandle service area.[844] Only 1% of line items for manual clearing distribution management spending were in the Texas Panhandle,[845] and under a list of herbicide application jobs performed in the test year, none were in the Texas Panhandle.[846] TCGA argues that if additional vegetation management expenses are approved, there should be an adjustment to the Cotton Gin rate class because almost all the

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838 CARD Ex. 2 (M. Garrett Dir.) at 40.

839 CARD Reply Brief at 19.

840 CARD Ex. 2 (M. Garrett Dir.) at 39.

841 CARD Initial Brief at 41-42.

842 TCGA Ex. 1 (Evans Cross-Reb.) at 15.

843 SWEPCO Ex. 10 (Seidel Dir.) at 1.

844 Tr. at 202.

845 TCGA Ex. 11, SWEPCO's response to CARD RFI 4-53 at 47-48; Tr. at 202.

846 *See* Tr. at 207-08.

vegetation management expenses are for work more than 300 miles away done for a different group of customers.[847]

f. ALJs' Analysis

The ALJs agree with SWEPCO and Staff that an additional $5 million for vegetation management is justified. The evidence shows that SWEPCO's service reliability is lacking and should improve through increased vegetation management. Without the requested increase, the evidence does not show that SWEPCO would otherwise be able to improve its service reliability scores. As recommended by Staff, the ALJs also agree that the additional $5 million should be spent on distribution vegetation management on SWEPCO's targeted circuit list. Although OPUC, CARD, and TCGA are correct that the sample size of past cleared circuits is small, SWEPCO's experience with these circuits shows that well-targeted additional spending should produce improved reliability results.

The ALJs further agree with SWEPCO's and Staff's recommendation to open a compliance docket to examine SWEPCO's vegetation management practices and spending. Given SWEPCO's compliance history, further study is prudent, and the periodic reporting should assist the Commission in ensuring that SWEPCO is spending the additional funds as committed in this docket.

The ALJs, however, decline to require SWEPCO to implement a four-year trim cycle. A four-year trim cycle comes at significant cost. OPUC, CARD, and TCGA already raise reasonable concerns about whether additional spending is worthwhile. A compliance docket will allow the parties to gather additional information for a future decision, and, if needed in the meantime, Staff has other enforcement methods to address SWEPCO's service reliability.

[847] TCGA Initial Brief at 12.

TCGA's concern—that vegetation management expenses are not attributable to its customer class so an adjustment to cotton gin rates is appropriate—is addressed below in the Cost Allocation section of this PFD.

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

To serve its retail and wholesale customers, SWEPCO purchases Network Integration Transmission Service (NITS) from SPP for the use of SPP's transmission system.[848] SPP charges for NITS pursuant to its FERC-approved OATT.[849] SPP allocates the cost of using its transmission system to NITS customers (referred to as Network Customers in the OATT)[850] based on the ratio of each customer's monthly "Network Load" to the total system load at the time of the monthly system peak.[851] To obtain the data necessary to make this allocation, SPP requires Network Customers, such as SWEPCO, to submit their monthly Network Load data to SPP.

In October 2018, SWEPCO changed how it reports its monthly Network Load to SPP by adding load served by retail behind-the-meter generation (BTMG).[852] In this context, BTMG refers to a generation unit that is behind the transmission system meter—*i.e.*, not directly connected to the bulk transmission system—and is intended to serve all or part of the capacity or energy needs for the load behind the meter without withdrawing energy from the SPP transmission system.[853]

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[848] SWEPCO Ex. 52 (Ross Reb.) at 4. SWEPCO has transferred functional control of its transmission facilities to SPP.

[849] SWEPCO Ex. 52 (Ross Reb.) at 4.

[850] SPP OATT at Part I, Section 1 "N – Definitions."

[851] SWEPCO Ex. 52 (Ross Reb.) at 5. 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." SWEPCO Ex. 51 (Locke Reb.) at 3.

[852] SWEPCO Initial Brief at 78; SWEPCO Ex. 52 (Ross Reb.) at 12.

[853] SWEPCO Ex. 52 (Ross Reb.) at 7.

Retail BTMG (in contrast to wholesale BTMG) is on-site generation operated by a retail end-use customer to serve its own local load requirements.[854] Retail BTMG may be large scale, such as an industrial customer with a cogeneration facility, or small scale, such as a residential rooftop solar facility.

Historically, for SPP transmission cost allocation purposes, SWEPCO had reported retail BTMG on a *net* basis, meaning that it excluded any portion of a retail customer's load served by its own BTMG.[855] However, in October 2018, SWEPCO began reporting retail BTMG on a *gross* basis, so that it now includes the load served by retail BTMG in its calculation of Network Load. In other words, SWEPCO is reporting the load it serves, plus the load the retail customer supplies to itself with its BTMG. SWEPCO made this change after SPP provided educational information to its stakeholders clarifying that FERC policy and the SPP OATT do not exclude or "net" BTMG from the Network Load calculation.[856]

At this time, SWEPCO is only reporting the retail BTMG load of one customer, Eastman. Eastman operates an on-site cogeneration facility that generates approximately 150 MW of power to supply the full load requirements of Eastman's operations.[857] However, during scheduled maintenance outages and forced/unscheduled outages when Eastman's generation is not operating, Eastman purchases standby electricity service from SWEPCO under SWEPCO's Supplementary, Backup, Maintenance and As-Available Power Service Tariff (SBMAA Tariff).[858] Under this tariff, Eastman pays a reservation demand charge for standby power each month and a daily demand charge when it actually takes standby power from SWEPCO.[859]

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[854] Eastman Ex. 1 (Al-Jabir Dir.) at 5.

[855] If the retail customer's BTMG was offline or not serving its full load requirement, the retail customer's actual load would have been included in Network Load if it occurred at a monthly peak.

[856] SWEPCO Ex. 51 (Locke Reb.) at 23; SWEPCO Ex. 52 (Ross Reb.) at 11.

[857] Eastman Ex. 1 (Al-Jabir Dir.) at 4, 11. Eastman purchased the cogeneration facility, a combined-cycle gas-fired turbine generator, from AEP in 2008 and has been a SWEPCO customer since then. Eastman Initial Brief at 5.

[858] Eastman Ex. 1 (Al-Jabir Dir.) at 4, 12.

[859] Eastman Ex. 1 (Al-Jabir Dir.) at 4.

During the test year, the Network Load that SWEPCO reported to SPP included 146 MW of load served by Eastman's BTMG.[860] The higher reported Network Load resulted in SPP allocating a higher share of its transmission system costs to SWEPCO, which was reflected in SWEPCO's NITS charges in the test year. SWEPCO requests recovery of its test year NITS charges in this proceeding. The charges are part of SWEPCO's overall transmission costs, which SWEPCO allocates jurisdictionally among Texas, Arkansas, and Louisiana. SWEPCO estimates that including the retail BTMG load in its calculation of Network Load resulted in an increase of $5.7 million to its Texas retail revenue requirement in the test year.[861] SWEPCO proposes to recover this additional cost, in part, through a new transmission charge that would apply solely to Eastman.[862] This charge would increase Eastman's annual cost by $3.96 million as proposed in SWEPCO's application or $3.27 million as revised in SWEPCO's rebuttal.[863]

Eastman and TIEC argue that SWEPCO should not have included retail BTMG load in its calculation of Network Load. Therefore, they recommend a disallowance of $5.7 million from SWEPCO's requested revenue requirement.

a. Parties' Positions

To support their competing positions, SWEPCO, Eastman, and TIEC advance various arguments regarding: (1) the applicability of the filed rate doctrine and FERC jurisdiction; (2) the proper interpretation of the SPP OATT; (3) whether SWEPCO's treatment of retail BTMG violates protections for qualifying facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 (PURPA);[864] (4) whether Eastman's BTMG has imposed additional costs on SWEPCO's system;

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[860] TIEC Ex. 1 (Pollock Dir.) at 13.

[861] Eastman Ex. 7, SWEPCO's response to TIEC RFI 5-1.

[862] Tr. at 1262-63.

[863] TIEC Ex. 77, Excerpt from RFP Schedule Q-7; TIEC Ex. 78, SWEPCO's response to Staff RFI 19-2, Attachment 1; Tr. at 1504-05.

[864] QFs are small power production facilities and cogeneration facilities that are either self-certified or certified by FERC as QFs under PURPA. *See* 16 U.S.C. § 796(17)(C), (18)(A); 18 C.F.R. § 292.203. QFs receive certain benefits, such as the right to sell power to utilities and the right to purchase certain services from utilities. Eastman Ex. 1 (Al-Jabir Dir.) at 20 n.16. Small solar rooftop generators are also QFs. Tr. at 1162.

(5) whether SWEPCO's treatment of Eastman's BTMG is discriminatory; and (6) whether SWEPCO has met its burden of proof regarding the proposed $5.7 million revenue-requirement increase.

i. Filed Rate Doctrine/FERC Jurisdiction

There is no dispute that the NITS charges included in SWEPCO's application were billed by SPP and paid by SWEPCO.[865] According to SWEPCO, that fact alone is sufficient to establish their reasonableness under the filed rate doctrine, which requires that interstate power rates filed with FERC or fixed by FERC be given binding effect by the Commission when determining interstate rates.[866] In support, SWEPCO cites Docket No. 42448, a SWEPCO TCRF case in which the Commission concluded that: "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*."[867]

SWEPCO also claims TIEC and Eastman are seeking to circumvent FERC's exclusive jurisdiction. According to SWEPCO, the retail BTMG issue boils down to a dispute between SPP and both Eastman and TIEC over how to interpret the SPP OATT, a matter solely within FERC's jurisdiction to resolve.[868] Under the Federal Power Act, FERC has exclusive jurisdiction over the wholesale sale or transmission of electricity in interstate commerce, and therefore, is the exclusive arbiter of disputes involving a tariff's interpretation.[869] SWEPCO contends it is immaterial whether FERC has specifically been asked to decide the proper treatment of retail BTMG under the SPP

[865] SWEPCO Initial Brief at 71.

[866] *Entergy Louisiana, Inc. v. Louisiana Pub. Serv. Comm'n*, 539 U.S. 39, 47 (2003).

[867] Docket No. 42448, Order at CoL No. 18 (Nov. 24, 2014) (emphasis added) (citing *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354, 373 (1988)).

[868] SWEPCO Initial Brief at 73-74.

[869] *AEP Texas North Co. v. Texas Indus. Energy Consumers*, 473 F.3d 581, 585-86 (5th Cir. 2006) ("FERC, not the state, is the appropriate arbiter of any disputes involving a tariff's interpretation. Congress has given FERC exclusive jurisdiction to determine whether wholesale rates are just and reasonable."); *see also* 16 U.S.C. § 824(b).

OATT, as FERC jurisdiction does not turn on whether a particular matter was actually determined in a FERC proceeding.[870] SWEPCO notes that Eastman witness Ali Al-Jabir and TIEC witness Jeffry Pollock agreed that FERC has exclusive jurisdiction to address violations of the SPP OATT.[871] SWEPCO further asserts that Eastman and TIEC may raise the issue at FERC if they choose to do so.[872]

Eastman responds that the filed rate doctrine does not apply here because Eastman is not disputing whether SPP applied the FERC-approved rate to calculate SWEPCO's NITS charges.[873] Instead, the higher allocation of jurisdictional costs is due to SWEPCO's voluntary decision to change its interpretation of the SPP OATT and start reporting Eastman's BTMG load. If SWEPCO had not changed how it reports retail BTMG load, SPP would not have billed the additional costs SWEPCO now seeks to recover. Eastman also contends that SWEPCO's treatment is contrary to one of the principles underlying the filed rate doctrine, which is to prevent carriers from engaging in pricing discrimination between ratepayers.[874] According to Eastman, SWEPCO's decision to report the retail BTMG load of only one customer in one jurisdiction actually results in price discrimination between ratepayers. Additionally, Eastman claims that SWEPCO's reliance on Docket No. 42448 is misplaced because it was a TCRF case designed to recover expenditures for transmission infrastructure improvement costs and changes in wholesale transmission charges.[875]

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[870] *See 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.").

[871] Tr. at 621, 644.

[872] SWEPCO Initial Brief at 74; *see also* 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.").

[873] Eastman Reply Brief at 7.

[874] Eastman Reply Brief at 8 (citing *Keogh v. Chicago & N.W. Ry. Co.*, 260 U.S. 156, 163 (1922) ("[The filed rate doctrine] prevails, because otherwise the paramount purpose of Congress—prevention of unjust discrimination—might be defeated."); *Town of Norwood, Mass. v. New England Power Co.*, 202 F.3d 408, 419 (1st Cir. 2000) ("It is quite true that one rationale of the filed rate doctrine is to prevent discriminatory damage awards to different customers."); *Marcus v. AT&T Corp.*, 138 F.3d 46, 58 (2d Cir. 1998) (recognizing one of the principles underlying the filed rate doctrine as "preventing carriers from engaging in price discrimination as between ratepayers")).

[875] Eastman Reply Brief at 8-10.

In this case, however, SWEPCO did not identify any new construction of transmission facilities that drives the new allocation of costs from SPP.

Eastman further argues that its redress is with the Commission, not FERC.[876] According to Eastman, there are at least three problems with SWEPCO suggesting FERC as the sole solution. First, it is questionable whether Eastman would have standing to file a complaint because it is not an SPP Network Customer as defined by the OATT. Second, SWEPCO has not addressed the Commission's jurisdiction to inquire whether a new SPP jurisdictional allocation of costs is includable in SWEPCO's revenue requirement under the facts of this case. And third, SWEPCO does not dispute that FERC's jurisdiction is exclusively wholesale, not retail. The Commission has sole authority to set SWEPCO's retail rates.

TIEC contends that the Commission precedent in Docket No. 42448 regarding the filed rate doctrine relates to amounts paid to SPP "pursuant to the SPP OATT," which does not apply here because, according to TIEC, SWEPCO's treatment of retail BTMG is inconsistent with the OATT.[877] TIEC further contends that the other cases SWEPCO cites do not deprive the Commission of the ability to disallow payments that were not pursuant to the OATT. Specifically, in *Entergy Louisiana, Inc.*, the court stated that "we have no occasion to address the exclusivity of FERC's jurisdiction to determine whether and when a tariff has been violated;"[878] thus, the court did not address the issue. *AEP Texas North Co.* is distinguishable in TIEC's view because the tariff at issue, a FERC-approved agreement, specifically authorized AEPSC to implement the agreement's cost-sharing terms. Therefore, when a state rejected AEPSC's determination, the state's decision was inconsistent with the tariff and preempted by federal law. Here, however, TIEC states that FERC has not designated SWEPCO as the sole, official arbiter of monthly Network Load calculations under the OATT, and SPP disclaims that it has any audit or enforcement responsibility.[879]

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[876] Eastman Reply Brief at 11-12.

[877] TIEC Reply Brief at 33.

[878] *See Entergy Louisiana, Inc.*, 539 U.S. at 51.

[879] TIEC Reply Brief at 34.

Finally, as discussed below, TIEC contends the $5.7 million revenue-requirement increase that SWEPCO identifies results from how SWEPCO allocated its transmission charges jurisdictionally.[880] Thus, TIEC concludes the issue here is not a disallowance of SPP charges, but rather, the appropriateness of SWEPCO's jurisdictional allocation, a matter well within the Commission's jurisdiction to address.[881]

ii. Interpretation of the SPP OATT

SWEPCO contends that the change in how it reports retail BTMG load was not the result of the Company's interpretation of the SPP OATT or a voluntary choice, despite Eastman's and TIEC's assertions otherwise.[882] Instead, SWEPCO was directed by SPP to change how it reports monthly Network Load.[883] In support, SWEPCO offered the testimony of Charles Locke, SPP's Director of Transmission Policy and Rates, who testified that FERC policy under Order Nos. 888 and 890 requires generation, including BTMG that serves Network Load, to be included in the Network Customer's load ratio share of costs.[884] According to Mr. Locke, the rules set forth in these FERC orders are implemented by SPP's OATT, which: (1) provides no exception to exclude or "net" BTMG from Network Load calculations; and (2) does not differentiate between retail and wholesale BTMG (thus, providing no basis to report the two differently).[885] As a result, all Network Customers should be including loads served by BTMG in their monthly Network Load calculations.[886]

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[880] TIEC Reply Brief at 27-28.

[881] *See Entergy Texas, Inc. v. Nelson*, 889 F.3d 205, 209-10 (5th Cir. 2018).

[882] SWEPCO Ex. 52 (Ross Reb.) at 8.

[883] SWEPCO Ex. 52 (Ross Reb.) at 10.

[884] SWEPCO Ex. 51 (Locke Reb.) at 6; *Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, 61 Fed. Reg. 21,540 (1996); *see Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, 72 Fed. Reg. 12,266, at P 1619 (2007).

[885] SWEPCO Ex. 51 (Locke Reb.) at 5. Eastman's and TIEC's witnesses on this topic acknowledged that *wholesale* BTMG is reported on a gross basis, but each argued that retail BTMG should be reported on a net basis. Eastman Ex. 1 (Al-Jabir Dir.) at 6-7; TIEC Ex. 1 (Pollock Dir.) at 17.

[886] SWEPCO Ex. 51 (Locke Reb.) at 5.

The calculation of monthly Network Load is specifically addressed in Section 34.4 of the SPP OATT, which provides that: "The Network Customer's monthly Network Load is its hourly load (60 minutes, clock-hour); provided, however, the Network Customer's monthly Network Load will be its hourly load coincident with the monthly peak of the zone where the Network Customer load is physically located."[887] Mr. Locke testified that this language requires SWEPCO to include in its monthly Network Load all electricity that a retail customer is providing to itself at the time of the zonal coincident peak.[888] He maintained that there are no exceptions—the requirement applies to QFs under PURPA and small generators such as rooftop solar.[889]

According to SWEPCO, SPP has confirmed the directive to report retail BTMG loads in multiple presentations to SPP members.[890] For example, in a March 2018 presentation regarding Network Load reporting, SPP asserted that "[f]or network service at a discrete delivery point, SPP understands FERC's general policy as requiring all actual load to be reported," and "[f]or a discrete delivery point under network service, SPP has identified no generally applicable exemptions for partial load served by: Behind-the-Meter Generation."[891]

Eastman and TIEC, however, disagree that there was an SPP directive for Network Customers to change how they report Network Load.[892] They note that, when asked to provide all instances in which SWEPCO was instructed to include retail BTMG load in Network Load, SWEPCO did not produce a single document.[893] At the hearing, Mr. Locke could not identify a specific date when SPP determined that retail BTMG load must be included.[894] Further, according to Eastman, the SPP presentations that SWEPCO relies on do not qualify as a directive, especially

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887 SPP OATT at Part III, Section 34.4.

888 Tr. at 817.

889 Tr. at 817-18.

890 SWEPCO Ex. 52 (Ross Reb.) at 7 and Exh. CRR-1R at 19-20, 42.

891 SWEPCO Ex. 52 (Ross Reb.), Exh. CRR-1R at 19-20.

892 Eastman Initial Brief at 12-13; TIEC Reply Brief at 29-30.

893 *See* TIEC Exs. 66-68, SWEPCO's responses to TIEC RFIs 14-1, 14-2, 14-3.

894 Tr. at 788.

when they note inconsistencies in the reporting practices of Network Customers and the "need for clarity."[895] Without a formal directive, Eastman claims SWEPCO's decision to report Eastman's BTMG load was voluntary.

The voluntariness of SWEPCO's decision is further shown, according to Eastman, by the fact that the dispute within SPP and among its stakeholders on how to report retail BTMG is not settled.[896] As support, Eastman lays out the chronology of events regarding the policy debate at SPP on the proper treatment of retail BTMG. In 2016 and 2017, SPP considered revisions to its business practices and OATT, respectively, (discussed in more detail below) that would have addressed retail BTMG, but neither proposal was adopted. SPP also conducted two surveys of its members regarding treatment of retail BTMG, one in 2017 to gain an understanding of the load reporting practices of Network Customers, and another in 2019 to gauge SPP stakeholder interest in changes to the Network Load reporting requirements.[897] In the 2019 survey, a minority of Network Customers (11 of 44) were reporting retail BTMG load on a gross basis.[898] In presentations in 2018 and 2019, SPP staff noted that Network Customers were not consistently reporting retail BTMG in their Network Load.[899] And more recently, in a presentation dated January 11-12, 2021, SPP staff proposed to "develop a whitepaper containing proposed policies for proper treatment of behind-the-meter load and generation," but such action was deferred until at least July 2021.[900]

Eastman further argues SWEPCO's inclusion of retail BTMG load was voluntary because Mr. Locke admitted that SPP has no authority to audit Network Customers' reports and has no enforcement responsibility.[901] According to Mr. Locke, SPP is obligated to accept the Network

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895 *See* SWEPCO Ex. 52 (Ross Reb.), Exh. CRR-1R at 41.

896 Eastman Initial Brief at 13-15.

897 *See* SWEPCO Ex. 51 (Locke Reb.) at 22.

898 TIEC Ex. 36A, SWEPCO response to TIEC RFI 13-2, Attachment 2.

899 *See* SWEPCO Ex. 52 (Ross Reb.), Exh. CRR-1R at 31-33, 41.

900 *See* Eastman Ex. 2 (Al-Jabir Supp. Dir.) at 11-12; SWEPCO Ex. 52 (Ross Reb.), Exh. CRR-1R at 37.

901 Eastman Initial Brief at 15 (citing Tr. at 771).

Load reports provided by its customers.[902] Given the lack of enforcement authority and inconsistency in how Network Customers were reporting retail BTMG loads, Eastman asserts SWEPCO should have declined to start including Eastman's BTMG load in its monthly reports.

In addition, both Eastman and TIEC contend SWEPCO's decision to change how it reports retail BTMG load was not required by the SPP OATT.[903] The OATT's definition of monthly Network Load has not changed since its adoption more than 20 years ago.[904] According to TIEC, adding retail BTMG load to SWEPCO's monthly Network Load is actually inconsistent with the plain language of the OATT.[905] Specifically, Section 34.4 of the OATT requires a Network Customer to report *its* hourly load coincident with the zonal peak. Here, the Network Customer is SWEPCO, not the retail customer, so the OATT is referring to *SWEPCO's* hourly load, not the retail customer's load served by its BTMG. TIEC also notes that AEP, on behalf of SWEPCO and its affiliates, previously agreed that load served by retail BTMG did not meet the OATT's definition of Network Load.[906] AEP explained, in response to SPP's 2019 survey, that the definition of Network Load includes "all load served by the output of any Network Resources designated by the Network Customer;"[907] however, the Network Customer does not serve load supplied by a retail customer's BTMG (unless the BTMG is offline), and such load is not a Network Resource as defined by the OATT.[908]

As further support for their interpretation of the OATT, Eastman and TIEC point to two SPP "revision requests" that were not adopted.[909] In 2016, the SPP Billing Determinants Task Force prepared a revision request to SPP's business practices to clarify that Network Load does

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902 Tr. at 774.

903 Eastman Initial Brief at 13; TIEC Initial Brief at 48-51.

904 *See* Tr. at 784.

905 TIEC Initial Brief at 50.

906 *See* TIEC Ex. 36B, AEP response to SPP 2019 survey.

907 SPP OATT at Part I, Section 1 "N – Definitions."

908 TIEC Ex. 36B, AEP response to SPP 2019 survey.

909 TIEC Initial Brief at 51-53; Eastman Reply Brief at 17. A revision request is an SPP process to amend certain SPP governing documents, including the OATT and SPP Business Practices. SWEPCO Ex. 51 (Locke Reb.) at 10 n.21.

not include the capacity of "a generator of an individual retail customer where the output of such generator is owned by the retail customer and is intended to be consumed by that retail customer," *i.e.*, retail BTMG.[910] Because there was no corresponding proposal to change the OATT, TIEC contends this revision request reflected an assumption that the existing OATT language did not include retail BTMG in monthly Network Load. Otherwise, a revision to the OATT, not a business practice, would have been required.

The following year, SPP staff proposed Revision Request (RR) 241, which would have amended Section 34.4 of the OATT to, among other things, add the following language related to retail BTMG:

> The output from a generation unit with a nameplate rating greater than 1.0 MW, or the sum of the output from generation units with a combined nameplate rating greater than 1.0 MW, located behind a retail end-use customer's meter shall be included in the Network Customer's determination of monthly Network Load.[911]

According to Eastman and TIEC, this language would have for the first time included retail BTMG load greater than 1.0 MW in the calculation of a Network Customer's monthly Network Load. Adding this language would have been unnecessary if the calculation of monthly Network Load already included retail BTMG load. They assert the plain language does not support SWEPCO's opposite interpretation that RR 241 would have excluded retail BTMG loads *less than* 1.0 MW. RR 241 was ultimately rejected,[912] so in Eastman's and TIEC's view, the OATT continues to exclude all retail BTMG when calculating Network Load.

Eastman and TIEC also assert that SWEPCO's interpretation of the OATT is contrary to a FERC decision addressing MISO's tariff, which defines monthly network load virtually identically

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910 TIEC Ex. 45 at Bates 016.

911 TIEC Ex. 42 at Bates 005.

912 TIEC Ex. 42 at Bates 002.

to SPP's OATT.[913] When Entergy joined MISO approximately ten years ago, it brought with it a number of QFs under PURPA that generated their own electricity.[914] MISO adopted an "Integration Plan" that allowed Entergy's operating companies to report the *net* load of QFs in Entergy's service area when determining network load.[915] A QF challenged the Integration Plan with FERC, but FERC declined to order changes to the Integration Plan or require it to be included in MISO's tariff.[916] Therefore, according to Eastman and TIEC, FERC has determined that reporting a QF's *net* electricity is consistent with MISO's tariff.[917]

Eastman also generally contends SWEPCO should have considered that other Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) do not require their network customers to include retail BTMG load in determining monthly network load.[918] While some of these entities, including PJM and the California Independent System Operator (CAISO), have gone to FERC for a specific ruling, Eastman and TIEC contend this fact is not dispositive in this case.[919] TIEC also notes that FERC's PJM decision was issued ten years before its decision in the MISO case discussed above, which TIEC concludes resolved any ambiguity that the existing language in the FERC OATT did not include retail BTMG load.[920]

SWEPCO responds to each of Eastman's and TIEC's arguments regarding the SPP OATT and whether retail BTMG load must be reported. As to whether there was an SPP "directive" to report retail BTMG load, SWEPCO asserts that the notion Mr. Locke, as SPP's Director of Transmission Policy and Rates, does not represent or speak on behalf of SPP is nonsense.[921]

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913 *See* TIEC Ex. 1A (Pollock Dir. Workpapers) at 835 (excerpt from MISO tariff regarding "Determination of Network Customer's Monthly Network Load").

914 Tr. at 1187.

915 TIEC Ex. 1A (Pollock Dir. Workpapers) at 840.

916 *Occidental Chem. Corp. v. Midwest Independent System Operator, Inc.*, 155 FERC ¶ 61,068 at P 76 (2016).

917 Eastman Initial Brief at 17-18; TIEC Initial Brief at 53-54.

918 Eastman Initial Brief at 17; *see also* Eastman Ex. 1 (Al-Jabir Dir.) at 19-22.

919 Eastman Reply Brief at 16; TIEC Reply Brief at 31.

920 TIEC Reply Brief at 31.

921 SWEPCO Reply Brief at 65.

According to SWEPCO, Eastman is essentially arguing that complying with SPP's directive was imprudent because SPP lacks enforcement authority.[922] However, SWEPCO emphasizes it does not operate in this manner. Moreover, the fact that SPP lacks authority to penalize SWEPCO does not preclude any other affected entity from filing a complaint with FERC alleging a tariff violation, which could have serious repercussions for SWEPCO. The Company notes that retail customers in other RTOs have done just that in similar circumstances.[923]

SWEPCO also disagrees with Eastman's and TIEC's suggestion that it is reasonable for SWEPCO to ignore SPP's directives regarding the reporting of Network Load because other Network Customers may be doing so.[924] SWEPCO's decision to comply with SPP's load reporting instructions and express directives is not dependent on the practices or decisions of other SPP Network Customers. According to SWEPCO, what other Network Customers do and whatever their motivations might be are not relevant to whether SWEPCO has acted in compliance with SPP's directive.

In addition, SWEPCO points out that Eastman and TIEC were both aware of SPP's position on Network Load reporting under the SPP OATT well before this case was filed, since they both engaged in efforts to change SPP's stance.[925] Thus, prior to this rate case, Eastman or TIEC could have filed a complaint at FERC alleging that SPP has directed Network Customers to report Network Load in a discriminatory and unreasonable manner in violation of the SPP OATT. SWEPCO notes that FERC has recognized that retail customers have standing to file complaints and protest transmission rates.[926]

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922 SWEPCO Reply Brief at 65.

923 SWEPCO Reply Brief at 65-66 (citing *National Railroad Passenger Corporation v. PPL Electric Utilities Corporation and PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,237 at PP 2, 5, 6, 13, 35 (2020)).

924 SWEPCO Initial Brief at 75.

925 SWEPCO Reply Brief at 66.

926 SWEPCO Reply Brief at 66-67.

SWEPCO also responded to critiques in the testimonies of Eastman witness Al-Jabir and TIEC witness Pollock claiming that SWEPCO failed to distinguish between retail and wholesale BTMG.[927] According to SWEPCO, this distinction is irrelevant. Mr. Locke testified that FERC policy and the SPP OATT do not differentiate between retail and wholesale BTMG.[928] SWEPCO states that Mr. Locke also refuted the operational considerations cited by Mr. Al-Jabir and Mr. Pollock for differentiating between retail and wholesale BTMG for purposes of Network Load reporting.[929]

As to the SPP revision requests, SWEPCO characterizes RR 241 as proposing to add an exception to the reporting requirement for Network Load, specifically, an exclusion of retail BTMG *less than* 1.0 MW.[930] (This interpretation is essentially the opposite of Eastman's and TIEC's that RR 241 would have required *inclusion* of BTMG *greater than* 1.0 MW.) RR 241 was not approved through the SPP stakeholder process and, therefore, was not filed at FERC for approval.[931] However, even if RR 241 had been approved, filed at FERC, and approved by FERC for incorporation into the SPP OATT, SWEPCO points out that it would not have provided an exception for the retail load served by Eastman's BTMG, which is greater than 1.0 MW.

As to the positions of other RTOs, SWEPCO argues that Eastman's and TIEC's analogy is inapt for at least three reasons.[932] First, what other RTOs include in their tariffs is not relevant or controlling in this case.[933] SWEPCO is a Network Customer of SPP and, as such, is bound by the FERC-approved SPP OATT's terms and conditions. Second, Mr. Locke testified that FERC has approved alternative proposals for netting BTMG load in the calculation of Network Load for at

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[927] SWEPCO Initial Brief at 74-75 (citing Eastman Ex. 1 (Al-Jabir Dir.) at 6, 18; TIEC Ex. 1 (Pollock Dir.) at 17).

[928] SWEPCO Ex. 51 (Locke Reb.) at 12.

[929] SWEPCO Ex. 51 (Locke Reb.) at 18-20.

[930] SWEPCO Initial Brief at 77.

[931] SWEPCO Ex. 51 (Locke Reb.) at 21.

[932] SWEPCO Initial Brief at 75-77.

[933] SWEPCO Ex. 52 (Ross Reb.) at 14.

least two RTOs—PJM and CAISO.[934] 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. Further, he noted that the PJM and CAISO exceptions do not apply under the SPP OATT. Third, as to the FERC decision regarding MISO's Integration Plan for Entergy, SWEPCO contends that FERC's orders in that case have limited applicability and do not encompass either the SPP OATT or the establishment of national policy regarding BTMG.[935] 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 transmission service or the establishment of transmission charges.[936]

Additionally, SWEPCO argues that TIEC's and Eastman's attempt to establish the SPP OATT's Network Load reporting requirements through extrinsic sources such as other RTOs' tariffs and an unsuccessful revision request reinforces that this issue turns on the interpretation of the SPP OATT, a matter FERC has exclusive jurisdiction to resolve.[937]

SWEPCO acknowledges that in response to SPP's 2019 survey, it took the position (through AEP) that retail BTMG load should not be included in Network Load calculations and that it violated the PURPA as it relates to QFs.[938] However, SWEPCO states that it appears SPP was unpersuaded by the arguments given that SPP released a presentation coming to the opposite conclusion in January of 2021.[939]

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[934] SWEPCO Ex. 51 (Locke Reb.) at 8-9.

[935] SWEPCO Ex. 51 (Locke Reb.) at 15.

[936] SWEPCO Ex. 51 (Locke Reb.) at 15-16.

[937] SWEPCO Reply Brief at 70.

[938] SWEPCO Reply Brief at 68.

[939] SWEPCO Ex. 52 (Ross Reb.) at 9 & Exh. CRR-1R at 36-82.

iii. Alleged Violation of Regulations Regarding Treatment of QFs Under PURPA

Eastman and TIEC contend that SWEPCO's treatment of Eastman's BTMG violates federal and state regulations regarding treatment of QFs under PURPA.[940] There is no dispute that Eastman's cogeneration facility is a QF under PURPA.[941] FERC's regulations provide that standby service provided to QFs "shall not be based (unless supported by factual data) upon the assumption that forced outages or other reductions in electric output by all QFs on an electric utility's system will occur simultaneously, or during the system peak, or both."[942] This provision is violated, according to Eastman and TIEC, because SWEPCO's treatment of retail BTMG results in costs being allocated to QFs as if all of their BTMG were offline at the time of the system peak. AEP took a similar position in its 2019 comments to SPP, asserting that SPP's interpretation of Network Load conflicted with PURPA.[943] The regulations are violated, according to Eastman, regardless of whether SWEPCO uses actual data or estimated loads because it includes QF loads that are not on SWEPCO's system at the time of monthly peak load.[944]

TIEC asserts that SWEPCO is further violating the PURPA regulations by: (1) treating Eastman's QF differently than other retail self-generators; and (2) discriminating against QFs compared to customers with similar load characteristics that do not generate their own electricity.[945] As to the first item, SWEPCO is discriminating against Eastman's QF in comparison to non-QF generators because it is not reporting the load of its non-QF retail customers. As to the

940 Eastman Initial Brief at 16-17; TIEC Initial Brief at 54-57.

941 Eastman Ex. 1 (Al-Jabir Dir.) at 9; *see also* 16 U.S.C. § 796(18)(A); 18 C.F.R. § 292.203.

942 18 C.F.R. § 292.305(c)(i). The Commission has adopted rules that implement this same ratemaking principle. 16 TAC § 25.242(k)(3).

943 TIEC Ex. 36B, AEP response to SPP 2019 survey at 1 ("SPP Conflicts with PURPA by reaching behind the retail meter. SPP['s] position is inconsistent with the spirit of PURPA. PURPA requires that the retail rates for standby power should not be based on the assumption that forced outages and all other reductions in output by QF's will occur simultaneously or during the time of system peak. Likewise, we do not assume that each individual retail load will be at its peak usage for billing purposes and allow that diversity. Why should we treat this differently as opposed to load that was just off during the peak?").

944 Eastman Reply Brief at 18.

945 *See* 18 C.F.R. § 292.305(a)(1)(ii), (2); 16 TAC § 25.242(k)(1)(A)-(B).

second item, SWEPCO is also treating customers with similar load characteristics differently. For example, two customers taking 10 MW from SWEPCO's system impose the same costs on SWEPCO, irrespective of whether one is also generating electricity for its own use.[946] Yet, under Mr. Locke's interpretation of the OATT, if one of those customers is a QF generating 40 MW for its own use, SWEPCO would report as Network Load 50 MW for that customer.[947] Mr. Locke's interpretation would apply even if the QF had load that was synced to go down when its generation goes down so that it could never take more than 10 MW from SWEPCO's system.[948] Thus, a QF that can never impose a load greater than 10 MW is treated differently than a non-QF that takes 10 MW. As applied to Eastman, the discriminatory treatment would result in discriminatory rates, as evidenced by the proposed $3.3 million annual increase in rates for Eastman in this case.[949]

SWEPCO responds that, in calculating the monthly peak load data it reports to SPP, SWEPCO does not assume that forced outages or other reductions in electric output by all QFs will occur simultaneously, or during the system peak, or both.[950] SPP's NITS charges to SWEPCO are based on actual loads, not anticipated loads, served with BTMG.[951] SWEPCO also states that the issue here is transmission service charges, not generating capacity and energy. Further, if TIEC and Eastman believe that SPP's Network Load directive violates federal law—*i.e.*, PURPA—and discriminates against QFs, they should file a complaint at FERC, as it is FERC's duty under the Federal Power Act to assess the broad public interests involved in determining interstate rates.[952]

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[946] *See* Tr. at 1144-46, 1149.

[947] Eastman Ex. 11, SWEPCO's response to TIEC RFI 13-1.

[948] Eastman Ex. 11, SWEPCO's response to TIEC RFI 13-1.

[949] *See* Tr. at 1504-05.

[950] SWEPCO Ex. 52 (Ross Reb.) at 15.

[951] SWEPCO Ex. 52 (Ross Reb.) at 15.

[952] *See AEP Texas North Co.*, 473 F.3d at 586.

iv. Impact on Cost of Providing Service

Eastman contends that the additional $5.7 million in revenue requirement does not represent SWEPCO's cost of providing service to Eastman or any other customer.[953] Eastman's operations are served by its retail BTMG and do not take power from SWEPCO or contribute to SWEPCO's system demand, except when the retail BTMG is offline due to an outage. Eastman coordinates scheduled outages with SWEPCO to occur when system loads are low in the spring and fall, so the only time Eastman's operations could impose a demand on SWEPCO's system at the time of the zonal peak would be rare instances when a forced outage coincides with the zonal peak.[954] On average, Eastman's unplanned outages requiring backup service from SWEPCO occur three days per year.[955] Moreover, in those rare instances, Eastman already compensates SWEPCO by paying for standby service under the SBMAA Tariff.

Eastman notes that its facilities and load characteristics have not changed for almost 20 years.[956] None of SWEPCO's witnesses identified any new or additional cost caused by Eastman for service, and SWEPCO admitted that it does not serve the portion of Eastman's load served by its retail BTMG.[957] According to Eastman, the additional transmission costs SWEPCO seeks to recover in this case should be disallowed, as they are due to SWEPCO's decision to artificially increase its reported load by adding retail BTMG load that it does not serve.

However, SWEPCO disagrees that the $5.7 million is not a cost of providing service. SWEPCO states that it must purchase NITS from SPP in accordance with the OATT to serve SWEPCO's retail and wholesale customers that are synchronized with the SPP transmission system, including retail BTMG customers like Eastman.[958]

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953 Eastman Initial Brief at 8-11.

954 Eastman Ex. 1 (Al-Jabir Dir.) at 10.

955 Eastman Ex. 1 (Al-Jabir Dir.) at 10.

956 Eastman Initial Brief at 7.

957 Tr. at 1144 ("The BTMG load is still there, but it's not being served by SWEPCO. The energy is not being transmitted from our resources to that customer.").

958 SWEPCO Reply Brief at 73.

v. Alleged Discriminatory Rates

Eastman and TIEC contend that SWEPCO's decision to solely report Eastman's retail BTMG load to SPP is discriminatory.[959] SWEPCO has 187 retail BTMG customers in Texas, including Eastman, but is only reporting Eastman's BTMG load.[960] Of these customers, at least three have cogeneration facilities (including Eastman) and the rest appear to be commercial or residential solar facilities.[961] Similarly, SWEPCO did not report any retail BTMG load for its customers in Arkansas or Louisiana even though it has at least one industrial retail BTMG customer (a paper mill) in Arkansas, and has solar retail BTMG customers in both Arkansas and Louisiana.[962] While SWEPCO has retail BTMG customers in both states, it does not propose to increase the transmission cost allocation from SPP in either state or to treat any other retail BTMG customer as it would treat Eastman.

Eastman notes that SWEPCO claims it did not include loads for other retail BTMG customers because it did not have data for each of them.[963] However, in that case, Eastman contends SWEPCO should have delayed its decision to report retail BTMG load until it had a reasonable method of collecting data from some, if not all, retail BTMG customers. Not doing so is arbitrary and unreasonably discriminatory.

Eastman acknowledges that it uses SWEPCO's transmission system to serve a portion of its BTMG load, but notes that such use is limited to a single transmission line over a relatively short distance on Eastman's campus.[964] Eastman claims that using this line is more efficient for Eastman, SWEPCO, and SWEPCO's customers than constructing a new transmission line to serve

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959 Eastman Initial Brief at 18-21; TIEC Initial Brief at 57.

960 *See* TIEC Ex. 2 (Pollock Supp. Dir.), Exh. JP-S1. Eastman's initial brief states that SWEPCO has 185 retail BTMG customers, but the exhibit it cites lists 187 customers.

961 TIEC Ex. 2 (Pollock Supp. Dir.), Exh. JP-S1.

962 Tr. at 1166, 1168; Eastman Ex. 3, SWEPCO's response to Eastman RFI 1-1.

963 Eastman Initial Brief at 19.

964 Eastman Reply Brief at 19; Eastman Ex. 2 (Al-Jabir Supp. Dir.) at 25.

the entirety of Eastman's BTMG load, as it avoids the duplication of facilities. According to Eastman, its use of the SWEPCO transmission line is incidental and limited at best, and does not justify allocating $5.7 million in additional costs to Texas or approving a rate that recoups $3.96 million of those costs annually from Eastman.

TIEC argues that SWEPCO's differential treatment of Eastman compared to similarly situated customers violates the prohibition against discriminatory rates in PURA § 36.003(b) and would subject Eastman to an unreasonable disadvantage under PURA § 36.003(c).[965] TIEC notes that SWEPCO has singled out only one of its 187 Texas retail customers with BTMG for assessing costs to its retail BTMG load. Specifically, SWEPCO proposes to implement a new transmission rate that would apply solely to Eastman,[966] which would increase Eastman's annual cost by $3.96 million as proposed in SWEPCO's application or $3.27 million as revised in SWEPCO's rebuttal.[967] The other 186 customers continue to have only the actual load served by SWEPCO included in the development of their rates. None of them, including dozens of other facilities SWEPCO identifies as cogeneration facilities (one of which is over 80 MW),[968] would experience the massive increase SWEPCO proposes for Eastman.

In addition, TIEC contends that SWEPCO tries to justify singling out Eastman by asserting that it excluded customers that were not synchronous.[969] However, Mr. Locke acknowledged that the load of any actual SWEPCO customer must be synchronous.[970] Generation that is asynchronous simply means it is behind an inverter, like most solar power. According to TIEC, whether generation is synchronous or asynchronous has no significance for SWEPCO's operations when the generation goes down, nor has SWEPCO explained why asynchronous generation

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965 TIEC Initial Brief at 57.

966 Tr. at 1262-63.

967 TIEC Ex. 77, Excerpt from Schedule Q-7; TIEC Ex. 78, SWEPCO's response to Staff RFI 19-2, Attachment 1; Tr. at 1504-05.

968 TIEC Ex. 2 (Pollock Supp. Dir.), Exh. JP-S1.

969 TIEC Reply Brief at 30.

970 Tr. at 813-14, 816; *see also* TIEC Ex. 2 (Pollock Supp. Dir.) at 3.

serving synchronous load would be treated differently than Eastman's load. Nothing in Section 34.4 of the OATT would make such a distinction.

In response, SWEPCO states that it initiated the data reporting changes beginning with the loads served by Eastman's BTMG due to the size of the facility, its impact on day-to-day SPP real-time operations, and the fact that Eastman's BTMG requires the use of the SPP transmission system to serve all of the load at the Eastman campus.[971] According to SWEPCO, 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.[972] SWEPCO witness Ross explained that, in some instances, SWEPCO did not include the other retail BTMG 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. He further testified that SWEPCO did not include in its Network Load report to SPP the loads served by smaller-scale rooftop solar behind retail distribution system points of delivery. However, Mr. Ross confirmed that SWEPCO is continuing to review these situations and, as appropriate, will update its data reporting procedures for SPP transmission billing.

vi. Burden of Proof Regarding the Proposed $5.7 Million Increase in Texas Revenue Requirement

TIEC contends SWEPCO failed to meet its burden of proof regarding the proposed $5.7 million increase in Texas rates because SWEPCO did not identify the additional SPP costs it has incurred—that amount is not in the record.[973] The $5.7 million is not the additional SPP costs to SWEPCO of including the load served by Eastman's BTMG, but rather, represents a shift of *all* transmission-related costs, not just SPP charges, from Arkansas and Louisiana to Texas.[974] The

[971] SWEPCO Initial Brief at 78; SWEPCO Ex. 52 (Ross Reb.) at 12. Eastman witness Al-Jabir confirmed that Eastman requires the use of one SWEPCO-owned transmission line to serve the entire load at its campus with its BTMG. Tr. at 630-31.

[972] SWEPCO Ex. 52 (Ross Reb.) at 12.

[973] TIEC Initial Brief at 58-60.

[974] TIEC Ex. 2 (Pollock Supp. Dir.) at 1-2.

shift results from SWEPCO's jurisdictional allocation methodology, which adds the load served by Eastman's BTMG to the load SWEPCO's resources were serving at the time of the monthly peaks.[975] For example, SWEPCO's actual coincident demand for Texas for April 2019, the first month of the test year, was 889.9 MW, but for purposes of jurisdictional allocation, SWEPCO added 139 MW of load served by Eastman's BTMG at the time of the monthly peak.[976]

Adding Eastman's BTMG load in Texas in the jurisdictional allocation, but not the retail BTMG loads of SWEPCO's customers in Arkansas and Louisiana, shifts costs to Texas. This shift is shown in TIEC Exhibit 74, which compares SWEPCO's jurisdictional allocation with and without Eastman's BTMG load:

		TOTAL	AT ISSUE			
Jurisdiction		COMPANY	TEXAS	ARKANSAS	LOUISIANA	FERC
with Eastman	REVENUE DEFICIENCY / (SURPLUS)	228,419,735	105,026,238	88,619,584	43,013,790	(8,239,877)
without Eastman	REVENUE DEFICIENCY / (SURPLUS)	228,419,735	99,339,170	90,652,000	46,668,442	(8,239,877)
		-	5,687,068	(2,032,415)	(3,654,652)	-

Adding Eastman's BTMG load to the Texas jurisdiction reduces the Arkansas revenue requirement by $2.0 million and the Louisiana revenue requirement by $3.7 million, for a total of $5.7 million added to the Texas revenue requirement. TIEC notes that SWEPCO has not provided evidence of what the Texas revenue requirement would have been if it included the retail BTMG load of all three jurisdictions in its jurisdictional allocation study. Instead, SWEPCO is applying one method to develop the Texas jurisdictional demand, and another method to calculate the Arkansas and Louisiana demands. TIEC claims that adding retail BTMG load for Arkansas and Louisiana would presumably reduce Texas's share of allocated transmission costs.

TIEC also notes that SWEPCO's jurisdictional allocation methodology is not limited to the allocation of SPP-related charges. Rather, it includes all of SWEPCO's transmission revenue

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975 Tr. at 1201-02.

976 Tr. at 1202-04; *compare* TIEC Ex. 73 (SPP-RTO coincident demands by jurisdiction) *with* SWEPCO Ex. 31 (Aaron Dir.), Exh. JOA-3. SWEPCO made this adjustment for each month in the test year, resulting in an average increase of 146 MW over the 12 months.

requirement, roughly 34% of which is unrelated to the SPP load ratio share.[977] TIEC states that SWEPCO did not explain why the change in how it reports retail BTMG load to SPP would affect the allocation of SWEPCO's non-SPP revenue requirement, including the return on SWEPCO's own transmission invested capital, SWEPCO's investment-related expenses, and its transmission-related O&M expenses.[978] According to TIEC, these costs are the same SWEPCO costs that the Commission has allocated based on actual load in all previous cases, and SWEPCO did not present a cost-based or other rationale for changing Commission precedent on allocating SWEPCO's non-SPP transmission costs.

Further, because the $5.7 million increase is due to SWEPCO's increase in the Texas jurisdictional allocator for transmission costs, TIEC contends the retail BTMG issue is not a disallowance issue, but rather, a jurisdictional allocation issue.[979] As shown in TIEC Exhibit 74 above, under both the "with Eastman" and "without Eastman" scenarios, the total company revenue deficiency is the same—$228,419,735. Thus, as SWEPCO has presented its case, Eastman's load has no impact on SWEPCO's total company revenue requirement. Rather, it affects only the zero-sum game of allocating the total company revenue requirement between the jurisdictions.[980]

Because the issue is actually SWEPCO's proposed jurisdictional allocation of its total transmission costs, TIEC contends SWEPCO's argument that the Commission lacks jurisdiction to disallow any SPP expense is inapposite.[981] TIEC contends that it is well-established that state commissions have jurisdiction to adopt jurisdictional allocation methodologies in allocating a utility's costs, even if different states adopt different allocation methodologies that result in

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[977] TIEC Ex. 2 (Pollock Supp. Dir.) at 2.

[978] TIEC Ex. 2 (Pollock Supp. Dir.) at 2.

[979] TIEC Reply Brief at 27.

[980] *See* Tr. at 1212-13.

[981] TIEC Reply Brief at 27.

recovery of less than the total company costs. That is a risk that a utility assumes when it chooses to operate in multiple jurisdictions.[982]

Further, even if SWEPCO was required to include retail BTMG load when reporting its monthly Network Load, TIEC asserts there is no argument that the SPP OATT requires the selective inclusion of a single one of the hundreds of customers who generate a portion of their own load.[983] Indeed, Mr. Locke opined that *all* retail load served by BTMG must be included, which would include SWEPCO's retail BTMG customers in Arkansas and Louisiana. Thus, the $5.7 million does not reflect accepting SPP's interpretation of the OATT. TIEC states that SWEPCO has provided no evidence of what the jurisdictional allocators would have been had SWEPCO actually applied Mr. Locke's interpretation and included retail BTMG load in Arkansas and Louisiana in its jurisdictional allocation of transmission costs.

Accordingly, TIEC advocates that SWEPCO be directed to use its actual load in calculating the Texas jurisdictional allocator for transmission costs, just as it does for Louisiana and Arkansas.[984]

SWEPCO responds that it met its burden of proof as to the NITS charges because the record evidence establishes that including Eastman's BTMG load in SWEPCO's Network Load increased SWEPCO's load ratio share, which in turn increased SPP's NITS charges to SWEPCO, and the test-year NITS charges were billed by SPP pursuant to the OATT and paid by SWEPCO.[985] As discussed above, SWEPCO contends this evidence is sufficient under the filed rate doctrine to demonstrate reasonableness.

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[982] *Entergy Texas, Inc.*, 889 F.3d at 209-10. In this case, however, TIEC notes there is no trapped cost issue because TIEC seeks the adoption of the same allocation methodology used in SWEPCO's other jurisdictions.

[983] TIEC Reply Brief at 28.

[984] TIEC Reply Brief at 33.

[985] SWEPCO Reply Brief at 72.

In addition, SWEPCO disagrees that it is required to identify the precise portion of its test-year SPP charges related to the inclusion of Eastman's BTMG Texas load in SWEPCO's Network Load reporting.[986] Identifying these discrete costs is not required by the rate filing package or Commission precedent. SWEPCO notes that the Commission rejected a similar argument in Docket No. 42448. In that SWEPCO TCRF case, CARD argued that "SWEPCO is required to show that the specific cost components underlying the SPP charges to SWEPCO are reasonable and necessary."[987] However, the ALJ rejected CARD's argument:

> CARD's contention that SWEPCO must prove (and the Commission may examine) the reasonableness of charges made to SWEPCO under the SPP OATT is violative of the filed rate doctrine. As SWEPCO noted, if CARD (or any other party) wished to challenge charges made to SWEPCO under the SPP OATT, that party could have done so at FERC. The Commission is not the proper forum for such a challenge.[988]

The Commission approved the ALJ's decision.[989]

Furthermore, SWEPCO states that it did, in fact, provide the estimated dollar impact on SWEPCO's revenue requirement ($5.7 million) of including versus excluding the retail BTMG in its monthly Network Load reports to SPP.[990] According to SWEPCO, the incremental amount of NITS charges is only relevant in the case of a disallowance—*i.e.*, the Commission agrees with Eastman's and TIEC's interpretation of the SPP OATT and orders the removal of the incremental costs. But, as SWEPCO notes above, the Commission has already concluded that it is not proper to look behind and examine the reasonableness of charges made to SWEPCO under the SPP OATT. SWEPCO reiterates that TIEC and Eastman can file a complaint with FERC if they believe SPP's and SWEPCO's practices are resulting in unreasonable transmission charges in violation of the SPP OATT.

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986 SWEPCO Reply Brief at 72-73.

987 Docket No. 42448, PFD at 8 (Oct. 10, 2014).

988 Docket No. 42448, PFD at 9.

989 Docket No. 42448, Order at 2 & CoL Nos. 12-18.

990 SWEPCO Reply Brief at 73.

b. ALJs' Analysis

As SWEPCO points out, there is no dispute that the NITS charges were billed by SPP and paid by SWEPCO in the test year. Therefore, the ALJs first address whether the charges are deemed reasonable as a matter of law due to the filed rate doctrine and FERC's exclusive jurisdiction over the wholesale sale or transmission of electricity in interstate commerce. In this context, the filed rate doctrine and FERC's exclusive jurisdiction are intertwined. The filed rate doctrine requires that "interstate power rates filed with FERC or fixed by FERC must be given binding effect by state utility commissions determining intrastate rates."[991] When the filed rate doctrine applies to state regulators, it does so as a matter of federal preemption through the Supremacy Clause.[992] "Thus, as applied to state regulators, the filed rate doctrine polices the jurisdictional line and protects FERC's authority."[993]

Eastman and TIEC both argue that FERC's exclusive jurisdiction does not apply here because SPP's NITS charges under the OATT are impacted by an intermediate step—how SWEPCO reports its monthly Network Load to SPP.[994] If SWEPCO had not changed how it reports retail BTMG load, its load ratio share of SPP's transmission costs would not have increased, and SPP would not have billed the additional costs SWEPCO now seeks to recover. However, the determination of monthly Network Load is specifically addressed in SPP's FERC-approved OATT,[995] and therefore, cannot be viewed in isolation. In addition, the resulting rate charged by SPP is a wholesale rate, and its reasonableness is therefore squarely within FERC's exclusive jurisdiction to determine.[996] Notably, FERC's jurisdiction applies not only to rates but

[991] *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 962 (1986); *see also Mississippi Power & Light Co.*, 487 U.S. at 372 ("States may not bar regulated utilities from passing through to retail consumers FERC-mandated wholesale rates.").

[992] *Entergy Louisiana, Inc.*, 539 U.S. at 47 (citing *Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 581-82 (1981)).

[993] *Entergy Texas, Inc.*, 889 F.3d at 212.

[994] Eastman Initial Brief at 7; TIEC Initial Brief at 34.

[995] SPP OATT at Part III, Section 34.4.

[996] *Mississippi Power & Light Co.*, 487 U.S. at 371.

also to power allocations that affect wholesale rates.[997] Accordingly, the ALJs find that SWEPCO's role in providing the data to SPP on which SPP relied to allocate NITS charges does not remove this issue from FERC's jurisdiction.

In addition, while FERC jurisdiction does not depend on whether FERC has directly spoken on an issue,[998] the parties on both sides in this case cite FERC orders to support their positions. SWEPCO witness Locke cites FERC Order Nos. 888 and 890 as requiring BTMG that serves Network Load to be included in the Network Customer's load ratio share of costs.[999] Conversely, TIEC and Eastman cite FERC's decision regarding MISO's Integration Plan for Entergy as determining that reporting a QF's *net* electricity is consistent with MISO's tariff (which defines monthly network load nearly identically to SPP's).[1000] However, the ALJs find that neither side has pointed to FERC precedent that is definitive. FERC Order Nos. 888 and 890 addressed treatment of *wholesale* BTMG, which is not at issue here. And, while FERC's decision regarding MISO's Integration Plan for Entergy is not inconsistent with *net* reporting of retail BTMG, the issue was not directly before FERC, and thus, was not decided. Therefore, the parties have not pointed to controlling FERC precedent.

TIEC notes that the filed rate doctrine only applies to charges that are "pursuant to the SPP OATT."[1001] Yet, in this case, the OATT does not expressly address retail BTMG, much less whether it should be reported on a gross or net basis. Notably, both sides point to extrinsic sources (*e.g.*, SPP revision requests, the practices of other RTOs/ISOs, and FERC orders) to support their opposite interpretations. Therefore, to determine whether the charges are pursuant to the OATT necessarily requires an interpretation of the OATT. The Commission, however, is not the proper forum for resolving the OATT's meaning. The appropriate arbiter of disputes involving the interpretation of a FERC-approved tariff, such as the OATT, is FERC pursuant to its exclusive

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[997] *Mississippi Power & Light Co.*, 487 U.S. at 371.

[998] *Entergy Louisiana, Inc.*, 539 U.S. at 50.

[999] SWEPCO Ex. 51 (Locke Reb.) at 6.

[1000] Eastman Initial Brief at 17-18; TIEC Initial Brief at 53-54.

[1001] TIEC Reply Brief at 33.

jurisdiction over wholesale rates.[1002] In fact, this case presents a prime example of why such disputes are more appropriately resolved by FERC. The evidence demonstrates that there is a lack of consensus among SPP and its Network Customers regarding how to report retail BTMG load. SPP has Network Customers in multiple states, including Texas, and conflicting interpretations of the OATT would undermine FERC's ability to ensure that a filed rate is uniform across different states.[1003] Accordingly, the ALJs conclude it is not the Commission's role to weigh in on this debate in a retail rate case for one of the many utilities that are subject to the OATT.

The ALJs are also not persuaded that SWEPCO's decision to report retail BTMG load was merely voluntary. While there does not appear to be a separate directive from SPP requiring that Network Customers report retail BTMG load on a gross basis, SWEPCO demonstrated that SPP has provided educational materials explaining that such reporting is required by the OATT. SWEPCO also presented the testimony of Mr. Locke, SPP's Director of Transmission Policy and Rates, who unequivocally stated it is SPP's position that Network Customers should be reporting retail BTMG load on a gross basis.[1004] And the ALJs agree with SWEPCO that its reporting practices should not be dependent on whether SPP has enforcement authority to penalize SWEPCO, or on the reporting practices of other Network Customers.

Accordingly, the ALJs conclude that SWEPCO's undisputed evidence that its test-year NITS charges were billed by SPP and paid by SWEPCO is sufficient to demonstrate their reasonableness as a matter of law under the filed rate doctrine.[1005] While there remains a dispute about whether those charges are "pursuant to the SPP OATT," that matter is within FERC's exclusive jurisdiction to decide. For the same reason, the ALJs do not address whether SPP's interpretation of the OATT violates PURPA.

[1002] *AEP Texas North Co.*, 473 F.3d at 585.

[1003] *See AEP Texas North Co.*, 473 F.3d at 586.

[1004] SWEPCO Ex. 51 (Locke Reb.) at 5.

[1005] *See Nantahala Power & Light Co.*, 476 U.S. at 962.

Finding that the NITS charges are reasonable, however, does not resolve whether the $5.7 million increase SWEPCO requests in this case is reasonable, necessary, and non-discriminatory. As TIEC and Eastman point out, the $5.7 million is not the increase in NITS charges that SWEPCO incurred due to reporting Eastman's BTMG load to SPP. Instead, it results from a change in how SWEPCO proposes to allocate its transmission costs jurisdictionally among Texas, Arkansas, and Louisiana, specifically by increasing Texas's load by 146 MW to add Eastman's BTMG load.[1006] The reasonableness of a utility's jurisdictional allocation is a matter within the state's jurisdiction to determine in setting the utility's retail rates, even when it impacts the allocation of costs charged pursuant to a FERC-approved tariff.[1007]

SWEPCO provided little support for changing its jurisdictional allocation. Notably, even though including retail BTMG load in the jurisdictional allocation of transmission costs is not consistent with how SWEPCO has allocated these costs in the past, its Application provided little indication that it was making this change. SWEPCO also did not explain why adjusting its jurisdictional allocation in this manner was the appropriate way to address the increase in SPP costs related to reporting Eastman's BTMG load to SPP. As TIEC points out, by changing the jurisdictional allocator for *all* transmission costs, Texas would receive a higher share not only of SWEPCO's SPP costs, but also its transmission costs that are not related to SPP. However, SWEPCO also did not explain why the change in how it reports retail BTMG load to SPP would impact the allocation of its non-SPP transmission costs.

Further, the ALJs find that SWEPCO's decision to revise its jurisdictional allocation to add the retail BTMG load of one customer (Eastman) in one jurisdiction (Texas) is unreasonable and results in unreasonably discriminatory rates for Texas customers. SWEPCO has retail customers with BTMG in all three of its jurisdictions. As a result, adding retail BTMG load solely to Texas likely results in the Texas jurisdiction receiving a higher allocation of SWEPCO's transmission costs than if the Company had treated each jurisdiction consistently. This inconsistency is also not

[1006] *See* TIEC Ex. 74, SWEPCO response to TIEC RFI 11-1.

[1007] *See Entergy Texas, Inc.*, 889 F.3d at 207, 209-10.

attributable to SPP requiring Network Customers to report retail BTMG load, as Mr. Locke testified that *all* retail BTMG load should be reported.[1008]

The ALJs are also not persuaded by the distinctions SWEPCO identifies for reporting only Eastman's BTMG load. While Eastman has the largest BTMG load of SWEPCO's retail customers, it is not the only customer with a sizable BTMG load. SWEPCO also did not show that Eastman's size imposes a greater cost on its transmission system, particularly here, where it is undisputed that Eastman rarely takes service from SWEPCO and is unlikely to take service during a system peak. SWEPCO also pointed out that, due to the configuration of Eastman's campus and BTMG, Eastman uses a SWEPCO-owned transmission line to serve all of its load. However, Eastman demonstrated that this configuration existed before it purchased the BTMG system from a predecessor of AEP and that Eastman's use of the line is incidental. Further, the use of the line does not appear to be imposing new costs on SWEPCO's system. Finally, as to whether the load is synchronous versus asynchronous, this distinction does not appear to be significant here, as any load SWEPCO is capable of serving must be synchronous.

For these reasons, the ALJs conclude that SWEPCO failed to demonstrate that its proposed jurisdictional allocation was reasonable, necessary, and non-discriminatory. Accordingly, the ALJs recommend that the 146 MW of Eastman's BTMG load that SWEPCO added to the Texas jurisdiction for allocation purposes be removed.

B. Generation O&M Expense

SWEPCO's test year level of generation non-fuel production O&M expense was \$130.1 million.[1009] SWEPCO asserts that its expenses are reasonable and states it has maintained tight control of its budget during the last three years, with an average deviation from control budget to expenditures of approximately 6%.[1010] From 2017 to the test year, SWEPCO's O&M expense

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[1008] *See* Tr. at 817-18.

[1009] SWEPCO Ex. 7 (McMahon Dir.) at 20.

[1010] SWEPCO Ex. 7 (McMahon Dir.) at 23.

decreased by approximately $6 million.[1011] SWEPCO also notes that it has decreased its staffing levels, and for large projects it outsources labor to avoid employing more people than necessary for normal plant operations.[1012] SWEPCO stresses that its O&M projects and expenses are scrutinized and approved at multiple levels of management, and expenditures are tracked and managed on a monthly basis.[1013]

Parties challenge SWEPCO's generation O&M expense in regard to plant retirements—the expected retirement of the Dolet Hills unit in December 2021 and the recent retirements of five gas-fired generating units.

1. Dolet Hills

SWEPCO proposes to include in its rates the O&M expense for Dolet Hills. Parties argue that SWEPCO's expenses should be adjusted for the plant's retirement.

CARD argues that because Dolet Hills will be retired two months after new base rates are expected to be placed into effect, for Dolet Hills, SWEPCO should recover two months of expenses at the test year average monthly O&M expense level of $1.04 million per month.[1014] SWEPCO incurred approximately $12.5 million for its ownership share of Dolet Hills non-fuel O&M during the test year.[1015] CARD's proposed adjustment would reduce SWEPCO's requested test year O&M expense for Dolet Hills by approximately $10.4 million on a total company basis.[1016] CARD argues that this adjustment is appropriate because, by failing to account for the Dolet Hills retirement, SWEPCO's requested revenue requirement is inflated: there will be no significant O&M costs

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[1011] SWEPCO Ex. 7 (McMahon Dir.) at 24.

[1012] SWEPCO Ex. 7 (McMahon Dir.) at 25.

[1013] SWEPCO Ex. 7 (McMahon Dir.) at 26.

[1014] CARD Ex. 3 (Norwood Dir.) at 6. The ALJs have previously discussed that the effective date for the rates in this docket—the relate-back date—is March 18, 2021, not the date of a Commission final order issued in this docket.

[1015] CARD Ex. 3 (Norwood Dir.) at 5.

[1016] CARD Ex. 3 (Norwood Dir.) at 6.

after the plant has been retired.[1017] And the O&M expenditures for the plant are likely to be greatly reduced by the time new base rates are placed in effect because Dolet Hills has been primarily restricted to operating in the summer months.[1018] Additionally, regardless of the plant's retirement, Dolet Hills' net capacity factor has declined—from an average of 35.4% in 2017, to 26.4% in 2018, to 20.6% in 2019—and this drop in production merits a reduction in O&M expenses because non-fuel O&M expenses for lignite-fired generating units vary with the volume of lignite burned for production.[1019]

Sierra Club also seeks to adjust SWEPCO's O&M expenses because of the Dolet Hills retirement.[1020] Sierra Club explains that use of a test year assumes that operations during the test year are representative of operations while rates will be in effect.[1021] But here SWEPCO will retire Dolet Hills shortly after the Company's new base rates will go into effect.[1022] Sierra Club further argues that, at a minimum, SWEPCO's expenses for Dolet Hills should be reduced by $3.5 million (25% of the proposed test year spending)—a reduction for the three months during which SWEPCO has committed not to operate the plant.[1023]

ETEC-NTEC states that Dolet Hills is a significant annual expense that, absent mitigation, SWEPCO will charge annually until its next base rate case.[1024] ETEC-NTEC argues that because Dolet Hills will be retired shortly after new rates become effective, a mitigation measure is needed to avoid unreasonable and problematic rate consequences.[1025] ETEC-NTEC proposes creating a regulatory liability for the non-fuel operating costs included in the revenue requirement related to

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[1017] CARD Ex. 3 (Norwood Dir.) at 5.

[1018] CARD Ex. 3 (Norwood Dir.) at 5-6.

[1019] CARD Initial Brief at 43.

[1020] Sierra Club Initial Brief at 19.

[1021] Sierra Club Initial Brief at 20.

[1022] Sierra Club Initial Brief at 20. Again, the rates in this docket will become effective as of March 18, 2021.

[1023] Tr. at 135-36, 176.

[1024] ETEC-NTEC Initial Brief at 11.

[1025] ETEC-NTEC Initial Brief at 12.

Dolet Hills for the month the unit is retired until the effective date of a new base rate case, so the regulatory liability can be used to offset the regulatory asset created for the remaining book value of Dolet Hills or other costs.[1026] ETEC-NTEC emphasizes that a regulatory liability is needed because Dolet Hills will be retired and SWEPCO has not demonstrated that new costs will arise that will displace the operating costs no longer incurred.[1027]

SWEPCO states that the recovery of Dolet Hills expenses is proper because the test year Dolet Hill plant O&M costs are reasonably representative of the costs the plant will incur in 2021.[1028] That is, until its retirement at the end of 2021, Dolet Hills will be offered into the energy market and will incur expenses to keep the unit available to operate, and Dolet Hills will operate seasonally in 2021 like it did in the test year, so its O&M expenses will be similar to the test year's.[1029]

SWEPCO disagrees with CARD's proposed adjustment, arguing that it would under-recover Dolet Hills' O&M expense in 2021 after the March 2021 effective date of rates: "it is not reasonable to eliminate O&M expense for a plant that will continue to operate for almost a year after the effective date of rates."[1030] And SWEPCO asserts that CARD's argument about Dolet Hill's dropping capacity factor is meritless because not only did CARD fail to offer evidence that "non-fuel O&M expenses for lignite-fired generating units vary with the volume of the lignite that is burned for energy production,"[1031] but O&M expenses extend beyond generation to labor, maintenance, and field support.[1032]

[1026] ETEC-NTEC Initial Brief at 12.

[1027] ETEC-NTEC Initial Brief at 12.

[1028] SWEPCO Initial Brief at 80.

[1029] SWEPCO Ex. 37 (McMahon Reb.) at 2.

[1030] SWEPCO Ex. 37 (McMahon Reb.) at 2, 6.

[1031] *See* CARD Initial Brief at 43.

[1032] SWEPCO Reply Brief at 75; SWEPCO Ex. 7 (McMahon Dir.) at 21.

SWEPCO also disagrees with Sierra Club. Although acknowledging that ratemaking is a forward-looking process using a test year to approximate a utility's anticipated costs of operating during the period when rates will be in effect, SWEPCO responds that the Dolet Hills expenses do in fact approximate the costs "when rates will be in effect" because the rates set in this case are effective from March 2021 when Dolet Hills provided service.[1033]

SWEPCO disagrees with ETEC-NTEC as well. SWEPCO reiterates that generally the cost of operating assets that are used and useful should be included in cost-of-service rates. SWEPCO asserts there is no reason to depart from that policy here. Again, because Dolet Hills was providing service when the rates being set in this case will become effective, SWEPCO's investment in the Dolet Hills plant is properly included in SWEPCO's historical test year rate base on which rates are to be set.

The ALJs agree with the parties requesting an adjustment to account for the Dolet Hills retirement. The central point is that Dolet Hills will soon be retired, so SWEPCO should not continue to recover O&M expenses that will no longer be incurred after December 31, 2021. CARD and Sierra Club each propose calculations to address the matter now. The ALJs recommend adopting CARD's approach of allowing SWEPCO to recover a test year average monthly O&M expense level of $1.04 million per month. But the ALJs disagree with CARD and Sierra Club about when rates will become effective in this case. The ALJs agree with SWEPCO that rates in this case will be effective from March 2021 forward. The ALJs therefore recommend that SWEPCO recover a test year average monthly O&M expense for Dolet Hills until its retirement in December 2021 but not after. This recognizes SWEPCO's point that the Dolet Hills plant is in service when rates will be in effect but also avoids recoupment for expenses that will no longer be incurred once Dolet Hills retires.

[1033] SWEPCO Reply Brief at 75. *See generally* PURA § 26.211(b); 16 TAC § 25.5(101).

2. Five Retired Natural Gas Plants

CARD argues that SWEPCO fails to properly account for five retired gas-fired generating units.[1034] CARD notes that one unit was retired in January 2019, and four units were retired in May 2020.[1035] CARD asserts that the retirement of these five units is a known and measurable change that will reduce O&M expenses.[1036] To address this, CARD requests that the test year expense for each plant reflect the level of generating capacity retirements made at each plant.[1037] CARD argues that SWEPCO's already-included ($616,316) reduction for the five retired units is insufficient because that is only approximately 5% of the total test year expense for the Knox Lee, Lieberman, and Lone Star gas plants, even though five of the eight existing gas units (or 62.5%) were retired during the period.[1038] CARD asserts that its proposed $1.1 million adjustment (in addition to SWEPCO's already-included reduction of approximately $600,000) to SWEPCO's $11.3 million test-year expenses is more appropriate: it is a 15% reduction to test-year expenses for the retired units.[1039]

SWEPCO disagrees and asserts CARD's adjustment is overstated. SWEPCO states that it already included an approximately ($600,000) adjustment for the five retired units.[1040] SWEPCO explains that this figure was calculated using benefiting location, which includes the costs at the generating unit level.[1041] In contrast, SWEPCO asserts, CARD's proposed adjustment is in addition to the amount SWEPCO already removed for the retired units.[1042] And for four of the five units, CARD's adjustment greatly exceeds the actual test year expense for the units.[1043] Also,

[1034] CARD Initial Brief at 43; CARD Ex. 3 (Norwood Dir.) at 6-7.

[1035] SWEPCO Ex. 7 (McMahon Dir.) at 9-10.

[1036] CARD Initial Brief at 44.

[1037] CARD Ex. 3 (Norwood Dir.) at 7, Attachment SN-6.

[1038] CARD Reply Brief at 21.

[1039] CARD Reply Brief at 21.

[1040] SWEPCO Ex. 37 (McMahon Reb.) at 2.

[1041] SWEPCO Ex. 37 (McMahon Reb.) at 3.

[1042] SWEPCO Ex. 37 (McMahon Reb.) at 4.

[1043] SWEPCO Ex. 37 (McMahon Reb.) at 4.

CARD assumes that plant-level O&M expenses are reduced by an amount equal to the percentage of capacity retired, ignoring that when a generating facility has multiple units, there are often shared assets, and when a unit retires, the expenses associated with those shared assets must be distributed among fewer units.[1044] Thus, SWEPCO argues, CARD's adjustment is not based on a known and measurable change and overstates the costs attributable to the retired units.[1045]

The ALJs agree with SWEPCO. A preponderance of the evidence shows that SWEPCO properly accounted for the reduction in non-fuel O&M expenses that resulted from the retirement of five gas-fired generation units. SWEPCO's O&M expense records using benefitting location identify costs at the generating unit level, and using these costs is preferable to the alternative proposed by CARD.

C. Labor-Related Expenses

1. Payroll Expense

a. SWEPCO's Position

SWEPCO states that its payroll costs were calculated using the actual employees on the payroll at the end of the test year (March 2020) and their base payroll amounts at that time plus a post-test year pay increase.[1046] SWEPCO witness Andrew Carlin explained that salary increases were implemented in April 2020, and the increases were collectively bargained for or determined and approved before there was any known impact from COVID-19.[1047] SWEPCO witness Baird further explained that the percentage increase in the payroll pro forma was 3.5% for all employees, but the adjustment included only the merit or general wage increases.[1048] Merit-eligible employees

[1044] SWEPCO Ex. 37 (McMahon Reb.) at 5.

[1045] SWEPCO Ex. 37 (McMahon Reb.) at 5.

[1046] SWEPCO Ex. 36 (Baird Reb.) at 31.

[1047] SWEPCO Ex. 21 (Carlin Dir.) at 18.

[1048] SWEPCO Ex. 36 (Baird Reb.) at 31.

were adjusted 3.0%, and hourly physical and craft employees were adjusted 2.5%, all of which was approved by the compensation committee and implemented by October 2020.[1049]

SWEPCO argues that it has made two known and measurable adjustments to its payroll: (1) annualizing its 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.[1050] SWEPCO states these two adjustments are consistent with the Commission's decisions in SWEPCO's two previous rate cases,[1051] and the Commission approved a 3.5% payroll increase in SWEPCO's last base rate case and should do so again here.[1052]

SWEPCO disagrees with Staff's and OPUC's proposal to use more recent payroll information. SWEPCO argues that is contrary to the Commission's Cost of Service Rule, which provides that "only the electric utility's historical test year expenses as adjusted for known and measurable changes will be considered."[1053] Although a retirement incentive package was offered after the end of the test year, SWEPCO argues that the impact of the retirement package is not "known and measurable" because an annualized payroll cannot be done until all employees have departed and decisions on filling the positions has been made, and when vacancies occur, associated reductions in payroll may be offset by increased spending in other cost categories (*e.g.*, outside services when work is redirected to contingent labor or outsourced).[1054]

b. Staff's and OPUC's Position

Staff and OPUC do not challenge a payroll increase. They instead recommend that SWEPCO's payroll expense be adjusted to align with recent payroll information:

1049 SWEPCO Ex. 36 (Baird Reb.) at 31.

1050 SWEPCO Initial Brief at 82.

1051 Docket No. 40443, Order on Rehearing at FoF Nos. 210-13 (Mar. 6, 2013); Docket No. 46449, Order on Rehearing at FoF Nos. 191-193 (Mar. 19, 2018).

1052 *See* Docket No. 46449, Order on Rehearing at FoF Nos. 191-193 (Mar. 19, 2018).

1053 16 TAC § 25.231(b).

1054 OPUC Ex. 37, SWEPCO response to OPUC RFI 6-2; SWEPCO Ex. 36 (Baird Reb.) at 35.

For SWEPCO's direct payroll expense, SWEPCO requests an increase of approximately $2.14 million to its test year payroll expense based on the annualization of the last pay period of the test year (March 2020) and a 3.5% salary increase to the base payroll cost.[1055] Staff notes that more recently, however, SWEPCO's October 31, 2020 payroll was annualized, resulting in an increased payroll expense.[1056] As a result, Staff requests an adjustment of $544,331 above SWEPCO's requested adjustment.[1057]

For SWEPCO's AEPSC-allocated payroll expenses, SWEPCO requests an increase of approximately $3.90 million to its test-year allocated AEPSC payroll expense based on an annualization of the end of test-year headcount and inclusion of a merit increase.[1058] Staff again notes, however, that SWEPCO provided an updated calculation based on an annualization of the October 2020 AEPSC payroll allocated to SWEPCO compared to the allocated test-year amount to derive an adjustment to the test-year amount of ($675,636).[1059] This change is due to a proportional difference in employees who accepted a recent retirement incentive package: one SWEPCO employee and 189 AEPSC employees accepted the retirement package.[1060] Staff thus proposes an adjustment of ($4,480,512)—the difference between SWEPCO's requested increase and the updated October 2020 payroll amount.[1061]

OPUC witness Cannady emphasized that because the retirement package was offered after the test year, and because there was a material number of employees who accepted the retirement

[1055] Staff Ex. 3 (Stark Dir.) at 6-7.

[1056] Staff Ex. 3 (Stark Dir.) at 6-7.

[1057] Staff Ex. 3 (Stark Dir.) at 6-7.

[1058] Staff Ex. 3 (Stark Dir.) at 7.

[1059] Staff Ex. 3 (Stark Dir.) at 7-8.

[1060] Staff Ex. 3 (Stark Dir.) at 8.

[1061] Staff Ex. 3 (Stark Dir.) at 8.

package, the employee headcount at the end of the test year is not an appropriate headcount on which to annualize payroll expenses.[1062]

c. CARD's Position

CARD opposes a proposed 3.5% payroll increase.[1063] CARD witness M. Garrett stated that a 3.5% payroll increase will almost never result in a 3.5% increase in payroll expense levels.[1064] He testified that the actual increase amount associated with a nominal pay raise is not known and measurable because too many other factors impact the overall change of payroll expense. Those factors include: the turnover of employees, with retiring employees taking higher salary levels off the system and new employees coming on at lower pay levels; workforce reorganizations, where significant reductions in the workforce are achieved on an ongoing basis through increased employee efficiencies; productivity gains, where smaller reductions in workforce levels are achieved on an ongoing basis through increased employee efficiencies; and capitalization ratio changes, where more payroll costs are capitalized (rather than expensed) during a period of capital expansion.[1065]

CARD recommends that payroll expenses be set in line with test year level expenses:

- SWEPCO expenses. CARD witness M. Garrett stated that SWEPCO's annualized base pay for the post-test year pay periods from October through December 2020 was 0.87% more than the base pay for the test year.[1066] He proposed that SWEPCO's payroll expenses be set at this amount to reflect all changes from the test year—not only the post-test year pay increases.[1067]

[1062] OPUC Ex. 1 (Cannady Dir.) at 32.

[1063] CARD Ex. 2 (M. Garrett Dir.) at 33.

[1064] CARD Ex. 2 (M. Garrett Dir.) at 33.

[1065] CARD Ex. 2 (M. Garrett Dir.) at 33-34.

[1066] CARD Ex. 2 (M. Garrett Dir.) at 35.

[1067] CARD Ex. 2 (M. Garrett Dir.) at 35.

- AEPSC allocated expenses. SWEPCO increased its AEPSC allocated payroll costs 9.8% above test year levels.[1068] CARD witness M. Garrett explained that this increase fails to account for the savings from the early retirement package.[1069] He added that AEPSC post-year payroll costs were comparable to the test year, increasing only 0.24%.[1070] He recommended that AEPSC payroll expenses be set at the test year level to reflect the reduction in employee levels that offset almost all increases that also may have occurred in the test-year period.[1071]

d. ALJs' Analysis

The ALJs agree with SWEPCO, Staff, and OPUC that an approximately 3.5% payroll increase should be approved. The Commission has approved a similar salary increase before, and the evidence supports approval of that level of increase here.

The ALJs agree with Staff, OPUC, and CARD that the retirement package and revised employee headcount is a known and measurable change that merits an adjustment. Although SWEPCO argues that the impact of the retirement package remains uncertain, its October 2020 payroll provides a sufficiently certain data point. Moreover, SWEPCO did not show it intended to replace the retired employees or that its employee headcount would recover or vary minimally from the test year. Rather, a material number of employees accepted the retirement package, so the employee headcount at the end of the test year is not an appropriate headcount on which to annualize payroll expenses. The ALJs therefore recommend that Staff and OPUC's adjustment be adopted: a $544,331 increase for SWEPCO's direct payroll increase, and a ($4,480,512) decrease for AEPSC's allocated expense.

[1068] CARD Ex. 2 (M. Garrett Dir.) at 36.

[1069] CARD Ex. 2 (M. Garrett Dir.) at 36.

[1070] CARD Ex. 2 (M. Garrett Dir.) at 36.

[1071] CARD Ex. 2 (M. Garrett Dir.) at 36.

2. Incentive Compensation

Staff and SWEPCO are in general agreement on incentive compensation, except that Staff notes two small errors in SWEPCO's proposal.[1072] First, SWEPCO found an error in the business unit financial-based goal percentage; a correction results in adjustments of ($50,709) and ($6,131) for SWEPCO and AESPC, respectively.[1073] Second, SWEPCO identified an erroneously included $43,345 of financial-based incentive compensation that was capitalized.[1074] Staff proposes an adjustment of ($42,039) to remove these costs net of amortization of $1,306 from SWEPCO's requested rate base.[1075] SWEPCO agrees with Staff regarding these two adjustments.[1076]

CARD and OPUC disagree with SWEPCO regarding short-term and long-term incentive compensation.

a. Short-Term Incentive (STI) Compensation

i. SWEPCO's Position

SWEPCO requests inclusion in its cost of service and rate base of the non-financial portion of the target level of STI expense, after excluding 50% of any financially-based funding mechanism for employees who are not union-represented.[1077] SWEPCO requests the full target level of STI expense be included in its cost of service for union-represented employees for whom STI compensation was collectively bargained.[1078] In both cases SWEPCO is requesting inclusion

[1072] Staff Ex. 3 (Stark Dir.) at 8-10.

[1073] Staff Ex. 3 (Stark Dir.) at 9.

[1074] Staff Ex. 3 (Stark Dir.) at 10.

[1075] Staff Ex. 3 (Stark Dir.) at 10.

[1076] SWEPCO Ex. 46 (Carlin Reb.) at 2.

[1077] SWEPCO Ex. 21 (Carlin Dir.) at 38-39.

[1078] SWEPCO Ex. 21 (Carlin Dir.) at 39.

of only a target level of the test year STI expense, which is the market-competitive level, rather than the larger actual per-books expense.[1079]

SWEPCO witness Carlin explained the purpose of STI compensation. Mr. Carlin stated that STI compensation benefits customers by enabling SWEPCO to attract and retain skilled employees who provide quality service to customers.[1080] Without STI compensation, he asserted, the compensation for many positions would be below the market-competitive range, which would impair SWEPCO's ability to attract and retain employees and would increase costs and result in declining service levels and increased cost to customers.[1081] Mr. Carlin opined that incentive compensation improves employee and company performance by more effectively communicating goals and objectives, better aligning employee efforts with these goals and objectives, more effectively engaging employees, and motivating employees to achieve better performance.[1082]

Mr. Carlin also explained how SWEPCO funds STI. Mr. Carlin stated that SWEPCO's requested cost recovery and rate base reflect the historical 70% weight on AEP's operating earnings for determining STI compensation plan funding.[1083] More specifically, in 2019, SWEPCO used a "balanced scorecard of performance measures" for STI funding: 70% for AEP operating earnings; 10% for safety and compliance; 9% for infrastructure investment; 4% for O&M savings; 4% for customer experience and quality of service; and 3% for workforce of the future and culture.[1084] In 2020, the funding was based entirely on AEP's operating earnings per share.[1085] According to Mr. Carlin, this was a temporary change made for 2020 due to the financial

[1079] SWEPCO Ex. 21 (Carlin Dir.) at 39.

[1080] SWEPCO Ex. 21 (Carlin Dir.) at 24.

[1081] SWEPCO Ex. 21 (Carlin Dir.) at 25.

[1082] SWEPCO Ex. 21 (Carlin Dir.) at 25.

[1083] SWEPCO Ex. 21 (Carlin Dir.) at 31-32.

[1084] SWEPCO Ex. 21 (Carlin Dir.) at 31.

[1085] SWEPCO Ex. 21 (Carlin Dir.) at 31.

volatility and rapidly changing business conditions caused by COVID-19.[1086] For 2021, STI funding is expected to revert to the balance scorecard approach.[1087]

In this case, SWEPCO applied a 50% exclusion to the 70% of the funding mechanism that was based on financial measures (*i.e.*, earnings per share), resulting in a 35% exclusion of STI based on the funding mechanism.[1088]

SWEPCO disagrees with CARD's argument that AEP financial incentive compensation plans have a 100% financial performance requirement to be funded. Mr. Carlin stated that the financial funding trigger has been in place for many years, and recently the Commission removed 50% of the weight of assigned to the AEP operating-earnings-per-share measure rather than treating the entirety of funding measures as financially-based due to the funding trigger.[1089] He added that some company discretion is part of incentive plans, but AEP's short-term incentive compensation plans have met the funding trigger each year for many years. According to Mr. Carlin, it is contrary to AEP's interest to reduce incentive compensation in a manner that reduces the perceived value of STI compensation without an offsetting increase in base pay, because that would impair the Company's ability to attract and retain employees and lead to reduced performance and increased overall costs.[1090] He added that this funding mechanism ensures that the AEP companies can afford employee incentive compensation while meeting commitments to other stakeholders and ensuring STI compensation does not impair the companies financially (*e.g.*, in the case of financial stress).[1091]

SWEPCO disagrees with CARD's proposed adjustment because the financial funding mechanism was 100% operating earnings per share for the final quarter of the test year. First,

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[1086] SWEPCO Ex. 21 (Carlin Dir.) at 31.

[1087] SWEPCO Ex. 21 (Carlin Dir.) at 31.

[1088] SWEPCO Ex. 21 (Carlin Dir.) at 31.

[1089] SWEPCO Ex. 46 (Carlin Reb.) at 8-9.

[1090] SWEPCO Ex. 46 (Carlin Reb.) at 9-10.

[1091] SWEPCO Ex. 21 (Carlin Dir.) at 32.

Mr. Carlin pointed out that the change only affected the last quarter of the test year—not the first three quarters.[1092] Second, Mr. Carlin noted the change was limited to 2020 STI compensation: it is not indicative of the practices before 2020, for the majority of the test year, or going forward.[1093] Third, he stated the change was a response to the unprecedented uncertainty posed by COVID-19 and was done to better ensure SWEPCO maintained access to capital at reasonable rates.[1094] In all, Mr. Carlin described the funding mechanism as a temporary change made because of the uncertainty and risks of the COVID-19 pandemic.[1095]

Similarly, SWEPCO disagrees with OPUC's argument to limit STI compensation to 2019 awards. Mr. Carlin testified that the target level of STI compensation is the amount intended to bring SWEPCO's target for total compensation in line with reasonable and market-competitive levels, and SWEPCO's STI compensation awards over the last five and ten years have been above target.[1096] SWEPCO argues that the use of the target amount of incentive compensation is consistent with Commission precedent.[1097] Mr. Carlin also emphasized that SWEPCO's history shows it provides awards at or above the target level on average over time.[1098] Mr. Carlin further stated that the target level for STI compensation is "known and measurable" and generally lower than the amount of STI compensation actually paid.[1099]

Finally, SWEPCO disagrees with OPUC's argument that STI compensation expenses for union employees should be reduced as it is for non-union employees. Mr. Carlin explained that SWEPCO's request for recovery of the target level of STI compensation for union employees is

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[1092] SWEPCO Ex. 46 (Carlin Reb.) at 7.

[1093] SWEPCO Ex. 46 (Carlin Reb.) at 7.

[1094] SWEPCO Ex. 46 (Carlin Reb.) at 7.

[1095] SWEPCO Ex. 46 (Carlin Reb.) at 8.

[1096] SWEPCO Ex. 46 (Carlin Reb.) at 4.

[1097] Docket No. 46449, PFD at 235, 237 (Sep. 22, 2017) (SWEPCO's incentive compensation was based on target levels); *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, PFD at 88-89, 93 (Oct. 12, 2015) (SPS request based on target level of incentive compensation).

[1098] SWEPCO Ex. 46 (Carlin Reb.) at 4.

[1099] SWEPCO Ex. 46 (Carlin Reb.) at 4.

based on the presumption in PURA § 14.006 that employee wages and benefits that are the product of collective bargaining are reasonable. SWEPCO argues that the collective bargaining agreement allows union employees to participate in the STI compensation plan, so the resulting STI compensation for union employees is a result of collective bargaining and presumed to be reasonable. In contrast, SWEPCO asserts, OPUC's proposal is inconsistent with PURA § 14.006, because it disallows costs presumed to be reasonable and interferes with employee wages and benefits that are the product of collective bargaining.[1100] SWEPCO adds that its inclusion of collectively bargained STI compensation expense is consistent with the Commission's order in its last rate case, although the matter was not contested.[1101]

ii. OPUC's Position

OPUC proposes a ($1,677,713) adjustment to SWEPCO's request for STI compensation, resulting in an impact to Texas retail operations of ($617,854).[1102] OPUC focuses on two areas: (1) using only 2019 awards rather than also including 2020 awards; and (2) removing financially-based performance amounts for union employees.[1103]

OPUC seeks to reduce STI compensation to 2019 awards. OPUC witness Cannady explained that SWEPCO's proposed STI compensation comes in two parts: 75% is for 2019 performance (awarded in March 2020), and 25% is what is expected to be awarded for 2020 performance (to be awarded in March 2021).[1104] Ms. Cannady stated that SWEPCO's compensation proposal assumes all employees are awarded 100% of the target payouts without knowing what the payouts will be for the 2020 performance year, and in November 2020, SWEPCO's estimated payout was only at the 85% target level.[1105] She argued that, at the time of

[1100] SWEPCO Initial Brief at 88-89,

[1101] Docket No. 46449, PFD at 235 (Sep. 22, 2017).

[1102] OPUC Ex. 1 (Cannady Dir.) at 41.

[1103] OPUC Ex. 1 (Cannady Dir.) at 41.

[1104] OPUC Ex. 1 (Cannady Dir.) at 36-37.

[1105] OPUC Ex. 1 (Cannady Dir.) at 37.

filing, SWEPCO's STI compensation was not "known and measureable."[1106] She testified that, although SWEPCO provided additional March 2021 information reflecting the short-term incentive compensation awarded, that award is "approximately a year beyond the test year end and should not be considered."[1107] Similarly, OPUC proposes an ($849,837) adjustment to SWEPCO's test-year expense for STI compensation billed to SWEPCO by AEPSC, resulting in a ($321,212) impact to Texas retain operations.[1108] As with compensation awards for SWEPCO employees, she states that the compensation for AEPSC employees relied on estimated 2020 compensation amounts that were not "known and measurable."[1109] For this reason, Ms. Cannady asserted, the proposed reduction is appropriate.[1110]

OPUC also argues that under 16 TAC § 25.246(b)(1)(B), SWEPCO can use initial estimates of costs for inclusion in base rates, provided actual cost information is submitted during an update period ending no later than 30 days before SWEPCO filed its rate application.[1111] OPUC explains that SWEPCO did not file updated information 30 days before this proceeding (and could not because the short-term incentive compensation payments were not made until March 2020, five months after the filing of the rate case).[1112] Therefore, OPUC argues, SWEPCO does not qualify for the limited exception to use initial estimates in rate base under 16 TAC § 25.246(b)(1)(B).

In addition, OPUC seeks to reduce STI compensation awarded to SWEPCO union employees based on financial performance measures.[1113] Ms. Cannady stated that although for most employees SWEPCO removed the amounts it determined to be based on financial

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[1106] OPUC Ex. 1 (Cannady Dir.) at 37.

[1107] OPUC Ex. 1 (Cannady Dir.) at 37.

[1108] OPUC Ex. 1 (Cannady Dir.) at 41-42.

[1109] OPUC Ex. 1 (Cannady Dir.) at 41-42.

[1110] OPUC Ex. 1 (Cannady Dir.) at 42.

[1111] OPUC Initial Brief at 19. *See* 16 TAC § 25.246(b)(1)(B).

[1112] SWEPCO Ex. 3 (Smoak Dir.) at 6.

[1113] OPUC Ex. 1 (Cannady Dir.) at 38-41.

performance measures, for union employees, SWEPCO did not remove compensation awarded based on financial performance.[1114] She agreed that PURA § 14.006 provides that an employee wage rate or benefit that is the product of collective bargaining is presumed to be reasonable.[1115] But she stated that here the agreement between SWEPCO and its union employees provides only that the employee may participate in the incentive plan.[1116] This is no different, in her view, from any other employee, and so STI compensation based on financial performance measures should be removed for union employees as well.[1117] She noted that SWEPCO remains free to contract with unions and pay union employees according to those contracts, but the costs of financially-based incentive compensation should not be passed on to ratepayers.[1118]

OPUC also argues that Commission precedent excluding financially-based performance measures from STI compensation pre-dated the union agreement signed in April 2018, so the Commission is not "interfering with" the product of collective bargaining.[1119] In other words, the union agreement was signed subject to the Commission's longstanding precedent and the background understanding that financially-based incentive compensation is excluded from allowable expenses.[1120]

iii. CARD's Position

CARD seeks to disallow a portion of SWEPCO's short-term incentive compensation based on the funding mechanism used during the test year. CARD witness M. Garrett explained that SWEPCO's request removed the incentive costs directly related to financial performance and removed 35% of the remaining incentives, which represents 50% of SWEPCO's *anticipated* 70%

[1114] OPUC Ex. 1 (Cannady Dir.) at 38.

[1115] OPUC Ex. 1 (Cannady Dir.) at 39. *See generally* PURA § 14.006.

[1116] OPUC Ex. 1 (Cannady Dir.) at 39.

[1117] OPUC Ex. 1 (Cannady Dir.) at 39-40.

[1118] OPUC Ex. 1 (Cannady Dir.) at 40.

[1119] OPUC Initial Brief at 21.

[1120] OPUC Initial Brief at 21.

funding.[1121] But SWEPCO's actual funding differed from what was anticipated: although AEP used a funding requirement of only 70% in 2019, it changed to a full earnings per share threshold of 100% for 2020 because of the uncertainty related to COVID-19.[1122] Mr. M. Garrett stated that it is better to calculate the sharing of incentive costs between customers and shareholders based upon the actual funding mechanism used during the test year rather than the anticipated funding mechanism that was not used.[1123]

CARD witness M. Garrett also testified that all incentive plan funding was contingent on meeting a particular share price.[1124] He asserted that, as a result, the Commission should recognize that 100% of the annual incentive plan compensation plan's funding is based on the Company's financial performance and therefore exclude 50% of the otherwise recoverable incentive plan costs.[1125]

iv. ALJs' Analysis

The ALJs agree with SWEPCO. Consistent with Commission precedent, for non-union employees, SWEPCO applied a 50% exclusion to the 70% of the funding mechanism that was based on financial measures (i.e., earnings per share), resulting in a 35% exclusion of STI compensation based on the funding mechanism.

The ALJs disagree with CARD that an earnings per share funding trigger makes the entire compensation plan based on SWEPCO's financial performance and therefore there should be a 50% disallowance. The fact that incentive compensation has a baseline funding trigger does not change that SWEPCO used a balanced scorecard of performance measures for awards. As Mr. Carlin explained, SWEPCO has met the funding trigger each year for many years; it is contrary

[1121] CARD Ex. 2 (M. Garrett Dir.) at 18.

[1122] CARD Ex. 2 (M. Garrett Dir.) at 18.

[1123] CARD Ex. 2 (M. Garrett Dir.) at 19.

[1124] CARD Ex. 2 (M. Garrett Dir.) at 20.

[1125] CARD Ex. 2 (M. Garrett Dir.) at 20.

to the Company's interest to reduce incentive compensation by setting an unachievable goal; and the funding method ensures that short-term compensation does not impair the Company. Thus, the trigger provides more of a baseline assurance of funding rather than a financial incentive for performance.

The ALJs also disagree with CARD that the 2020 change from the balanced scorecard approach to earnings per share merits a disallowance. The change was limited: the Company previously used the balanced scorecard approach; the change only affected the last quarter of the test year; and the change does not reflect future plans. Moreover, the change was a response to the uncertainty of the COVID-19 pandemic and done to maintain access to capital. Overall, the evidence shows this was a temporary change because of a pandemic.

The ALJs disagree with OPUC that the timing of payments under SWEPCO's short-term incentive compensation plan—75% for 2019 performance (awarded in March 2020), and 25% for 2020 performance (to be awarded in March 2021)—means the last quarter of payments should be disallowed because they are not "known and measurable." SWEPCO's STI compensation is set at a target level. The target level is known and measurable. The Commission has approved this practice in the past. And SWEPCO demonstrated that historically it provides awards at or above the target level. Because SWEPCO's target level expenses are known and measurable and based on information provided for the test year, the ALJs are not persuaded that 16 TAC § 25.246(b)(1)(B), involving estimates and later updates with actual information, is on point.

Finally, the ALJs disagree with OPUC's position regarding compensation for union employees. The Commission's prior precedent in preventing SWEPCO from recovering a portion of executive compensation expense from customers does not change that under PURA § 14.006 employee wages and benefits that are the product of collective bargaining are presumed to be reasonable. Neither OPUC's arguments nor its evidence showed that the benefit provided to union employees for participating in the short-term incentive compensation system and receiving benefits under it was unreasonable. The ALJs therefore recommend that SWEPCO recover the reasonable expenses incurred for providing union employees short-term incentive compensation.

In sum, the ALJs recommend no change to SWEPCO's short-term incentive compensation expense.

b. Long-Term Incentive (LTI) Compensation

SWEPCO states that it adjusted its LTI expense for both SWEPCO and AEPSC to remove the performance unit portion (75%). Thus, for LTI expense, SWEPCO only requests the target level of the restricted stock unit (RSU) portion.[1126] Only CARD challenges SWEPCO's proposed LTI compensation.

i. SWEPCO's Position

Approximately 1,300 employees (about 7% of AEP employees) received a LTI award in the test year.[1127] Participation is generally limited to employees in positions that have responsibility for decisions that have a longer-term impact on the AEP companies and their customers.[1128]

SWEPCO witness Carlin explained the RSUs. He stated that RSUs vest subject to the participants' continued AEP employment on three vesting dates over a three or more year period;[1129] RSUs are not tied to performance measures;[1130] RSUs do not have any metrics or goals but rather are designed to vest a number of years after employee service;[1131] and participants who remain continuously employed with AEP through an RSU vesting date receive an equal number

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[1126] SWEPCO Ex. 46 (Carlin Reb.) at 11.

[1127] SWEPCO Ex. 21 (Carlin Dir.) at 42.

[1128] SWEPCO Ex. 21 (Carlin Dir.) at 43.

[1129] SWEPCO Ex. 21 (Carlin Dir.) at 44.

[1130] SWEPCO Ex. 21 (Carlin Dir.) at 44.

[1131] SWEPCO Ex. 46 (Carlin Reb.) at 12.

of shares of AEP common stock as the number of RSUs that vest on such date.[1132] In sum, he opined that RSUs are a retention incentive to foster management continuity.[1133]

SWEPCO admits that LTI compensation is treated differently by state regulatory agencies: although western U.S. states generally disallow all LTI compensation, eastern states may not.[1134] But in Texas, SWEPCO emphasizes, the Commission has consistently approved recovery of RSU expenses, as it did in Dockets 40443 and 46449.[1135] Each time the Commission found that RSUs are not based on financial measures and are appropriate to include in rates. SWEPCO urges that the same be done here, particularly because the facts have not changed.

Finally, SWEPCO warns that reducing the value of its market-competitive compensation package, of which RSUs are a part, would put it at a competitive disadvantage with respect to attracting and retaining suitably skilled employees.[1136] Mr. Carlin stated that utility companies compete for skilled and experienced employees. He asserted CARD ignores the benefits that market-competitive compensation provides to customers by enabling the retention of employees needed to provide quality service.[1137]

ii. CARD's Position

CARD argues that SWEPCO should be denied recovery of the RSU expenses. CARD witness Mr. M. Garrett stated that RSUs are tied to financial performance because the value of the RSU is directly tied to the value of the Company's common stock.[1138] Like performance units, RSUs are tied to financial performance measures because the value of the compensation the

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[1132] SWEPCO Ex. 21 (Carlin Dir.) at 44.

[1133] SWEPCO Ex. 46 (Carlin Reb.) at 13.

[1134] SWEPCO Ex. 46 (Carlin Reb.) at 13.

[1135] Docket No. 40443, PFD at 84 (May 20, 2013); Docket No. 46449, Order on Rehearing, FoF No. 199 (Mar. 19, 2018).

[1136] SWEPCO Ex. 46 (Carlin Reb.) at 15-16.

[1137] SWEPCO Ex. 46 (Carlin Reb.) at 16.

[1138] CARD Ex. 2 (M. Garrett Dir.) at 27.

employees receive is tied to the appreciation of AEP's stock price over the vesting period.[1139] As a result, he argued, RSUs are designed to align the interest of AEP's management with the interest of shareholders and to promote the financial success and growth of AEP.[1140] Mr. Garrett further opined that longer-term incentive plans are designed to tie executive compensation to the financial performance of AEP, and because the employees' compensation is tied over a long period of time to AEP's stock price, it motivates employees to make business decisions from the perspective of long-term shareholders.[1141] It would be inappropriate, he stated, to require ratepayers to bear the costs of incentive plans designed to encourage employees to put the interests of the shareholders first.[1142]

CARD also argues that disallowing SWEPCO's request for LTI compensation will not place SWEPCO at a competitive disadvantage.[1143] Mr. M. Garrett testified that when SWEPCO competes with other utilities for qualified executives, and the executive compensation plans of those other utilities are not being recovered through rates, SWEPCO is not placed in a competitive disadvantage when its executive incentive compensation is excluded as well.[1144] And because most states exclude executive compensation, he opined, SWEPCO would actually be given an unfair advantage if its executive plans were included in rates.[1145] Mr. M. Garrett stated that long-term, stock-based incentives (including RSUs) are not allowed in most states.[1146] He testified that a survey found that 20 of the 24 western states tend to exclude all or virtually all long-term stock-based incentive pay, and in the other four states the issue has not been addressed.[1147]

[1139] CARD Ex. 2 (M. Garrett Dir.) at 27.

[1140] CARD Ex. 2 (M. Garrett Dir.) at 27.

[1141] CARD Ex. 2 (M. Garrett Dir.) at 28.

[1142] CARD Ex. 2 (M. Garrett Dir.) at 28.

[1143] CARD Ex. 2 (M. Garrett Dir.) at 28.

[1144] CARD Ex. 2 (M. Garrett Dir.) at 28.

[1145] CARD Ex. 2 (M. Garrett Dir.) at 28.

[1146] CARD Ex. 2 (M. Garrett Dir.) at 31.

[1147] CARD Ex. 2 (M. Garrett Dir.) at 31.

CARD states that recovery for LTI compensation should be disallowed. Mr. Garrett explained that the Commission has previously disallowed rate case expenses associated with trying to recover financially-based long-term incentives.[1148] However, Mr. M. Garrett acknowledged that in SWEPCO's last rate case, the Commission allowed recovery for RSUs. The Commission's decision states that "restricted stock units are not based on financial performance measures as are other SWEPCO or AEP incentive plans and are appropriate to include in SWEPCO's rates."[1149] CARD disagrees and argues that the Commission was previously mistaken that long-term RSUs are not financially-based. Mr. Garrett stated that payments in stock are financial-based per se, especially those that vest over time because they are designed to align the interests of the employee with the financial interests of the Company.[1150] He recommended following Oklahoma's example and disallowing 100% of long-term executive incentive plan costs.[1151]

iii. ALJs' Analysis

The ALJs agree with SWEPCO's position on RSUs. RSUs have no financial performance target and are awards paid only for time. The evidence shows they are intended to retain executives. The Commission has previously authorized recovery of RSUs, and the evidence here does not merit departing from Commission precedent. The ALJs therefore recommend that SWEPCO recover its RSU expenses.

3. Severance Costs

OPUC seeks a ($1,403,705) adjustment to SWEPCO's severance pay expense.[1152] OPUC seeks a denial of $767,100 in severance costs for SWEPCO during the test year and a reduction of severance costs incurred by AEPSC and charged to SWEPCO from a requested $1,460,876 to

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[1148] CARD Ex. 2 (M. Garrett Dir.) at 29.

[1149] Docket No. 46449, Order on Rehearing, FoF No. 199 (Mar. 19, 2018).

[1150] CARD Ex. 2 (M. Garrett Dir.) at 30.

[1151] *See* CARD Ex. 2 (M. Garrett Dir.) at 30.

[1152] OPUC Ex. 1 (Cannady Dir.) at 44.

$824,300.[1153] OPUC witness Cannady stated that SWEPCO's test-year severance pay expense is not a normal level of expense and thus unjustified.[1154] OPUC argues, in other words, that SWEPCO's test year severance costs "spiked" and are "inflated." In 2017 and 2018, SWEPCO did not pay severance pay, and AEPSC charged SWEPCO with less than $550,000 for each year.[1155] But in the test year from April 2019 through March 2020, SWEPCO recorded $756,100 in severance pay, and AEPSC charged SWEPCO $1,460,876 in severance pay.[1156] Ms. Cannady testified that because this level of severance pay is not "a normal expense on a going forward basis," the entire test year amount of severance pay to former SWEPCO employees should be removed and the 2017, 2018, and test year severance pay AEPSC charges should be averaged.[1157]

SWEPCO contends that it prudently incurred severance costs and should recover them. SWEPCO states that its severance program allows management to evaluate operations on a continuing basis to provide the most efficient and effective operation at the lowest reasonable cost for customers.[1158] SWEPCO then notes that, under the Cost of Service Rule, only a utility's historical test year expenses, as adjusted for known and measurable changes, will be considered.[1159] SWEPCO asserts that OPUC's recommendation to depart from test year expenses is not a known and measurable change but "cherry-picking historical data."[1160] For AEPSC severance costs allocated to SWEPCO, the average of the costs incurred in the 2017, 2018, and 2019 calendar years was $1,313,281—similar to the test year's $1,460,876.[1161]

1153 OPUC Ex. 1 (Cannady Dir.) at 43-44.

1154 OPUC Ex. 1 (Cannady Dir.) at 43-44.

1155 OPUC Ex. 1 (Cannady Dir.) at 44.

1156 OPUC Ex. 1 (Cannady Dir.) at 43-44.

1157 OPUC Ex. 1 (Cannady Dir.) at 44.

1158 SWEPCO Ex. 36 (Baird Reb.) at 33.

1159 16 TAC § 25.231(b).

1160 SWEPCO Reply Brief at 84.

1161 SWEPCO Ex. 36 (Baird Reb.) at 34.

After considering the evidence, the ALJs agree with OPUC. The evidence shows that SWEPCO's test year severance costs significantly exceeded prior years. In comparison with prior years' expenses, SWEPCO failed to show that its test-year severance expense was reasonable and necessary and expected to continue at the requested level. The ALJs thus agree with OPUC that an adjustment is appropriate to normalize this expense. To do this, the ALJs recommend adopting OPUC's proposal to average the 2017 calendar year, 2018 calendar year, and test year (April 2019 through March 2020) severance costs for AEPSC severance costs charged to SWEPCO. The ALJs disagree with OPUC's proposal to disallow SWEPCO's direct severance costs, but rather recommend that these costs also be normalized through the three-year average.

4. Other Post-Retirement Benefits

SWEPCO seeks to recover its other post-employment benefits (OPEB) expense.[1162] SWEPCO states that its requested OPEB 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 the Company's independent actuary.[1163] SWEPCO notes that although CARD witness M. Garrett previously reported a discrepancy in SWEPCO's calculation of OPEB expense,[1164] SWEPCO filed a corrected work paper with a revised calculation.[1165] SWEPCO states that the corrected work paper shows no adjustment is due.[1166] CARD does not argue the matter in post-hearing briefing.[1167] The ALJs conclude that no adjustment is due and SWEPCO should recover its requested OPEB expense.

[1162] SWEPCO Ex. 6 (Baird Dir.) at 25.

[1163] SWEPCO Ex. 6 (Baird Dir.) at 25.

[1164] CARD Ex. 2 (M. Garrett) at 32.

[1165] SWEPCO Initial Brief at 93.

[1166] SWEPCO Ex. 36 (Baird Reb.) at 39-40.

[1167] CARD Initial Brief at 53; CARD Reply Brief at 25.

D. Depreciation and Amortization Expense [PO Issues 29, 34]

Depreciation is the process used for recovering the cost of electric plant in service. It is a system of accounting that aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It focuses on allocation rather than valuation. The FERC USofA defines depreciation, as applied to depreciable electric plant, as:

> the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[1168]

SWEPCO calculated its depreciation rates using the Average Remaining Life method, which recovers the original cost of the plant, adjusted for net salvage, less accumulated depreciation over the average remaining life of the plant.[1169] SWEPCO witness Jason Cash conducted a depreciation study based on electric utility plant in service as of December 31, 2019, adjusted as necessary for the units that were retired in 2020.[1170] The depreciation rates determined by the study are intended to provide recovery of invested capital, cost of removal, and credit for salvage over the expected life of the applicable property. Based on the study, Mr. Cash recommended revised depreciation accrual rates for SWEPCO, and SWEPCO witness Baird used those depreciation rates to develop test-year-adjusted depreciation expense.[1171]

The revised depreciation rates recommended by Mr. Cash result in a $31.7 million increase to SWEPCO's annualized depreciation expense/accrual amounts on a total company basis, which is primarily due to increases in investment levels since the Company's last depreciation study dated

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[1168] 18 C.F.R. Part 101, Def. 12.

[1169] SWEPCO Ex. 16 (Cash Dir.) at 6.

[1170] SWEPCO Ex. 16 (Cash Dir.) at 2, Exh. JAC-2.

[1171] SWEPCO Ex. 16 (Cash Dir.) at 5; *see also* SWEPCO Ex. 1 (Application), Schedule D-4.

December 31, 2015.[1172] Even though Dolet Hills remains in service, SWEPCO excluded all costs related to the plant for the purpose of calculating depreciation rates.[1173]

The contested depreciation issues in this case relate to: (i) the treatment of the remaining net book value of SWEPCO's five retired gas-fired generating units (Knox Lee Units 2, 3, and 4; Lieberman Unit 2, and Lone Star Unit 1) and Dolet Hills, which will retire on December 31, 2021; (ii) the production plant net salvage calculation (specifically, the use of a contingency factor in SWEPCO's production plant demolition study and the escalation of plant demolition study results); and (iii) the selection of the survivor curve and average remaining life combinations for nine mass asset accounts.

1. Treatment of Remaining Net Book Value of Retired Gas-Fired Generating Units and Dolet Hills

As discussed in Section V.A, the remaining net book value of SWEPCO's five retired gas-fired generating units should be removed from base rates, placed in a regulatory asset, and amortized over four years. In addition, the remaining net book value of Dolet Hills (and the associated Oxbow investment) should be removed from base rates and recovered through the Dolet Hills Rate Rider based on a 2046 useful life.

2. Net Salvage/Demolition Study

Terminal production net salvage includes the final cost to remove production plant facilities on their retirement, less any salvage received from property removed.[1174] The final terminal net salvage amount is the cost expected to be incurred when the plant is removed after the end of its useful life.

[1172] SWEPCO Ex. 16 (Cash Dir.) at 3. Increases in SWEPCO's generating plant investment levels accounted for $16.4 million, or a little over half, of the $31.7 million total annualized depreciation expense/accrual increase. *Id.*

[1173] SWEPCO Ex. 16 (Cash Dir.) at 9.

[1174] SWEPCO Ex. 43 (Cash Reb.) at 6-7.

For unique assets such as power plants, SWEPCO contends that the cost of removal and net salvage should be determined by taking the specific characteristics of each power plant into account.[1175] For this reason, SWEPCO retained an independent engineering firm, Sargent & Lundy (S&L), to prepare a study of the expected terminal costs to remove (*i.e.*, dismantle or demolish) each of SWEPCO's generating plants and the components associated with each plant, net of the salvage expected to be realized in connection with the removal. The S&L study provided the terminal net salvage amounts for production plant in 2020 dollars.[1176] SWEPCO then applied a 2.22% inflation rate factor to those amounts to determine the terminal net salvage amount at each plant's retirement year. The terminal net salvage amount after inflation was used in the calculation of net salvage percentages in SWEPCO's depreciation study. In this proceeding, SWEPCO seeks an overall terminal net salvage percentage for its generating plants of negative 4%.[1177]

CARD raises two objections to the calculation of the terminal net salvage amount. First, CARD opposes the inclusion of a 10% contingency factor in S&L's demolition cost estimate, arguing instead that there should be no contingency factor.[1178] Second, CARD criticizes SWEPCO's use of an escalation factor to adjust the dismantling costs from 2020 levels to the values that would apply at the end of the expected life of each plant.[1179]

a. Contingency Factor

S&L's demolition study applied a positive 10% contingency factor to estimated labor costs, materials costs, and indirect costs, and a negative 10% contingency factor to scrap value.[1180] SWEPCO states that it included the contingency factors because it is not possible to precisely

[1175] SWEPCO Ex. 43 (Cash Reb.) at 7.

[1176] SWEPCO Ex. 16 (Cash Dir.) at 7.

[1177] SWEPCO Ex. 43 (Cash Reb.) at 9.

[1178] CARD Ex. 1 (D. Garrett Dir.) at 8-9.

[1179] CARD Ex. 1 (D. Garrett Dir.) at 9.

[1180] SWEPCO Ex. 15 (Eiden Dir.), Exh. PME-2 at 7.

anticipate all the ways a plant will be modified over time and, based on experience, unknown challenges will occur during demolition that cannot be predicted.[1181]

However, CARD argues that the use of a contingency factor is inappropriate because the underlying costs themselves—the costs to demolish a generation plant at some distant point in the future—are not known and measurable.[1182] As a comparison, CARD witness David Garrett noted that the Commission disallows interim retirements (*i.e.*, retirements of plant components prior to the retirement of the plant itself) for not being known and measurable.[1183] He asserted that future decommissioning cost estimates are even less known and measurable than interim retirements and similarly should be disallowed. According to CARD, applying a 10% contingency factor on top of future costs that are uncertain further exacerbates the underlying problem with such costs. While the unpredictability of future demolition costs may justify the use of a contingency factor as a matter of standard industry practice, CARD argues that doing so fails to pass muster in a ratemaking context, which requires a utility's revenue requirement to be based on historic test-year costs adjusted for known and measurable changes.[1184]

CARD also contends that the contingency factors are arbitrary.[1185] CARD points out that SWEPCO claims the contingency factors are based on the level of detail included in the cost estimates regarding the scope of demolition for the plants.[1186] However, SWEPCO did not provide any calculations or other formal analysis to show why a 10% contingency factor is appropriate for the expected costs to demolish these particular plants. Even if the percentage may vary with the scale of the study—higher if less detailed or lower if more detailed[1187]—CARD claims there is no credible evidence that 10% is the correct contingency factor level for this particular study.

[1181] SWEPCO Ex. 42 (Eiden Reb.) at 4.

[1182] CARD Initial Brief at 55.

[1183] CARD Ex. 1 (D. Garrett Dir.) at 8.

[1184] CARD Reply Brief at 26.

[1185] CARD Initial Brief at 56.

[1186] SWEPCO Ex. 42 (Eiden Reb.) at 5.

[1187] SWEPCO Ex. 42 (Eiden Reb.) at 5.

CARD acknowledges that the Commission approved the use of a 10% contingency factor for SWEPCO in its last rate case, Docket No. 46449.[1188] However, CARD urges reconsideration given that the Commission rejected the inclusion of interim retirements in calculating depreciation rates in Docket No. 40443. According to CARD, neither interim retirements of generation plant facilities, nor estimates of the future costs to demolish a generation plant, constitute known and measureable changes to test-year costs.

SWEPCO responds that CARD witness D. Garrett made the same arguments against a contingency factor in SWEPCO's last two rate cases, which were rejected in both instances.[1189] In particular, SWEPCO points out that the 10% contingency factor is consistent with Commission precedent in Docket No. 46449, where the Commission made the following findings of fact:

> The plant demolition studies SWEPCO used to develop terminal removal cost and salvage for each of SWEPCO's generating facilities, when adjusted to account for a 10% contingency factor, are reasonable.
> It is common practice to include contingency amounts in cost estimates for contract work across all industries.[1190]

In addition to this precedent, SWEPCO witness Paul Eiden, an officer, vice president, and project director with S&L, explained that it is appropriate to use a contingency factor when preparing demolition cost estimates because it is common practice, is reasonable, and more accurately reflects the realities of power plant operating lives.[1191] Mr. Eiden confirmed that, based on his experience in performing engineering tasks for over 30 years, including a contingency factor is necessary. He testified that S&L's standard practice is to include a contingency factor of 15% for power plant demolition estimates, but to comply with prior Commission precedent, S&L used a 10% factor in the demolition study provided to SWEPCO in this case.[1192]

[1188] CARD Initial Brief at 56.

[1189] SWEPCO Initial Brief at 95-96.

[1190] Docket No. 46449, Order on Rehearing at FoF Nos. 177, 179 (Mar. 19, 2018).

[1191] SWEPCO Ex. 42 (Eiden Reb.) at 3-4.

[1192] SWEPCO Ex. 42 (Eiden Reb.) at 6.

b. Escalation Factor

SWEPCO proposes to escalate the present estimated generation plant demolition costs by an annual inflation rate of 2.22%.[1193] This rate was taken from "The Livingston Survey," which is published by the research department of the Federal Reserve Bank of Philadelphia and provides a long-term inflation outlook that projects an inflation rate for a 10-year period.[1194]

CARD argues against applying an escalation factor for two reasons.[1195] First, the escalation of estimated demolition costs is unwarranted given that the underlying costs are not known and measurable. According to CARD, the 2.22% escalation factor results in an additional $116 million in costs that SWEPCO is asking ratepayers to pay. Yet, in light of the uncertainty in whether the underlying demolition costs will ever be incurred, CARD contends the burden on ratepayers should not be increased by applying an escalation factor.

Second, CARD claims the escalation factor deprives ratepayers of the time value of money; that is, it is not proper to charge current ratepayers for a future cost that has not been discounted to present value.[1196] According to CARD, this basic notion is reflected in the Discounted Cash Flow Model, which is widely used to calculate a regulated utility's return on equity. This model applies a growth rate to a company's dividends many years in the future and that dividend stream is then discounted back to the current year by a discount rate in order to arrive at the present value of an asset. In contrast, CARD claims that SWEPCO proposes to escalate the present value of its demolition costs decades into the future and is essentially asking current ratepayers to pay the future value of a cost with present-day dollars.

[1193] SWEPCO Initial Brief at 96-97.

[1194] SWEPCO Ex. 16 (Cash Dir.) at 8.

[1195] CARD Initial Brief at 57.

[1196] CARD Ex. 1 (D. Garrett Dir.) at 9.

SWEPCO contends that CARD's position is at odds with straight-line depreciation principles and fails to take into account how depreciation is treated in the ratemaking process.[1197] SWEPCO witness Cash explained that customers receive a return on the net salvage component of depreciation expense through accumulated depreciation as a reduction to rate base, which reduces the required return to be included in rates (*i.e.*, customers receive a return via lower base rates).[1198] He further testified that, because straight-line depreciation is meant to allocate costs evenly over time, discounting the net salvage costs back to a net present value level would produce (all other factors being the same) the need for an increase in the depreciation accrual expense each year, shifting the cost from current to future customers, despite the plant being of at least equal utility to current customers.[1199] Thus, applying an escalation factor allocates the depreciation expense more evenly over the life of the plant. Finally, SWEPCO notes that the use of an escalation factor is consistent with Commission precedent established in Docket Nos. 40443 and 46449.

CARD disagrees with SWEPCO's contention that CARD's approach is inconsistent with depreciation principles because customers receive a return on the net salvage component of depreciation expense.[1200] CARD contends that any ratepayer benefit that might arise due to a reduced return will only occur when SWEPCO files a rate case, which may not occur for another four years. The delay arises because any changes to accumulated depreciation only occur after SWEPCO's depreciation expense is credited to the accumulated depreciation account and any resulting reduction to rate base and impact to retail rates are addressed in a rate case.

c. ALJs' Analysis

As SWEPCO notes, CARD's arguments regarding the contingency and escalation factors were litigated and rejected by the Commission in SWEPCO's last two rate cases, Docket Nos. 40443 and 46449. In this proceeding, CARD has not pointed to any change in law, policy, or

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[1197] SWEPCO Initial Brief at 96-97; SWEPCO Ex. 43 (Cash Reb.) at 10.

[1198] SWEPCO Ex. 43 (Cash Reb.) at 10-11.

[1199] SWEPCO Ex. 43 (Cash Reb.) at 11.

[1200] CARD Reply Brief at 27-28.

fact that warrants a reconsideration of this established precedent. Accordingly, the ALJs recommend that the Commission adopt SWEPCO's terminal production net salvage amounts in calculating depreciation rates.

3. Service Lives of Mass Property Accounts

Both SWEPCO witness Cash and CARD witness D. Garrett performed actuarial analyses of SWEPCO's mass property accounts to produce depreciation parameters, such as the average service life, dispersion curve, and remaining life.[1201] For each account, they created an observed life table (OLT) using SWEPCO's historical property data, which they plotted graphically to form a curve (OLT curve). They then compared each one to the well-established Iowa curves to determine which Iowa curve and average life best matched the Company's data shown in the OLT curves.[1202] Both witnesses agreed that the curve-fitting process involves a combination of visual and mathematical matching techniques, as well as professional judgment.[1203] While their analyses were similar, they recommended different curve life combinations for nine of SWEPCO's mass property accounts.

SWEPCO and CARD each urge adoption of their respective witnesses' recommendations. Their arguments that apply to all of the accounts are summarized here, while their account-specific arguments are addressed below.

For each of the nine accounts at issue, CARD recommends longer average service lives than SWEPCO and, therefore, lower depreciation expense. CARD notes that Mr. Cash agreed at the hearing that the Commission may consider ratepayers' ability to pay in establishing just and reasonable rates.[1204] Further, the COVID-19 pandemic created unprecedented economic hardship

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[1201] SWEPCO Ex. 43 (Cash Reb.) at 12. Mass property refers to property in accounts that include large numbers of similar units where the life of any one unit is not dependent on the life of the other units. *Id.*

[1202] The Iowa curves are empirically derived curves based on extensive studies of the actual mortality patterns of many different types of industrial property. CARD Ex. 1 (D. Garrett Dir.) at 10 & Appendix B.

[1203] SWEPCO Ex. 43 (Cash Reb.) at 15; CARD Ex. 1 (D. Garrett Dir.) at 10.

[1204] Tr. at 558.

for many of SWEPCO's customers, a fact that CARD contends the Commission should consider in exercising its broad discretion in setting rates.

SWEPCO states that Mr. Cash's selections are based on visual and mathematical fits as well as an understanding of the property included in the accounts.[1205] According to SWEPCO, Mr. Cash routinely works with and understands the nature of the property in the accounts. In contrast, SWEPCO contends Mr. D. Garrett simply wants to delay and push a higher depreciation expense on future customers.[1206]

a. Account 353 – Transmission Station Equipment

For Account 353, SWEPCO witness Cash proposed an S0.0-68 curve,[1207] and CARD witness D. Garrett recommended an L0.5-75 curve.[1208] CARD's recommendation would decrease annual depreciation expense by $1,318,069.[1209]

CARD acknowledges that both curves provide relatively close visual fits to the relevant observed data, but contends its curve is superior because it results in a longer average life and lower depreciation rate.[1210] According to CARD, SWEPCO's curve is not unreasonable for this account, but CARD's curve should be adopted because it will help mitigate the rate increase SWEPCO seeks in this proceeding, particularly given the impact of COVID-19. CARD notes that Mr. Cash testified that he considered "additional factors" in making his recommendations for this

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[1205] SWEPCO Initial Brief at 98.

[1206] SWEPCO Reply Brief at 87.

[1207] SWEPCO Ex. 16 (Cash Dir.), Exh. JAC-2 at 23. The letter/number combination preceding the dash (here, S0.0) designates the particular Iowa curve selected, and the number after the dash (here, 68) is the average service life recommended.

[1208] CARD Ex. 1 (D. Garrett Dir.) at 12-13.

[1209] CARD Ex. 1 (D. Garrett Dir.), Exh. DJG-3 at 3.

[1210] CARD Initial Brief at 58; CARD Ex. 1 (D. Garrett Dir.) at 12-13.

account, but did not offer any analysis or explanation as to why those factors better supported his curve selection, and thus, did not provide a meaningful basis for selecting SWEPCO's curve.[1211]

SWEPCO witness Cash testified that depreciation rates should be selected with the intention of matching the loss in the asset's service value over the remaining life of the asset.[1212] He opined that purposely calculating a lower depreciation rate to provide rate relief to current customers only makes future customers pay more in future depreciation costs than current customers, which is contrary to generational equity and the matching concept. He also identified the following "additional factors" that support his recommendation for Account 353: (1) the average age of the property in Account 353 is 13.56 years and only 0.33% of the property balance is older than the 68-year life he selected; and (2) his curve life selection calculates that 25% of the $703 million in Account 353 (*i.e.*, $176 million) is expected to last longer than 93 years versus Mr. D. Garrett's selection, which calculates that 32% of the $703 million in Account 353 (*i.e.*, $225 million) is expected to last longer than 93 years.[1213]

The two proposed curve life combinations are quite similar, and even CARD notes that SWEPCO's recommendation is not unreasonable. CARD's primary basis for supporting its curve is that it produces a lower depreciation expense. However, the ALJs agree with Mr. Cash that depreciation rates should be selected with the goal of matching the loss in the asset's service value over the remaining life of the asset. This approach best fulfills the Commission's duty to set rates that are just and reasonable to both the consumers and the utility.[1214] The ALJs also find that the impacts of COVID-19 do not justify departing from this general concept. The evidence did not show that COVID-19 impacted the service lives of the assets, and making adjustments due to the current economic impacts on customers elevates present-day economic challenges over those that

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[1211] CARD Reply Brief at 29-31.

[1212] SWEPCO Ex. 43 (Cash Reb.) at 19.

[1213] SWEPCO Ex. 43 (Cash Reb.) at 18-19.

[1214] *See* PURA § 11.002 ("The purpose of this title [PURA] is to establish a comprehensive and adequate regulatory system for public utilities to assure rates, operations, and services that *are just and reasonable to the consumers and to the utilities.*") (emphasis added).

may occur in the future. Accordingly, the ALJs recommend that the Commission adopt SWEPCO's recommended S0.0-68 curve life combination for this account.

b. Account 354 – Transmission Towers and Fixtures

For Account 354, SWEPCO witness Cash proposed an L3.0-65 curve,[1215] and CARD witness D. Garrett recommended an S1.5-74 curve.[1216] CARD's recommendation would decrease annual depreciation expense by $130,874.[1217]

According to CARD, both of the selected Iowa curves provide relatively close and reasonable fits to the observed data, but all else being held equal, the S1.5-74 curve would result in a lower depreciation rate and expense. CARD also argues that its curve provides a better mathematical fit. Mathematical curve fitting essentially involves measuring the distance between the OLT curve and the selected Iowa curve.[1218] The best mathematically fitted curve is the one that minimizes the distance between the OLT curve and the Iowa curve. The "distance" between the curves is calculated using a technique known as the "sum of squared differences" (SSD). Specifically, the SSD for the Company's curve is 0.0157 while the SSD for CARD's recommended curve is 0.0112. The smaller the value of the SSD, the better the mathematical fit.

SWEPCO witness Mr. Cash noted that SWEPCO's 65-year average service life selection represents a five-year increase in the 60-year average service life that is embedded in current rates.[1219] He also criticized Mr. D. Garrett for making a selection to lower depreciation rate and expense, and for relying primarily on mathematical fit. He noted that Mr. D. Garrett's selection of a 74-year average service life means that approximately $12 million of the $40 million in Account 354 is expected to last longer than 88 years.

[1215] SWEPCO Ex. 16 (Cash Dir.), Exh. JAC-2 at 23.

[1216] CARD Ex. 1 (D. Garrett Dir.) at 13-15.

[1217] CARD Ex. 1 (D. Garrett Dir.), Exh. DJG-3 at 3.

[1218] CARD Ex. 1 (D. Garrett Dir.) at 14.

[1219] SWEPCO Ex. 43 (Cash Reb.) at 22.

Here again, the two proposed curve life combinations provide close visual fits. CARD demonstrated, however, that its recommendation provides a better mathematical fit, and SWEPCO did not explain how the other factors Mr. Cash considered might outweigh that fact. Accordingly, the ALJs recommend that the Commission adopt CARD's recommended S1.5-74 curve life combination for this account, which results in a decrease of $130,874 in annual depreciation expense.

c. Account 355 – Transmission Poles and Fixtures

For Account 355, SWEPCO witness Cash proposed an S0.5-46 curve,[1220] and CARD witness D. Garrett recommended an L1.5-49 curve.[1221] CARD's recommendation would decrease annual depreciation expense by $1,795,499.[1222]

CARD notes that, as with Accounts 353 and 354, both parties' curves provide relatively close fits to the observed data.[1223] However, CARD argues its curve has a superior mathematical fit to the data as its SSD is 0.0047 whereas SWEPCO's curve has an SSD of 0.0064. Further, CARD's curve results in a lower depreciation rate, which CARD asserts is an added reason to adopt it given the economic hardship resulting from COVID-19.

SWEPCO witness Mr. Cash testified that SWEPCO's 46-year average service life selection represents a four-year decrease in the 50-year average service life that is embedded in current depreciation rates.[1224] He again criticized Mr. D. Garrett for making a selection to lower depreciation rate and expense, and for relying primarily on mathematical fit. He stated that Mr. D. Garrett's selection of a 49-year average service life means that approximately $53 million

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1220 SWEPCO Ex. 16 (Cash Dir.), Exh. JAC-2 at 23.

1221 CARD Ex. 1 (D. Garrett Dir.) at 15-16.

1222 CARD Ex. 1 (D. Garrett Dir.), Exh. DJG-3 at 3.

1223 CARD Initial Brief at 59.

1224 SWEPCO Ex. 43 (Cash Reb.) at 24-25.

of the $759 million in Account 355 is expected to last longer than 86 years and 5% of the property, or about $38 million, is expected to last longer than 93 years.

The deciding factor here is CARD's mathematical fit analysis. As with Account 354, CARD demonstrated its curve provides a better mathematical fit, and SWEPCO did not explain how the other factors Mr. Cash considered might outweigh that fact. Accordingly, the ALJs recommend that the Commission adopt CARD's recommended L1.5-49 curve life combination for this account, which results in a decrease of $1,795,499 in annual depreciation expense.

d. Account 356 – Overhead Conductors and Devices

For Account 356, SWEPCO witness Cash proposed an R2.0-70 curve,[1225] and CARD witness D. Garrett recommended an L1.5-80 curve.[1226] CARD's recommendation would decrease annual depreciation expense by $1,285,746.[1227]

CARD acknowledges that both parties' curves provide relatively close fits to the OLT curve.[1228] However, CARD's curve results in a lower depreciation rate, which CARD suggests is an added reason for its adoption given the economic hardship resulting from COVID-19.

As with Account 353, SWEPCO witness Cash testified that purposely calculating a lower depreciation rate than justified to provide rate relief to current customers is inappropriate as it makes future customers pay more in future depreciation costs than current customers, which is contrary to generational equity and the matching concept.[1229] He noted that SWEPCO's 70-year average service life selection is not changed from the average service life that is embedded in current rates.

1225 SWEPCO Ex. 16 (Cash Dir.), Exh. JAC-2 at 23.

1226 CARD Ex. 1 (D. Garrett Dir.) at 16-17.

1227 CARD Ex. 1 (D. Garrett Dir.), Exh. DJG-3 at 3.

1228 CARD Initial Brief at 59-60.

1229 SWEPCO Ex. 43 (Cash Reb.) at 27.

CARD's primary support for its recommended curve is that it produces a lower depreciation expense. As with Account 353, the ALJs conclude this fact is not a sufficient basis for rejecting SWEPCO's proposal, which CARD agrees provides a close fit to the Company's data. Accordingly, the ALJs recommend that the Commission adopt SWEPCO's recommended R2.0-70 curve life combination for this account.

e. Account 364 – Poles, Towers, and Fixtures

SWEPCO witness Cash's depreciation study indicated that he used the S0.5 Iowa curve for Account 364, but he explained in rebuttal that this notation was an error and the S-.5 Iowa curve should have been used instead.[1230] As corrected, he recommended an S-.5-55 curve. Because the S0.5 Iowa curve was inadvertently used as an input throughout Mr. Cash's analysis, he testified that SWEPCO's proposed depreciation rate for Account 364 should be updated from 2.83% to 2.65%, resulting in a decrease in total company depreciation expense of $847,189.[1231] CARD witness D. Garrett recommended an L0.0-62 curve for this account.[1232] CARD's recommendation would decrease annual depreciation expense by $2,741,568 from SWEPCO's as-filed case.[1233]

Even with the change in SWEPCO's curve from S0.5-55 to S-.5-55, CARD argues that Mr. D. Garrett's recommended L0.0-62 curve is superior.[1234] CARD's curve and SWEPCO's revised curve both provide close visual fits to the Company's data through the 80-year age interval. CARD's curve also decreases depreciation expense by a larger amount than SWEPCO's revised curve, which CARD asserts is a further reason to adopt it given the economic hardship resulting from COVID-19. In addition, CARD contends that SWEPCO did not explain why its revised curve should be adopted over CARD's curve.[1235]

[1230] SWEPCO Ex. 43 (Cash Reb.) at 29.

[1231] SWEPCO Ex. 43 (Cash Reb.) at 29.

[1232] CARD Ex. 1 (D. Garrett Dir.) at 17-19.

[1233] CARD Ex. 1 (D. Garrett Dir.), Exh. DJG-3 at 4.

[1234] CARD Initial Brief at 60.

[1235] CARD Reply Brief at 33.

SWEPCO witness Mr. Cash testified that, despite the correction to his own recommended curve, Mr. D. Garrett's proposed curve life combination should be rejected.[1236] He noted that the average service life he recommended remains unchanged from the average service life approved in SWEPCO's prior rate case, Docket No. 46449.

As CARD points out, SWEPCO provided little explanation for why its revised curve was superior to the one recommended by Mr. D. Garrett. However, the ALJs conclude SWEPCO met its burden regarding the reasonableness of the revised curve. In particular, SWEPCO's revised curve provides a close visual fit to the OLT curve, including beyond the 80-year age interval.[1237] In addition, SWEPCO proposes to retain the average service life approved in its last rate case, which, while not definitive standing alone, is further evidence of its reasonableness. Accordingly, the ALJs recommend that the Commission adopt SWEPCO's revised S-.5-55 curve life combination for this account, which results in a decrease in total company depreciation expense of $847,189 from SWEPCO's filed case.

f. Account 366 – Underground Conduit

For Account 366, SWEPCO witness Cash proposed an R4.0-70 curve,[1238] and CARD witness D. Garrett recommended an R4.0-80 curve.[1239] Given that both witnesses propose an R4.0 Iowa curve, the difference in their recommendations is that Mr. D. Garrett advocates a ten-year longer average service life. CARD's recommendation would decrease annual depreciation expense by $148,914.[1240]

[1236] SWEPCO Ex. 43 (Cash Reb.) at 30.

[1237] *See* SWEPCO Ex. 43 (Cash Reb.) at 28.

[1238] SWEPCO Ex. 16 (Cash Dir.), Exh. JAC-2 at 23.

[1239] CARD Ex. 1 (D. Garrett Dir.) at 19-20.

[1240] CARD Ex. 1 (D. Garrett Dir.), Exh. DJG-3 at 4.

CARD points out that the Company's data for this account shows a 70% survival rate at the 90-year age interval for the assets in this account.[1241] Even though both curves assume the retirement rate will decrease going forward, SWEPCO's R4.0-70 curve is too short at this time, according to CARD, given that the data show that 70% of the assets survive to the 90-year age interval. In addition, CARD's curve has an SSD of 0.0129 whereas SWEPCO's curve has an SSD of 0.0411, which shows that CARD's curve is the better mathematical fit.

SWEPCO witness Mr. Cash testified that the main factor he considered for this account was whether a change was justified from the 2015 depreciation study, which used the same R4.0-70 curve life combination.[1242] Since there have not been many retirements from Account 366, he recommended retaining the same curve life combination approved in Docket No. 46449.

CARD demonstrated that its curve life combination is the better choice for calculating depreciation of this account. The SSD resulting from CARD's choice shows a superior mathematical fit. Accordingly, the ALJs recommend the Commission adopt CARD's recommended R4.0-80 curve life combination for this account, which results in a decrease of $148,914 in annual depreciation expense.

g. Account 367 – Underground Conductor

For Account 367, SWEPCO witness Cash proposed an R3.0-46 curve,[1243] and CARD witness D. Garrett recommended an R1.0-62 curve.[1244] CARD's recommendation would decrease annual depreciation expense by $2,081,345.[1245]

[1241] SWEPCO Initial Brief at 60-61.

[1242] SWEPCO Ex. 43 (Cash Reb.) at 32.

[1243] SWEPCO Ex. 16 (Cash Dir.), Exh. JAC-2 at 23.

[1244] CARD Ex. 1 (D. Garrett Dir.) at 20-21.

[1245] CARD Ex. 1 (D. Garrett Dir.), Exh. DJG-3 at 4.

CARD asserts that Figure 9 in Mr. D. Garrett's direct testimony shows that SWEPCO's R3.0-46 curve does not provide a close visual fit or description of the historical retirement rate observed thus far in this account compared to CARD's proposed curve.[1246] In addition, CARD's curve is a better mathematical fit—CARD's curve has an SSD of 0.0011 whereas the Company's curve has an SSD of 0.1426. While CARD acknowledges that its curve is based on a truncated OLT curve, it contends that it eliminates a mere 1% of the data at the tail end of the OLT curve because, as Mr. D. Garrett testified, that data has minimal analytical value.[1247] That is because points at the tail end of the curve are often based on fewer dollars exposed to retirement and therefore may be given less weight than points based on larger samples.[1248] By not truncating the data, SWEPCO's curve gives undue weight to the statistically less valuable part of the data and less weight to the more valuable upper and middle portions of the data on the OLT curve, according to CARD.

SWEPCO witness Cash criticized Mr. D. Garrett for using a truncated OLT curve, which Mr. Cash asserted drastically impacts the results of the analysis.[1249] Mr. Cash testified that the National Association of Regulatory Utility Commissioners' *Public Utility Depreciation Practices* describes a truncation or "T-cut" as follows:

> A T-cut is a truncation of the observed life table values and is generally used in a mathematical fitting of a curve to the observed values. A T-cut is used to mathematically perform a function that is automatic in visual fitting (i.e., setting a point beyond which the observed data are considered irrelevant or unreliable and are, therefore, ignored).[1250]

Mr. Cash noted that if he had done a similar T-cut, he might have agreed with Mr. D. Garrett on this account. However, a T-Cut was not necessary for this account, according to Mr. Cash, because the observed data beyond 45 years continues to be relevant for the analysis. In support, he provided

[1246] CARD Initial Brief at 61.

[1247] CARD Reply Brief at 35; CARD Ex. 1 (D. Garrett Dir.) at 11.

[1248] CARD Ex. 1 (D. Garrett Dir.) at 11.

[1249] SWEPCO Ex. 43 (Cash Reb.) at 33-36.

[1250] SWEPCO Ex. 43 (Cash Reb.) at 36.

two graphs comparing the results both with and without the T-cut at approximately year 45.[1251] He asserted that, as shown in the graphs, the retirements occurring after year 50 are very important to make the proper selection of a curve and life for Account 367. He testified that his recommended curve life selection did not include a T-cut and is more representative of the retirements occurring in this account.

A review of the two graphs provided by Mr. Cash supports his position that truncating the Company's data has a significant impact on selecting the appropriate curve life combination for Account 367. Mr. Cash and Mr. D. Garrett agreed that truncation of the data can be appropriate in the right circumstances. However, the question is whether it was appropriate for this account. While Mr. D. Garrett testified generally that data at the tail end of the OLT curve may have minimal analytical value, he did not flag that he had used a truncated OLT curve for this specific account or explain why it was appropriate to do so here. Thus, the evidence does not show that truncating the data was appropriate in this case. Mr. Cash's proposed curve life combination appears to be a better fit for the non-truncated data. Accordingly, the ALJs recommend the Commission adopt SWEPCO's recommended R3.0-46 curve life combination for this account.

h. Account 369 – Services

For Account 369, SWEPCO witness Cash proposed an R3.0-59 curve,[1252] and CARD witness D. Garrett recommended an R1.5-76 curve.[1253] CARD's recommendation would decrease annual depreciation expense by $806,053.[1254]

CARD argues that its proposed curve provides a better visual fit than does SWEPCO's curve.[1255] In addition, CARD's curve has an SSD of 0.0254, compared to the SSD of 0.4459 for

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[1251] SWEPCO Ex. 43 (Cash Reb.) at 34-35.

[1252] SWEPCO Ex. 16 (Cash Dir.), Exh. JAC-2 at 23.

[1253] CARD Ex. 1 (D. Garrett Dir.) at 22-23.

[1254] CARD Ex. 1 (D. Garrett Dir.), Exh. DJG-3 at 4.

[1255] CARD Initial Brief at 35.

SWEPCO's curve, which shows that CARD's curve has a better mathematical fit. CARD witness D. Garrett used a truncated OLT curve for this account, which CARD contends was appropriate for the same reasons discussed above regarding Account 367.

SWEPCO witness Cash again criticized Mr. D. Garrett's use of truncated data.[1256] As with Account 367, Mr. Cash provided two graphs comparing the results both with and without the T-cut, this time with the T-cut at approximately year 65.[1257] He asserted that, as shown in the graphs, truncation was not necessary for Account 369 because the observed data beyond 65 years continues to be relevant for the analysis. Mr. Cash noted that his curve life selection did not use truncated data and is more representative of the retirements occurring in this account.

The ALJs apply the same analysis here as with Account 367 because the parties' arguments are essentially the same. The two graphs provided by Mr. Cash for Account 369 show a significant impact from truncating the data. Mr. D. Garrett's testimony did not indicate that he used truncated data for this specific account or explain why it was appropriate to do so. Thus, the evidence does not show that truncating the data was appropriate here. Mr. Cash's proposed curve life combination appears to be a better fit for the non-truncated data. Accordingly, the ALJs recommend the Commission adopt SWEPCO's recommended R3.0-59 curve life combination for this account.

i. Account 370 – Meters

Account 370 consists of distribution meters, and the parties' differing proposals relate primarily to the impact of SWEPCO replacing electromechanical meters with electronic meters. For this account, SWEPCO witness Cash proposed an L0.0-15 curve,[1258] and CARD witness

[1256] SWEPCO Ex. 43 (Cash Reb.) at 37-40.

[1257] SWEPCO Ex. 43 (Cash Reb.) at 38-39.

[1258] SWEPCO Ex. 16 (Cash Dir.), Exh. JAC-2 at 23.

D. Garrett recommended an O2.0-21 curve.[1259] CARD's recommendation would decrease annual depreciation expense by $2,527,878.[1260]

CARD argues that its O2.0-21 curve provides a better visual fit than does SWEPCO's L0.0-15 curve.[1261] CARD's curve is also a better mathematical fit, with an SSD of 0.0062 compared to the SSD of 0.7716 for SWEPCO's curve. CARD witness D. Garrett explained that the primary purpose of Iowa curve fitting is to develop a smooth and complete survivor curve to conduct an average life calculation.[1262] With regard to the data in this account, he testified that the OLT curve is already smooth and complete, which makes the Iowa curve fitting process relatively straightforward.

SWEPCO states that Mr. D. Garrett apparently based his selected curve on the retirement history for Account 370, but in this instance, the account history does not accurately reflect the average life of the meters currently in the account.[1263] The full history includes electromechanical meters, which often had an average service life of 25 to 30 years.[1264] However, Mr. Cash confirmed that SWEPCO replaced almost all of the meters in its service territory with electronic meters, which have a manufacturer-prescribed useful life of 15 years or less.[1265] As a result, Mr. Cash graphed Account 370 for the activity years 2000 to 2019 to reflect a period when the electronic meters would have been installed by the Company.[1266]

[1259] CARD Ex. 1 (D. Garrett Dir.) at 23-24.

[1260] CARD Ex. 1 (D. Garrett Dir.), Exh. DJG-3 at 4.

[1261] CARD Initial Brief at 62.

[1262] CARD Ex. 1 (D. Garrett Dir.) at 24.

[1263] SWEPCO Initial Brief at 98-99.

[1264] SWEPCO Ex. 43 (Cash Reb.) at 40.

[1265] SWEPCO Ex. 43 (Cash Reb.) at 40.

[1266] SWEPCO Ex. 43 (Cash Reb.) at 40.

CARD disagrees with SWEPCO's contention that Mr. Garrett failed to account for the fact that SWEPCO has replaced its electromechanical meters with electronic meters.[1267] CARD notes that Mr. Garrett's analysis is based on the data SWEPCO provided, which includes the retirement histories of both types of meters. CARD also criticizes Mr. Cash's testimony regarding the service lives of both types of meters. Mr. Cash stated that the electromechanical meters "often had" an average service life of 25 to 30 years, but did not elaborate on what he meant by "often" and did not show any firsthand experience or understanding of the meters. For the electronic meters, Mr. Cash relied on manufacturers' estimates without specifying the type(s) of meter that SWEPCO has installed or the life expectancy of those meters. Further, Mr. Cash testified that SWEPCO "has almost completely" replaced its electromechanical meters, but the exact extent to which SWEPCO has done so is not known. Thus, CARD contends SWEPCO's proposed service life for Account 370 is based on vague and unsupported factual claims.

The ALJs find that SWEPCO raised a valid consideration—the expected service life of the newer electronic meters—when considering the appropriate curve life combination for this account. While SWEPCO could have provided more detail about the types of meters installed, their specific life expectancies, and the exact meter count for each type of meter, the ALJs conclude Mr. Cash's testimony is sufficient to demonstrate that it was reasonable to limit the analysis of this account to more recent activity years to reflect a period when the electronic meters would have been installed by the Company. SWEPCO therefore showed that Mr. D. Garrett's analysis, which considered the full retirement history of the account, is not representative of SWEPCO's current installed investment. Accordingly, the ALJs recommend the Commission adopt SWEPCO's recommended L0.0-15 curve life combination for this account.

4. Amortization

According to Staff, SWEPCO's application included an amount of amortization related to an intangible asset that was fully amortized as of the end of the test year.[1268] Staff witness Stark

[1267] CARD Reply Brief at 35-36.

[1268] Staff Initial Brief at 60.

proposed a reduction of $1,855,750 to correct this error.[1269] SWEPCO witness Baird indicated in rebuttal that he does not contest Ms. Stark's adjustment to intangible plant amortization,[1270] and SWEPCO does not contest this item.[1271] Accordingly, the ALJs conclude that intangible plant amortization should be reduced by $1,855,750 from SWEPCO's filed case.

1. Purchased Capacity Expense

1. The Cajun Contract

SWEPCO purchases power under a contract with the Louisiana Generating Company (formerly Cajun Electric Power Cooperative). SWEPCO asserts that these costs should be recovered through base rates, rather than through the fuel factor.[1272] TIEC agrees and supports SWEPCO's request.[1273] CARD disagrees.

CARD argues that the costs incurred under the contract should be removed from SWEPCO's base rates and recovered through the fuel factor as reconcilable purchased energy costs.[1274] CARD argues that in a recent fuel reconciliation case SWEPCO sought to treat purchased operating reserves as reconcilable purchased energy costs and to recover those costs through the fuel factor.[1275] CARD adds that SWEPCO's proposed recovery of purchased operating reserve costs through base rates is inconsistent with the Commission's decision in a prior SWEPCO fuel

[1269] Staff Ex. 3 (Stark Dir.) at 16.

[1270] SWEPCO Ex. 36 (Baird Reb.) at 36.

[1271] SWEPCO Reply Brief at 88.

[1272] SWEPCO Initial Brief at 100-01.

[1273] TIEC Initial Brief at 65.

[1274] CARD Initial Brief at 63.

[1275] CARD Initial Brief at 62; CARD Ex. 3 (Norwood Dir.) at 10.

reconciliation case.[1276] There, the Commission concluded that the purchase of ancillary services were purchases of energy and thus properly recorded as eligible fuel expenses.[1277]

SWEPCO responds that CARD is mistaken. First, SWEPCO states that it does not recover any portion of capacity costs through the fuel factor.[1278] Second, SWEPCO asserts that previously the Commission recognized the contract at issue as providing capacity.[1279] Third, SWEPCO argues that under the contract there is a difference between "Operating Reserve Capacity Charges" and "Operating Reserve Energy," and CARD confuses the two.[1280] SWEPCO purchased "Operating Reserve Capacity"; it did not purchase "Operating Reserve Energy."[1281] SWEPCO explains that capacity is purchased several months before the peak summer season; firm transmission must be obtained from SPP (taking time); and purchased capacity is acquired for a longer term (at least four months), as compared to energy.[1282] This is distinguishable from the SPP definition of "operating reserves," which are procured in the day-ahead and real-time market and is economically cleared simultaneously with the energy offers in the SPP Integrated Marketplace based on the bids and offers submitted by market participants.[1283] SWEPCO also points out that the contract has different charges for capacity and energy: "Operating Reserve Capacity" is a capacity charge and priced on a $/kW month basis; "Operating Reserve Energy" is an energy charge and priced on per-kWh basis.[1284] SWEPCO adds that the purchased capacity is paid for by a fixed monthly payment—consistent with a capacity product, rather than an energy product.[1285]

[1276] CARD Initial Brief at 63; *Application of Southwestern Public Service Company for Authority to Reconcile Fuel and Purchased Power Costs*, Docket No. 48973, Order on Rehearing at FoF No. 98 (Feb. 18, 2020); PFD at 14 (Oct. 17, 2019).

[1277] Docket No. 48973, Order on Rehearing at FoF No. 98 (Feb. 18, 2020).

[1278] SWEPCO Ex. 47 (Stegall Reb.) at 7.

[1279] Docket No. 40443, PFD at 293 (May 20, 2013).

[1280] SWEPCO Initial Brief at 100.

[1281] SWEPCO Ex. 47 (Stegall Reb.) at 9.

[1282] SWEPCO Ex. 47 (Stegall Reb.) at 8-9.

[1283] SWEPCO Ex. 47 (Stegall Reb.) at 8.

[1284] SWEPCO Ex. 47 (Stegall Reb.) at 8.

[1285] *See* SWEPCO Ex. 1 (Application), Schedule H-12.4c.

And its uses the purchased capacity to meet its SPP capacity requirement.[1286] Thus, SWEPCO argues, the capacity payments should continue to be recovered through base rates.

The ALJs agree with SWEPCO. The preponderance of the evidence shows that SWEPCO is purchasing operating capacity under this contract, rather than energy or ancillary services for energy. As such, capacity costs are recovered through base rates, rather than as an eligible fuel expense that would be recovered through the fuel factor.

2. Wind Contracts

SWEPCO purchased power from four wind projects. SWEPCO and OPUC argue that the cost of the wind energy should continue to be collected through SWEPCO's fuel factor. TIEC argues that these contracts contain a capacity component, which should be imputed to the contracts, recovered through base rates, and be removed from the fuel factor. CARD disagrees with TIEC's proposed imputed capacity calculation and argues that TIEC's proposal should be rejected.

SWEPCO and OPUC argue that these wind contract costs have consistently been collected through the fuel factor and reconciled as energy purchases. According to SWEPCO, this practice began in Docket No. 40443, a SWEPCO base rate and fuel reconciliation proceeding, where the first wind power purchase agreement was considered, and none of the costs incurred under that agreement were attributed to capacity and included in base rates.[1287] This practice continued in Docket No. 46449, where the Commission found that the wind contracts entered into as part of a settlement were economic, that SWEPCO prudently agreed to include the contracts in the settlement, and no capacity component was imputed to these contracts.[1288] Further, because the wind contracts came into service on or before 2013, there has been ample opportunity for the

[1286] SWEPCO Ex. 47 (Stegall Reb.) at 9.

[1287] Docket No. 40443, PFD at 293 (May 20, 2013) ("SWEPCO's only current [capacity] contract in Texas rates is an 18-year contract with Louisiana Generating LLC.").

[1288] *See* Docket No. 46449, Order on Rehearing, FoF Nos. 150-151 (Mar. 19, 2018).

Commission to reconsider the treatment of the contracts if it were inclined to do so.[1289] In contrast, SWEPCO and OPUC assert that the only authority offered by TIEC is from a settled case with no precedential value.[1290]

TIEC argues that, if the wind contracts provide capacity, a Commission rule and precedent provide that the expense must be recovered through base rates, rather than through the fuel factor. TIEC contends that, under 16 TAC § 25.236(a)(6), absent a finding of special circumstances, for eligible fuel expenses the electric utility may not recover capacity costs: capacity costs are not considered to be eligible fuel expense and, as such, are not recovered through the fuel factor.[1291] TIEC also argues that, where the Commission concluded in prior dockets that contracts provide capacity benefits by offering system-wide reliability and firm supply, the Commission concluded that the contracts' embedded capacity component should be recognized.[1292]

TIEC continues that it is irrelevant that no party has ever proposed imputing capacity for these wind contracts, and the Commission's determination should be based on the evidence in this case.[1293] Here, TIEC argues, the evidence shows that the wind contracts provide capacity.[1294] And that capacity is used to meet SWEPCO's SPP reserve margin requirement.[1295]

[1289] OPUC Ex. 60 (Georgis Cross-Reb.) at 8.

[1290] *Application of El Paso Electric Company to Change Rates*, Docket No. 44941, Order at 15 (Aug. 25, 2016) ("Entry of this Order consistent with the amended and restated agreement does not indicate the Commission's endorsement or approval of any principle or methodology that may underlie the amended and restated agreement. Entry of this Order shall not be regarded as precedent as to the appropriateness of any principle or methodology underlying the amended and restated agreement.").

[1291] 16 TAC § 25.236(a)(6). *See generally Entergy Gulf States, Inc. v. Pub. Util. Comm'n of Tex.*, 173 S.W.3d 199, 211-12 (Tex. App.—Austin 2005, pet. denied) (plain language of previous fuel rule prohibited a utility from recovering capacity charges associated with purchased power).

[1292] *Application of Entergy Gulf States, Inc. for the Authority to Reconcile Fuel Costs*, Docket No. 23550, Order at 2-3 (Aug. 2, 2002); *see also City of El Paso v. Pub. Util. Comm'n of Tex.*, 344 S.W.3d 609, 619-22 (Tex. App.—Austin 2011, no pet.).

[1293] TIEC Reply Brief at 36.

[1294] TIEC Ex. 4 (LaConte Dir.) at 23-24.

[1295] TIEC Ex. 4 (LaConte Dir.) at 23-24.

SWEPCO responds that because the contracts are for wind resources, SPP only allows a utility a portion of the nameplate capacity in satisfying SPP's reserve margin capacity.[1296]

Acknowledging the intermittency of the wind resource, TIEC replies that its calculations therefore used the capacity that SPP accredits to the wind resources and that SWEPCO includes when conducting system planning.[1297] TIEC contends that the wind contracts provide capacity value, and SWEPCO did not challenge TIEC witness LaConte's calculation of imputed capacity costs for the wind contracts.[1298]

CARD, however, does dispute TIEC's calculation. CARD does not disagree with the concept of imputing capacity charges for wind energy power purchase agreements and recovering those amounts through base rates.[1299] Nor does CARD disagree with TIEC's use of SPP's accredited capacity rating of SWEPCO's wind contracts as the basis for calculating the imputed capacity value.[1300] But CARD argues that TIEC's assigned value for the imputed capacity cost adjustment is based on an unreasonably high $/kW estimate of avoided cost of capacity.[1301] First, CARD asserts that SWEPCO forecasts having excess capacity on its system until at least 2024, so the Company's current avoided cost of capacity is very low.[1302] TIEC responds that CARD is mistaken because SWEPCO's 2019 Integrated Resource Plan did not account for certain plant retirements, and SWEPCO has stated that it projects it will need to add capacity beginning in 2023. CARD contends that SWEPCO will have excess capacity until the Pirkey plant is retired at the end of 2023. Second, CARD notes that Ms. Laconte's calculation uses an approximately $80/kW-year avoided capacity cost proxy, which is used by utilities to evaluate the

[1296] SWEPCO Initial Brief at 102.

[1297] TIEC Ex. 4 (LaConte Dir.) at 23-24; Tr. at 663; TIEC Ex. 28, SWEPCO response to CARD RFI 1-12.

[1298] TIEC Reply Brief at 36; TIEC Ex. 4 (LaConte Dir.) at 26.

[1299] CARD Initial Brief at 64.

[1300] CARD Initial Brief at 64-65.

[1301] CARD Initial Brief at 65.

[1302] CARD Ex. 7 (Norwood Cross-Reb.) at 5.

cost-effectiveness of energy efficiency programs less the estimated cost of ancillary costs.[1303] CARD argues that SWEPCO forecasts that capacity will be available for purchase within SPP at a price of $9.13/kW-year for the next ten years—a rate far lower than Ms. Laconte's proposed rate for an annual capacity charge of approximately $80/kW-year.[1304] In other words, TIEC's proposed imputed capacity rate is nearly eight times SWEPCO's forecasted market-capacity price as shown in the Company's 2019 Integrated Resource Plan. And SWEPCO can purchase capacity through bilateral contracts with other utilities within SPP.[1305] Additionally, CARD argues that TIEC's imputed capacity computation method is untested and has not been accepted by the Commission.

Finally, OPUC argues against moving any portion of the cost of the wind contracts from the fuel factor to base rates because doing so will misalign costs and shift costs from large industrial and commercial customers to residential and small commercial customers.[1306] OPUC witness Tony Georgis explains that the costs of the wind contracts have consistently been recovered as fuel costs and recovered on an energy-related basis.[1307] OPUC argues that shifting the wind generation costs from an energy-related basis in fuel costs to a demand-related basis in base rates will misalign costs. According to OPUC, industry practice aligns how costs are incurred with how those costs are allocated to customers.[1308]

The ALJs recommend that that costs incurred under the wind contracts continue to be accounted for as energy. SWEPCO has met its burden of proof to show that these contracts are energy-only contracts and, contrary to TIEC's arguments, there is no capacity to impute to these contracts that would, as capacity costs, be recovered through base rates. CARD's concerns about the cost of imputed capacity and the untested nature of the proposed computation further support

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[1303] TIEC Ex. 4 (LaConte Dir.) at 25; 16 TAC § 25.181(d)(2) (calculation of avoided cost of capacity when evaluating the cost-effectiveness of energy-efficiency programs).

[1304] TIEC Ex. 4 (LaConte Dir.) at 29-30.

[1305] *See* Tr. at 1112.

[1306] OPUC Ex. 60 (Georgis Cross-Reb.) at 10.

[1307] OPUC Ex. 60 (Georgis Cross-Reb.) at 10.

[1308] OPUC Ex. 60 (Georgis Cross-Reb.) at 12.

that the costs incurred under the wind contracts should continue to be accounted for as energy at this time.

F. Affiliate Expenses

SWEPCO incurred approximately $87.60 million in adjusted total company test year affiliate charges. Staff proposes two adjustments involving affiliates—one to remove carrying charges associated with affiliate or shared assets, and another to remove carrying charges SWEPCO received from affiliates in the form of rent billings (and included in rent income). Reducing rent income partially offsets the reduction for carrying charges paid by SWEPCO. The net adjustment to SWEPCO's revenue requirement resulting from these adjustments is ($634,043).[1309] SWEPCO does not contest the adjustments.[1310] The ALJs recommend adoption of Staff's position on this issue, which SWEPCO accepts.

G. Federal Income Tax Expense

SWEPCO and Staff agree that federal income tax expense should be updated and synchronized with the final revenue requirement in this case.[1311] SWEPCO and Staff also agree on how to calculate federal income tax expense. SWEPCO calculated federal income taxes using the "return" method (or Method 1) for the historical test year.[1312] Staff used the same method.[1313] Their calculations are consistent with PURA § 36.060 and 16 TAC § 25.231(b)(1)(D).[1314]

The differences in federal income tax expense calculated by the parties reflect only flow-through impacts of their positions on other disputed issues. Staff's proposed calculation of federal income tax expense is consistent with SWEPCO's calculation presented on Schedule G-7.8 of its

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1309 Staff Ex. 3 (Stark Dir.) at 13-14.

1310 SWEPCO Reply Brief at 92.

1311 Staff Initial Brief at 61; SWEPCO Reply Brief at 92.

1312 SWEPCO Ex. 17 (Hodgson Dir.) at 17.

1313 Staff Ex. 3 (Stark Dir.) at 54.

1314 SWEPCO Ex. 17 (Hodgson Dir.) at 20; Staff Ex. 3 (Stark Dir.) at 54.

application, except for (1) the proposed return and synchronized interest amounts related to Staff's proposed change in invested capital and rate of return and (2) an adjustment for Staff's proposed amortization of protected excess of ADFIT.[1315]

The ALJs' recommended federal income tax expense includes adjustments for (1) the proposed return and synchronized interest for the recommended amounts of invested capital and rate of return and (2) an adjustment for Staff's proposed amortization of protected excess ADFIT.

H. Taxes Other Than Income Tax

1. Ad Valorem (Property) Taxes

Staff raised four issues with SWEPCO's ad valorem taxes. Three of them are now uncontested:

- Capital lease balances should be included when calculating the effective ad valorem tax rate;[1316]
- Operating leases should be excluded from the rate base on which the effective tax rate is applied;[1317] and
- Dolet Hills and the retired gas-fired generating units should remain in the ad valorem tax calculation.[1318]

1315 Staff Ex. 3 (Stark Dir.) at 54.

1316 SWEPCO agrees with Staff's recommendation to include capital lease balances in the calculation of the effective ad valorem tax rate. SWEPCO Reply Brief at 93, n. 490. Staff witness Stark explains that SWEPCO had approximately $26 million in capital leases on its books that was included in the numerator but not the denominator of the calculation, resulting in an overstated effective ad valorem tax rate. Staff Ex. 3 (Stark Direct) at 49. Correcting this error reduces SWEPCO's effective ad valorem tax rate from approximately 1.0026% to .9986%. Staff Ex. 3 (Stark Dir.) at 49.

1317 SWEPCO agrees with Staff's recommendation to exclude operating leases from the rate base on which the effective tax rate is applied. SWEPCO Reply Brief at 93, n.490. Staff witness Stark states that because SWEPCO does not separately account for the property taxes on its operating leases in its property tax expense account, and SWEPCO confirms that it does not separate non-lease components like property taxes from the associated lease components, including non-operating leases in the calculation of property tax expense would have the effect of double-counting this expense in SWEPCO's cost of service. Staff Ex. 3 (Stark Dir.) at 52.

1318 Staff agrees that removing Dolet Hills and the retired gas-fired generating units from the ad valorem tax calculation would be inconsistent with the Commission's decision in a prior case. Docket No. 46449, Order on

The remaining issue is how to address Texas-only adjustments in the ad valorem tax calculation.

Staff states that SWEPCO included two pro forma plant adjustments in the March 2020 plant balance—one for Texas-only depreciation rates and another for a Texas-only allowance for funds used during construction (AFUDC) rate.[1319] The adjustments recognize what the balance of the plant and accumulated depreciation accounts would be if the Texas depreciation and AFUDC rates were used in all SWEPCO jurisdictions.[1320] Staff does not challenge SWEPCO's jurisdictional adjustments to accumulated depreciation or AFUDC.[1321] But Staff states that SWEPCO failed to include the January 2019 Texas depreciation and AFUDC adjustments in the January 2019 net plant balance used to calculate the effective tax rate.[1322] According to Staff, the failure to include the January 2019 balance Texas-only adjustments in calculating the effective tax rate while applying the effective rate to the March 2020 balance that includes them fails to properly synchronize the effective ad valorem tax rate with the associated property subject to tax and the assets to which it is applied.[1323] This results in an overstated effective ad valorem tax rate, Staff asserts.[1324]

SWEPCO responds that a Texas-only adjustment should not be applied to the 2019 rate base when calculating the effective tax rate to be applied because this would misstate the actual ad valorem tax rate being incurred by SWEPCO, which is based on the actual composite book value of SWEPCO's rate base.[1325] The Texas-only adjustment is then applied to the test year end rate

Rehearing at FoF Nos. 261-264 (Mar. 19, 2018). Staff agrees that these plants should be included in the ad valorem tax calculation. Staff Reply Brief at 41.

1319 Staff Ex. 3 (Stark Dir.) at 50.

1320 Staff Ex. 3 (Stark Dir.) at 50.

1321 Staff Reply Brief at 44.

1322 Staff Ex. 3 (Stark Dir.) at 50.

1323 Staff Ex. 3 (Stark Dir.) at 51.

1324 Staff Ex. 3 (Stark Dir.) at 51.

1325 SWEPCO Initial Brief at 107.

base to allocate those taxes to SWEPCO's three state jurisdictions.[1326] SWEPCO adds that removing the Texas-only adjustments results in other states subsidizing Texas customers.[1327]

Staff replies in two parts. First, Staff points out that SWEPCO includes Texas jurisdictional differences in the calculation of its effective tax rate—including items that reduce the balance of plant subject to the tax (and therefore increase the effective rate), such as the Texas jurisdictional Turk imprudence disallowance, Texas vegetation management write-offs, and capitalized incentive compensation.[1328] Staff argues SWEPCO offers no reason why it is appropriate to include Texas jurisdictional differences that increase the effective rate but not those that decrease it.[1329] Second, Staff states it is not opposed to including the Texas jurisdictional depreciation and AFUDC differences in the ad valorem tax calculation if the effective ad valorem tax rate is synchronized by including these differences in the determination of the rate.[1330] Staff explains that SWEPCO confirmed that the Texas jurisdictional depreciation and AFUDC differences existed in January 2019 and that the effective ad valorem tax rate if the January 2019 balances of the Texas jurisdictional differences are included in the calculation of the rate is .961262%.[1331] Staff urges that this .961262% effective ad valorem tax rate be used.[1332]

The ALJs agree with Staff. Staff's proposed adjustment will synchronize the effective ad valorem tax rate with the associated property subject to tax and the assets to which it is applied. And although SWEPCO raised concerns about removing Texas-only jurisdictional adjustments, SWEPCO failed to explain why including some but not other Texas-only jurisdictional adjustments is appropriate when calculating its effective tax rate.

[1326] SWEPCO Initial Brief at 107.

[1327] SWEPCO Ex. 36 (Baird Reb.) at 38.

[1328] SWEPCO Ex. 1 (Application), WP A-3.13.1 (ad valorem).

[1329] Staff Initial Brief at 65.

[1330] Staff Reply Brief at 42.

[1331] Staff Ex. 12 at 17-13.

[1332] Staff Initial Brief at 66.

2. Payroll Taxes

There are two payroll tax issues. The first involves Staff's proposed payroll adjustment. The ALJs agreed with Staff's recommended payroll adjustment (for SWEPCO's payroll and for its AEPSC allocated payroll). SWEPCO and Staff agree that a payroll adjustment requires an adjustment to payroll tax: the Commission should synchronize payroll tax expense with payroll adjustments, if any.[1333] The ALJs therefore recommend that payroll taxes expense be revised to include Staff's recommended payroll adjustment.[1334]

But SWEPCO and Staff part ways on whether a proposed adjustment to incentive compensation merits an adjustment to payroll taxes. When previously addressing executive compensation, the ALJs agreed with SWEPCO and Staff that there were two small errors in SWEPCO's incentive compensation expense but otherwise no adjustments were appropriate. The remaining question is whether, given the adjustment to executive compensation expense, SWEPCO's payroll tax should be adjusted.

SWEPCO argues that its payroll tax should not be adjusted. It contends that even if financially-based incentive compensation is excluded from allowable expenses because it is more properly borne by shareholders than ratepayers, the reasonableness of the Company's compensation from a cost or market-competitive standpoint was not challenged. As a result, the compensation provided is part of a market-competitive package, and any reduced or eliminated part of this package would need to be offset to maintain its overall market-competitiveness. Therefore, SWEPCO argues, it will still incur the attendant payroll and other taxes on the additional base wages in lieu of incurring it on wages paid in the form of incentive compensation, so these taxes should not be removed from its cost of service.

[1333] SWEPCO Ex. 36 (Baird Reb.) at 34; Staff Initial Brief at 66-67.

[1334] *See* Staff Ex. 3 (Stark Dir.) at 53, Attachment RS-57 (specifying SWEPCO and AEPSC payroll adjustments).

Staff argues that what SWEPCO might do in response to a disallowance of a portion of executive compensation expense is speculative. Staff also argues that "the Commission has previously ruled that removing the corresponding flow-through reductions associated with the elimination of incentive plan costs results in an allowable expense for the incentive plan that is reasonable and necessary for the provision of service."[1335]

The ALJs agree with Staff that what SWEPCO might do in response to a disallowance is speculative. The ALJs further note that the rationale for excluding executive compensation similarly extends to excluding the payroll taxes on that executive compensation: if the executive compensation is more properly borne by shareholders, then the payroll taxes on that executive compensation are too. The ALJs thus agree with Staff on both payroll tax matters and recommend adopting Staff's adjustment to payroll taxes.

3. Gross Margin Tax

SWEPCO's calculation of the cost of service margins was not contested. The parties agree that revenue-related taxes should be updated and synchronized with the final revenue requirement set in this case.

I. Post-Test-Year Adjustments for Expenses [PO Issue 45]

Contested post-test year adjustments are addressed in other areas of this PFD specific to an adjustment.

VIII. BILLING DETERMINANTS [PO ISSUES 4, 5, 6, 54]

SWEPCO's adjusted test year billing determinants used to design rates are sponsored by SWEPCO witnesses Brian Coffey, Chad Burnett, John Aaron, and Jennifer Jackson, and are

[1335] Staff Initial Brief at 67 (quoting Docket No. 46449, Order on Rehearing at FoF No. 198 (Mar. 19, 2018)).

detailed in various RFP schedules.[1336] Staff and ETSWD raise two issues regarding billing determinants

A. Staff's Opposition to Adjusting Billing Determinants Based on Estimates

In the Billing Determinants section of its initial brief, Staff argues that the Commission should reject SWEPCO's proposal to "adjust billing determinants to account for estimated customer migration issues from the General Services [GS] Tariff to the Lighting and Power [LP] Tariff."[1337] Staff witness Narvaez testified that adjusting billing determinants to account for customer migration "would violate 16 TAC § 25.234(b), which requires that rates be 'determined using revenues, billing and usage data for a historical Test Year adjusted for known and measurable changes. . . .'"[1338] According to Mr. Narvaez, any estimates regarding unknown future customer migration would not meet the "known and measurable" standard.[1339] Staff therefore recommends that "SWEPCO's proposed use of estimates to adjust billing determinants based on speculative customer migration should be rejected."[1340] In the Billing Determinants section of its reply brief, however, Staff simply states: "Staff addresses SWEPCO's proposal to adjust billing determinants to account for estimated customer migration issues from the General Services (GS) tariff to the Lighting and Power (LP) tariff . . . below."[1341]

SWEPCO responds that the RFP, which it is required to use to prepare and file its major base rate cases, specifically authorizes the use of estimated billing units.[1342] SWEPCO explains that migration adjustments, similar to test year adjustments and normalization, are performed to

[1336] SWEPCO Exs. 29 (Coffey Dir.) at 2; 30 (Burnett Dir.) at 10-11; 31 (Aaron Dir.) at 20; and 32 (Jackson Dir.) at 5.

[1337] Staff Initial Brief at 68.

[1338] Staff Ex. 4 (Narvaez Dir.) at 28.

[1339] Staff Ex. 4 (Narvaez Dir.) at 28.

[1340] Staff Initial Brief at 68.

[1341] Staff Reply Brief at 45.

[1342] SWEPCO Ex. 55 (Jackson Reb.) at 17 (quoting *Electric Utility Rate Filing Package for Generating Utilities* (Sept. 9, 1992), Schedule Q-7, Proof of Revenue Statement).

estimate a reasonable rate year set of billing determinants on which to design new rates. Taking into account the effect of customer migration based on new pricing is comparable to and is part of the process of normalizing estimated test year billing determinants.[1343] SWEPCO concludes that its commercial rate design proposals reasonably estimate the new class billing determinants based on test year adjusted billing determinants.[1344]

The ALJs conclude that there appears to be some confusion regarding this issue, and Staff may be intermixing billing determinants and rate design issues in the Billing Determinants sections of its initial and reply briefs. The billing determinant issue presented by Staff appears to be its dispute over whether SWEPCO can use estimates to adjust the billing determinants to account for potential customer migration among rate schedules. This issue is distinct from two related, but different, rate design issues raised by Staff with regard to the GS rate schedule, and Staff's request that SWEPCO be required to revise many of its rate schedules in its next base rate case to prevent customers from migrating among multiple rate schedules. Those latter two issues are addressed separately below in the Rate Design section of this PFD, and not in this Billing Determinants section. Thus, the ALJs conclude that the sole specific "billing determinant" issue raised by Staff is Staff's opposition to SWEPCO's proposed use of estimates to adjust billing determinants based on what Staff characterizes as speculative customer migration.

On this issue, the ALJs agree with SWEPCO. RFP Schedule Q-7, Proof of Revenue Statement, directs the utility to "Provide a proof of revenue statement (sometimes known as a pro forma revenue statement) showing expected *or estimated adjusted billing units*, proposed prices, and the resulting base rate revenue and fuel revenue for the proposed rate classes."[1345] SWEPCO is allowed to use estimated billing units in determining the resulting base rate revenues for its proposed rate classes. Staff and any party are free to challenge the Company's evidence supporting potential customer migration, but SWEPCO can use estimated adjusted billing units to calculate

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[1343] SWEPCO Ex. 55 (Jackson Reb.) at 18.

[1344] SWEPCO Ex. 55 (Jackson Reb.) at 10.

[1345] SWEPCO Ex. 55 (Jackson Reb.) at 17 (emphasis added). RFP Schedule Q-7 also states "Estimates of billing units are acceptable."

the resulting base rate revenues based on its evidence. For these reasons, the ALJs recommend that the Commission reject Staff's opposition to the use of estimated adjusted billing units (or billing determinants) to prepare its proposed rates.

B. ETSWD's Proposed COVID-19 Adjustment

ETSWD proposes that SWEPCO should update its class cost of service study (also referred to as a CCOSS) to incorporate new data and account for the "enduring 'work from home'" shift and other effects of COVID-19.[1346] Alternatively, ETSWD recommends that the Commission instruct SWEPCO to recalculate and adjust its class cost of service study using the data provided in SWEPCO's response to ETSWD Request for Information (RFI) 3-1 because, according to ETSWD, it is the most current information regarding changes in customer usage by customer class since the COVID-19 pandemic began.[1347] Finally, ETSWD recommends SWEPCO update the CCOSS to reflect the loss of certain customers' load since the filing of this case as reflected in SWEPCO's response to ETSWD RFI 3-2.[1348] SWEPCO, Staff, OPUC, TIEC, and CARD oppose ETSWD's recommended COVID-19 adjustments. SWEPCO also explains why it should not update its studies to reflect lost customer load as proposed by ETSWD.

1. Arguments Opposing ETSWD's Proposed COVID-19 Adjustments

SWEPCO, Staff, OPUC, TIEC, and CARD argue that ETSWD's proposal should be rejected because the adjustments ETSWD seeks are not known and measurable. Staff argues that ETSWD's proposal does not comply with the Commission's known and measurable standard because the adjustment is not reasonably quantifiable and does not describe a situation that is apt

[1346] ETSWD Ex. 1 (Pevoto Dir.) at 5, 14.

[1347] ETSWD Ex. 1 (Pevoto Dir.) at 5, 14. ETSWD supports its requests for an updated cost of service study by citing 16 TAC § 25.231(a) ("rates are to be based upon an electric utility's cost of rendering service to the public during a historical test year, adjusted for known and measurable changes."); *Entergy Texas, Inc. v. Public Util. Comm'n*, 490 S.W.3d 224, 232 (Tex. App.-Austin 2016) (affirming a Commission decision to deny known and measurable changes that relied on uncertain forecasts of future costs). ETWSD Initial Brief at 3, n.14.

[1348] ETSWD Ex. 1 (Pevoto Dir.) at 14-15.

to prevail in the future.[1349] Among other things, OPUC argues that the Commission has impliedly found that the pandemic's long-term effects, if any, are unknown.[1350] CARD asserts that the effect of ETSWD's proposal would mean that a residential customer would pay a rate that is disproportionate to the cost it actually caused the utility to incur.[1351] TIEC adds that ETSWD has not:

> provided a specific adjustment, leaving it unclear how the Commission would implement this recommendation if it were inclined to do so. TIEC would note that parties are entitled to review, analyze, and take positions on any data used to set rates in this case, and it is unclear how they would have that opportunity under ETSWD's proposal.[1352]

Staff, OPUC, and CARD present additional arguments in opposition to ETWSD's proposal, which are subsumed within the SWEPCO arguments set out in more detail below.

As an initial matter, SWEPCO notes that its Application in this docket included pro forma adjustments to the test year billing determinants for all of the known and measureable items at the time this case was filed.[1353] SWEPCO argues that ETSWD's primary recommendation fails for two reasons. First, as noted by other parties including Staff, the proposed adjustment is not known and measurable. ETSWD acknowledges that the goal of a pro forma adjustment is to reflect conditions that are likely to prevail in the future; that is, when the rates approved in this case are in effect. But, according to SWEPCO, there is no evidence that its sales and usage data during the pandemic, which by definition is a transitory event, are representative of what is likely to prevail

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[1349] Staff Ex. 4B (Narvaez Cross-Reb.) at 6. OPUC makes a similar argument in its reply brief, arguing that ETSWD has not accounted for the "apt to apply in the future" requirement. OPUC Reply Brief at 24 (citing *Southwestern Public Service Co v. Pub Util. Comm'n of Tex.*, No. 07-17-00146-CV (Tex. App.—Amarillo 2018) (citing *City of El Paso v. Pub. Util. Comm'n of Tex.*, 883 S.W.2d 179, 188 (Tex. 1994)).

[1350] *See Application of El Paso Electric Company to Amend Its Certificate of Convenience and Necessity for an Additional Generating Unit at the Newman Generating Station in El Paso County and the City of El Paso*, Docket No. 50277, PFD at 24 (Sep. 3, 2020) (Docket No. 50277). There, the ALJs rejected an argument that the effects of the COVID-19 obviated the need for a new generating facility. Specifically, the ALJs explained that the long-term effect of the COVID-19 pandemic "remains no more than speculation." *See also* Docket No. 50277, Order at 1 (Oct. 16, 2020) (approving the PFD).

[1351] CARD Reply Brief at 42-43.

[1352] TIEC Reply Brief at 49.

[1353] SWEPCO Ex. 53 (Burnett Reb.) at 4.

in the future.[1354] Second, ETSWD has not provided and the record does not contain the information necessary to implement the recommendation. SWEPCO contends ETSWD concedes as much in its initial brief when it requests that the Commission instruct SWEPCO to provide "current, certain, and actual data regarding customer class usage."[1355]

SWEPCO acknowledges that the pandemic affected SWEPCO's Texas jurisdictional load in the months immediately after the end of the test year, but contends that the pandemic's effects were temporary and are not expected to continue.[1356] SWEPCO argues that ETSWD witness Kit Pevoto's testimony bears this out:

- On July 2, 2020, Governor Abbott issued an order requiring face coverings for all public spaces in Texas.[1357] However, by March 2, 2021, Governor Abbott issued an executive order (Executive Order GA-34) removing the mask mandate and allowing businesses in Texas to operate at 100% capacity with no restrictions.[1358] Given Executive Order GA-34, SWEPCO argues that it is now known that businesses that were temporarily forced to limit their operations in response to the pandemic in 2020 will not be under the same restrictions moving forward.[1359]

- SWEPCO agrees with Ms. Pevoto's observation that, compared to 2019, SWEPCO's total Texas Retail kWh sales dropped 3.2% in 2020, and, while Residential kWh sales increased by 3.3 percent, Commercial and Industrial kWh consumption declined by 5.0% and 6.9%, respectively.[1360] SWEPCO witness Burnett agreed that the impact of the pandemic was severe initially.[1361] But Mr. Burnett explained that this impact has been offset as businesses have been able to reopen, vaccinations have come in place, and the government has put significant stimulus money into the economy.[1362]

[1354] SWEPCO Ex. 53 (Burnett Reb.) at 4.

[1355] SWEPCO Reply Brief at 99 (citing ETSWD Initial Brief at 5-6); *see also* Staff Ex. 4b (Narvaez Cross-Reb.) at 5-6.

[1356] SWEPCO Ex. 53 (Burnett Reb.) at 4.

[1357] SWEPCO Ex. 53 (Burnett Reb.) at 5.

[1358] SWEPCO Ex. 53 (Burnet Reb.) at 5; *see also* ETSWD Ex. 9 (Executive Order No. 34 relating to the opening of Texas in response to the COVID-19 disaster).

[1359] SWEPCO Ex. 53 (Burnett Reb) at 6; *see also* Tr. at 1481-82.

[1360] ETSWD Ex. 1 (Pevoto Dir.) at 10.

[1361] Tr. at 1494.

[1362] Tr. at 1494-95.

- Mr. Burnett also testified that the sales data Ms. Pevoto cites in her testimony is not reflective of what SWEPCO expects going forward. Instead, the most recent data from April 2021 shows that the "narrative is flipped"; that is, residential sales are down and Commercial and Industrial sales are up significantly.[1363]

- Finally, Mr. Burnett testified that Table 2 in Ms. Pevoto's direct testimony illustrates that despite the initial severity of the pandemic, its impact has lessened as time has passed.[1364] That is, the evidence shows that SWEPCO's billing determinants are moving back to normal.[1365]

SWEPCO argues that ETSWD's alternative recommendation—that the Commission direct SWEPCO to update its CCOSS to account for COVID-19—should also be rejected because, as with its primary recommendation, the result ETSWD seeks is not known and measurable. SWEPCO concedes that its response to ETSWD RFI 3-1 shows that, compared to 2019, SWEPCO's total Texas Retail kWh sales dropped 3.2% in 2020, and, while Residential kWh sales increased by 3.3%, Commercial and Industrial kWh consumption declined by 5.0% and 6.9%, respectively.[1366] SWEPCO witness Burnett agreed that the impact of the pandemic was severe initially.[1367] But he explained that this impact has been offset as businesses have been able to reopen, vaccinations have come in place, and the government has put significant stimulus money into the economy.[1368] To accept ETSWD's recommendation to make a pro forma adjustment based on the "known" post-test year normalized sales data, SWEPCO states one would have to assume that the pandemic's effect on SWEPCO's Texas jurisdictional sales is permanent.[1369] SWEPCO contends that assumption is not consistent with the evidence, and is not reasonable given Governor Abbott's March 2021 executive order.

[1363] Tr. at 1474, 1495-96.

[1364] Tr. at 1493-94.

[1365] SWEPCO Initial Brief at 110-11.

[1366] ETSWD Ex. 1 (Pevoto Dir.) at 10.

[1367] Tr. at 1494.

[1368] Tr. at 1494-95.

[1369] SWEPCO Reply Brief at 100.

Finally, SWEPCO agrees with ETSWD that SWEPCO identified in response to ETSWD RFI 3-2 the loss of load for two customers (one commercial and one industrial) due to business closures after the Company filed this case. SWEPCO argues, however, that ETSWD's recommendation that SWEPCO include a pro forma adjustment to reflect this loss of load is unreasonable because the commercial customer has only "temporarily idled its operations."[1370] SWEPCO states that a pro forma adjustment should not be used to address a temporary event, because a pro forma adjustment instead is intended to ensure that test year data better represents a utility's ongoing operations.[1371] Consequently, it is inappropriate to adjust for an item that is known but temporary because doing so would not represent the expected ongoing operations for the utility.[1372] As to the small industrial customer, SWEPCO did not make a pro forma adjustment because the customer announced its plant shutdown after SWEPCO filed this case.[1373] SWEPCO states that when it files a base rate case, significant effort is made to ensure that all of the key assumptions and inputs are coordinated and provide a comprehensive assessment of the need for the base rate adjustment.[1374] SWEPCO states that it does not, however, continuously update these assumptions and inputs after the case has been filed,[1375] nor would such an approach be consistent with the rules governing base rate cases.

2. ETSWD's Responses

ETSWD argues that SWEPCO bears the burden of proof in this case to justify its proposed rates, and it has not shown that its proposed rates are just and reasonable without a COVID-19 adjustment to its CCOSS. ETSWD argues that SWEPCO's CCOSS "ignores all but the first week of the single most disruptive event to hit the country's economic patterns in at least one hundred years" and this proceeding "should not knowingly rely on antiquated data and an obsolete view of

[1370] ETSWD Initial Brief at 7; *see also* ETSWD Ex. 1 (Pevoto Dir.), Exh. KP-4; SWEPCO Ex. 53 (Burnett Reb) at 2.

[1371] SWEPCO Ex. 53 (Burnett Reb.) at 2.

[1372] SWEPCO Ex. 53 (Burnett Reb.) at 2.

[1373] SWEPCO Ex. 53 (Burnett Reb.) at 3.

[1374] SWEPCO Ex. 53 (Burnett Reb.) at 3.

[1375] SWEPCO Ex. 53 (Burnett Reb.) at 3.

the world."[1376] ETSWD claims that SWEPCO witness Burnett testified to two critical facts regarding this topic: (1) SWEPCO has much more current information about loads among customer classes that it has not included in the record to date; and (2) data in SWEPCO's possession quantifies differences in current usage patterns among the classes.[1377] ETSWD asserts that SWEPCO concedes that the assumptions about usage across customer classes utilized in SWEPCO's Application are antiquated.[1378]

Next, ETSWD argues that the Commission "may, in its discretion, go outside the test year when necessary to achieve just and reasonable rates that will *more accurately reflect the cost of service* that is apt to apply to the utility in the future."[1379] ETSWD asserts that no party has challenged the accuracy of SWEPCO's data reported in its response to ETSWD RFI 3-1.[1380] ETSWD states that the opposing parties' witnesses acknowledged under cross-examination that COVID-19 continues to impact economic and usage patterns in ways not incorporated into SWEPCO's test year study.[1381] ETSWD also argues that, while Staff's, OPUC's, and SWEPCO's speculations about a return to pre-COVID work-from-home behaviors and a pre-COVID economy would not require a known and measurable change, "the *Entergy* case shows the Commission's unwillingness to rely on unsubstantiated and unquantified forecasts of the future in setting rates."[1382]

[1376] ETSWD Initial Brief at 2-3 (citing Tr. at 1472, 1496).

[1377] Tr. at 1496-97.

[1378] Tr. at 1496-97 (related to new data in SWEPCO's possession); Tr. at 1491 (SWEPCO's response to ETSWD RFI 3-1, which is ETSWD Ex. 1 (Pevoto Dir.), Exh. KP-2, represents the most current information on customer usage by revenue class currently in the record of this docket).

[1379] Emphasis added (citing *Southwestern Public Service Co.*, No. 07-17-00146-CV (emphasis added) (citing *City of El Paso*, 883 S.W.2d at 188).

[1380] ETSWD notes that Staff witness Narvaez contends that SWEPCO's data will need to be disaggregated before it could be applied for purposes of making known and measurable changes. Staff Ex. 4b (Narvaez Cross-Reb) at 7. ETSWD does not disagree with Staff that disaggregation would be appropriate. ETSWD Initial Brief at 4.

[1381] *See, e.g.*, Tr. at 1409-10.

[1382] ETSWD Initial Brief at 6 (citing *Entergy Texas, Inc.*, 490 S.W.3d at 232 (the Commission rejected the inclusion of cost data that was fraught with uncertainty and significant variability)); *Rizkallah v. Conner*, 952 S.W.2d 580, 587 (Tex. App.—Houston [1st Dist.] 1997) (in the context of civil litigation, pointing out, "Conclusory statements without factual support are not credible and are not susceptible to being readily controverted.").

ETSWD asserts that the Commission has noted the potential for COVID-19 to affect class consumption.[1383] Consistent with ETSWD witness Pevoto's recommendation, the best way for the Commission "to determine whether" COVID-19 has caused a shift in class consumption is for the Commission to order SWEPCO to update its customer class of service studies with the most current data available.[1384] ETSWD urges that the opposing parties' predictions lacks statistical support and are contradicted by multiple forms of information both in the evidence and in SWEPCO's possession. For example, if the Governor's March 2, 2021 order did, in fact, mark the return to pre-COVID electricity consumption behaviors as implied by SWEPCO witness Burnett[1385] and OPUC witness Georgis,[1386] then updated data in SWEPCO's possession would prove that shift in usage among customer classes and a return to "normalcy."[1387] ETSWD contends that an updated run of the analyses "is not likely" to show a return to normalcy.[1388] ETSWD concludes that new record data from SWEPCO and statements reveal even more recent data in SWEPCO's possession that continues to show that a return to pre-COVID electricity consumption behaviors among classes has not occurred.[1389]

3. ALJs' Analysis

The ALJs conclude that SWEPCO, Staff, OPUC, and CARD have presented credible evidence and argument that the continuing effects of COVD-19 are transitory and unknown.[1390] As such, updating SWEPCO's cost of service study through post-test year data would not result in rates that are known to be reflective of customer demands going forward. ETSWD impliedly

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[1383] Docket No. 50277, PFD at 24 (Sep. 3, 2020).

[1384] ETSWD Ex. 1 (Pevoto Dir.) at 5.

[1385] SWEPCO Ex. 53 (Burnett Reb.) at 7.

[1386] OPUC Ex. 60 (Georgis Cross-Reb.) at 5-6.

[1387] ETSWD Initial Brief at 5.

[1388] ETSWD Initial Brief at 5.

[1389] ETSWD Ex. 1 (Pevoto Dir.) at Exh. KP-3.

[1390] The ALJs also agree with TIEC's comments regarding the lack of clarity on how the Commission could implement ETSWD's proposal, or how the parties could respond to the data used to set rates through a COVID-19 adjusted cost of service study.

concedes as much when it argues "an updated run of the analyses 'is not likely' to show a return to normalcy."[1391] ETSWD's own words—"is not likely"—shows the speculative nature of its request. Similarly, although ETSWD appears to concede that updated billing determinants need not be based on a "known and measureable change," it highlights that, at least in the context of a post-test year adjustment, the Commission is unwilling to rely on "unsubstantiated and unquantified forecasts of the future in setting rates."[1392] But that essentially is what ETSWD is requesting. In short, ETSWD is requesting that the Commission discard the filed adjusted cost of service study and instead require a new cost of service study based solely on its snap shot-based speculation that the COVID-19 effects are not transitory. Even if a more recent study shows a change in customers' usage, which a new study could show despite a pandemic situation, ETSWD has not shown that a more recent study would be more apt to show the usage that will prevail into the future before SWEPCO's rates are re-set in its next base rate case.

SWEPCO's evidence also shows, based on April 2021 data, that the "narrative is flipped" with residential sales moving down as commercial and industrial sales move up "significantly."[1393] Similarly, SWEPCO's evidence showed, at the time it filed rebuttal testimony on April 23, 2021, that the impact of the pandemic has lessened as time has passed.[1394] The ALJs also decline to recommend approval of ETSWD's proposals because approval could serve as future precedent whereby an adjusted test year-based cost of service study filed in accordance with the Commission's rules and historical practice is essentially abandoned and replaced with a new cost of service study (or at least new billing determinants) shortly after the close of the applicable test year. That perhaps would be advisable if the dramatic post-test year changes were known and measureable and would be apt to prevail in the future, but that is not the case with COVID-19.

The ALJs are also persuaded by SWEPCO's evidence that adjustments for a customer that has since returned after a temporary shutdown, or a customer that shut down after the close of the

[1391] ETSWD Initial Brief at 5.

[1392] ETSWD Initial Brief at 6.

[1393] Tr. at 1474, 1495-96.

[1394] Tr. at 1493-94.

test year in what could not have been foreseen as a known and measureable change, are not warranted and should not be implemented in this case.

In conclusion, the ALJs agree with SWEPCO, Staff, OPUC, TIEC, and CARD that SWEPCO should not be required to update its customer class cost of service study to incorporate new data and account for the “enduring ‘work from home’” shift and other effects of COVID-19. The Commission also should not instruct SWEPCO to recalculate and adjust its class cost of service study using the data provided in SWEPCO’s response to ETSWD RFI 3-1. The ALJs also recommend that the Commission not require SWEPCO update the class cost of service study to reflect the loss of certain customers’ loads as requested by ETSWD.

IX. FUNCTIONALIZATION AND COST ALLOCATION [PO ISSUES 4, 5, 31, 52, 53, 55, 56, 57, 58]

For non-ERCOT Texas electric utilities, the cost allocation aspects of ratemaking involve primarily two types of allocations. First, jurisdictional allocation examines the allocation of the portion of SWEPCO’s “total company costs,” which comprise SWEPCO’s costs from all of its jurisdictions (Texas, Arkansas, Louisiana, and FERC) to its Texas retail jurisdiction.[1395] The question with jurisdictional allocation is whether Texas retail customers are only paying for their share of SWEPCO’s total system costs. Second, once the reasonable amount of jurisdictional costs are allocated to Texas retail, the next step is to allocate that Texas retail jurisdictional total cost of service among the SWEPCO’s Texas retail customer classes, such that each class (at a high level, the Residential, Commercial, Industrial, Municipal, and Lighting classes) is bearing its appropriate share of the total Texas retail amount. The point of the class cost of service analysis is to determine the reasonable and necessary cost that each customer class should contribute to SWEPCO’s Commission-approved annual revenue requirement. This does not end the analysis, however, because in the next section of the PFD the ALJs address rate moderation (also known as

[1395] SWEPCO’s Texas wholesale customers (as distinct from SWEPCO’s Texas retail customers) are treated as within the FERC jurisdiction.

"gradualism") to avoid "rate shock," and how rates are designed to recover costs allocated within each specific class.

Staff witness Narvaez prepared Staff's jurisdictional and class cost of service studies based on the revisions recommended by Staff witnesses to SWEPCO's as-filed proposed revenue requirement. Staff's class cost of service study results in a total retail Texas revenue requirement of $410,378,080.[1396] Mr. Narvaez's studies were filed with his direct testimony on April 7, 2021.

On April 23, 2021, SWEPCO witness Aaron filed SWEPCO's rebuttal Texas jurisdictional and class cost of service studies with his rebuttal testimony to reflect: (1) changes to certain costs allocated to the Texas retail jurisdiction; and (2) allocation changes among SWEPCO's Texas retail classes.[1397] SWEPCO's proposed rebuttal Texas retail jurisdictional revenue requirement reflects changes in total company values made from SWEPCO's as-filed case to its rebuttal case.[1398] SWEPCO's rebuttal cost of service reflects a $5 million decrease to the Texas retail base rate revenue requirement as compared to its as-filed case, and includes shifts of base rate revenues among the retail customer classes. The table below summarizes the changes to SWEPCO's Texas base rate revenue requirement in total and by major class grouping at an equalized return.[1399]

	FILED	REBUTTAL	CHANGE
Texas Retail	$ 451,529,538	$ 446,466,201	$ (5,063,337)
Residential	$ 188,152,651	$ 188,778,452	$ 625,801
Commercial	$ 193,497,125	$ 191,044,316	$ (2,452,809)
Industrial	$ 57,506,958	$ 54,451,107	$ (3,055,851)
Municipal	$ 4,303,143	$ 4,219,413	$ (83,730)
Lighting	$ 8,069,661	$ 7,972,913	$ (96,748)

[1396] Staff Ex. 4 (Narvaez Dir), Attachment AN-4 at 2.

[1397] SWEPCO Ex. 54A (Aaron Reb. Workpapers).

[1398] SWEPCO Ex. 36 (Baird Reb.), Exh. MAB-1R.

[1399] SWEPCO Ex. 54 (Aaron Reb.) at 6. Mr. Aaron's rebuttal workpapers include this table as well as a table showing his changes to SWEPCO's as-filed cost of service studies, his rebuttal jurisdictional cost of service study, and his rebuttal class cost of service study. SWEPCO Ex. 54A (Aaron Reb. Workpapers).

The difference between Staff's class cost of service study and SWEPCO's rebuttal class cost of service study is just over $36 million ($446.5 million less $410.4 million). The ALJs' analyses in this section start with SWEPCO's as-filed cost of service studies, accept SWEPCO's revisions that resulted in its rebuttal cost of service studies, and then address the numerous, primarily class, cost of service issues raised by Staff and the other parties.

A. Jurisdictional Allocation [PO Issues 55, 57]

1. SWEPCO's Jurisdictional Allocation, as Revised by Its Rebuttal Case

a. Production Demand

SWEPCO used a four coincident peak (4CP) allocation methodology for the jurisdictional assignment of production demand-related costs, reflecting the jurisdictions' use of SWEPCO's production facilities at the time of the system peak demands for June through September.[1400] Each jurisdiction's allocation factor is a ratio of the average of that jurisdiction's 4CP demand to the average of the SWEPCO's total production system 4CP.[1401] SWEPCO reduced the average of the 4CP demand for SWEPCO's FERC jurisdiction by customer supplied resources, the output of which is included in the metered values in SWEPCO's demand and energy accounting. According to SWEPCO, allocating production costs on the unadjusted gross 4CP value would inappropriately allocate production costs to the wholesale jurisdiction.[1402] No party contests this methodology.

b. Production Energy

Production energy-related costs, including expenses recorded in FERC Account 501 not recovered through SWEPCO's fuel clause (*i.e.*, non-reconcilable fuel expenses), were allocated to

[1400] SWEPCO Ex. 31 (Aaron Dir.) at 14.

[1401] SWEPCO Ex. 31 (Aaron Dir.) at 14.

[1402] SWEPCO Ex. 31 (Aaron Dir.) at 14-15.

each jurisdiction based on adjusted test year annual kWh sales as reflected in RFP Schedule O-4.1.[1403] No party contested this allocation methodology.

c. Transmission

Transmission-related costs are allocated to SWEPCO jurisdictions using the average of SWEPCO's twelve monthly peak demands (12CP) coinciding with the monthly peaks in Zone 1 of the SPP. SWEPCO states this allocation methodology appropriately reflects SWEPCO's load responsibility in the SPP.[1404] No party contested this allocation methodology.

d. Distribution

Distribution plant was directly assigned to the states based on geographic location and allocated to the FERC jurisdiction by individual FERC distribution accounts. Certain wholesale customers take service from SWEPCO pursuant to wholesale formula rates at distribution voltage levels. SWEPCO states this methodology appropriately assigns the cost responsibility to the FERC jurisdiction.[1405] Customer-related distribution costs such as investment in meters and lights were also directly assigned to the jurisdictions by individual FERC distribution accounts. Customer accounting, information, and service expenses were allocated to each jurisdiction using a combination of adjusted test year-end number of customers, manually billed customers, and other customer-based allocators as provided on RFP Schedule P-11.[1406] These methodologies were not contested.

e. General Plant

SWEPCO's investment in general plant is allocated using the labor allocation factors developed in RFP Schedules P-7 and P-10, which allocate the labor portion of each O&M expense

[1403] SWEPCO Ex. 31 (Aaron Dir.) at 15.

[1404] SWEPCO Ex. 31 (Aaron Dir.) at 15.

[1405] SWEPCO Ex. 31 (Aaron Dir.) at 15-16.

[1406] SWEPCO Ex. 31 (Aaron Dir.) at 16.

account on the same basis as the total expense. These labor allocation factors are also used to allocate many administrative and general expense items.[1407] No party contested this allocation methodology.

f. Revenues

In the jurisdictional cost of service study, electricity sales revenues are directly assigned to the jurisdictions based on the existing approved jurisdictional tariffs.[1408]

g. Revisions From SWEPCO's As-Filed Case to Its Rebuttal Case

SWEPCO notes in its initial brief that it inadvertently directly assigned certain distribution investments to the wholesale class in its as-filed jurisdictional cost of service study.[1409] The Company contends there should have been no such assignment because it collects revenues from wholesale customers for the associated investments, thereby reducing cost allocation. SWEPCO argues that removing this allocation from the wholesale jurisdiction in its rebuttal jurisdictional cost of service study increases the allocation to other jurisdictions that is offset by a larger allocation of distribution miscellaneous revenues.[1410] CARD raises concerns with this revision, which are discussed below.

In responding to discovery from ETSWD, SWEPCO determined that pro forma adjustments to test year load and customer data related to the loss of three large industrial customers were not properly reflected in the as-filed jurisdictional production and transmission demand allocations. SWEPCO included these adjustments in its rebuttal jurisdictional cost of service study, resulting in a slight decrease to the jurisdictional production allocation and a slight

[1407] SWEPCO Ex. 31 (Aaron Dir.) at 16.

[1408] SWEPCO Ex. 31 (Aaron Dir.) at 19.

[1409] SWEPCO Initial Brief at 115.

[1410] SWEPCO Ex. 54 (Aaron Reb.) at 6.

increase to the jurisdictional transmission allocation.[1411] As to the three customers who permanently left the system, there is no dispute about removing their customer data from the cost of service, but there is a dispute about other customers that SWEPCO contends only left temporarily. These disputes are discussed below.

h. Eastman BTMG

As addressed in Section IV above, Eastman disputes SWEPCO's allocation to the Texas retail jurisdiction of $5.7 million in transmission costs related to Eastman's load served by its retail BTMG, arguing that such allocation is not based on cost causation requirements.[1412] As also noted above, SWEPCO argues that if these retail BTMG costs are removed from the Texas jurisdictional allocations, the costs incurred to provide service to SWEPCO's Texas jurisdiction would be inappropriately shifted to SWEPCO's other jurisdictions (Arkansas, Louisiana, and FERC).[1413]

2. Staff's and Intervenors' Positions Regarding Jurisdictional Allocation and ALJs' Analysis on Each Issue

The parties addressed three issues with regard to jurisdictional cost allocation:

- The allocation of $5.7 million in SPP charges to the retail BTMG load, primarily borne by Eastman Chemical;
- SWEPCO's removal of costs inadvertently assigned in Schedule P-3 (Allocation of Rate Base to Proposed Rate Classes) to the wholesale class through the as-filed jurisdictional cost-of-service study; and
- SWEPCO agrees with Staff's Jurisdictional Cost of Service Summary prepared by Staff witness Narvaez, but SWEPCO does not agree with Staff's calculated results.

[1411] SWEPCO Ex. 54 (Aaron Reb.) at 6-7.

[1412] Eastman Ex. 1 (Al-Jabir Dir.) at 26.

[1413] SWEPCO Ex. 54 (Aaron Reb.) at 1-2; SWEPCO Initial Brief at 116.

a. $5.7 Million Allocated to the Texas Retail Jurisdiction Related to Retail BTMG

Because this BTMG issue has already been addressed above in the context of transmission O&M expense, it will not be repeated in this section in the context of jurisdictional and class cost of service studies. However, to ensure that the Eastman load served by its retail BTMG does not seep into the cost of service analyses, the ALJs recommend that SWEPCO's allocation of Eastman's load served by its retail BTMG should be removed from the jurisdictional cost of service study approved by the Commission in this docket.[1414]

b. SWEPCO's Removal of Certain Distribution Investments from the Wholesale Class

SWEPCO states it inadvertently assigned costs to the wholesale jurisdiction in RFP Schedule P-3 (Allocation of Rate Base to Proposed Rate Classes) of the as-filed jurisdictional cost of service study.[1415] The Company states costs should not have been directly assigned to the wholesale class because revenues are collected from the wholesale customers for the associated investments, reducing the amounts to be collected from other jurisdictions.[1416] For this reason, SWEPCO removed these costs from the allocation to the wholesale jurisdiction. SWEPCO argues that removing the allocation of selected distribution investments from the wholesale jurisdiction increases the allocation of those costs to other jurisdictions that is offset by a larger allocation of distribution miscellaneous revenues.[1417]

CARD disagrees with SWEPCO's proposal to remove certain distribution investments from the wholesale class. CARD argues that this removal from the wholesale class deviates from the methodology approved by the Commission in Docket No. 46449, and that SWEPCO's

[1414] This same recommendation applies to SWEPCO's class cost of service study, which is addressed in Section IX.B. below.

[1415] SWEPCO Reply Brief at 102-03.

[1416] SWEPCO Ex. 54 (Aaron Reb.) at 6.

[1417] SWEPCO Ex. 54 (Aaron Reb.) at 6.

rationale for the removal is incorrect.[1418] CARD explains that by adjusting the assignment of costs so that there are no costs directly assigned to the wholesale class, SWEPCO is improperly removing the allocation of certain distribution costs from the wholesale jurisdiction, which consequently increases the allocation to other jurisdictions. CARD notes that SWEPCO witness Aaron alleged that the increased cost allocation is offset by a larger allocation of distribution miscellaneous revenues but provided no support for this contention. CARD does not outright oppose this removal of distribution investment from the wholesale class, but instead urges, absent "an understanding of how this change impacts the rate classes and recognizing that this change deviates from the methodology approved in Docket No. 46499," SWEPCO's proposed adjustment should be rejected and the Commission should instead rely on SWEPCO's as-filed cost of service study as to this issue.[1419] The only additional point that SWEPCO makes in response to CARD's opposition to this wholesale class issue is that, while CARD complains that Mr. Aaron offered no support for this offset, "CARD does not offer nor point to any evidence that controverts it, or explains why it is incorrect."[1420]

The ALJs agree with SWEPCO on this issue. CARD has neither presented evidence that controverts SWEPCO's position, nor explained why its position is supported by the Commission's decision in Docket No. 46499. Instead, CARD simply does not want SWEPCO to make this adjustment because it has the effect of moving costs from the wholesale class to other jurisdictions, including, implicitly, the Texas retail jurisdiction.[1421] CARD's response does not explain why SWEPCO is wrong, but instead simply states that the distribution costs should stay with the wholesale class so other classes do not have to pick them up. In this situation, the ALJs conclude that SWEPCO has met its burden of proof to support removing these distribution costs from the wholesale class. Accordingly, the ALJs recommend that SWEPCO not be required to include these distribution-related costs in its wholesale class.

[1418] Citing SWEPCO Ex. 54 (Aaron Reb.) at 6.

[1419] CARD Initial Brief at 68; CARD Reply Brief at 40.

[1420] SWEPCO Reply Brief at 103.

[1421] CARD Reply Brief at 41 ("By adjusting the assignment of costs so that there are no directly assigned costs to the wholesale class, SWEPCO is improperly removing the allocation of certain distribution costs from the wholesale jurisdiction, which consequently increases the allocation to other jurisdictions.")

c. Staff's Jurisdictional Cost of Service Study vs. SWEPCO's Rebuttal Jurisdictional Cost of Service Study

In both its initial and reply briefs, Staff simply urges that the Commission adopt Staff's jurisdictional cost of service study presented by Staff witness Narvaez.[1422] Both Staff's jurisdictional and class cost of service studies result in Staff's $410 million annual revenue requirement as compared to SWEPCO's $446 million final (rebuttal) request. In the context of jurisdictional allocation, what Staff essentially is requesting is that the Commission accept all of Staff's recommendations, including those regarding rate base, ROE, and expenses and, by doing so, the Commission would be adopting Staff's proposed jurisdictional (and class) cost of service studies.

As addressed in the prior sections of this PFD dealing with rate base, ROE, and expenses, the ALJs recommend some, but not all, of the disallowances recommended by Staff and the other parties. Using the ALJs' recommended figures in the cost of service studies through the number running process results in a recommended annual revenue requirement. The ALJs recommend that the cost of service resulting from their analyses in this PFD be adopted by the Commission. As such the ALJs do not recommend a blanket approval of Staff's as-filed studies.

B. Class Allocation [PO Issues 53, 58]

SWEPCO's Texas jurisdictional production, transmission, and distribution demand-related components are allocated differently in the class cost of service study. Customer-related costs are allocated on a similar manner in both the jurisdictional and class cost of service studies.[1423] For the class cost of service study:[1424]

[1422] Staff Ex. 4 (Narvaez Dir.), Exh. AN-2; Staff Initial Brief at 69; Staff Reply Brief at 45.

[1423] SWEPCO Initial Brief at 116.

[1424] These class allocation methodology summaries are derived from SWEPCO's descriptions in its initial brief at 116-18.

- Production demand-related costs are allocated to the various retail customer classes on the average and excess demand 4CP methodology (A&E/4CP).[1425]

- Transmission-related costs also are allocated to the retail customer classes on an A&E/4CP basis.[1426]

- Distribution plant costs recorded in FERC Accounts 360-368 are allocated on the basis of customer class Maximum Diversified Demands (MDD) during the test year. MDDs are the maximum demand placed on the system regardless of the relationship of that point in time to the system peak. Customer-related distribution costs recorded in FERC Accounts 369 through 373 are limited to the costs that vary directly with the number of customers (*i.e.*, meters, service drops, transformers, and associated expenses). These costs and associated expenses are allocated to the customers who require such facilities using a weighted-number-of-customers methodology.[1427]

- Electricity sales revenues reflect test year adjusted retail sales assigned to classes by the tariff code designated for the type of service. Late Payment Charges and Miscellaneous Service Revenues are directly assigned to the retail jurisdictions. Other Miscellaneous Electric Revenue are first functionalized based upon an analysis of the Company’s records and then allocated to the jurisdictions based on the functional assignment of the asset used to generate the revenue.[1428]

The parties raised numerous issues with regard to class allocation and the class cost of service, including arguments regarding whether or how the BTMG costs should be allocated among the customer classes, and opposition to ETSWD’s proposed COVID-19 adjustments. The BTMG and COVID-19 issues are discussed separately above in Sections VII and VIII of this PFD, and will not be addressed again here.

[1425] SWEPCO Ex. 31 (Aaron Dir.) at 17.

[1426] SWEPCO Ex. 31 (Aaron Dir.) at 18. SWEPCO notes in its initial brief, in its description of its transmission cost class allocation, that “The A&E 4CP allocation for transmission-related costs differs from the A&E 4CP allocation used for production-related costs because the transmission allocation includes synchronized BTMG included in SWEPCO’s transmission load responsibility in the SPP.” SWEPCO Initial Brief at 117.

[1427] SWEPCO Ex. 31 (Aaron Dir.) at 17-18.

[1428] SWEPCO Ex. 31 (Aaron Dir.) at 19.

1. CARD's Class Allocation Issues

CARD raises four class allocation issues: (1) allocation of line transformers; (2) allocation of major account representative costs; (3) assignment of costs to the wholesale class; and (4) opposition to ETSWD's proposed COVID-19 adjustments. The latter two of these four issues have been addressed in prior sections of this PFD and will not be addressed again here. The assignment of costs to the wholesale class is addressed in the prior Section IX.A. ETSWD's proposed COVID-19 adjustments are addressed in the context of billing determinants addressed in Section VIII.

In the context of the first two class allocation issues, CARD argues generally that SWEPCO is incorrect in its assertion that "the allocation factors and process are the same as those approved by the Commission in Docket No. 46449 and updated in Docket No 48233."[1429]

a. SWEPCO's Allocation of Line Transformers

CARD notes that SWEPCO allocated both primary and secondary line transformer costs (FERC Account 368) among the customer classes on the same percentage basis.[1430] However, according to CARD, Nucor witness Daniel argued that allocations should be different for primary and secondary line transformer costs.[1431] CARD argues that SWEPCO's proposal is a deviation from the allocation factors and methodologies the Commission approved in Docket No. 46449 and from SWEPCO's response to CARD RFI 11-7, but that SWEPCO nevertheless incorporated this adjustment to the allocation of line transformer costs in the Company's rebuttal cost of service study.[1432] CARD contends that this adjustment to the allocation of line transformer costs will result in an improper allocation of costs. While the allocations SWEPCO presented in its as-filed cost of service study did not change the primary line transformer cost allocations, CARD asserts the

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[1429] CARD Initial Brief at 67 (citing CARD Exh. 19 (SWEPCO's response to CARD RFI 11-7)).

[1430] SWEPCO Exh. 54 (Aaron Reb.) at 2.

[1431] Nucor Ex. 1 (Daniel Dir.) at 15, 18.

[1432] SWEPCO Exh. 54 (Aaron Reb.) at 2.

allocation presented in SWEPCO's rebuttal class cost of service study unfairly result in the secondary class receiving a higher allocation of secondary line transformer costs, and subsequently more total line transformer costs.[1433]

SWEPCO responds that CARD's overarching criticism of SWEPCO's revisions introduced through its rebuttal class cost of service study is its position that they deviate from the allocation factors and methodologies approved in Docket No. 46449. As to the line transformer costs from FERC Account 368, only a portion of the account should have been allocated to primary service customers, and the as-filed class cost of service study had incorrectly allocated all of that account to primary service customers.[1434] Therefore, this change in SWEPCO's rebuttal class cost of service study was reasonable and appropriate.

The ALJs agree with SWEPCO on this issue. CARD has not explained how SWEPCO's correction to the allocation of line transformer costs is contrary to Docket No. 46449. SWEPCO explained that it was correcting an error in the allocation of line transformer costs in its rebuttal cost of service study, as pointed out by Nucor witness Daniel. CARD's reply brief on this issue simply points back to its initial brief without explaining why SWEPCO's correction is wrong or contrary to Docket No. 46449. Based on SWEPCO's evidence, the ALJs conclude the correction was appropriate and necessary. The ALJs therefore recommend against CARD's proposal regarding the allocation of line transformer costs in the class cost of service study.

b. Major Account Representative Costs and Prepayments

CARD states that SWEPCO made two changes to the cost of service study presented in its as-filed direct case. The first change was to the components of its test-year prepayment balances included in rate base.[1435] The second adjustment SWEPCO made was to the quantification and

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[1433] Citing SWEPCO Exh. 54A (Aaron Reb. Workpapers).

[1434] Nucor Ex. 1 (Daniel Dir.) at 15, Exh. JWD-5 (SWEPCO's response to Nucor RFI 3-20).

[1435] SWEPCO Exh. 54A (Aaron Reb. Workpapers) at 7.

allocation of major account representative costs recorded in FERC Account 908.[1436] CARD claims that these changes are not consistent with the allocation factors approved in Docket No. 46449.[1437] CARD concedes that these changes have a relatively small impact on the overall revenue requirement, but nevertheless urges the ALJs to reject the adjustment to the components of the test-year prepayment balances included in rate base and the adjustment SWEPCO made to the quantification and allocation of major account representative costs recorded in FERC Account 908.

As an overarching matter raised in the context of these two issues, CARD correctly notes that SWEPCO's rebuttal case adjustments caused a shift in costs from SWEPCO's as-filed cost of service study to its rebuttal cost of service study, resulting in an increase to the residential class, despite an overall $5 million reduction to the cost of service.[1438] CARD suggests that unreasonable changes were proposed by the commercial and industrial parties to shift costs to the residential class based on allocation factors that deviate from the factors approved in Docket No. 46449.[1439]

SWEPCO responds that it has not assigned major account representative costs to the residential class,[1440] and the Commission's order in Docket No. 46449 precludes the Company from doing so. Findings of fact in that order include the following:

> 296. SWEPCO uses major account representatives to work with 69 large commercial and 68 industrial customers.
>
> 297. It is reasonable to allocate major-account-representatives expenses solely to the large commercial and industrial customers who benefit from that service.

1436 SWEPCO Exh. 54A (Aaron Reb. Workpapers) at 7.

1437 Docket No. 46449, Order on Rehearing at 47 (Mar. 19, 2018).

1438 *See* SWEPCO Ex. 54 (Aaron Reb.) at 6, which shows a $625,801 increase in the Residential class, despite an overall decrease of $5 million.

1439 CARD Initial Brief at 70.

1440 SWEPCO Ex. 54A (Aaron Reb. Workpapers) at "JOA WP – SWEPCO TX COS_Class TY 3_2020 Rebuttal.xlsx," Tab "COS Changes – Discovery," Lines 69-72, 100-108 (reproducing SWEPCO's response to TIEC RFI 7-1(d)); *see also* SWEPCO Ex. 54 (Aaron Reb.) at 7.

298. Major account representative costs should not be assigned to residential and general-service customers who do not receive these services.[1441]

SWEPCO explains further that its rebuttal adjustment to FERC Account 908 was merely to remove certain labor expenses that are not related to major account representative expenses from the direct assignment to these customers.[1442]

As to the prepayments issue, CARD does not explain how or why SWEPCO's correction deviates from Docket No. 46449, and does not address this issue in its reply brief.

The ALJs agree with SWEPCO on both of these issues. The evidence does not show that SWEPCO, through its rebuttal cost of service studies, allocated any major account representative costs to the residential class, and SWEPCO correctly points out that these costs can only be allocated to large commercial and industrial customers in accordance with Commission precedent. CARD also has not presented a reason why SWEPCO's correction regarding prepayments was in error, or how that correction deviated from Docket No. 46449. For these reasons, the ALJs recommend against CARD's proposals regarding major account representatives and prepayments.

2. TIEC's Class Allocation Issues

TIEC addresses two aspects of SWEPCO's proposed class cost of service study. First, the Commission should adopt SWEPCO's rebuttal proposal to use a single coincident peak (1CP) system load factor to weight average demand in the A&E/4CP allocation methodology. Second, the Commission should reject SWEPCO's proposed allocation of costs purportedly caused by SWEPCO's decision to report Eastman's BTMG load to SPP as part of SWEPCO's Monthly Network Load.

[1441] Docket No. 46449, Order on Rehearing at FoF Nos. 296-298 (Mar. 19, 2018).

[1442] SWEPCO Ex. 54A (Aaron Reb. Workpapers) at "JOA WP – SWEPCO TX COS_Class TY 3_2020 Rebuttal.xlsx," Tab "COS Changes – Discovery," Lines 73-76 (reproducing SWEPCO's response to TIEC RFI 7-1(d)).

As to the system load factor issue, as noted in the summary bullets above, SWEPCO's CCOSS uses the A&E/4CP methodology to allocate production and transmission costs.[1443] According to TIEC, a key component of A&E/4CP is the system load factor,[1444] which is the ratio of the average load over a designated period compared to the peak demand in that period.[1445] In its Application, SWEPCO inadvertently used a system load factor calculated based on the average of SWEPCO's four coincident peaks (4CP) rather than the actual peak demand (1CP).[1446] However, after TIEC witness Pollock pointed out this error in his direct testimony,[1447] SWEPCO revised its class allocation through its rebuttal CCOSS to use a system load factor based on its 1CP.[1448] No party filed in opposition to SWEPCO's correction. TIEC argues that the use of a 1CP system load factor is consistent with cost-causation and well-established Commission precedent.[1449] Because this issue is now not contested due to SWEPCO's correction in its rebuttal case, the ALJs recommend approval of the method SWEPCO ultimately used to allocate production and transmission costs to its classes.

As to the retail BTMG issue, as discussed in Section VII above, SWEPCO proposes to change its *jurisdictional* allocation of transmission costs by adding Eastman's BTMG load to the Texas jurisdiction. TIEC points out that SWEPCO made a similar adjustment to the *class* allocation.[1450] Specifically, SWEPCO imputed Eastman's BTMG load to the LLP-T class. This adjustment increased the LLP-T class's purported peak demand from 97.7 MW to 246.7 MW.[1451] According to TIEC, the consequence of imputing this load to the LLP-T class is a massive cost

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1443 SWEPCO Ex. 31 (Aaron Dir.) at 17-18.

1444 TIEC Ex. 1 (Pollock Dir.) at 30-31.

1445 TIEC Ex. 1 (Pollock Dir.) at 33.

1446 SWEPCO Ex. 54 (Aaron Reb.) at 3; TIEC Ex. 1 (Pollock Dir.) at 31-32.

1447 TIEC Ex. 1 (Pollock Dir.) at 32-35.

1448 SWEPCO Ex. 54 (Aaron Reb.) at 3.

1449 TIEC Ex. 1 (Pollock Dir.) at 32-34.

1450 TIEC Initial Brief at 69.

1451 SWEPCO Ex. 54 (Aaron Reb.), Exh. JOA-1R. This exhibit shows the production and transmission demands by class. As Mr. Aaron explained, the only difference between the peak demand shown for production and transmission for each class is that 149 MW was added to the LLP-T class to account for BTMG. *Id.* at 3.

shift. While imputing Eastman's BTMG load to Texas at the jurisdictional level increased the revenue requirement in this case by $5.7 million, doing so at the class level increased the LLP-T class's share of transmission costs by nearly $8 million.[1452] Given that the transmission allocation must equal 100%, increasing the share to the LLP-T class necessarily reduces the allocation to all remaining classes. In particular, under SWEPCO's proposal, the remaining classes see a decrease of approximately $2.3 million, which is the difference between the $8 million allocated to the LLP-T class and the $5.7 million Texas retail revenue requirement impact from imputing Eastman's BTMG load in the jurisdictional allocation.[1453]

For the same reasons discussed above regarding SWEPCO's jurisdictional allocation, the ALJs find that SWEPCO's corresponding change to the class allocation should be rejected. SWEPCO did not demonstrate that the allocation was reasonable, necessary, and non-discriminatory. Accordingly, the ALJs recommend that Eastman's BTMG load that SWEPCO added to the LLP-T class for allocation purposes be removed.[1454]

3. OPUC's Class Allocation Issue

OPUC states that it does not oppose SWEPCO's requested class allocations.[1455] OPUC requests, however, that OPUC's revenue requirement adjustments be applied to SWEPCO's proposed cost of service model.[1456] OPUC also expresses some concern over SWEPCO's proposed revenue distribution for future rates, which moves the residential customer class to cost at a relative rate of return of 1.0, while still leaving the large industrial customer class 7% under cost at a relative rate of return of 0.93 (1.0 when combined with the commercial class).[1457]

[1452] TIEC Ex. 74, SWEPCO's response to TIEC RFI 11-1, at Bates 002; Tr. at 1216.

[1453] TIEC Ex. 74 SWEPCO's response to TIEC RFI 11-1, at Bates 002.

[1454] Because different allocators are used to allocate transmission costs at the jurisdictional and class levels (12CP and A&E/4CP, respectively), the adjustment differs slightly. For the class allocation, SWEPCO imputed 149 MW of 4CP demand and 146 MW of average demand for Eastman. TIEC Ex. 1 (Pollock Dir.) at 32.

[1455] OPUC Initial Brief at 26.

[1456] OPUC Ex. 57 (Georgis Dir.) at 5-8.

[1457] OPUC Initial Brief at 27 (citing SWEPCO Ex. 32 (Jackson Dir.), Exh. JLJ-1 at 3).

TIEC responds to OPUC's concern that the large industrial class remains under cost in SWEPCO's class cost of service study by claiming that OPUC is referring to SWEPCO's as-filed class cost of service study.[1458] TIEC refers to SWEPCO's rebuttal CCOSS and concludes that "when proper revisions are made, the residential class is shown as having a lower relative rate of return than, for example, the LLP-T customer class."[1459]

Neither OPUC nor SWEPCO address OPUC's concern in their reply briefs. Because OPUC did not request a change to SWEPCO's proposed allocations, and its arguments were citing to SWEPCO's direct case rather than its rebuttal case, in which the rebuttal CCOSS was presented, the ALJs conclude that no changes are needed to SWEPCO's class cost of service based on OPUC's concerns regarding where classes ultimately were positioned with regard to relative rate of return.

4. Walmart's Class Allocation Issue

Walmart states that it does not oppose the Company's proposed revenue allocation. Walmart requests, however, that if the Commission approves a revenue requirement lower than that proposed by the Company, the Commission should use the reduction from proposed revenue requirement to move the customer classes closer to their respective costs of service while ensuring that no class receives an increase larger than that proposed by the Company.[1460]

The ALJs' recommendations in this docket result in a reduction to SWEPCO's proposed revenue requirement. The ALJs recommendations will be flowed through the class cost of service study and result in rates derived through that final, approved cost of service study.

[1458] TIEC Reply Brief at 48 (citing OPUC Initial Brief at 27-28, where OPUC is citing SWEPCO Ex. 32 (Jackson Dir.), Exh. JLJ-1 at 2).

[1459] TIEC Reply Brief at 48 (citing TIEC Ex. 1 (Pollock Dir.), Exh. JP-3 at 2-3). The ALJs understand that Mr. Pollock's direct testimony was filed before SWEPCO filed its rebuttal CCOSS, but the point made by TIEC is that the rebuttal CCOSS purportedly moved classes closer to unity.

[1460] Walmart Initial Brief at 6-7.

5. TCGA's Class Allocation Issues

TCGA's primary issue in this case is that it opposes SWEPCO's proposed class allocation and class cost of service study, arguing that it "inequitably and unreasonably allocates costs to the Cotton Gin class that the class did not cause."[1461] TCGA's issue also involves revenue distribution and rate design, addressed below, because TCGA urges that the Commission direct SWEPCO to essentially re-design the Cotton Gin class rates. All of the TCGA issues regarding the Cotton Gin class are addressed in this Class Allocation section of the PFD.

TCGA argues that the cost allocations made to the Cotton Gin class are not equitable or reasonable considering the unique attributes of the class. First, SWEPCO has proposed in this case a high base rate increase on SWEPCO's Cotton Gin class, and Staff proposes to significantly increase those rates over multiple years.[1462] TCGA contends this proposed high base rate increase is based on a test-year that reflected a low ginning season that will cause the revenues and the resulting relative rate of return from the Cotton Gin class to increase dramatically in years with average or above-average ginning. TCGA states that SWEPCO has recognized:

- Having few customers in a class can result in unusual circumstance in load from year to year;
- Unusual outcomes generally refer to the result of abnormal operating levels or different load and service characteristics that can occur from year to year in rate classes with few customers, making the class more susceptible to swings in the cost allocation results; and
- If unusual operating levels are reflected in the test year, considering the rate class with few customers on a stand-alone basis can skew the results from rate case to rate case causing unstable fluctuations in rates based on abnormalities. [1463]

[1461] TCGA Initial Brief at 14-20.

[1462] TCGA is referring in part here to the Revenue Distribution/Gradualism recommendation by Staff, which is addressed in detail in the next section of this PFD.

[1463] Citing TCGA Ex. 33, SWEPCO's response to Nucor RFI 3-12.

TCGA states:

- As a result of the variations in the quantity of cotton ginned the energy consumption of cotton gins between years can vary significantly;

- The consumption levels and patterns of cotton gin customers are driven by the quantity of cotton harvested by cotton growers in their respective areas, and this is in turn driven by weather in that area and the prevailing market price for cotton; and

- With these highly variable factors in play, the quantity of cotton grown, harvested, and ginned in specific areas can also vary significantly between years. [1464]

Because SWEPCO's current Cotton Gin class rate only includes a customer charge and a seasonally differentiated kWh charge, significant variations in energy consumption between years will cause the amount of base rate revenues from the Cotton Gin class to also vary significantly.[1465] Thus, imposing a high base rate increase in multiple years on SWEPCO's Cotton Gin class based on a low ginning season will cause Cotton Gin class revenues and the relative rate of return for the class to increase dramatically in years with average or above-average ginning. [1466]

TCGA explains further that the ginning season for its class occurs during the autumn and winter months and generally runs from mid-October to early February each year:

> Consequently, during the spring and summer months, their consumption is very low. During those months, their average consumption per cotton gin is less than 300 kWh per month. Therefore, the peak consumption and demands for the Cotton Gin Service class occurs outside of the four peak summer months for SWEPCO's generation and transmission facilities. Because the ginning season occurs outside the four peak summer months and the 4CP demands at generation is a major factor in the allocation of non-fuel production and transmission costs, the increased ginning and the associated increased consumption and revenues from Cotton Gin customers would not be expected to result in an increase in base rate costs allocated

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[1464] TCGA Ex. 1 (Evans Cross-Reb.) at 14. The cover page to Evan Evans's cross-rebuttal testimony states that it is his "direct" testimony, but the body of this testimony indicates it is cross-rebuttal testimony.

[1465] TCGA Ex. 1 (Evans Cross-Reb.) at 14.

[1466] TCGA Initial Brief at 17 (citing TCGA Ex. 1 (Evans Cross-Reb.) at 15-17).

> to the Cotton Gin Service class. Therefore, again, the ROR earned from the Cotton Gin Service class will be significantly higher during average and above average ginning years.[1467]

TCGA adds that most of the base rate cost of service for the Cotton Gin class is for Distribution Primary and Distribution Secondary-related costs. The size of SWEPCO's distribution system and the size and capacity of the various feeders is driven by the load put on those various feeders during the peak months.[1468] TCGA contends this "is in stark contrast" with the annual peak months for the Cotton Gin class.[1469] For investor-owned utilities in Texas, TCGA witness Evans testified that it is very rare for distribution substations, primary lines, and secondary lines to peak in the winter months. Due to the lower ambient temperatures and higher typical wind speeds, distribution substations, conductors, and line transformers can typically carry more load during winter months without approaching their peak operating temperature ratings than they can during the summer months.[1470] This is particularly true for the Texas Panhandle where the difference between the average daily temperatures and the average wind speeds for winter months compared to the summer months can be quite substantial.[1471]

Additionally, the Cotton Gin class has been allocated a substantial amount of investment and costs associated with distribution secondary poles, lines, and underground conduit, and conductor within the CCOSS; however, because the Cotton Gin class is served at secondary voltages typically direct from the line transformer and not secondary lines, these costs are not reasonably allocated to this class.[1472] Similarly, TCGA argues that it is unusual for rural loads, like those from remote cotton gins in the Panhandle, to be served through any underground secondary conduit and conductor.[1473] Despite these unique attributes and specific considerations,

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[1467] TCGA Initial Brief at 17, summarizing TCGA Ex. 1 (Evans Cross-Reb.) at 15-17.

[1468] Tr. at 183.

[1469] TCGA Initial Brief at 18.

[1470] TCGA Ex. 1 (Evans Cross-Reb.) at 18.

[1471] TCGA Ex. 1 (Evans Cross-Reb.) at 18.

[1472] TCGA Initial Brief at 18 (citing TCGA Ex. 1 (Evans Cross-Reb.) at 18).

[1473] TCGA Ex. 1 (Evans Cross-Reb.) at 18.

distribution-related costs that are not "caused" by cotton gins comprise the largest portion of the costs allocated to Cotton Gin class.

Lastly, according to TCGA, SWEPCO's proposal to increase vegetation management expenses results in a class cost allocation of these expenses when virtually no vegetation management expenses are incurred in SWEPCO's Texas Panhandle/North Texas service area where all of the cotton gin customers are located. The individual line items regarding all mechanical/manual clearing distribution vegetation management spending for the test year, less than 1% of this expense, approximately $40,000, was actually utilized in the Texas Panhandle/North Texas service area.[1474] Similarly, in evaluating a list of all herbicide application jobs performed during the test year, there were zero instances of a Texas Panhandle/North Texas job.[1475] TCGA argues that, despite vegetation management expenses being an example of costs directly related to a particular service area, all of this cost—almost $10 million—is proportionally allocated to the Cotton Gin class. TCGA concludes that cotton gin customers are bearing costs that they have not caused, and "it is entirely unreasonable to allocate a system-average for the exorbitant vegetation management costs to the Cotton Gin class."[1476] TCGA concludes and recommends:

> While there are several proposals to consider, the Parties to this docket seem to agree that a rate increase is appropriate, and TCGA agrees with this position. TCGA respectfully requests the ALJs to recommend a rate design in its PFD consistent with the positions set out above, resulting in a rate increase for the cotton gin class that is no more than the lower of either the system average base rate increase or a rate increase no more than of 37.44%.[1477]

SWEPCO, in response to TCGA's detailed criticism of the costs allocated to the Cotton Gin class, argues neither TCGA's witness nor its brief "offers any alternative proposal for allocation of these costs or makes any cost allocation recommendation whatsoever."[1478] SWEPCO

[1474] Citing TCGA Ex. 11, SWEPCO's Response to CARD RFI 4-53; Tr. at 202-07.

[1475] *E.g.*, Tr. at 207-08.

[1476] TCGA Initial Brief at 20.

[1477] TCGA Reply Brief at 12-13; *see also* TCGA Initial Brief at 21.

[1478] SWEPCO Reply Brief at 106.

adds that its witness Mr. Aaron explained in detail the allocation methodologies for distribution-demand related costs, customer-related distribution costs, and generation- and transmission-related costs, and the rationale behind them.[1479] SWEPCO relies on Mr. Aaron's explanation that a class's unique attributes (demand, consumption, and time of peak) are taken into account when determining cost allocation factors for generation, transmission and distribution services. As noted by TCGA, SWEPCO's A&E/4CP used for the allocation of generation and transmission costs to classes reflects the fact that Cotton Gin customers have very low summer loads.[1480] SWEPCO also states that it does not allocate costs based on location.[1481] Further, costs for distribution facilities are allocated on demands at the time of the class peak, not the system peak, during the summer months. SWEPCO argues that costs are allocated to the cotton ginners based on their contribution to the SWEPCO system peak for generation costs and the peak at the time of SPP peaks for transmission costs during the summer months. For the allocation of distribution costs to the Cotton Gin class, the annual class peak demand, or MDD, reflects the winter peaking attribute of the class. The MDD allocation when compared to the MDD allocations of other retail classes reflects the diversity of SWEPCO's distribution system design to serve the loads during the peak months for a wide range of customers and appropriately allocates all distribution-related costs.[1482] SWEPCO adds that TCGA's criticism of SWEPCO's cost allocation "flies in the face of long-standing Commission precedent requiring uniform, system-wide rates."[1483] Essentially, SWEPCO argues that it uses accepted and approved allocation methods to allocate costs to the Cotton Gin class.

The ALJs conclude that TCGA makes a number of valid points as to how it is markedly different from SWEPCO's other commercial classes located in northeast Texas. The TCGA members are located in the Texas Panhandle, far removed from SWEPCO's primary service territory in northeast Texas. The evidence shows that TCGA is not served by underground conduit,

[1479] SWEPCO Ex. 31 (Aaron Dir.) at 18-19.

[1480] TCGA Initial Brief at 18.

[1481] SWEPCO Reply Brief at 106.

[1482] SWEPCO Ex. 31 (Aaron Dir.) at 18.

[1483] SWEPCO Reply Brief at 106.

or primarily from secondary lines, and its vegetation management requirements are much less than those required by SWEPCO's northeast Texas customers.[1484] The ALJs are also concerned that the Cotton Gin class historically has had a relative rate of return far below unity, meaning that the Cotton Gin class historically under-collects its allocated costs and must thereby be subsidized by other classes. These considerations suggest to the ALJs that SWEPCO's CCOSS, or its rate design, may not be applied properly to the Cotton Gin class. An example, which SWEPCO may need to reconsider, is its assertion that it "does not allocate costs based on location." SWEPCO has not addressed why its few Cotton Gin class customers in the Texas Panhandle should be treated the same, essentially, as commercial class customers in far northeast Texas.[1485]

But neither has TCGA submitted an alternative class allocation (or rate design) proposal that the Commission could consider for adoption in this docket. That is, the ALJs are not presented with an alternative to SWEPCO's essentially standard class cost allocation methods that could address TCGA's situation. The ALJs, therefore, do not recommend that the Commission take additional action in this docket to address the Cotton Gin class. The ALJs recommend, however, that the Commission direct SWEPCO to address the rather unique Cotton Gin class situation in its direct testimony in its next base rate case, and there address whether some actions can be taken to address the Cotton Gin class's historical under-recovery of its cost of service calculated through the CCOSS. For reasons that will become apparent in the Rate Design section below, the ALJs also recommend that SWEPCO be required to address in its next base rate case why the Oilfield Secondary and Public Street and Highway Lighting rate classes historically far under-recover the costs assigned to them through the Company's cost allocation and rate design methods. The ALJs are not suggesting that, generally, SWEPCO's class cost allocation (and rate design) methods are flawed. However, based on TCGA's testimony, SWEPCO may be assuming that the Cotton Gin

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[1484] The fact that the cotton ginners may take service primarily in the late fall and winter months, however, may be properly reflected in the methods used to allocate costs in the class cost of service study. For example, SWEPCO's use of an A&E/4CP allocator to allocate generation and transmission costs to classes accounts the fact that Cotton Gin class customers have very low summer loads.

[1485] The ALJs also do not accept SWEPCO's assertion that TCGA is essentially requesting a deviation for "system-wide rates." SWEPCO Reply Brief at 106. This is not a situation in which a municipality is proposing to require SWEPCO to charge rates to its residential customers that are different than the rates charged by SWEPCO to its residential customers that are not within the municipality's city limits.

class (and the others mentioned) should be paying more than is justified given their unique situations.

TCGA's ultimate request is that the resulting rate increase for the Cotton Gin class in this docket "is no more than the lower of either the system average base rate increase or a rate increase no more than of 37.44%."[1486] This request is essentially that the ALJs recommend a rate gradualism approach that leaves TCGA with a rate increase that does not exceed 37.44%. Gradualism is addressed in the next section of this PFD and the ALJs' recommendation on gradualism responds to TCGA's request. Schedule C in the number running schedules attached to this PFD shows that the Cotton Gin class rate increase resulting from the ALJs' recommendations is 32.84%.

6. Staff's Class Allocation Issue

Staff supports the class allocation shown in its "Class-Functional Cost of Service Summary" attached to the direct testimony of Staff witness Narvaez.[1487] The only specific comment that Staff raises in its post-hearing briefs is that it agrees with the correction made by SWEPCO in its rebuttal testimony to revise its system load factor to reflect the single annual coincident peak as consistent with the Commission's decision in Docket No. 46449.[1488]

SWEPCO responds that both the jurisdictional and class cost of service studies prepared by Mr. Narvaez appear accurate but for a few minor inconsistencies on selected functional calculations.[1489] SWEPCO states the inconsistencies do not change the retail revenue requirement by class or function, only the calculated base rate revenue deficiency by function.[1490] First, the functional calculations for GEN DEMAND, GEN ENERGY, and TRAN functions have proposed

[1486] TCGA Reply Brief at 12-13; *see also* TCGA Initial Brief at 21.

[1487] Staff Ex. 4 (Narvaez Dir.), Attachment AN-3. Staff Initial Brief at 69; Staff Reply Brief at 46.

[1488] SWEPCO Ex. 54 (Aaron Reb.) at 3; Staff Reply Brief at 46.

[1489] SWEPCO Reply Brief at 104.

[1490] SWEPCO Ex. 54 (Aaron Reb.) at 4.

revenue (line 65 of these functional calculations) reduced by miscellaneous revenues when proposed revenues should equal cost of service. Second, the Class Summary, DIST SEC, and DIST CUST calculations are missing calculations (lines 65-80 of these functional calculations) for the Residential Distributed Generation and Light and Power Distributed Generation classes.[1491]

SWEPCO agrees with the underlying methodology and calculations of Staff's class cost of service study when updated for the revisions described in SWEPCO witness Aaron's rebuttal testimony, but SWEPCO does not agree with Staff's calculated results.[1492] SWEPCO states it disclosed changes needed to its class allocation in response to several data requests and in Mr. Aaron's rebuttal testimony that should be reflected in Commission Staff's number running calculations.[1493]

The ALJs conclude that there is not a disagreement between SWEPCO and Staff regarding the underlying methodologies and calculations used in SWEPCO's rebuttal CCOSS. When SWEPCO states that it "agrees to the underlying methodology and calculations of Staff's class cost-of-service study when updated for the revisions described in SWEPCO witness Aaron's rebuttal testimony," the ALJs assume that SWEPCO is stating that it agrees with the mechanics of Staff's CCOSS, but not the result. That is, the ALJs assume that SWEPCO is not agreeing in its post-hearing briefs to Staff's proposed $410.4 million annual revenue requirement, as compared to SWEPCO's rebuttal $446.5 million revenue requirement.

With that assumption stated, the ALJs recommend that the class cost of service analysis should start with SWEPCO's as-filed CCOSS, as then revised by its rebuttal CCOSS. SWEPCO's rebuttal revisions resulted in a $5 million revenue requirement reduction from $451.5 million to $446.5 million.[1494] The resulting rebuttal studies ($446.5 million), *however*, must be further modified to account for the numerous revenue revisions (typically disallowances) proposed by

[1491] SWEPCO Ex. 54 (Aaron Reb.) at 4-5.

[1492] Staff Reply Brief at 104.

[1493] SWEPCO Ex. 54 (Aaron Reb.) at 5.

[1494] SWEPCO Ex. 54 (Aaron Reb.) at 6.

Staff and intervenors that the ALJs are recommending be adopted in this case. Specifically, the ALJs recommend the following to derive a final Commission-approved class costs of service study:

1. Start with SWEPCO's as-filed (direct case) cost of service studies included with Mr. Aaron's direct case; then

2. Adjust the as-filed studies to arrive at the $5 million revenue requirement reduction recommended by Mr. Aaron in his rebuttal testimony and rebuttal cost of service studies; then

3. Further adjust the studies to account for the disallowances that the ALJs recommend in this PFD.

This results in the ALJs' recommended class cost of service study, which will be compiled through the number running process.[1495] Through this process, the ALJ-recommended cost of service summaries are produced and attached to this PFD, based on SWEPCO's underlying methodologies and calculations. The rates resulting from these costs of service, however, reflect the ALJs' recommendations, rather than the rates reflected in Staff's proposed cost of service studies.

C. Municipal Franchise Fees [PO Issues 31, 56]

SWEPCO develops the effective rate for municipal franchise fees based on test year actual municipal franchise taxes paid, less the amount in excess of the base amount and test year actual kWh sales, and applies this effective rate to the test year-adjusted kWh sales to determine the *pro forma* amount to include in SWEPCO's cost of service.[1496] No party raised an issue with regard to SWEPCO's municipal franchise fees. Based on the evidence presented by SWEPCO, the ALJs recommend that SWEPCO's method for calculating and allocating franchise fees to its test year-adjusted kWh sales should be approved.

[1495] The number running schedules attached to this PFD include a summary of class costs of service. At this stage of the allocation-to-rate design process, the jurisdictional cost of service has flowed into the class cost of service, so the resulting cost of service study that matters for designing rates is the class cost of service study.

[1496] SWEPCO Ex. 6 (Baird Dir.) at 30.

X. REVENUE DISTRIBUTION AND RATE DESIGN [PO ISSUES 4, 5, 47, 48, 52, 59, 60, 61, 62, 75, 76, 77, 78, 79]

The class revenue distribution is the rate design mechanism by which a utility's approved annual revenue requirement is assigned to the customer classes. The revenue distribution also determines the revenue requirement targets for each class.[1497] The percent increase in base rates for each class is based on its revenue deficiency as determined by the class cost of service study. The revenue deficiency determines the revenue requirement needed to bring each class to an equalized (sometimes referred to as "unity") return. The revenue requirement at an equalized return is the amount of revenue needed from each class to recover the full costs of serving that customer class.[1498] The equalized revenue requirement and revenue change based on that requirement is the starting place for the revenue distribution. Other factors may also be taken into consideration such as customer migration, and a potential need to moderate a rate increase through rate gradualism to avoid rate shock.[1499]

As an initial and overarching matter before moving to rate moderation, Staff criticizes SWEPCO's revenue distribution calculations, alleging that they fail to recognize the Company's DCRF and TCRF revenues when assigning costs to the rate classes.[1500] Staff contends that the final order in SWEPCO's last rate case requires SWEPCO to evaluate a class's present revenues *inclusive* of TCRF and DCRF revenues when evaluating a potentially large rate increase that could warrant gradual movement to cost.[1501] Staff states that, although SWEPCO is proposing a 30.31%

[1497] SWEPCO Ex. 32 (Jackson Dir.) at 9-10.

[1498] SWEPCO Ex. 32 (Jackson Dir.) at 8-9.

[1499] *E.g.*, SWEPCO Ex. 32 (Jackson Dir.) at 9.

[1500] Staff Ex. 4 (Narvaez Dir.) at 15-17. Nucor and TIEC also contend that the TCRF and DCRF test year revenues should be included in evaluation of a proposed base rate increase.

[1501] Staff Ex. 4 (Narvaez Dir.) at 15-16 (citing Docket No. 46449, Order on Rehearing at FoF No. 314 (Mar. 19, 2018), which states "SWEPCO's proposed gradualism methodology, which reduces the subsidization among individual rate classes, is reasonable and should be adopted, *except that a class's present revenues should be evaluated inclusive of existing TCRF and DCRF revenues, which are base-rate related revenues.*") (Emphasis added.)

gross increase in base rates,[1502] the actual net increase is 24.96% when the DCRF and TCRF revenues are moved into base rates.[1503]

SWEPCO responds that its adjustments to base rates include costs recovered through the TCRF and DCRF riders, but not in the initial calculations. Instead, SWEPCO states that "*after* the appropriate adjustment to base rates is determined to assure full recovery based on the class cost of service study, SWEPCO's revenue distribution indicates the rate class bill impact associated with the change in the TCRF and DCRF revenues recovered during the test year."[1504] SWEPCO argues that no changes to SWEPCO's proposal are necessary in order to recognize TCRF and DCRF revenues.[1505]

The ALJs agree with Staff. SWEPCO has not adequately explained why it does not factor its TCRF and DCRF revenues into its proposed base rate increase at the outset of its cost of service and revenue distribution calculations. Based on both Staff's and SWEPCO's testimony, SWEPCO does not evaluate a class's *present* revenues *inclusive* of TCRF and DCRF revenues as required by Docket No. 46449. If it had done so, SWEPCO's actual proposed net base rate revenue increase is in the range of 25%, rather than 30%.[1506] Either percentage is a significant increase but, for revenue distribution purposes, a 25% increase is less harsh than a 30% increase. In its next base rate case, SWEPCO should present its rate change request such that its then-present revenues show the total present revenues inclusive of the TCRF and DCRF revenues.

[1502] Citing SWEPCO Ex. 32 (Jackson Dir.), Exh. JLJ-1.

[1503] Staff. Ex. 4 (Narvaez Dir.) at 17. Although SWEPCO reduced its requested annual revenue requirement by $5 million in its rebuttal case, that reduction does not resolve the issue of whether SWEPCO should have accounted for its TCRF and DCRF revenues up front in presenting its proposed percentage base rate increase.

[1504] SWEPCO Initial Brief at 120-21 (emphasis added).

[1505] SWEPCO Ex. 55 (Jackson Reb.) at 8-9, Exh. JLJ-1R; Tr. at 1531-32.

[1506] SWEPCO acknowledges that its proposed base rate revenue increase, inclusive of TCRF and DCRF revenues, is "26.01%" exclusive of fuel and (other non-TCRF and DCRF) riders. SWEPCO Ex. 1 (Application) at 4.

A. Rate Moderation/Gradualism [PO Issue 52]

1. SWEPCO's Proposal

SWEPCO witness Jackson sponsors SWEPCO's as-filed proposed revenue distribution.[1507] The proposed revenue distribution shows the present rate schedule revenue by class along with each class's present rate of return, return relative to the retail total class return at the proposed return level (relative rate of return), equalized base increase, target base change in revenue, and total rate design proposed base change in revenue. The target base change in revenue determines the rate design revenue target for each class and is the basis for the class rate design.[1508]

To mitigate the large increases and large impacts to certain classes resulting from SWEPCO's significant base rate increase, SWEPCO proposes that classes with similarly situated customers should be combined into four "major rate classes" and the combined change in class revenue requirement at an equalized rate of return should be applied to the individual classes.[1509] In this PFD, the four major rate classes proposed by SWEPCO are referred to as "class Groups" or a "class Group." SWEPCO's four class Groups are: (1) Residential, (2) Commercial and Industrial, (3) Municipal, and (4) Lighting. SWEPCO states it proposes these four class Groups as a mitigation mechanism, as well as to maintain relationships between rate schedules.[1510] Under SWEPCO's proposal, the combined change in class revenue requirement at an equalized rate of return is applied to the individual classes within an applicable class Group.[1511]

The class Groups were determined based on the results of the class cost of service study, precedent from prior rate cases, increases in certain customer classes and how to moderate the

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[1507] SWEPCO Ex. 32 (Jackson Dir.), Exh. JLJ-1.

[1508] SWEPCO Ex. 32 (Jackson Dir.) at 9-10, Exh. JLJ-1.

[1509] SWEPCO Ex. 32 (Jackson Dir.) at 10, Exh. JLJ-1 at 2-3.

[1510] SWEPCO Ex. 32 (Jackson Dir.) at 10-11. The ALJs understand that this major class grouping concept is unique to SWEPCO, and varies somewhat from case-to-case. Tr. at 1256; Nucor Ex. 1 (Daniel Dir.) at 11. Nucor opposes SWEPCO's class Group concept, arguing "This approach limits the ability to significantly move a specific customer class closer to its cost of service. As a result, the problem of inter-class subsidies is never fixed." *Id.*

[1511] SWEPCO Ex. 55 (Jackson Reb.) at 4, 9-10.

resulting bill impact, and the ability of customers to take service under other rate schedules within the class Group.[1512] For example, SWEPCO is proposing to group the GS, LP, LLP, Metal Melting, Oilfield, and Cotton Gin classes into one large rate class group: the Commercial and Industrial class Group. Under SWEPCO's proposal, the classes within this Commercial and Industrial class Group will share the proposed increase among all the customers in the individual rate classes within this Group.[1513] As another example, unlike the Commercial and Industrial class Group, there is only one rate class in the Residential class Group—the Residential rate class.[1514]

Because there is general consensus among the parties regarding rate increase moderation for rate classes with equalized increases multiple times greater than the system average increase, SWEPCO proposed a rebuttal revenue distribution that moved all classes closer to cost.[1515] In its rebuttal case, SWEPCO applied an approximate 43% cap to the increases of three individual rate classes that were significantly below unity: the Cotton Gin, Oilfield Secondary, and Public Street and Highway Lighting rate classes.[1516] SWEPCO concedes that application of this cap creates a subsidy among the other classes that share the major class grouping with those classes, but SWEPCO claims this methodology is consistent with the Commission's order in Docket No. 46449 and moves all classes closer to cost, while recognizing the billing units associated with the proposed commercial rate structure proposals.[1517] SWEPCO states that the rebuttal revenue distribution continues to recognize cost to serve, bill impacts, and rate moderation. SWEPCO also states that, under its rebuttal approach, the individual rate class increases for the GS and LP classes

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[1512] Tr. at 1255-56.

[1513] SWEPCO Ex. 32 (Jackson Dir.) at 11. Ms. Jackson also states on this page that this grouping is intended to "facilitate sustainable migration among the customer classes within a family of rate options." It is unclear from SWEPCO's testimony if this statement is meant to support SWEPCO's grouping approach for gradualism purposes, or is intended to address a separate issue involving migration between the General Service and Lighting and Power classes, which is addressed below in the Rate Design section of this PFD.

[1514] *E.g.*, SWEPCO Ex. 55 (Jackson Reb.), Exh. JLJ-1R.

[1515] SWEPCO Ex. 55 (Jackson Reb.) at 7-8, Exh. JLJ-1R.

[1516] Tr. at 1247-48.

[1517] SWEPCO Ex. 55 (Jackson Reb.) at 8.

are applied before including the Cotton Gin class subsidy.[1518] SWEPCO's rebuttal case, however, retains the same class Group approach described above.

2. Intervenors' and Staff's Positions

As SWEPCO recognized in its rebuttal case, the parties and Staff agree that some form of rate moderation or gradualism is appropriate. TIEC, Nucor, and Staff, however, disagree on how and to what degree gradualism should be implemented.

TIEC recommends that increases for classes that are "producing negative rates of return and would require excessive base rate increases" be limited to approximately 43%, based on the cap approved in Docket No. 46449.[1519] The ALJs note that, to this point, TIEC and SWEPCO generally agree. TIEC, however, does not accept SWEPCO's proposal to group 19 to 22 individual rate classes into the four class Groups.[1520] Instead, TIEC's class cost of service study results in 13 rate classes.[1521] TIEC opposes SWEPCO's class Group approach for a number of reasons, including: (1) SWEPCO modified its proposed gradualism proposal in rebuttal in a manner that diminishes the importance of the major class groups; and (2) the Commission has applied gradualism without reference to major-class groupings in prior cases, and "the evidence in this case does not support the use of that technique here."[1522] Because TIEC does not accept the class Group concept proposed by SWEPCO, TIEC's proposal "spreads any resulting subsidy among all

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[1518] SWEPCO Ex. 55 (Jackson Reb.) at 7.

[1519] TIEC Ex. 1 (Pollock Dir.) at 46. The 43% increase (or also referred to as a 43% cap) is generally accepted by all parties that address the gradualism issue, including SWEPCO and Staff. *See also* TIEC Initial Brief at 79-80.

[1520] TIEC states that SWEPCO has 22 individual rate classes, although some of those classes take service under a single rate schedule. *See* TIEC Initial Brief at 76, citing TIEC Ex. 1 (Pollock Dir.) at 4, 42-43. However, SWEPCO Ex. 32 (Jackson Dir), Exh. JLJ-1 at 2-3, shows 19 rate classes. For purposes of dealing with the gradualism and rate design issues contested in this case, the ALJs conclude that the question of whether SWEPCO has 22 or 19 rate classes is immaterial. Some of the confusion may be based on an interpretation of the rate classes versus rate schedules. According to TIEC: "[S]everal of these [SWEPCO classes] take service under the same rate schedule. For example, while SWEPCO uses three distinct Light & Power classes in its CCOSS, all three take service under the same rate schedule. *See* TIEC Ex. 1 (Pollock Dir.) at 43-44.

[1521] TIEC Ex. 1 (Pollock Dir.) at 45, Exh. JP-4.

[1522] TIEC Initial Brief at 80 (footnote omitted, which includes citations to precedent TIEC asserts supports its position).

other rate classes in proportion to their base rate increases, rather keeping it within the 'major class.'"[1523]

Nucor recommends that gradualism should only be applied to three relatively small rate classes: the Cotton Gin, Oilfield Secondary, and Public Street and Highway Lighting classes. According to Nucor, the base rate revenue increases for these three rate classes should be limited to 1.5 times the average SWEPCO percent increase of 24.96%, or 37.44%. Nucor states the revenue shortfall resulting from this gradualism should be proportionately assigned to those rate classes that receive below-average base rate revenue percent increases. In effect, Nucor is also not adopting SWEPCO's class Group approach because Nucor assigns the revenue shortfall to rate classes that have a below-average base rate increase regardless of which class Group the rate class has been assigned by SWEPCO. Adopting Nucor's gradualism approach, according to Nucor, reduces the inter-class subsidies to $421,839, as compared to SWEPCO's proposed inter-class subsidies of $6,047,984.[1524]

Walmart does not oppose SWEPCO's proposed revenue distribution but recommends that if the Commission approves a lower revenue requirement, that the reduction move individual customer classes closer to their respective cost to serve while ensuring that no class receives an increase larger than that proposed by SWEPCO.[1525]

Staff proposes the greatest departure from SWEPCO's gradualism proposal as compared to the other parties. In sum, Staff states that relying on the class groupings does not adequately address the requirement that rates are based on cost.[1526] As noted by Nucor, Staff also explains that

[1523] TIEC Initial Brief at 79-80.

[1524] Nucor Ex. 1 (Daniel Dir.) at 16-17, Exh. JWD-6.

[1525] Walmart Ex. 1 (Perry Dir.) at 19.

[1526] Staff Ex. 4 (Narvaez Dir.) at 22:

> When rates are set at cost, the revenues that a utility recovers through these rates reflect the costs that customers impose on a utility's system. Cost-based rates will more closely match the costs incurred as customer usage changes over time. When rates are set below cost, the revenues recovered through the below-cost rates will be insufficient to recover the cost to serve that group of customers.

SWEPCO's approach, which is been applied in SWEPCO's recent past rate cases, has not resulted in moving a number of classes to unity; meaning some classes continue to be subsidized significantly by other classes based on the filed cost of service studies. To finally resolve this historical subsidization situation, Staff recommends a four-year, phased-in gradualism approach.[1527] In the first year, "Phase One Rates" would be set consistent with the Commission's approved revenue distribution methodology approved in Docket No. 46449, and would be implemented upon the conclusion of this proceeding. That is, starting with the results of the class cost of service study reflecting the Commission's decisions on cost and allocation issues, revenue increases for any individual class, net of changes in TCRF and DCRF revenues, would be capped at 43%. Then, the residual revenues from classes subject to the 43% cap would be reallocated proportionally among the classes within the class Group that are not subject to the 43% cap. Staff is particularly focused on the same three classes addressed by Nucor that historically have been well under unity: the Cotton Gin, Oilfield Secondary, and Public Street and Highway Lighting classes.[1528] To achieve their relative rate of return in this docket, the cost responsibility for those three classes would need to increase by significantly greater than 43%. Thus, to stay at or within the 43% cap, in the first year of Staff's four-year gradualism proposal, the Cotton Gin and Oilfield Secondary classes would be capped at a 43% net increase, and the residual revenue amount would be allocated proportionally among the other classes within the class Group to which they are assigned—the Commercial and Industrial class Group. The Public Street and Highway Lighting class would also be capped at a 43% net increase and the residual revenue amount would be allocated proportionally among the other classes within the Group to which this class is assigned—

> Furthermore, setting subsidized rates for some customers requires that the rates for other customers be set above cost.

[1527] Staff Ex. 4 (Narvaez Dir) at 23-25. Mr. Narvaez agrees that this approach has not been used in an electric base rate case, but has been implemented in two water utility-related cases. *Application of SWWC Utilities Inc. DBA Water Services, Inc. for Authority to Change Rates*, Docket No. 47736, Order at 12-13, 17 (Oct. 16, 2019); *Application of Undine Texas, LLC and Undine Texas Environmental, LLC for Authority to Change Rates*, Docket No. 50200, Order at 22 (Nov. 5, 2020). The ALJs note that the Commission's orders in both of these water utility cases approved unanimous agreements submitted by the parties, rather than contested issues with evidence subject to cross-examination at a hearing on the merits.

[1528] These are the same three classes that Nucor addresses in its proposed gradualism method.

the Municipal class Group.[1529] This same process would be repeated in years two, three, and four by increasing an under-paying class's rates by 43% per year (year two would be capped at an 86% net increase; year three at a 129% increase; and year four at a 172% net increase).[1530] Under Staff's proposal, by the end of year four, all of SWEPCO's rate classes, including the three referenced classes, would have achieved unity: "This means that all rates would be set at cost during Phase IV."[1531]

CARD supports SWEPCO's proposal, and urges the Commission to reject TIEC's and Nucor's gradualism proposals, arguing primarily that TIEC's and Nucor's proposals shift costs to the residential class and away from the commercial and industrial classes. CARD also opposes Staff's four-year phased-in gradualism proposal, arguing that Staff's proposal has "one crucial flaw – the proposal is based on the idealistic simplification that present test-year base rate revenues remain constant over the four-year term of the phase-in plan."[1532] Moreover, CARD witness Karl Nalepa testified that Staff's plan ignores the reality that, between rate cases, rate classes grow at different rates. According to CARD, Staff's phase-in plan could result in some of the classes moving further away from cost rather than closer to cost.[1533]

3. ALJs' Analysis

The Commission approved SWEPCO's class Group approach in SWEPCO's last base rate case. In its Order on Rehearing in Docket No. 46449, the Commission found (as did the ALJs in the PFD) that SWEPCO's class Group approach:

- Had been approved in SWEPCO's prior base-rate proceeding, Docket No. 40443;

[1529] Staff Ex. 4 (Narvaez Dir.) at 24. Although the class name "Public Street and Highway Lighting Service" would indicate that this class would be placed in the Lighting class Group, SWEPCO assigns this class to the Municipal class Group (along with the Municipal Lighting class). *See* SWEPCO Ex. 32 (Jackson Dir.), Exh. JLJ-1 at 2-3. No party challenged this assignment to the Municipal class Group.

[1530] Staff Ex. 4 (Narvaez Dir) at 23-25.

[1531] Staff Ex. 4 (Narvaez Dir.) at 25.

[1532] CARD's Initial Brief at 75; CARD Reply Brief at 45; *see also* Tr. at 1414.

[1533] CARD Ex. 8 (Nalepa Cross-Reb.) at 7-8.

- Moved all customer classes closer to cost of service, sets larger customer groups of similar size and type at cost of service, and facilitates sustainable migration among customer rates; and

- SWEPCO's proposed gradualism methodology, which reduces the subsidization among individual rate classes, is reasonable and should be adopted, except that a class's present revenues should be evaluated inclusive of existing TCRF and DCRF revenues, which are base-rate-related revenues.[1534]

The ALJs are guided by the precedent supporting SWEPCO's approach and agree that it should be followed again in this case. No party has provided a sufficient explanation as to why that precedent should be rejected in this case. More specific analyses of the parties' positions on this issue, however, are addressed below.

The ALJs recognize there is an historical problem with regard to SWEPCO's revenue distribution: a number of its rate classes remain, and will remain, far from unity. This appears to be the situation in particular for the Cotton Gin, Oilfield Secondary, and Public Street and Highway Lighting classes.[1535] The ALJs are sympathetic to Nucor's proposal, which focuses on these three rate classes, and to Staff's proposal, which recognizes that these three classes would be most affected by the annual rate increases that would occur under Mr. Narvaez's proposal to finally move all classes—including these three—to equalized full cost of service rates.

However, as CARD notes and the ALJs agree, the effect of the Nucor and TIEC proposals is to spread the revenue deficiency primarily to the residential class. SWEPCO's class Group approach has the benefit of spreading the resulting revenue deficiency experienced by a class only to the other classes within that class's class Group. The ALJs understand, as noted by TIEC, that there potentially is a wide variation in the aspects of the rate classes within the Commercial and Industrial class Group. For example, some of the rate classes within the Commercial and Industrial

[1534] Docket No. 46449, Order on Rehearing at 48, FoF Nos. 312-314 (Mar. 19, 2018).

[1535] SWEPCO Ex. 55 (Jackson Reb.), Exh. JLJ-1R. Note the column titled "Proposed Relative Rate of Return," in which almost all rate classes are at or very close to 1.0 (unity) except for: the Cotton Gin Service class at 0.11; the Oilfield Secondary Service class at 0.50; and the Public Street and Highway Lighting class at 0.34.

class Group are "low population" as compared to other classes within that Group.[1536] The ALJs note, however, that the rate classes in the Commercial and Industrial class Group are properly considered to be rate classes that are generally either commercial or industrial customers. None of the rate classes in the Commercial and Industrial class Group are residential customers. TIEC's rejection of the class Group approach ignores that important distinction and, as CARD argues, opens the door to require customers that are not commercial or industrial customers to nevertheless subsidize commercial or industrial classes. This same observation applies to Nucor's proposal, which also would shift cost responsibility resulting from gradualism primarily to residential customers.

SWEPCO's revenue distribution approach requires related classes within the Commercial and Industrial class Group to cover the revenue shortfall that continues to apply to the Cotton Gin and Oilfield Secondary services, and classes within the Municipal class Group to cover the deficiency in the Public Street and Highway Lighting class, rather than to the residential class.[1537] Application of the 43% cap limits the severity of the rate increases that could be borne by the Cotton Gin, Oilfield Secondary, and Public Street and Highway Lighting rate classes if there were no cap, or a higher cap. The ALJs agree with SWEPCO that this approach "creates a small subsidy among the other classes that share the major class grouping with those classes, but this methodology is consistent with the Order on Rehearing in Docket No. 46449 and moves all classes closer to cost, while recognizing the billing units associated with the proposed commercial rate structure proposals."[1538]

The ALJs appreciate Staff's efforts to deal squarely with the failures of past gradualism methods to move all of SWEPCO's rate classes to unity. But the ALJs also agree that Staff's approach is not supported by Commission precedent, is cumbersome in that it would require a rate change for the three targeted classes every year for four years, and, as SWEPCO argues, "could

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[1536] TIEC Initial Brief at 78.

[1537] The Public Street and Highway Lighting class subsidy would stay within the Municipal class Group.

[1538] SWEPCO Initial Brief at 122 (citing SWEPCO Ex. 55 (Jackson Reb.) at 8).

result in SWEPCO foregoing an opportunity to recover its cost to serve its customers until the phase-in period is over."[1539] In essence, the actual effects of Staff's proposal—the unintended consequences—are unknown, and it would require significant rate increases for the three targeted classes each year for four years. For these reasons, the ALJs recommend that the Commission approve SWEPCO's gradualism mechanism as proposed in its rebuttal case.

B. Rate Design and Tariff Changes [PO Issues 60, 61, 62]

In addition to pricing changes to all of SWEPCO's rate schedules that result from its proposed revenue distribution, the Company proposes a number of structural changes to some of its rate schedules, and proposes to add three new rate schedules.[1540] Most of these revisions are not addressed or contested by the parties.[1541] In this section, the ALJs will address only those rate design issues challenged by the parties.[1542] The ALJs recommend approval of the uncontested rate design-related revisions, which would be incorporated into SWEPCO's compliance filing after the Commission issues its final order in this docket.

Three parties raise four rate design issues:

- Staff opposes SWEPCO's proposal to remove the provision in the GS rate schedule that restricts availability of the rate schedule to customers with a maximum demand that does not exceed 50 kW.

[1539] SWEPCO Ex. 55 (Jackson Reb.) at 9. As noted, the water rate cases cited by Mr. Narvaez were from dockets in which settlements were approved, rather than the Commission ruling on the merits of a multi-year, phased-in rate change approach.

[1540] SWEPCO Ex. 32 (Jackson Dir.) at 14-15. As Ms. Jackson explains, the structural revisions and new proposed rate schedules primarily involve time-of-use and plug-in electric vehicle options, and revisions to the Company's lighting rate schedules to implement light emitting diode usage.

[1541] As addressed above and in Section X.D below, the ALJs recommend the Commission reject SWEPCO's proposed new transmission rate for BTMG. Issues involving SWEPCO's Renewable Energy Credits (REC) Rider are discussed in Section X.D below. SWEPCO's Rate Case Surcharge (RCS) Rider is addressed in the context of rate case expenses in Section XII below.

[1542] ETSWD's proposal regarding COVID-19 adjustments to the cost of service, which would flow through to rates if adopted, is addressed in Section VIII above in the context of billing determinants. TCGA's issues regarding the rate structure for the Cotton Gin class are discussed in Section IX above in the context of class cost allocation.

- Walmart opposes SWEPCO's proposal to shift demand-related costs from per kW demand charges to per kWh energy charges in the LP Secondary rate schedule.

- TIEC argues that the allocation of revenues to rates within the LLP rate schedule should be based on the CCOSS results and reflect cost causation.

- TIEC also argues that SWEPCO's proposal to increase its reactive power charge should be rejected.

1. Staff's Issues Regarding the GS Rate Schedule and Customer Migration

Staff raises two rate design issues: one involving the GS rate schedule and the other involving Staff's request to essentially preclude customers from migrating among numerous rate schedules between rate cases. These two issues are somewhat related to Staff's billing determinants "estimates" issue address in Section VIII above.

a. The GS Rate Schedule 50 kW Maximum Demand

Staff argues that the Commission should reject SWEPCO's proposal to revise its GS rate schedule to remove the provision that restricts availability of the rate schedule to customers with a maximum demand that does not exceed 50 kW. Staff argues that removing the maximum demand cap would allow customer migration from the LP rate schedule to the GS rate schedule.[1543] According to Staff, this could result in rates being insufficient to recover costs to serve those classes.[1544] Staff witness Narvaez testified that, if SWEPCO's proposal results in a large volume of customers migrating to GS service, "the rates approved by the Commission in this case for the two classes within the General Service tariff would no longer be sufficient to recover the costs of

[1543] Based on the parties' briefs, there may be some confusion between this GS rate schedule 50 kW maximum demand cap, and the migration among rate schedules addressed in the context of billing determinants in Section VIII above. These are two different but related concepts. Here, Staff is opposing SWEPCO's GS rate schedule proposal, not because of traditional inter-rate case migration, but because removing the 50 kV cap would allow LP rate schedule customers to flood into the GS class regardless of whether the LP customers' loads change.

[1544] Staff Ex. 4 (Narvaez Dir.) at 26-28.

providing service to the two classes within the General Service tariff."[1545] Mr. Narvaez also testified:

> While it is normal to expect that the number of customers taking service under a specific tariff to vary somewhat from [year-to-year], structural tariff changes specifically designed to encourage customer migration from tariffs that are less economical is a significant change that could drastically alter the cost of service of the two General Service classes.[1546]

Summing up Mr. Narvaez's testimony and Staff's position on this issue, Staff contends that SWEPCO's proposal:

> completely ignores the purpose of classifying customers into certain rate classes based on their usage characteristics – the need to establish rates that reasonably reflect the costs to serve similarly situated customers. Without reasonably fixed customer classes based on cost-causation characteristics, one cannot design just and reasonable rates for a class that reasonably reflects the costs to serve that class, as customers could simply migrate to a class that is less costly to serve.[1547]

SWEPCO counters that it proposes to revise its GS rate schedule to accommodate lower load factor customers, including churches and schools, consistent with customer requests.[1548] SWEPCO characterizes Staff's recommendation as one that "lacks a recognition of customer focus and customer satisfaction by the utility."[1549] According to SWEPCO, based on Staff's argument, structural changes to existing rate schedules and proposing new rate schedules would not be allowed, making "it far more difficult for SWEPCO to provide rate solutions that are responsive to the evolving ways customers use electric energy."[1550] SWEPCO emphasizes that migration

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[1545] Staff Ex. 4 (Narvaez Dir.) at 27. It is not clear what Mr. Narvaez means by "the two classes within the General Service tariff," but SWEPCO witness Jackson's Rebuttal Revenue Distribution table at SWEPCO Ex. 55 (Jackson Reb.), Exh. JLJ-1R, shows a GS class "W/DEM" and a GS class "WO/DEM," which may indicate a distinction between customers within the GS class who take service with a billing demand in excess of 10 kW, and those who do not take service in excess of 10 kW.

[1546] Staff Ex. 4 (Narvaez Dir.) at 28.

[1547] Staff Reply Brief at 52.

[1548] SWEPCO Ex. 55 (Jackson Reb.) at 20.

[1549] SWEPCO Ex. 55 (Jackson Reb.) at 19.

[1550] SWEPCO Ex. 55 (Jackson Reb.) at 20.

between the GS and LP rate schedules can occur after the test year and after approval of the new rate design, and that is no different from customer movement "(additions, removals, and changes in customer loads)" that occurs between rate cases for the existing classes: "[I]t is fluid at all times. SWEPCO has always provided additional rate options under which a customer may be eligible for service. The Commission has consistently approved those options. Providing rate options for customers puts SWEPCO in a position of better meeting its customers' needs."[1551]

The ALJs agree with Staff that the 50 kW maximum demand cap in the GS rate schedule should not be removed. What SWEPCO is proposing here is to blur distinctions between the separate GS and LP rate schedules, and this leads into Staff's second issue discussed below regarding its opposition to allowing customers to choose to take service under multiple rate schedules. SWEPCO's GS rate schedule proposal here does not reflect the typical situation in which customers can migrate from one rate schedule to another between rate cases as described by SWEPCO witness Jackson. Under SWEPCO's proposal, customers with higher demands that take service under the LP schedule, for example at 100 kW, would now be able to migrate to the GS schedule even if there are no "additions, removals, or changes" in the LP customers' loads. The ALJs agree with Staff that SWEPCO's GS proposal is not one that simply accounts for typical movement between rate cases. SWEPCO has not shown that its proposal will facilitate "sustainable" migration among customer rates; instead it could cause a flood away from the LP class into the GS class, resulting in the unknowable cost recovery issues pointed out by Staff. The ALJs understand that some of SWEPCO's customers may want the option to choose between taking service under either the LP or GS rate classes, but SWEPCO has not shown that its proposal is justified from a revenue distribution standpoint. For these reasons, the ALJs recommend that the Commission reject SWEPCO's proposal to remove the 50 kW that limits those customers who can take service under the GS rate schedule.

[1551] SWEPCO Ex. 55 (Jackson Reb.) at 10-11.

b. Staff's Proposal to Eliminate Migration Among Rate Classes

Staff also requests that the Commission:

> order SWEPCO to revise its tariff in its next major rate proceeding to eliminate the potential for customer migration between rate schedules or between any other customer classification that would result in the potential for customers with the same cost of service characteristics to face different rates, so that any particular customer is only eligible to receive service under a single set of base rates."[1552]

Mr. Narvaez testified that SWEPCO is unusual among utilities regulated by the Commission in that the Company allows for many customers to choose to take service under a variety of rate schedules. He states that "almost all the customers of other electric utilities regulated by the Commission, and a substantial number of SWEPCO's own customers, are required to take service under a single base rate schedule." He contends that SWEPCO's policy of providing special treatment to some customers by allowing them to choose to take service under multiple different rate schedules "undermines the Commission's ability to establish just and reasonable rates."[1553]

SWEPCO responds to this issue with similar arguments that it raised in response to Staff's opposition to removing the maximum demand cap in the GS rate schedule. Here, SWEPCO argues:

> [C]customer movement (additions, removals, and changes in customer loads) between rate cases for the existing classes is typical and expected; it is fluid at all times**.** SWEPCO has always provided additional rate options under which a customer may be eligible for service, and those options have been consistently approved by the Commission. Providing rate options for customers puts SWEPCO in a position of better meeting its customers' needs.[1554]

[1552] Staff Ex. 4 (Narvaez Dir.) at 29.

[1553] Staff Ex. 4 (Narvaez Dir.) at 29.

[1554] Staff Reply Brief at 109 (citing SWEPCO Ex. 55 (Jackson Reb.) at 10-11).

SWEPCO explains it made "migration adjustments, similar to test year adjustments and normalization, to estimate a reasonable rate year set of billing determinants on which to design these new rates."[1555] SWEPCO concludes that Staff's recommendation "is in direct conflict with Commission precedent based on SWEPCO's currently approved tariff book that has multiple rate options in order to serve its customers. Staff's recommendation is harmful to customers, targets SWEPCO's tariff for different treatment and should be rejected."[1556]

The ALJs observe that this issue is not well developed. It is not clear from Staff's testimony and arguments why customers having the ability to choose from multiple established and fixed rate schedules is problematic. This structure could lead to some uncertainty in designing rates, because the Company does not know how many customers will migrate to different rate schedules, and how often, between rate cases. On this point, although SWEPCO states it made migration adjustments to estimate rate year billing determinants, the Company does not explain how it computed those adjustments. That is, how valid are the estimates in this case and was a study performed to support those adjustments? On the other hand, SWEPCO states the Commission has not had a problem with this practice in SWEPCO's past rate cases and, again, having multiple available rate schedules "meets its customers' needs." Staff's recommendation, if adopted, apparently would require customers to choose one rate schedule. This could cause confusion and potential irritation among customers, but it is not clear from SWEPCO's case why having access to multiple rate schedules "meets its customers' needs." For example, does this mean the customers are price shopping and, if yes, how does that affect SWEPCO's ability to design rates so that it recovers its cost of service for any particular class?[1557] Finally, the ALJs understand that other Texas electric utilities may allow some customers to switch between rate offerings without noting

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[1555] SWEPCO Reply Brief at 112.

[1556] Staff Reply Brief at 112; *see also* SWEPCO Ex. 55 (Jackson Reb.) at 5.

[1557] SWEPCO witness Jackson indirectly raises this issue in her rebuttal testimony: "Assigning individual class increases can skew those results and make it harder to predict migration *because customers are moving to a new rate schedule based on pricing without substantially changing their operating requirements*. An example of this occurred recently when a large customer moved between LLP to [Metal Melting Service] between rate cases based on the final pricing**.**" SWEPCO Ex. 55 (Jackson Reb.) at 6 (emphasis added).

a change in their load characteristics, but Staff's presentation suggests that this is a more widespread practice on the SWEPCO system.

Given the uncertainty and unanswered questions regarding this issue, the ALJs recommend that SWEPCO should not be required to revise its rate schedules in its next rate case to preclude the potential for customer migration between rate schedules or between any other customer classifications. However, the ALJs recommend that the Commission direct SWEPCO to address this issue in more detail in the direct testimony it will file with its next base rate case. That testimony should explain how SWEPCO computes its migration adjustments to account for customers moving among rate schedules, including whatever studies or data it uses to make its billing determinant estimates. The testimony should also explain what prompts customers to move among rate schedules, including whether this is a seasonal or more long-term phenomenon.

2. Walmart's LP Secondary Rate Schedule Issue

Walmart opposes SWEPCO's proposed changes to the current LP Secondary schedule rate design "that move away from the cost of service by collecting demand charges through an energy charge."[1558] Instead, Walmart argues that costs should be collected in a manner that reflects how they are incurred. "Collecting fixed demand-related costs through energy charges violates cost causation principles and creates a subsidy for lower load factor customers."[1559] Walmart's witness Lisa Perry testified that SWEPCO's proposed change in demand-related costs from per kW demand charges to per kWh energy charges for the LP Secondary rate schedule results in a shift in demand cost responsibility from lower load factor customers to higher load factor customers. According to Walmart, this shift results in a misallocation of cost responsibility as higher load factor customers overpay for the demand-related costs incurred by the Company to serve them.[1560] To correct this misallocation, Walmart recommends that the Commission should apportion any increase to LP Secondary as follows:

[1558] Walmart Ex. 1 (Perry Dir.) at 20-21.

[1559] Walmart Ex. 1 (Perry Dir.) at 22.

[1560] Walmart Ex. 1 (Perry Dir.) at 22-23.

(1) Assign 9.3% – equal to the percent of LP Secondary costs that are energy-related – to the kWh charge revenue requirement;

(2) Maintain the Company's proposed changes to the minimum charge revenue requirement and the additional transformer and kilovolt-ampere reactive (kVAR) charges; and

(3) Apply the remaining revenue requirement increase to the kW charge.[1561]

In its initial brief, SWEPCO states that Walmart's witness advocates a more targeted approach to the LP rate schedule design, arguing that the Commission's rate design goals should include the removal of subsidies contained in the rates within the rate schedules. To accomplish this, Walmart suggests assigning the majority of the LP class increase to the demand component of the rate schedule. However, "there is a concern that this proposed change would negatively impact lower load factor customers in favor of higher load factor customers. Walmart did not offer any analysis in support of this recommendation or offer customer impact for customers at different load profiles."[1562]

The ALJs agree with Walmart's arguments and concerns. SWEPCO states that Walmart's proposal "would negatively impact lower load factor customers in favor of higher load factor customers." SWEPCO's proposal, however, does the opposite: it would negatively impact higher load factor customers in favor of lower load factor customers. SWEPCO has not explained or justified why it is appropriate, in this case, to collect fixed demand-related costs through energy charges to the detriment of the higher load factor customers in the LP Secondary class. The ALJs, therefore, recommend that the Commission reject SWEPCO's rate design change with regard to this class and instead adopt Walmart's recommendation, with one clarification. The clarification is that Ms. Perry's second of three requests is to maintain "the Company's proposed changes to the minimum charge revenue requirement and the additional transformer and kVAR charges."[1563]

[1561] Walmart Ex. 1 (Perry Dir.) at 23-24, Exh. LVP-6.

[1562] SWEPCO Initial Brief at 125 (citing SWEPCO Ex. 55 (Jackson Reb.) at 11).

[1563] Walmart Ex. 1 (Perry Dir.) at 23-24.

In the following section, the ALJs recommend that SWEPCO not be authorized to increase its reactive power charge. Thus, to be consistent, the kVAR charge should remain at its current rate, rather than SWEPCO's proposed increased reactive power charge rate.

3. TIEC's LLP Rate Schedule and Reactive Power Issues

TIEC raises two issues with regard to LLP rate schedule rate design: (1) the rate of return for the LLP-Transmission (referred to as "LLP-T") as compared to LLP-Primary; and (2) SWEPCO's proposed increase to the reactive power rate.

As to the LLP-T versus LLP-Primary rate design issue, TIEC argues that the revenue requirement allocated to the rates within a rate schedule should be informed by the class cost of service study results.[1564] TIEC's class cost of service study shows that LLP-T is providing a much higher rate of return than LLP-Primary.[1565] Accordingly, to the extent that a rate increase is ordered in this case, LLP-Primary should receive a correspondingly higher increase than LLP-T. For example, at SWEPCO's proposed revenue requirement, LLP-Primary customers should receive a 32% increase, while LLP-T customers should receive a 3.2% increase.[1566]

SWEPCO does not address this issue in either its initial or reply briefs. The ALJs, nevertheless, recommend against TIEC's proposal regarding LLP-T and LLP-Primary rate design because the ALJs have recommended against adopting TIEC's proposed revenue distribution method. As explained earlier in this section, the ALJs recommend approval of SWEPCO's revenue distribution. As such, TIEC's rate design proposal regarding the LLP-Primary class would undermine the recommended revenue distribution approach because it is based on a revenue distribution model that the ALJs recommend rejecting. Moreover, TIEC has not explained why

[1564] TIEC Ex. 1 (Pollock Dir.) at 7.

[1565] Specifically, LLP-T is providing a relative rate of return of 207 at present rates, compared to a relative rate of return of 96 for LLP-Primary. TIEC Ex. 1 (Pollock Dir), Exh. JP-3 at 3-4.

[1566] TIEC Ex. 1 (Pollock Dir.) at 49.

the results of SWEPCO's rebuttal CCOSS are somehow flawed in the way costs are allocated to the LLP class, and the ALJs are not recommending adoption of TIEC's CCOSS.

As to the reactive power rate design issue, TIEC states that SWEPCO proposes to increase the LLP rate schedule reactive demand charge by 29.4%, but SWEPCO did not provide any support for this increase in its application.[1567] Accordingly, TIEC recommends that no increase to the reactive demand charge be approved unless and until SWEPCO provides a study justifying the cost-based need for such an increase.[1568] "If SWEPCO wishes to increase this charge, it should be required to provide a study demonstrating the cost basis for this increase."[1569]

SWEPCO acknowledges that it has not performed a reactive demand study but contends that a separate reactive demand study was not performed outside of the cost of service study because the reactive demand charge "is encompassed within and is part of the overall cost increase."[1570] Because the reactive demand charge can apply to multiple rate classes, SWEPCO utilized the system average increase to update the reactive demand charge. "The proposed reactive demand charge is $0.66 per reactive kW, increased from the current charge of $0.51. The proposed methodology is a reasonable way to adjust the reactive demand charge."[1571]

The ALJs agree with TIEC. There may be a reason that the reactive demand charge should be increased above $0.51 per reactive kW, but simply assuming that increase is the same as the system average increase is not supported by the evidence. SWEPCO, therefore, has not met its burden of proof to justify its proposed $0.16 increase in the reactive charge, and this charge should remain at $0.51 per reactive kW.

[1567] TIEC Ex. 1 (Pollock Dir.) at 48-49.

[1568] TIEC Ex. 1 (Pollock Dir.) at 48-49.

[1569] TIEC Ex. 1 (Pollock Dir.) at 49.

[1570] SWEPCO Ex. 55 (Jackson Reb.) at 14-15.

[1571] SWEPCO Ex. 55 (Jackson Reb.) at 14-15.

C. Transmission Rate for Retail BTMG

The ALJs addressed the BTMG issue in detail in Section VII above, recommending that SWEPCO's request to allocate BTMG-related costs to its Texas retail customers, and Eastman in particular, be denied. The ALJs also recommend above that Eastman's self-served BTMG load be removed from SWEPCO's jurisdictional and class cost of service studies. In its rebuttal testimony, SWEPCO proposed that its Synchronous Self-Generation Load (SSGL) rate could apply to any BTMG customer load included in SWEPCO's transmission load ratio share, in addition to Eastman.[1572] SWEPCO witness Jackson acknowledged that it would be reasonable to create separate rate schedule for the SSGL charge.[1573]

The ALJs recommend rejection of SWEPCO's proposal to establish a rate schedule (or a charge that could be applied within other rate schedules) to allow recovery of BTMG costs from customers in addition to Eastman. Because the ALJs recommend that the Commission deny SWEPCO's proposal to allocate the BTMG-related costs to its Texas retail customers, and at least initially solely to Eastman, the Commission should also reject SWEPCO's proposed BTMG-related transmission rates, including the SSGL charge (or rate schedule).[1574]

[1572] SWEPCO Ex. 55 (Jackson Reb.) at 14; Tr. at 1502.

[1573] Tr. at 1502-03.

[1574] The tension brought on by SWEPCO's BTMG proposal is captured in part by TIEC's initial statements in its reply brief addressing the Company's proposed SSGL rate:

> SWEPCO's proposed SSGL charge should be rejected. The charge would apply to service that SWEPCO does not actually provide—transmission service to customers who serve their own load with BTMG. The charge is based on, as Eastman aptly puts it, "phantom load" that does not reflect actual costs imposed on the transmission network at the time of peak. Moreover, the charge would apply only to Eastman's phantom load because SWEPCO has not reported the phantom load of any of the nearly 200 other retail BTMG customers it has in Texas (or of any of the BTMG customers it has in other states). SWEPCO's proposed SSGL charge is thus unreasonable and discriminatory.

See TIEC Reply Brief at 59 (footnotes omitted, referencing, among other things, the hearing transcript and TIEC witness Pollock's testimony).

D. Riders [PO Issues 47, 48, 75, 76, 77, 78, 79]

1. Proposed Residential Service Plug-in Electric Vehicle Rider [PO Issues 75, 76, 77, 78, 79]

SWEPCO proposes a residential plug-in electric vehicles (PEV) rider for customers taking service under the Residential Service rate schedule who use PEV charging.[1575] Under this option, an installed sub-meter separately measures PEV kWh usage while a standard meter measures total residence kWh usage.[1576] A feature of this rider is the application of a billing credit for all off-peak period PEV kWh usage measured at the sub-meter.[1577]

No party raised any issue with SWEPCO's PEV Rider proposal. The ALJs find that SWEPCO has met its burden of proof on this issue, and the Commission should approve the PEV Rider.

2. Renewable Energy Credit Rider [PO Issues 47, 48]

The Renewable Energy Credit (REC) Rider is a voluntary rider available to customers wishing to support the Renewable Energy Certificates derived from SWEPCO's investment in renewable energy resources. These certificates are issued when one MWh of electricity is generated and delivered to the grid from a renewable energy resource. Customers may purchase RECs that are equivalent up to 100% of their total monthly billed kWh usage.[1578] SWEPCO treats proceeds from the REC sales, net of transaction costs, as a revenue credit to customers through SWEPCO's fuel balance. As such, all of SWEPCO's Texas customers benefit from the proposed REC rider because the proceeds will reduce SWEPCO's fuel balance and the rider will enable participating customers to meet either their personal or corporate environmental and sustainability

[1575] SWEPCO Ex. 3 (Smoak Dir.) at 8-9; SWEPCO Ex. 32 (Jackson Dir.) at 27-28, Exh. JLJ-3.

[1576] SWEPCO Ex. 3 (Smoak Dir.) at 8-9; SWEPCO Ex. 32 (Jackson Dir.) at 27.

[1577] SWEPCO Ex. 3 (Smoak Dir.) at 9.

[1578] SWEPCO Ex. 32 (Jackson Dir.) at 30, Exh. JLJ-6.

goals by purchasing the environmental attributes of renewable energy resources at a reasonable, market-based rate.[1579] Walmart and TIEC raise issues regarding the REC Rider.

Walmart welcomes the opportunity to purchase RECs through utility tariffs, but requests that the REC Rider provide customers with an opportunity to purchase RECs that the customer can link to the underlying resource creating such REC. Walmart is concerned that the REC Rider fails to provide crucial information necessary to allow the customer to link the REC to a specific renewable resource.[1580] Walmart states that, for itself and other customers with aggressive renewable energy goals, "it is important that the Company show the customer is receiving energy from new and *specific* renewable resources to meet those goals."[1581] SWEPCO does not address Walmart's request in either of its post-hearing briefs or in Company witness Jackson's rebuttal testimony. The ALJs therefore conclude that Walmart's request has merit and is not challenged by SWEPCO. In its compliance filing in this docket, SWEPCO should revise the REC Rider to allow a customer to link its RECs to specific renewable resources.

TIEC's issue is not with the REC Rider itself, but instead with the REC opt-out provision available to transmission-level customers. In accordance with 16 TAC § 25.173(j), a transmission-level voltage customer who submits an opt-out notice to the Commission is not required to pay any costs incurred by an investor-owned utility for acquiring RECs. A REC opt-out charge is a mechanism that refunds the REC costs associated with a customer that has opted out. TIEC witness Pollock explains that, as a result of the settlement in Docket No. 47533 (SWEPCO's prior fuel reconciliation), the Company agreed to impute a value of the RECs for its renewable energy purchases. The test-year REC value is $1.281 million. The Texas retail share of these REC costs is approximately $466,500. Mr. Pollock testified that the LLP-T class would be allocated approximately $52,800 of test-year REC costs. Assuming that all of the LLP-T customers were to submit opt-out letters pursuant to 16 TAC § 25.173(j), they would not be charged for these costs.

[1579] SWEPCO Ex. 32 (Jackson Dir.) at 31.

[1580] SWEPCO Ex. 32 (Jackson Dir.) at 31.

[1581] Walmart Ex. 1 (Perry Dir.) at 25.

Mr. Pollock explained, assuming $52,800 of REC costs are allocated to the LLP-T class, the REC opt-out charge would be a credit of 0.064¢ per kWh. TIEC therefore recommends that SWEPCO implement a REC opt-out credit of approximately 0.064¢ per kWh.[1582]

SWEPCO agrees that it must file a REC opt-out tariff in the compliance phase of this case, and that it agreed in its last fuel reconciliation to impute a value of the RECs for its renewable energy purchases.[1583] SWEPCO states its calculation of the REC opt-out credit factor is based on the imputed total company REC values and allocation to SWEPCO's Texas retail jurisdiction and eligible rate classes.[1584] SWEPCO argues the allocation is demand-based because the REC value is recorded in FERC Account 555 and the credit factor is developed based on kWh sales at the meter for eligible customers.[1585]

The contested issue here is whether the REC opt-out allocation should be demand-based or energy-based. TIEC contends that SWEPCO "erroneously used a demand allocator to allocate the REC costs," which resulted in a smaller credit than was calculated by Mr. Pollock.[1586] TIEC argues that RECs are energy-related, and this point is supported by SWEPCO itself when it notes that the REC certificates "are issued when one [MWh] of electricity is generated and delivered to the grid from a renewable energy resource."[1587] TIEC also notes that the Commission's REC rule defines RECs as representing "one MWh of renewable energy."[1588] TIEC contends that the fact that the REC value is recorded in FERC Account 555 (Purchased Power) has no bearing on this

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1582 TIEC Ex. 1 (Pollock Dir.) at 49-50.

1583 SWEPCO Ex. 55 (Jackson Reb.) at 15.

1584 SWEPCO Ex. 55 (Jackson Reb.), Exh. JLJ-2R.

1585 SWEPCO Ex. 55 (Jackson Reb.) at 15.

1586 TIEC Initial Brief at 83 (citing SWEPCO Ex. 55 (Jackson Reb.), Exh. JLJ-2R).

1587 SWEPCO Initial Brief at 128 ("These certificates are issued when one megawatt-hour (MWh) of electricity is generated and delivered to the grid from a renewable energy source.") *See also* SWEPCO Ex. 32 (Jackson Dir.) at 30.

1588 16 TAC § 25.173(c)(13).

issue because purchased power expenses recorded to FERC Account 555 can be demand- or energy-based.[1589]

The ALJs agree with TIEC. SWEPCO has failed to explain why credits that accrue on a per-MWh basis, rather than a per-MW (or kW) basis, should be allocated based on demand rather than energy. The "per-MWh" indicates an energy-based charge, rather than a per-kW demand-based charge. The ALJs also agree with TIEC that the fact that these credits are booked to FERC Account 555 does not bear on the question of whether the credits are demand- or energy-related because costs booked to that account can be either energy- or demand-related.[1590] The ALJs therefore recommend that the Commission adopt TIEC's REC opt-out calculation, which results in an REC opt-out credit of approximately 0.064¢ per kWh.

E. Retail Choice Pilot Project

ETWSD witness Pevoto testified that a retail choice pilot project in SWEPCO's service territory "makes sense as a tool for the Commission to obtain information on whether sufficient demand exists to entertain the idea" of opening up SWEPCO to retail open access.[1591] Ms. Pevoto noted that ETSWD filed a petition for a declaratory order in Docket No. 51257 asking the Commission "to clarify whether current law and SWEPCO tariffs require that SWEPCO provide a retail pilot project."[1592] ETSWD did not address this retail choice pilot project in either of its post-hearing briefs, presumably because the Commission announced its ruling denying ETSWD's petition at its open meeting on June 11, 2021.[1593]

[1589] *See* 18 C.F.R. Pt. 101, 555 Purchased Power ("A. This account shall include the cost at point of receipt by the utility of electricity purchased for resale . . . . B. The records supporting this account shall show, by months, the demands and demand charges, kilowatt-hours and prices thereof . . . .").

[1590] Under the Commission's Fuel Rule, demand or capacity costs booked to FERC Account 555 are not deemed to be eligible fuel expenses and, as such, are not recoverable through SWEPCO's fuel factor. 16 TAC § 25.236(a)(6). This preclusion of recovering demand-related purchased power costs through the fuel factor, however, has no bearing on whether a cost booked to FERC Account 555 is an energy-related or a demand-related cost.

[1591] ETSWD Ex. 1 (Pevoto Dir.) at 21.

[1592] ETSWD Ex. 1 (Pevoto Dir.) at 20.

[1593] *Petition of East Texas Salt Water Disposal Company for Declaratory Order and Request for the Opening of a Pilot Project Implementation Project*, Docket No. 51257, Declaratory Order (Jun. 22, 2021).

Because the Commission denied ETSWD's petition for a declaratory order on this topic, and ETSWD failed to pursue this issue in its post-hearing briefs, the ALJs find that ETSWD's is moot and should not be pursued.

XI. BASELINES FOR COST RECOVERY FACTORS [PO ISSUES 4, 5, 52, 63]

SWEPCO and Staff are the only parties that addressed baselines for cost-recovery factors. SWEPCO requests that its current TCRF and DCRF be set to zero, and that this case establish the baseline values consisting of the inputs to the calculations used to calculate SWEPCO's TCRF, DCRF, and GCRR in future dockets.[1594] Staff states that it "supports the adoption of its proposed TCRF and DCRF baselines based on the CCOSS approved by the Commission."[1595] Staff does not otherwise raise any issues with regard to how SWEPCO calculated the baselines, and does not oppose re-setting the current TCRF and DCRF rates to zero as required by the Commission's rules. SWEPCO responds that the revisions reflected in its rebuttal CCOSS, "are necessary and should be incorporated into the cost of service study used to derive the appropriate baseline values adopted by the Commission."[1596]

A. Interim Transmission Cost of Service

SWEPCO states this issue is not pertinent to SWEPCO. The ALJs agree. Because SWEPCO does not provide transmission service within ERCOT, it does not offer open access transmission service that otherwise would be subject to an interim transmission cost of service.[1597]

[1594] SWEPCO Ex. 31 (Aaron Dir.) at 26-35. In this testimony, and in his Exhibits JOA-5, JOA-6, and JOA-7, Mr. Aaron explains and sponsors the baseline values established in accordance with the Commission's substantive rules that are proposed to be used in SWEPCO's future TCRF, DCRF, and GCRR proceedings.

[1595] Staff Initial Brief at 79 (citing Staff Ex. 4 (Narvaez Dir.) at 37-40, Attachment AN-5).

[1596] SWEPCO Reply Brief at 117 (citing SWEPCO Ex. 54 (Aaron Reb.) at 2-5); SWEPCO Exs. 54A and 54B (Aaron Reb. Workpapers).

[1597] 16 TAC § 25.192(a) does not apply to SWEPCO because SWEPCO does not provide transmission service within ERCOT.

B. Transmission Cost Recovery Factor

SWEPCO's proposal to exclude TCRF revenues in its proposed rate increase calculation is addressed in Section X above. SWEPCO's proposal to defer net SPP charges to a future TCRF or base rate proceeding is also addressed in Section VII above.

No party opposed the Company's request to reset the baseline value of the TCRF for future filings. The ALJs recommend approval of SWEPCO's proposal to re-set its TCRF to zero. The TCRF baseline should be set in the compliance phase of this case after the Commission makes final rulings on the various contested issues that may affect the TCRF baseline calculation.[1598]

C. Distribution Cost Recovery Factor

SWEPCO's proposal to exclude DCRF revenues in its proposed rate increase calculation is addressed in Section X above

No party opposed the Company's request to reset the baseline value of the DCRF for future filings. The ALJs recommend approval of SWEPCO's proposal to re-set its DCRF to zero. The DCRF baseline should be set in the compliance phase of this case after the Commission makes final rulings on the various contested issues that may affect the DCRF baseline calculation.

D. Generation Cost Recovery Rider

No party addressed or opposed the Company's request to establish the baseline value for the GCRR. The GCRR baseline should be set in the compliance phase of this case after the Commission makes final rulings on the various contested issues that may affect the GCRR calculation.

[1598] The schedules attached to this PFD include the recommended TCRF and DCRF baseline values based on the ALJs' recommendations in this PFD.

XII. REASONABLENESS AND RECOVERY OF RATE CASE EXPENSES [PO ISSUES 26, 27, 28]

SWEPCO requests recovery of its reasonable rate case expenses (RCEs) incurred in this proceeding as well as those expenses it pays to reimburse CARD for CARD's RCEs.[1599] SWEPCO also seeks to recover RCEs associated with its most recent TCRF filing, Docket No. 49042,[1600] its pending fuel reconciliation, Docket No. 50997,[1601] as well as appellate expenses related to its last two base rate proceedings, Docket Nos. 40443 and 46449.[1602]

The statutory basis for the recovery of RCEs incurred by a regulated utility is set forth in PURA § 36.061. PURA § 33.023 establishes the statutory foundation for the recovery of the expenses of municipalities incurred for participating in ratemaking proceedings before the Commission. The Commission's RCE Rule, 16 TAC § 25.245, addresses the means by which a utility is required to present and prove up its reasonable rate case expenses.

In this case, the RCE issues were not severed into a separate docket as had been the historical practice until last year.[1603] Severance of the RCEs would have allowed consideration of all RCEs related to these cases in a single docket decided after the Commission issues its final order in this docket. Instead, because RCEs are to be addressed in this docket, a cut-off was established after the close of the hearing and prior to issuing this PFD that would address recovery of most but not all RCEs incurred to process this docket and the four prior or pending SWEPCO dockets listed above.[1604] SOAH Order No. 13 set the procedures by which the parties would file

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[1599] SWEPCO Ex. 5 (Ferry-Nelson Dir.) at 24.

[1600] *Application of Southwestern Electric Power Company to Amend its Transmission Cost Recovery Factor,* Docket No. 49042, Order (Jul. 18, 2019).

[1601] *Application of Southwestern Electric Power Company for Authority to Reconcile Fuel Costs,* Docket No. 50997 (pending).

[1602] SWEPCO Ex. 5 (Ferry-Nelson Dir.) at 24.

[1603] For example, the rate case expenses incurred by SWEPCO and CARD in SWEPCO's last base rate case were severed and addressed in Docket No. 47141. *Review of Rate Case Expenses Incurred by Southwestern Electric Power Company and Municipalities in Docket 46449,* Docket No. 47141, Order (Aug. 27, 2020).

[1604] Both SWEPCO and CARD filed periodic updates to their RCE reports commencing in March 2021.

their final RCE reports and testimony for consideration in this docket. On July 6, 2021, in accordance with SOAH Order No. 13, SWEPCO and CARD filed their final supplemental RCE reports. As indicated in those reports, SWEPCO's RCEs subject to review in this docket are those incurred by the Company through May 2021; CARD's RCEs subject to review in this docket are those incurred through June 2021. Also in accordance with SOAH Order No. 13, Staff filed its final supplemental direct testimony addressing RCEs on July 20, 2021, and SWEPCO filed its final supplemental rebuttal testimony addressing RCEs on July 27, 2021.[1605]

All RCEs incurred up to the cut-off date found to be reasonable by the Commission will be recovered from SWEPCO's customers through SWEPCO's Rate Case Surcharge (RCS) Rider. SWEPCO will reimburse CARD for its Commission-authorized RCEs to the extent it has not already done so. Any additional RCEs incurred for this docket after the cut-off date, referred to as "trailing RCEs," would be recorded as a regulatory asset and deferred for analysis and recovery in a future docket.

The total RCEs sought for recovery by SWEPCO and CARD are $3,769,007.[1606] Two RCE-related issues remain contested in this case.[1607] First, Staff opposes CARD's request for reimbursement of $6,321 in RCEs CARD incurred in Docket No. 47141 after the agreed RCE

[1605] "Final Supplemental Testimony of Ruth Stark," and "Final Supplemental Rebuttal Testimony of Lynn Ferry-Nelson," respectively. Because these testimonies, and the reports filed by SWEPCO and CARD on July 6, 2021, were filed after the hearing on the merits in accordance with SOAH Order No. 13, they do not have stated exhibit numbers. In this PFD, they are referred to by their names, such as "Stark Final RCE Testimony," rather than by an exhibit number. These documents are part of the record in this case. On this point, SWEPCO's and CARD's RCE reports filed on and before July 6, 2021, Ms. Stark's Final RCE testimony filed on July 20, 2021, and Ms. Ferry-Nelson's Final RCE testimony filed on July 27, 2021, are admitted into the record in this docket, and are so noted on the Exhibit Attestation filed in conjunction with this PFD. This includes SWEPCO's Second Supplemental RCE Report filed on June 11, 2021, and CARD's First Supplemental RCE Report filed on June 18, 2021. CARD filed a Statement of Position regarding its RCEs on July 27, 2021, which adds no new arguments or evidence.

[1606] Stark Final RCE Testimony at 7; Ferry-Nelson Final RCE Testimony at 4.

[1607] Prior to filing its post-hearing briefs, Staff raised a third issue involving a potential $45,457 double-counting in the RCEs. In its initial brief, however, Staff addressed this double-counting issue but concluded "Staff agrees that the $45,457 is recoverable by SWEPCO." Staff Initial Brief at 81.

cut-off date in that proceeding.[1608] Second, Staff recommends a $65,167 disallowance of SWEPCO's requested RCEs related to legal billings in excess of $550 per hour.[1609]

A. Amounts Sought for Recovery and the Proposed Recovery Method

SWEPCO's RCEs fall into four categories of costs: outside legal counsel, outside consultants, cities' expenses, and miscellaneous expenses.[1610] SWEPCO witness Lynn Ferry-Nelson's Exhibits LFN-1 and LFN-2 to her direct testimony and Exhibit LFN-1R to her rebuttal testimony contain a summary of the items that make up SWEPCO's requested RCEs. CARD's RCEs, which are subsumed within SWEPCO's RCEs, are supported by CARD witness Catherine Webking.[1611]

The total RCEs requested by SWEPCO and CARD, by docket, are reflected in the following table:

Total RCEs Subject to Review in this Docket[1612]

Docket No.	SWEPCO	CARD	Total
40443	$ 188,132	$ 18,029	$ 206,161
46449	$ 183	$ 0	$ 183
47141	$ 0	$ 6,320	$ 6,320
49042	$ 176,913	$ 41,463	$ 218,376
50997	$ 382,257	$ 219,813	$ 602,070
51415	$1,992,830	$ 743,067	$2,735,897
Total	$2,740,315	$1,028,692	$3,769,007

[1608] Staff Ex. 3B (Stark Supp. Dir.) at 12.

[1609] Stark Final RCE Testimony at 7.

[1610] SWEPCO Ex. 5 (Ferry-Nelson Dir.) at 31.

[1611] CARD Ex. 5 (Webking Dir.).

[1612] Stark Final RCE Testimony at 8, Attachment RS-1FS.

SWEPCO proposes that the Commission: (1) review and determine the reasonableness of its and CARD's RCEs presented in their RCE reports filed on and before the July 6, 2021 cut-off date; and (2) authorize recovery of any expenses found to have been reasonably incurred through the RCS Rider.[1613] No party opposes the RCS Rider recovery method. As to the trailing RCEs that will be subject to a future proceeding, SWEPCO agrees with Staff's recommendation that the Commission authorize SWEPCO to establish a regulatory asset to record both SWEPCO's and CARD's trailing RCEs from this proceeding to be reviewed and recovered to the extent found to be reasonable in a future docket.[1614]

The ALJs agree that approved RCEs in this docket should be recovered through SWEPCO's proposed RCS Rider, and that the trailing expenses should be booked as a regulatory asset for review and potential recovery in a future case.

B. The Docket No. 47141 Issue Regarding CARD's RCEs

Staff contends that CARD's requests for $6,321 in RCEs associated with Docket No. 47141 should be denied because the amended unanimous settlement (settlement) adopted in that docket precludes recovery of this amount.[1615] The findings of fact in the Commission's order approving the settlement include the following:

> 78. The parties agreed that SWEPCO would recover $5,429,804.52 in rate-case expenses. This black-box amount includes reimbursement to CARD in the amount of $1,086,322.14 through April 13, 2020. In addition, the black-box amount includes reimbursement to CARD for actual expenses incurred in this docket after April 13, 2020 but caps that reimbursement at $2,500.

[1613] SWEPCO Ex. 5 (Ferry-Nelson Dir.) at 26.

[1614] SWEPCO Reply Brief at 118. CARD does not oppose these proposals; CARD's only issue is with Staff's proposed disallowance of $6,321 adjustment related to Docket No. 47141.

[1615] Citing Docket No. 47141, Order at 12-13, FoF Nos. 78 and 79 (Aug. 27, 2020). *See* Stark Final RCE Testimony at 7.

> 79. SWEPCO and CARD agreed not to request any additional recovery for rate-case expenses incurred in this docket, in litigation before the Commission in Docket Nos. 40443 and 46449, and in Docket Nos. 48233 and 47553.[1616]

Staff argues that because the Commission's order in Docket No. 47141 prohibits recovery of any additional expenses related to that proceeding, CARD's requested rate-case expenses should be adjusted by ($6,321).[1617]

CARD agrees that the $6,321 was incurred after April 13, 2020, and the settlement caps reimbursement of such expenses at $2,500.[1618] CARD argues that Staff's calculation of the adjustment is not accurate because it fails to account for the $2,500 in rate-case expenses that SWEPCO was required to reimburse CARD pursuant to the settlement. Hence, according to CARD, the correct adjustment is a reduction of $3,821 and not $6,321 (that is, $6,321 - $2,500 = $3,821).

The ALJs agree with CARD. The disallowance necessary to recognize the $2,500 cap in the settlement is $3,821, not $6,321. It appears that the dispute as to the amount of the disallowance arises because Staff construes FoF No. 79 to mean that CARD is not entitled to *any* additional RCEs incurred in Docket No. 47141 (presumably after April 13, 2020). Standing alone, the ALJs understand how Staff arrived at that interpretation. FoF No. 78, however, must be read in conjunction with FoF No. 79. Finding of Fact No. 78 allows CARD to recover up to $2,500 in RCEs for Docket No. 47141; that is, CARD is authorized to recover up to an additional $2,500. The ALJs read the words "any *additional* recovery" in FoF No. 79 to mean that CARD is precluded from recovering any RCEs in addition to (or above) the amounts authorized in FoF No. 78. Finding of Fact No. 78 allows CARD to recover $1.09 million plus up to an additional $2,500. For these reasons, Staff has justified the disallowance of $3,821 in CARD's RCEs subject to recovery in this docket, but CARD has also justified recovery of $2,500 related to RCEs incurred in Docket No.

[1616] Docket No. 47141, Order at 12-13, FoF Nos. 78 and 79 (Aug. 27, 2020).

[1617] Staff Initial Brief at 85 (citing Staff Ex. 3b (Stark Suppl. Dir.) at 12). Staff does not address this issue in its reply brief.

[1618] CARD Reply Brief at 46-47.

47141. The ALJs therefore recommend that CARD be allowed to recover $2,500, but not $6,321, related to Docket No. 47141.

C. Staff's Proposed $550 Per-Hour RCE Cap

Staff's proposes to reduce SWEPCO's requested RCEs by $65,167, arguing that any amounts billed above an hourly rate above $550 an hour are excessive under the Commission's RCE Rule and, therefore, are neither reasonable nor recoverable.[1619] Staff identified two instances in which SWEPCO paid attorneys based on an hourly rate in excess of $550 per hour: one for an attorney with Eversheds Sutherland US LLP (Eversheds), who billed at $1,230 per hour, and the other for a Baker Botts LLP (Baker Botts) attorney who billed at $1,010 per hour.

The Company requests recovery of the entire amounts paid regardless of the hourly rate. Staff is not proposing to disallow all fees charged by the two attorneys who billed in excess of $550 per hour. Instead, Staff's proposal is to allow SWEPCO to recover dollars resulting from the number of hours billed times $550. Thus, Staff's proposal is to disallow the amounts billed in excess of $550 per hour, but not amounts incurred up to that hourly rate.[1620]

In her Supplemental Direct testimony filed on May 5, 2021, Staff witness Stark proposed a RCE disallowances related to hourly billing rates in excess of $550 per hour as follows:[1621]

- With respect to Docket No. 51415, SWEPCO incurred $12,423 of legal expenses for services provided by [Eversheds] consisting of 10.1 hours billed at an hourly rate of $1,230.

[1619] Stark Final RCE Testimony at 7; Staff Ex. 3B (Stark Supp. Dir.) at 7.

[1620] Staff Ex. 3B (Stark Supp. Dir.) at 7. Staff's final recommended $65,167 disallowance is based on the final RCE reports filed by SWEPCO and CARD on July 6, 2021. Ms. Stark's figure is the product of multiplying the number of hours billed in each of the two instances identified by Staff by the portion of the hourly billing rate that is above $550. *See* Staff Ex. 3B (Stark Supp. Dir.) at 8.

[1621] Staff Ex. 3B (Stark Suppl. Dir.) at 7.

- With respect to the appeal of Docket No. 40443, SWEPCO incurred legal expenses for services provided by [Baker Botts] a portion of which included $96,354 for 95.4 hours billed at an hourly rate of $1,010.[1622]

In her Final RCE testimony filed on July 20, 2021, based on SWEPCO's and CARD's final RCE Reports filed on July 6, 2021, Ms. Stark testified:

> [I] recommend an additional disallowance of $14,414 of SWEPCO's legal expenses based on SWEPCO's Second and Third Supplemental rate-case expense filings. This combined with the previously recommended disallowance in my supplemental direct testimony equals a total recommended disallowance of $65,167 of SWEPCO's rate-case expenses for this proceeding related to legal billings in excess of $550 per hour.[1623]

In her Final RCE Testimony, Ms. Stark does not state how much of the $14,414 increase from her Supplemental Direct testimony is attributable to Eversheds and how much is attributable to Baker Botts. But SWEPCO does not dispute Ms. Stark's testimony that the total amount in this docket attributable to billings in excess of $550 per hour is $65,147. Thus, the issue is not how the amount was calculated, but whether the ALJs should recommend for or against imposing a $550 per-hour cap on recoverable RCEs.

1. Staff's Arguments and Evidence

Staff relies on the Commission's RCE Rule to support its proposed $550 per-hour cap:

> (c) **Criteria for review and determination of reasonableness**. In determining the reasonableness of the rate-case expenses, the presiding officer shall consider the relevant factors listed in subsection (b) of this section and any other factor shown to be relevant to the specific case. The presiding officer shall decide whether and the extent to which the evidence shows that:
>
> (1) the fees paid to, tasks performed by, or time spent on a task by an attorney or other professional were *extreme or excessive*; . . . .[1624]

[1622] Staff Ex. 3B (Stark Supp. Dir.) at 7.

[1623] Stark Final RCE Testimony at 7.

[1624] 16 TAC § 25.245 (emphasis added).

Ms. Stark noted that, in considering the pending adoption of 16 TAC § 25.245, the Commission commented on the need to establish a more robust process for reviewing attorney's fees, and that such "fees need to be proven up with real evidence from credible experts."[1625] Ms. Stark explained that the Commission's order adopting 16 TAC § 25.245 concluded that "adopting clear evidentiary standards and specific criteria for the review and determination of the reasonableness of rate-case expenses will incentivize utilities and municipalities to act more like self-funded litigants, while still providing for recovery of reasonable rate-case expenses."[1626] In recent years, Staff has consistently recommended that any amount billed above an hourly rate of $550 an hour is excessive under 16 TAC § 25.245(c)(1).[1627]

Ms. Stark also relies on a 2016 memorandum and 2019 follow-up memorandum issued by the Office of the Attorney General of Texas (OAG) to state agencies, university systems, and institutions of higher education outlining policies and procedures relating to the retention of outside legal counsel, which states that unless expressly approved, the hourly rate for attorneys shall not exceed $525 per hour.[1628] The memoranda state: "Timekeeper Rates—Unless expressly approved by the First Assistant Attorney General in advance, hourly rates for attorneys shall not exceed $525/hour, while hourly rates for paralegals shall not exceed $225/hour."[1629]

Ms. Stark further testified that the majority of the legal billings requested by SWEPCO and CARD in this proceeding relate to services provided by three law firms: Duggins Wren Mann

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[1625] Staff Ex. 3B (Stark Supp. Dir.) at 8.

[1626] *Rulemaking to Propose New Subst. R. § 25.245 Relating to Recovery of Expenses for Ratemaking Proceedings*, Project No. 41622, Order Adopting Rule § 25.245 at 13-14 (Aug. 6, 2014) (RCE Rule Preamble).

[1627] Staff Ex. 3B (Stark Supp. Dir.) at 7.

[1628] Staff Ex. 3B (Stark Supp. Dir.) at 8-9, and Attachments RS-1S (2016 OAG Memorandum) and RS-2S (2019 OAG Memorandum). Ms. Stark notes that the 2019 memorandum superseded the 2016 memorandum, but the $525 per hour cap remained unchanged. The memoranda specifically addressed "Outside Counsel Contract Rules and Templates."

[1629] Staff Ex. 3B (Stark Supp. Dir.), Attachment RS-1S at 7. In the OAG's 2019 memorandum, the hourly rate caps language replaced the word "paralegal" in the 2016 memorandum with "non-attorney legal work (limited to paralegals, legal assistants, and other timekeepers performing similar legal work)." Stark Final RCE Testimony, Attachment RS-2S at 7. The hourly rate caps were not changed in the 2019 memorandum.

& Romero, LLP (Duggins Wren), Herrera Law & Associates, PLLC (Herrera Law), and Scott, Douglass & McConnico, LP, and the hourly billing rates for the lawyers in this docket range from $250 per hour to $550 per hour.[1630]

Staff cites as additional support the PFD in Docket No. 45979.[1631] Ms. Stark notes that, while the Commission ultimately dismissed Docket No. 45979, the PFD in that case is instructive:[1632]

> The ALJ agrees with Staff and OPUC that, in general, a cap on hourly fees charged by attorneys in utility rate cases before the Commission is appropriate and, in this case, the record supports a $550 per hour cap . . . While Rule 25.245(c)(1) does not specify a cap on attorneys' fees, it contemplates that fees paid to an attorney or other professional could be "extreme or excessive." Otherwise, there would be no purpose for Rule 25.245 to identify the level of fees paid to an attorney (or other professional) as a consideration under that rule.[1633]

Staff also quotes the following from the Docket No. 45979 PFD:

> Setting attorneys' fees in an RCE case based on the upper end of hourly rates charged by large, national law firms would remove the intended incentive for regulated public utilities to act more like self-funded litigants . . . National law firms may charge $600 and more per hour, and Sharyland is free to hire such firms to represent it before the PUC, but that does not mean that rates in that range are reasonable for practitioners before the PUC, and Sharyland's captive customers should not be expected to cover hourly fees at and above $550 per hour.[1634]

[1630] Staff Ex. 3B (Stark Supp. Dir.) at 9. The most experienced lawyers at Duggins Wren who worked on this case billed at $420 per hour. *E.g.*, SWEPCO Ex. 34 (Ferry-Lynn Reb.), Exh. LFN-2R at 922. Herrara Law's hourly rates ranged from $250 to $485 per hour. CARD Ex. 5 (Webking Dir.), Attachment CJW-2 at 2. These exhibits indicate that Ms. Webking bills at $550 per hour.

[1631] *Review of Rate Case Expenses Incurred by Sharyland Utilities, L.P. in Docket No. 45414*, Docket No. 45979, PFD (Oct. 29, 2018). *See also* Staff Ex. 3B (Stark Supp. Dir.) at 9-10.

[1632] Docket No. 45979, Order of Dismissal at 1 (Oct. 8, 2019), "The Commission finds that Sharyland's original request to recover rate-case expenses from Docket No. 45414 is obsolete and moot, given the agreement and final order in Docket No. 48989 prohibiting Sharyland from recovering those expenses, and the Commission therefore finds good cause under 16 TAC § 22.181(d) to grant Sharyland's motion to dismiss."

[1633] Staff Ex. 3B (Stark Supp. Dir.) at 9-10 (citing Docket No. 45979, PFD at 41-42).

[1634] Staff Ex. 3B (Stark Supp. Dir.) at 10 (citing Docket No. 45979, PFD at 42-43).

Staff also argued in its initial brief that SWEPCO should not be allowed to recover rate case expenses above $550 an hour because SWEPCO failed to provide information regarding the charges about $550 per hour until after the discovery period closed in this case.[1635]

Staff notes that the Commission has approved a cap on attorney fees in some settled cases but has yet to rule on the issue in a contested proceeding.[1636] Staff witness Stark explained that Staff's recommended $550 per-hour cap does not limit SWEPCO from paying above $550 an hour for legal counsel services: "[m]y recommendation is only intended to be a cap on the amount that should reasonably be recovered from ratepayers."[1637]

2. SWEPCO's Arguments and Evidence

SWEPCO counters that a fixed $550 per-hour cap is inconsistent with how courts and the Commission typically consider the reasonableness of attorneys' fees and is inconsistent with the Commission's RCE Rule.[1638] SWEPCO notes that the Commission's RCE Rule does not specify a cap on professional fees. Instead, the rule states that the presiding officer shall consider multiple relevant factors in deciding whether the fee paid to an attorney or other professional was extreme or excessive, including, among other factors: (1) the nature, extent, and difficulty of the work; (2) the time and labor required and expended; (3) the nature and scope of the case, including but not limited to the amount of money or value of property or interest at stake and the novelty or complexity of the issues addressed; and (4) the amount of rate-case expenses reasonably associated with each issue.[1639] SWEPCO contends that courts consider a variety of factors in determining whether attorneys' fees are reasonable and they do not employ bright-line limitations such as the

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1635 Staff Ex. 3B (Stark Supp. Dir.) at 11. Staff states in its initial brief that SWEPCO's RCE witness waited until her supplemental rebuttal testimony, rather than her direct or rebuttal testimony, to describe the services provided by the attorneys who charged more than $550 per hour, describe the issues they addressed, and address the rates that they charged. Staff Initial Brief at 83-84.

1636 *See Application of El Paso Electric Company to Change Rates,* Docket No. 46831, FoF No. 64 (Dec. 18, 2017).

1637 Staff Ex. 3B (Stark Supp. Dir.) at 11.

1638 SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 4.

1639 SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 5; *see also* 16 TAC § 25.245.

one Staff recommends.[1640] For example, other relevant factors to consider include the experience, reputation, and ability of the professional and the fees customarily charged for similar professional services.[1641]

SWEPCO also argues that the OAG opinions and Docket No. 45979 PFD cited by Staff do not support limiting the recovery of every professional in a ratemaking proceeding to $550 per hour. First, the OAG memoranda sets an amount of $525 per hour as presumptively reasonable for an attorney's hourly rate for routine matters, and simply requires pre-authorization for an hourly rate exceeding $525.[1642] According to SWEPCO, if a firm $525 per hour cap were uniformly imposed, there would be no reason for the OAG to allow for an exception in circumstances in which a higher hourly rate might be appropriate.[1643] Second, the Docket No. 45979 PFD also does not require that a $550 per hour cap must be applied to every professional in a ratemaking proceeding. Instead, as the PFD noted, the RCE Rule is intended to help ensure that utilities act more like self-funded litigants.[1644]

SWEPCO's witness Ferry-Nelson explains the expertise and SWEPCO's need for counsel from its two outside attorneys who charged in excess of $550 per hour: Mr. Bradley M. Seltzer, who is an energy tax law expert, and former Chief Justice of the Supreme Court of Texas Thomas Phillips. Ms. Ferry-Nelson confirmed that these two attorneys are routinely hired by self-funded litigants for their expert representation at the same or greater rates than those charged to SWEPCO.[1645] Ms. Ferry-Nelson testified that, in this rate case, SWEPCO is litigating the treatment of a complex tax issue involving SWEPCO's net operating loss carry-forward accumulated deferred federal income tax asset.[1646] The vast majority of this issue was handled by

[1640] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 5.

[1641] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 5.

[1642] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 7.

[1643] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 7.

[1644] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 7.

[1645] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.), Exh. LFN-1SR (Affidavit of Thomas R. Phillips), Exh. LFN-2SR (Affidavit of Bradley M. Seltzer).

[1646] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 8.

internal SWEPCO employees who were assisted by in-house and outside counsel charging an hourly rate lower than Staff's recommended $550 per hour cap.[1647] However, due to the complex nature and the amount at stake with this issue, SWEPCO contends that it was reasonable to hire an outside energy tax law expert to opine on the substantial risk that adopting Staff's proposed tax approach would violate normalization consistency rules.[1648] Ms. Ferry-Nelson concludes that, although his hourly rate is over $550, Mr. Seltzer's expertise and experience are counterbalanced by efficiency in dealing with an extremely complex topic, making his fees reasonable.[1649]

Ms. Ferry-Nelson explained that SWEPCO hired Justice Phillips to represent SWEPCO in the appeal before the Texas Supreme Court wherein SWEPCO successfully defended the Commission's order in Docket No. 40443.[1650] Ms. Ferry-Nelson testified that, at all other levels of the appellate process, SWEPCO used less expensive appellate counsel.[1651] However, at the Supreme Court level, it was reasonable to hire Justice Phillips because he is intimately familiar with the procedure at the Texas Supreme Court and is experienced in preparing written and oral arguments. He provided SWEPCO with efficient and effective service in defending the Commission's order and reversing the decision made by the Austin Court of Appeals over an issue with a major financial impact.[1652] Justice Phillips was therefore not providing standard utility rate case counsel, but counsel that combined the unique aspects of utility ratemaking with the appellate process before the Supreme Court of Texas.[1653]

SWEPCO emphasizes its claim that it acted like a reasonable, self-funded litigant with regard to both Mr. Seltzer and Justice Phillips.[1654] Ms. Ferry-Nelson testified:

[1647] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 8.

[1648] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 8.

[1649] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 8.

[1650] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 8.

[1651] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 8.

[1652] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 8-9.

[1653] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 9.

[1654] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 9. SWEPCO Initial Brief at 139-40. SWEPCO's reply brief summarizes and reiterates the RCE arguments it made in its initial brief.

> [T]he facts in this case demonstrate that SWEPCO acted like a reasonable, self-funded litigant. The vast majority of SWEPCO's outside attorneys and consultants are well below Staff's proposed $550/hour cap. For those few whose rates exceed the cap, it was reasonable to exceed that hourly amount based on their experience and the complexity of the issues addressed. Further, as discussed in my supplemental rebuttal testimony, these professionals are routinely hired by self-funded litigants for their expert representation at the same rates charged to SWEPCO. [1655]

3. ALJs' Analysis

The ALJs find that Staff's proposed $550 per-hour cap on hourly rates sought for recovery as RCEs in this case is reasonable and supported by the record in this case. The ALJs, however, are not recommending that a hard $550 per-hour cap should apply in all future cases for two primary reasons. First, at some point in the future, hourly rates in excess of $550 per hour may not be deemed excessive, and instead might be deemed reasonable, depending on the then-existing circumstances, such as the economy, inflation, or any other number of factors. Today, however, and particularly in light of the OAG's 2016 and 2019 memoranda on this topic, $550 is the upper limit. Second, there may be instances in the near term, not present here, where an electric utility could justify a request to recover in excess of $550 per hour from its customers.

In this case, SWEPCO has not met its burden of proof to show the reasonableness of RCEs in excess of $550 per hour. The RCE Rule requires SWEPCO to file sufficient information that details and itemizes all rate-case expenses.[1656] SWEPCO did not provide sufficient information in its direct or rebuttal case explaining, or justifying, why it would be reasonable for SWEPCO's customers to reimburse SWEPCO for legal counsel rates in excess of $550. As Staff noted, this $550 per hour cap issue is not novel to this rate case, and SWEPCO could have anticipated that this issue would be contested. Staff, however, presented a compelling case that legal fees in excess

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[1655] Ferry-Nelson Final RCE Testimony at 5.

[1656] 16 TAC § 25.245(b).

of $550 per hour in this rate case are excessive and, therefore, unreasonable and should not be borne by the SWEPCO's customers.

Moreover, SWEPCO has not shown that the considerations specified in the RCE Rule justify the rates charged in excess of $550 per hour in this case. The ALJs agree that the "nature, extent, and difficulty of the work" in electric utility rate and fuel reconciliation dockets may not be something that a junior associate could handle competently, and that many issues in a rate case, routinely handled by lawyers who bill at less than $550 per hours, are complex and sometimes novel. Ms. Ferry-Jackson concedes that, as to Mr. Seltzer's work, "[t]he vast majority of this issue was handled by internal SWEPCO employees who were assisted by in-house and outside counsel charging an hourly rate lower than Staff's recommended $550 per hour cap."[1657] Similarly, for Justice Phillips, "at all other levels of the appellate process, SWEPCO used less expensive appellate counsel."[1658] SWEPCO has not explained why these issues could not have been handled by its in-house or traditional outside counsel, or by other attorneys who bill at $550 per hour or less. Considerations regarding the time and labor required by Mr. Seltzer and Justice Phillips are not addressed in SWEPCO's case, other than to note the number of hours they both billed to these projects.

The ALJs also conclude that SWEPCO's argument that it was "acting like a reasonable, privately funded litigant" by paying attorneys' fees in excess of $550 per hour (and in fact over $1000 per hour) is flawed. The reference to "self-funded litigants" in the preamble to the RCE Rule is there to "incentivize" utilities and municipalities to act with some restraint when incurring RCEs—as would self-funded litigants who do not recover their legal expenses from their captive customers.[1659] A true self-funded litigant relies on its shareholders or association members to pay, or cover, its legal fees, not its customers. SWEPCO argues that it is nevertheless "acting" like a

[1657] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 8.

[1658] SWEPCO Ex. 35 (Ferry-Nelson Supp. Reb.) at 8.

[1659] As noted, the particular language in the preamble states: "[A]dopting clear evidentiary standards and specific criteria for the review and determination of the reasonableness of rate-case expenses will incentivize utilities and municipalities to act more like self-funded litigants, while still providing for recovery of reasonable rate-case expenses." RCE Rule Preamble at 13-14.

self-funded litigant because self-funded litigants routinely hire Mr. Seltzer and Justice Phillips at the same rates those two attorneys charged to SWEPCO.[1660] Essentially, SWEPCO argues that if some person or company is willing to hire Mr. Seltzer and Justice Phillips in excess of $550 per hour (in these cases, in excess of $1000 per hour), then SWEPCO's customers should be expected to also cover RCEs in excess of $550 per hour. The evidence shows that Mr. Seltzer and Justice Phillips bill out at hourly rates in excess of $1000 per hour. SWEPCO, however, has pointed to nothing in the RCE Rule that suggests that if a consultant or lawyer hired by a utility or municipality routinely bills at a rate in excess of $550 per hour to non-utility clients, then that rate is, essentially, *de facto* reasonable in the context of utility rate case RCEs.

As addressed in the Docket No. 45979 PFD, the ALJs have some reservations about recommending a $550 per hour cap for attorneys' fees in this case because this recommendation could lead some lawyers providing services in ratemaking proceedings to assume they can increase their hourly rates to $550. That is not the intent of this recommendation. The $550 cap recommended in this case is a reasonable cap for the highest fees charged by the most experienced attorneys participating in a complex base rate case.[1661] SWEPCO and CARD can agree to pay more than $550 per hour to their outside counsel and consultants, but they should not expect to be compensated for charges in excess of that amount without a compelling showing that the payment is reasonable and not excessive. In any event, they must justify all of their requested RCEs regardless of hourly rate.

For these reasons, the ALJs recommend that the Commission adopt Staff's position on this issue, and disallow $65,167 in RCEs requested by SWEPCO in this docket. This disallowance is reflected in the table on page 8 of Ms. Stark's Final RCE testimony filed on July 20, 2021, with the clarification that the total allowed amount presented on that page in her testimony should be increased by $2,500 to account for the CARD RCEs discussed above in the context of Docket

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[1660] *E.g.*, Ferry-Nelson Final Supplemental RCE Testimony at 5, where she states "these professionals are routinely hired by self-funded litigants for their expert representation at the same rates charged to SWEPCO."

[1661] *See* Docket No. 45979, PFD at 43. The ALJs recognize that there may be instances in other cases in which a $550 per-hour fee is unreasonable, depending on the facts in that case.

No. 47141. Taking these adjustments into account, the total amount of RCEs the ALJs recommend for recovery in this case for both SWEPCO's and CARD's RCEs is $3,700,021.[1662]

The ALJs also suggest that the Commission consider re-instating its prior practice that severed RCEs from electric base rate cases and allowed the RCEs to be addressed in a self-contained docket after a final order had been issued in the underlying base rate case. Doing so would avoid situations, as in this docket, where it was necessary to allow SWEPCO, CARD, and Staff to continue to file RCE reports and testimony up to two months after the close of the hearing to ensure that as many RCEs as possible could be addressed in this PFD. As noted above, there are still considerable "trailing" RCEs attributable to this docket that have not yet been addressed and will need to be handled in some future docket. In this docket, SWEPCO's RCEs are those through May 2021, meaning that all outside legal and consultant fees incurred in June 2021 to prepare the Company's post-hearing briefs, and all fees that will be incurred to prepare exceptions and replies to exceptions to this PFD, and potentially motions for rehearing after the Commission issues its order in this case, are not addressed in this PFD. The ALJs are aware that the Commission recently rejected a proposal in a Sharyland base rate case to use estimated RCEs and then later true up the estimates in a compliance filing.[1663] In the Sharyland case, the Commission provided the parties with two alternatives: one allowing RCE recovery as an expense in the utility's revenue requirement, and the other allowing recovery through a rider. The ALJs' suggestion that the Commission allow electric utilities to sever the RCE issues from their base rate dockets for consideration in a separate docket does not appear to contradict the Commission's ruling in the Sharyland case. The ALJs are not suggesting that estimates should be used, and the recommended proposal is that the RCEs subject to this docket will be recovered through SWEPCO's RCS Rider.

[1662] *See* the table in Stark Final RCE Testimony at 8 and add $2,500 to the Docket No. 47141 line in the columns labeled "CARD" and "Total."

[1663] *Application of Sharyland Utilities, L.L.C. for Authority to Change Rates,* Docket No. 51611, Order Remanding Case to Docket Management (Jun. 28, 2021).

XIII. OTHER ISSUES [INCLUDING BUT NOT LIMITED TO PO ISSUES]

A number of the issues addressed in this section either were not challenged by any party, or may have been challenged by a party, but SWEPCO agreed with the challenged party's position and agreed to the proposed adjustment. In those situations, where an issue was not contested, or where SWEPCO agreed to the opposing party's adjustment, the ALJs find that the unchallenged or agreed proposal is reasonable and should be approved by the Commission.

A. Additional Issues

1. Factoring Expense

SWEPCO agrees with Staff that the final approved return on equity should be included in the factoring rate calculation to synchronize factoring expense properly to the approved revenue requirement.[1664] SWEPCO notes that that a final "compliance" cost of service study that properly reflects the Commission's final decisions will be completed at the conclusion of this case. The ALJs agree that compliance cost of service study is intended to synchronize all impacts of the case, including factoring expense.[1665] The final approved return on equity should be included in the factoring rate calculation to synchronize factoring expense to the approved revenue requirement, and this will be accomplished through the compliance cost of service study.

2. Interest on Customer Deposits

SWEPCO does not contest Staff's adjustment to update the customer deposit interest amount to incorporate the Commission-approved 2021 interest rate.[1666] No other party addressed this issue. The ALJs agree that the customer deposit interest amount should incorporate the approved 2021 interest rate.

[1664] SWEPCO Ex. 36 (Baird Reb.) at 36.

[1665] SWEPCO Ex. 36 (Baird Reb.) at 5.

[1666] SWEPCO Ex. 36 (Baird Reb.) at 37.

3. Supplemental Employee Retirement Plan (SERP)

SWEPCO argues that SERP is not an extraordinary or discretionary benefit. Instead, this retirement plan provides the same benefits that general (or "qualified") pension plans do. The two differ only in when the IRS allows the tax deduction to be taken. Contributions for benefits under qualified pension plans, which had a specific compensation limit of $270,000 in 2017, are deducted in the current year. The pension benefits for the portion of an employee's salary that exceeds the compensation limit would be in the SERP and that deduction would occur when the employee receives the benefit.[1667] Nevertheless, SWEPCO has removed this SERP expense from its requested cost of service based on the Commission's precedents in Docket Nos. 40443 and 46449.[1668] Staff witness Stark, however, raised concerns with how SERP was removed from SWEPCO's requested cost of service.[1669] SWEPCO states that it does not contest Ms. Stark's recommended additional adjustment for SERP expenses.[1670]

4. Pension Expense

Staff originally challenged SWEPCO's use of the actual payroll capitalization rate in the cost of service. Staff, however, has since accepted SWEPCO's approach.[1671] This issue is no longer contested by any party.

5. Executive Perquisites

SWEPCO concedes that, given the Commission's decisions in Docket Nos. 40443 and 46449, it does not contest Staff's recommended adjustment for executive perquisites.[1672]

[1667] Docket No. 46449, PFD at 248 (Sep. 22, 2017).

[1668] SWEPCO Ex. 6 (Baird Dir.) at 26.

[1669] Staff Ex. 3 (Stark Dir.) at 10-12.

[1670] SWEPCO Ex. 36 (Baird Reb.) at 35.

[1671] Staff Initial Brief at 90-91 ("Ms. Stark concedes that the use of the actual test year capitalization ratio is more appropriate.")

[1672] SWEPCO Ex. 36 (Baird Reb.) at 36.

6. Potential Natural Gas Conversion of the Welsh Plant

SWEPCO addresses the Welsh Plant conversion issues in Sections II and X of its post-hearing briefs. In Section X of its briefs, SWEPCO summarizes Sierra Club witness Glick's request that the Commission not allow the recovery of future capital or fixed O&M associated with a conversion of the Welsh generating plant to operate on natural gas until SWEPCO has presented an analysis justifying such conversion. SWEPCO urges that Ms. Glick's recommendation is premature at this time.[1673]

This issue is addressed in full in Section V of this PFD, dealing with rate base items. The ALJs' recommendation on this issue is provided in Section V.

B. Construction Work in Progress [PO Issue 17]

SWEPCO has not included any Construction Work in Progress in its requested rate base.[1674]

C. Cash Working Capital [PO Issue 18]

SWEPCO's request regarding Cash Working Capital is uncontested. SWEPCO notes that, by using the last approved lead-lag study, as supported by Staff, SWEPCO anticipates savings of around $75,000 in rate-case expenses, which is the average cost of the last SWEPCO and AEP Texas lead-lag studies.[1675] SWEPCO agrees with Staff that the amount of Cash Working Capital should be synchronized with the Commission's final decision.[1676]

[1673] SWEPCO Ex. 33 (Brice Reb.) at 16-17.

[1674] SWEPCO Ex. 6 (Baird Dir.) at 6.

[1675] SWEPCO Ex. 6 (Baird Dir.) at 58-59.

[1676] SWEPCO Ex. 36 (Baird Reb.) at 28.

D. Administrative and General O&M Expenses [PO Issue 25]

SWEPCO notes that it inadvertently included $46,306 in its requested regulatory commission expenses that should have been removed.[1677] Staff witness Stark's adjustment of ($46,306) excludes this amount from SWEPCO's requested revenue requirement.[1678] SWEPCO agrees with this adjustment.[1679] No other party raised any issue with respect to the Company's administrative and general expenses.

E. Tax Savings From Liberalized Depreciation [PO Issue 34]

As explained and supported by Company witness Hodgson, SWEPCO's federal income taxes were calculated consistent with PURA § 36.059, the provisions addressing treatment of tax savings derived from liberalized depreciation and amortization, the investment tax credit, or similar methods.[1680] No party challenged this issue or SWEPCO's federal income tax calculation or methodology.

F. Advertising Expense [PO Issue 35]

No party challenged SWEPCO's proposed advertising expense.[1681]

G. Competitive Affiliates [PO Issue 43]

SWEPCO has competitive affiliates but states that it did not include any competitive affiliate charges in its rate request in this proceeding.[1682] No party raised an issue with respect to competitive affiliate charges.

[1677] Staff Ex. 3 (Stark Dir.), Attachment RS-18.

[1678] Staff Ex. 3 (Stark Dir.) at 15.

[1679] SWEPCO Ex. 36 (Baird Reb.) at 36.

[1680] SWEPCO Ex. 17 (Hodgson Dir.) at 3, 20.

[1681] SWEPCO Ex. 6 (Baird Dir.) at 9, 30, 62; *see also* SWEPCO Ex. 1 (Application) at Schedules G-4, G-4.1-G-4.1c, G-4.1d, G-4.2-4.2c, and G-4.3-4.3e.

[1682] SWEPCO Initial Brief at 126.

H. Deferred Costs [PO Issues 50, 51]

SWEPCO is not seeking to include in rates any costs previously deferred by an order of the Commission.

As to costs SWEPCO seeks to defer from this case to a future case, as discussed in Section VII of this PFD, the ALJs recommend that the Commission reject SWEPCO's proposal that the portion of its ongoing net SPP OATT bill that is above or below the net test year level be deferred into a regulatory asset or liability, which would then be addressed in a future TCRF or base-rate proceeding. As to RCEs, discussed in Section XII above, SWEPCO agrees Staff's recommendation that the Commission authorize SWEPCO to establish a regulatory asset to record both SWEPCO's and CARD's trailing expenses from this proceeding to be recovered in the future.[1683] As recommended in Section XII, the ALJs agree with this proposal to address trailing RCEs in a future proceeding.

I. Proposed Time-of-Use Rate Pilot Projects [PO Issues 80, 81, 82, 83, 84, 85]

SWEPCO witnesses Smoak and Jackson support SWEPCO's proposal to offer Texas customers a time-of-use rate.[1684] Specifically, SWEPCO proposes an optional Residential Time-of-Use rate schedule as a pilot available to residential customers and a Commercial Time-of-Use rate schedule for commercial loads of 100 kW or greater.[1685] The pilots will gauge interest and utilization of the time-of-use format by customers that do not qualify for SWEPCO's Off Peak Rider for LP, LLP, and Metal Melting Service.[1686] Under the offerings, participating

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[1683] Staff Initial Brief at 87.

[1684] *See* SWEPCO Ex. 3 (Smoak Dir.) at 9-10; SWEPCO Ex. 32 (Jackson Dir.) at 28-30, Exhs. JLJ-4 and JLJ-5.

[1685] SWEPCO Ex. 3 (Smoak Dir.) at 9; SWEPCO Ex. 32 (Jackson Dir.) at 28-29 (describing the proposed optional residential time of use offering) and 29-30 (describing the commercial time-of-use offering).

[1686] SWEPCO Ex. 3 (Smoak Dir.) at 9-10.

customers can more precisely manage their energy costs by shifting energy consumption to off-peak periods.[1687] No party addressed or challenged this proposal.

J. Experimental Economic Development Rider

SWEPCO witnesses Smoak and Jackson support SWEPCO's proposal to update its economic development rider.[1688] SWEPCO states that these update is intended to spur economic growth in its Texas service territory, providing long-term benefits to SWEPCO's customers.[1689] The proposed tariff revisions offer two options to attract loads from a variety of businesses with different load requirements.[1690] No party addressed or challenged these proposals.

K. Any Exceptions Requested to PUC Rules [PO Issue 64]

As addressed in Section II.A.1 of this PFD, the Commission's 16 TAC § 25.231 requires that an asset in rate base be depreciated over its service life. After the excess ADFIT offset to the remaining undepreciated value of Dolet Hills, SWEPCO proposes an additional mitigation measure to expense the remaining value of SWEPCO's investment in Dolet Hills over four years, the anticipated period between rate cases.[1691]

The ALJs recommend that the Commission reject SWEPCO's proposed treatment for Dolet Hills after it is retired on December 31, 2021. If the Commission agrees with the ALJs, SWEPCO's request for an exception to 16 TAC § 25.231 is, therefore, moot.

[1687] SWEPCO Ex. 3 (Smoak Dir.) at 10; SWEPCO Ex. 32 (Jackson Dir.) at 29.

[1688] *See* SWEPCO Ex. 3 (Smoak Dir.) at 11-12; SWEPCO Ex. 32 (Jackson Dir.) at 26; SWEPCO Ex. 1 (Application) at Schedule Q-8.8, Sheet IV-17.

[1689] SWEPCO Ex. 3 (Smoak Dir.) at 11.

[1690] SWEPCO Ex. 32 (Jackson Dir.) at 26.

[1691] SWEPCO Ex. 6 (Baird Dir.) at 49.

L. Any Requests for Waivers [PO Issue 65]

SWEPCO has provided all of the schedules and workpapers required by the Commission's RFP for Generating Utilities.[1692] However, SWEPCO requests a waiver of the portions of the RFP that request information related to fuel reconciliation proceedings.[1693] SWEPCO did not file a fuel reconciliation request in this docket; therefore, the schedules dealing with fuel reconciliation proceedings are not applicable.[1694] Schedule V of SWEPCO's RFP details the specific schedules that are not required in this proceeding related to fuel reconciliation, as well as certain other waivers requested by SWEPCO.[1695] SWEPCO's requested waivers are uncontested.

SWEPCO also requested and was granted a waiver of the requirement to file Schedule S (Independent Audit of the Application) in Docket No. 50917.[1696] Commission Staff states in its initial brief that it supports this waiver.[1697] No other party addressed this Schedule S issue in evidence or post-hearing briefs.

The ALJs agree with both waiver requests and recommend that the Commission approve the Company's requests that it not be required to file fuel reconciliation schedules. The Commission has already granted SWEPCO's request for waiver of the RFP requirement to file a Schedule S in this docket

M. Compliance with Docket No. 46449 [PO Issue 66]

Ordering Paragraph 10 of the Order on Rehearing in Docket No. 46449, SWEPCO's last base-rate case, states, "[t]he regulatory treatment of any excess deferred taxes resulting from the

[1692] SWEPCO Ex. 4 (Brice Dir.) at 5.

[1693] SWEPCO Ex. 4 (Brice Dir.) at 5.

[1694] SWEPCO Ex. 4 (Brice Dir.) at 5.

[1695] SWEPCO Ex. 1 (Application) at Schedule V.

[1696] SWEPCO Ex. 4 (Brice Dir.) at 5; *Application of Southwestern Electric Power Company for Waiver of Rate Filing Package Schedule S*, Docket No. 50917, Order at 1 (Dec. 17, 2020).

[1697] Staff Initial Brief at 92.

reduction in the federal-income-tax rate will be addressed in SWEPCO's next base-rate case." SWEPCO's compliance with this requirement is addressed in the direct testimonies of SWEPCO witnesses Brice and Baird.[1698] Although the ALJs do not recommend SWEPCO's proposals with regard to excess deferred taxes, and instead propose a different treatment, the regulatory treatment of excess deferred taxes is addressed in this PFD.

XIV. CONCLUSION

The ALJs recommend that the Commission implement their recommendations and findings set forth in the discussion above by adopting the following proposed findings of fact and conclusions of law in the Commission's final order.

XV. FINDINGS OF FACT, CONCLUSIONS OF LAW, AND PROPOSED ORDERING PARAGRAPHS

A. Findings of Fact

Procedural History

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

2. SWEPCO serves approximately 187,400 Texas retail customers, all of whom are affected by SWEPCO's application to change rates.

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

4. On October 14, 2020, SWEPCO filed its Petition and Statement of Intent requesting that the Public Utility Commission of Texas (Commission) authorize SWEPCO to increase its Texas retail base rate revenue by $90,199,736, which is an increase of 26.03% over its adjusted Texas retail test year base rate revenues exclusive of fuel and rider revenues. The overall impact of the proposed revenue requirement increase, considering both fuel and non-fuel revenues, is a 15.57% increase.

5. SWEPCO employed the 12-month period ending March 31, 2020, as its historical test year.

[1698] SWEPCO Ex. 4 (Brice Dir.) at 7-8; *see also* SWEPCO Ex. 6 (Baird Dir.) at 23, 48-49.

6. SWEPCO's proposed rate increase reflects incremental investment in generation since its last test year and incremental investment in transmission and distribution since SWEPCO last modified its Transmission Cost Recovery Factor (TCRF) and Distribution Cost Recovery Factor (DCRF).

7. SWEPCO proposes revisions to many of its rate schedules and riders, and requests that the Commission set SWEPCO's TCRF and DCRF to zero, and establish the baseline values consisting of the inputs to the calculations that will be used to calculate SWEPCO's TCRF and DCRF in future proceedings.

8. Additionally, SWEPCO has announced the early retirement of its Dolet Hills Power Plant (Dolet Hills) as of December 31, 2021. As a result, SWEPCO proposes rate treatments to address this early retirement.

9. SWEPCO requests an increase of $5 million over test year costs to expand its distribution vegetation management program.

10. SWEPCO also requests that the Commission approve certain policy-oriented proposals, including the establishment of a self-insurance reserve, deferred recovery of Hurricane Laura restoration cost, and certain charges billed to SWEPCO by the Southwest Power Pool (SPP).

11. SWEPCO provided notice of its application by publication for four consecutive weeks in newspapers having general circulation in each county of SWEPCO's Texas service territory. Individual notice of its proposed rate change was provided to all of its retail customers by bill inserts and direct mailing. SWEPCO timely served notice of its statement of intent to change rates on all municipalities retaining original jurisdiction over its rates and services. Additionally, SWEPCO electronically provided notice to the Staff of the Public Commission of Texas (Staff), the Office of Public Utility Counsel (OPUC), and legal representatives of all parties to SWEPCO's most recent base case, Docket No 46449.

12. The following intervening parties participated in this docket: OPUC; Cities Advocating Reasonable Deregulation (CARD); Eastman Chemical Company (Eastman); Texas Industrial Energy Consumers (TIEC); Nucor Steel-Longview; Texas Cotton Ginners Association; Northeast Texas Electric Cooperative, Inc. (NTEC) and East Texas Electric Cooperative, Inc.; Sierra Club and Dr. Lawrence Brough (Sierra Club); East Texas Salt Water Disposal Company and East Texas Oil and Gas Producers (ETSWD); and Walmart Inc.. Staff also participated in this docket.

13. On October 30, 2020, the Commission referred this case to the State Office of Administrative Hearings (SOAH).

14. On November 19, 2020, SWEPCO filed an Agreed Motion to Adopt Procedural Schedule in which it agreed to extend the statutory deadline to October 27, 2021.

15. On December 17, 2020, the Commission issued its Preliminary Order identifying the issues to be addressed in this proceeding.

16. On November 23, 2020, SOAH Order No. 2 was issued, setting the hearing on the merits for May 19-28, 2021.

17. Collectively, the Commission's Preliminary Order and SOAH Order No. 2 include a statement of the time, place, and nature of the hearing; a statement of the legal authority and jurisdiction under which the hearing is to be held; a reference to the particular sections of the statutes and rules involved; and either a short, plain statement of the factual matters asserted, or an attachment that incorporates the reference by factual matters asserted in the complaint or petition filed with the state agency.

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

19. The hearing on the merits commenced before four SOAH Administrative Law Judges (ALJs) on May 19, 2021, and concluded on May 26, 2021.

20. The parties submitted initial post-hearing briefs on June 17, 2021, and reply briefs on July 1, 2021. Proposed Findings of Fact, Conclusions of Law, and Ordering Paragraphs were filed July 1, 2017, and the record closed on that date.

21. In accordance with Order No. 13, SWEPCO and CARD filed final rate case expense (RCE) reports on July 6, 2021.

22. On July 20, 2021, Staff filed its Final Supplemental Direct Testimony regarding rate case expenses.

23. On July 27, 2021, SWEPCO filed its Final Supplemental Rebuttal Testimony on RCEs, and CARD filed a Statement of Position on its final requested RCEs.

24. The ALJs issued a Proposal for Decision in this docket on August 27, 2021.

Rate Base/Invested Capital

Generation, Transmission, and Distribution Capital Investment

25. 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.

26. SWEPCO has incurred a total amount of $143.5 million of distribution capital investment placed in service during the period July 1, 2016, through March 31, 2020.

27. No party contested SWEPCO's transmission or distribution investment. The entirety of the transmission and distribution investment is used and useful in providing service to the public and is reasonable and necessary.

New Generation Capital Investment

28. SWEPCO regularly reviews capital projects that could provide economic, environmental, reliability, or safety-related benefits to 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.

29. The Commission's Electric Utility Rate Filing Package for Generating Utilities (RFP) Schedule H-5.2b provides a list of every capital project with a value of greater than $100,000 placed in service since the close of the previous rate case test year through the end of the test year in this case. This schedule provides a description of the reason for the capital investment, including: (1) Immediate Personnel Safety Requirement, (2) Regulatory Safety of Operations Requirement, (3) Regulatory Commitment (not classified in (2)), (4) Plant Efficiency Improvement, (5) New Building, (6) Productivity Improvement, (7) Reliability, (8) Economic, (9) Habitability, and (10) Other. The schedule also indicates whether a cost-benefit analysis was done for the project, which was done for a large majority of the projects.

30. SWEPCO uses multiple processes to ensure its generation operations and maintenance (O&M) expenses are reasonable. These include the use of budget controls, the review of cost trends, and tracking of staffing levels at its power plants.

31. RFP Schedule H-1.2 provides a description of the operations and maintenance (O&M) expenses incurred by FERC Account, by plant, for each month of the test year. RFP Schedule H-3 provides historical SWEPCO generation O&M expenses, by FERC Account, by year since 2015. RFP Schedule H-4 provides the major O&M projects undertaken during the test year by plant.

32. Except for Sierra Club's challenges to the test-year capital and O&M spending at the Flint Creek, Welsh, and Dolet Hills plants, no party contested the prudence of SWEPCO's generation capital investments since the end of the Docket No. 46449 test year, nor the reasonableness of the test-year O&M expenses.

33. The legally competent, credible evidence presented in this case does not show that SWEPCO's capital investment at Flint Creek, Welsh, and Dolet Hills was imprudent, or that the O&M expenses were unreasonable or unnecessary.

34. SWEPCO's capital investment placed in service since the end of the Docket No. 46449 test year, including the test year capital spending at the Flint Creek, Welsh, and Dolet Hills plants, is prudent.

35. SWEPCO's O&M expenses incurred at its generating plants during the test year, including Flint Creek, Welsh, and Dolet Hills, are a reasonable and necessary component of SWEPCO's cost of service.

Retired Gas-Fired Generating Units

36. 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.

37. In deciding to retire these 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. The prudence of those retirement decisions was unchallenged.

38. SWEPCO accounted for these retirements in accordance with the FERC Uniform System of Accounts (USofA), which requires that the book cost of the unit retired be credited to electric plant and the same book cost be charged to the accumulated provision for depreciation applicable to that property.

39. SWEPCO used that method to account for the retirement of Lieberman Unit 1 in Docket No. 46449, although this was uncontested and thus not specifically addressed by the Commission in that docket.

40. Although 16 Tex. Admin. Code (TAC) § 25.72(c) requires SWEPCO to maintain its books and records according to the FERC Uniform System of Accounts USofA, this prescribed accounting treatment does not necessarily control the treatment of the assets for ratemaking purposes.

41. In Docket No. 46449, the Commission determined that: (1) because Welsh Unit 2 was retired and no longer generating electricity, it was not used by and useful to SWEPCO in providing electric service to the public; (2) because Welsh Unit 2 was no longer used and useful, SWEPCO could not include its investments associated with the plant in its rate base and earn a return on that remaining investment; (3) allowing SWEPCO a return of, but not on, its remaining investment in Welsh Unit 2 properly balances the interests of customers and shareholders with respect to a plant that no longer provides service; and (4) the appropriate accounting treatment that results in the appropriate ratemaking treatment was to record the undepreciated balance of Welsh Unit 2 in a regulatory-asset account rather than leaving it in Accumulated Depreciation.

42. Consistent with the Commission's rate treatment of the retired Welsh Unit 2 in Docket No. 46449, the net book values of the retired Lieberman Unit 2, Lone Star Unit 1, and Knox Lee Units 2, 3, and 4 should be removed from rate base, so as to cease earning a return, and be placed in a regulatory asset.

43. The regulatory asset should be amortized over the four-year period in which the rates approved in this case are expected to be in effect.

<u>Dolet Hills</u>

44. Dolet Hills is a lignite-fueled generating unit located southeast of Mansfield, Lousiana, and jointly owned by SWEPCO; Cleco Power, LLC (CLECO); NTEC; and Oklahoma Municipal Power Authority. CLECO is the majority owner and operator of Dolet Hills.

45. Dolet Hills went into commercial operation in 1986, and its previously established useful life extends until 2046.

46. Dolet Hills is fueled by lignite mined in the same area by Dolet Hills Lignite Company (DHLC), a SWEPCO subsidiary. An equity return on DHLC and associated taxes is currently included in SWEPCO's rate base.

47. An investment in the Oxbow Mine reserves is also included in SWEPCO's rate base.

48. In early 2020, SWEPCO and CLECO determined that all economically recoverable lignite at the Dolet Hills associated mines had been depleted, that mining operations should cease, and that Dolet Hills should be retired by the end of 2021.

49. In deciding whether to retire Dolet Hills, SWEPCO evaluated mining operations and the costs of operating the plant beyond 2021. SWEPCO studied the expected total SWEPCO system cost to serve customers, comparing the scenario where Dolet Hills continues to serve customers through 2046 versus through a December 31, 2021 retirement. The study determined that the expected least-cost path for SWEPCO and its customers lay in retiring the plant.

50. No party contested the prudence of SWEPCO's decision to retire Dolet Hills at the end of 2021. The decision was prudent.

51. Dolet Hills will be retired on December 31, 2021, and will continue providing service until that time. SWEPCO plans to continue operating the plant on a seasonal basis, principally during the peak summer months, as it has done in recent years. However, the plant remains available in case called upon by SWEPCO or CLECO's respective regional transmission organizations for reliability reasons.

52. Until its retirement, output from Dolet Hills 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.

53. Although mining operations ceased in May 2020, SWEPCO's investment in the Oxbow reserves will continue to provide service until Dolet Hills' retirement, as the plant will continue to burn previously mined lignite to generate electricity.

54. Similarly, DHLC will continue to exist and deliver lignite to Dolet Hills, and SWEPCO will continue incurring this non-eligible fuel expense through the plant's retirement.

55. In this case, the rate year began on the relate-back date, March 18, 2021.

56. Dolet Hills, SWEPCO's Oxbow investment, and DHLC have provided service to customers during the rate year.

57. Good cause exists to make post-test-year reductions to SWEPCO's rate base to reflect, consistent with the Commission's rate treatment of Welsh Unit 2 in Docket No. 46449, that Dolet Hills, the Oxbow investment, and DHLC will cease to provide service to SWEPCO's customers when the plant retires on December 31, 2021.

58. It is appropriate to remove all cost recovery for Dolet Hills, the Oxbow investment, and DHLC from base rates and address these issues instead in a Dolet Hills Rate Rider.

59. Through the Dolet Hills Rate Rider, SWEPCO should be permitted, with respect to the period between March 18, 2021 (the date when the rates are effective) and December 31, 2021 (the date of Dolet Hills' retirement) (the Operative-Plant Phase of the Dolet Hills Rate Rider), to recover the costs ordinarily permitted for an operating generating plant, including a return on the plant's net book value, depreciation, and O&M. SWEPCO should similarly be permitted to continue earning a return on the Oxbow investment and the return on equity (ROE) and associated taxes for DHLC.

60. With respect to the period after December 31, 2021 (the Post-Retirement Phase of the Dolet Hills Rate Rider), the remaining net book values of Dolet Hills and of the Oxbow investment should be placed in a regulatory asset to be amortized without a return. All other cost recovery for Dolet Hills, the Oxbow investment, or DHLC should cease, as the assets will no longer be providing service.

61. SWEPCO's recovery of Dolet Hills' remaining net book value (whether through depreciation during the Operative-Plant Phase or recovery from the regulatory asset during the Post-Retirement Phase) should be amortized in accord with the asset's useful life ending in 2046.

62. SWEPCO's recovery of its Oxbow investment following the Dolet Hills retirement should be amortized according to the same schedule as with the Dolet Hills plant.

63. Amortizing these assets in accord with Dolet Hills' useful life ending in 2046 equitably balances the interests of SWEPCO and both its current and future customers.

64. It would be inequitable to SWEPCO's current customers to accelerate SWEPCO's recovery of these assets, as SWEPCO proposes to do, through offsetting the excess

Accumulated Deferred Federal Income Taxes (ADFIT) SWEPCO owes to its current customers and/or amortizing the balance over only four years.

65. SWEPCO's calculation and use of estimated demolition costs for Dolet Hills is reasonable.

Coal and Lignite Inventories

66. 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 kilowatt-hour (kWh) of electricity, within the constraints of safety, reliability of supply, unit design, and environmental requirements.

67. 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.

68. Setting inventory levels for SWEPCO's coal power plants (Welsh, Flint Creek, and Turk) and lignite power plants (Pirkey and Dolet Hills) based on the average level of burn from the test year would negatively impact SWEPCO's ability to reliably serve the needs of its customers and SPP and expose SWEPCO's customers to reliability risk.

69. Setting coal and lignite inventory targets for SWEPCO's coal and lignite power plants based on full-load burn ensures that adequate inventory is available to provide the necessary reliability for SWEPCO customers and SPP.

70. The target coal and lignite inventory levels SWEPCO requests to include in rate base are reasonable and necessary to ensure adequately reliable service to its customers.

71. However, because Dolet Hills will be retired on December 31, 2021, and consistent with the findings regarding the appropriate rate treatment of SWEPCO's investments in that plant, the Oxbow reserves, and DHLC, SWEPCO's lignite inventory for Dolet Hills should be removed from rate base and placed in the Dolet Hills Rate Rider; SWEPCO should recover a return on that inventory only during the Operative-Plant Phase, and have no cost recovery for the inventory during the Post-Retirement Phase.

72. Good cause exists to make these post-test year adjustments regarding SWEPCO's lignite inventory for Dolet Hills.

Prepaid Pension and OPEB Assets

73. SWEPCO records an additional cash investment in the pension trust fund as a prepaid pension asset in accordance with Generally Accepted Accounting Principles (GAAP) under Accounting Standards Codification 715-30. The prepaid pension asset is the cumulative additional pension cash contributions beyond the amount of pension cost.

74. No party has contested, and the evidence establishes, that an additional cash investment recorded as a prepaid pension asset should be included in rate base in accordance under § 36.065 of the Public Utility Regulatory Act, Tex. Util. Code §§ 11.001-64.158 (PURA).

NOLC ADFIT

75. SWEPCO records its stand-alone federal income tax net operating loss carry-forward (NOLC) ADFIT on its books and records consistent with GAAP and the USofA.

76. For the period 2009 through the March 20, 2020 test year end, SWEPCO recorded a total net amount of stand-alone tax NOLC ADFIT of $455,122,490.

77. SWEPCO does not file a separate federal income tax return, as it is a subsidiary of AEP and included in AEP's consolidated federal income tax return.

78. SWEPCO participates in the AEP Tax Allocation Agreement for allocating the consolidated income taxes for AEP and its consolidated affiliates.

79. Under the AEP Tax Allocation Agreement, through the March 20, 2020 test year end, SWEPCO received net cash payments of $455,122,490 for the use of its tax net operating losses to offset the taxable income of its affiliates on the AEP consolidated income tax return.

80. SWEPCO reflected its receipt of these tax allocation payments in its financial books and records by reducing the balance of its NOLC ADFIT to $0.

81. SWEPCO used the tax allocation payments to finance plant assets now in its rate base. In essence, SWEPCO exchanged its previously recorded NOLC ADFIT asset (an asset that would reduce ADFIT and therefore increase rate base) for plant assets now included in rate base.

82. Under these circumstances, SWEPCO's proposed adjustment to recognize the $455,122,490 NOLC ADFIT again would effectively double the proper rate base impact of the NOLC ADFIT, contrary to normalization requirements.

83. Staff's recommendation instead to reflect SWEPCO's book NOLC ADFIT balance of $0 is consistent with PURA § 36.060, prevents SWEPCO from earning a return on the same $455,122,490 twice, and is consistent with normalization principles.

Excess ADFIT

84. The Tax Cuts and Jobs Act of 2017 reduced the corporate federal income tax rate from 35% to 21% effective January 1, 2018. This reduction, and the associated revaluation of the ADFIT balances previously recorded at 35% decreased due to the new 21% tax rate, results in excess ADFIT balances that should be returned to SWEPCO's customers.

85. The Commission determined in Docket No. 46449 that the regulatory treatment of excess deferred taxes resulting from the reduction in the federal tax rate would be addressed in SWEPCO's next base rate case. This proceeding is SWEPCO's next base rate base after Docket No. 46449.

86. In determining the amount of excess ADFIT available to its Texas customers, it is reasonable for SWEPCO to use the Texas retail allocation factor of 35.01% approved in Docket No. 46449.

87. Excess ADFIT related to differences in method and life for calculating depreciation expense for book versus tax purposes is considered to be "protected" excess ADFIT that cannot be returned to customers more rapidly than over the remaining lives of the assets that gave rise to the deferred taxes. All other excess ADFIT is considered to be unprotected, meaning there are no limitations on the timing or manner of returning it to customers.

88. SWEPCO began amortizing the protected excess ADFIT on January 1, 2018, by recording a provision for refund on its books as a regulatory liability related to the Texas jurisdictional portion of the excess ADFIT amortization.

89. SWEPCO should refund the balance of excess ADFIT available to return to customers (both unprotected ADFIT and accrued protected ADFIT) by first crediting the balance against any amount owed by customers because of the March 18, 2021 relate-back date in this proceeding, then refunding any excess ADFIT balance remaining over a six-month period, with carrying charges at the Commission-allowed weighted average cost of capital.

90. The remaining balance of protected excess ADFIT should be returned to customers as an amortization included in rates, in a manner consistent with normalization requirements.

Accumulated Depreciation

91. SWEPCO's calculation of accumulated depreciation was not contested and is reasonable.

92. SWEPCO's adjustments to accumulated depreciation were not contested, are reasonable, and should be adopted.

Self-Insurance Reserve

93. SWEPCO requests approval of a self-insurance reserve pursuant to PURA § 36.064 and 16 TAC § 25.231(b)(1)(G).

94. SWEPCO's proposed self-insurance reserve would be funded by an annual accrual of $1,689,700, consisting of $799,700 to account for annual expected O&M losses from storm damage in excess of $500,000, plus $890,000 to build a target reserve of $3,560,000 in four years.

95. SWEPCO further proposes to charge its Texas jurisdictional Hurricane Laura restoration costs against the self-insurance reserve.

96. SWEPCO did not present a cost-benefit analysis demonstrating that, with consideration of all costs, self-insurance is a lower-cost alternative than commercial insurance and that customers will receive the benefits of the self-insurance plan.

Rate of Return

97. An ROE of 9.45% will allow SWEPCO a reasonable opportunity to earn a reasonable return on its invested capital.

98. A 9.45% ROE is consistent with SWEPCO's business and regulatory risk.

99. SWEPCO did not demonstrate that either a size or credit risk adjustment was appropriate in setting its ROE.

100. A downward adjustment to the ROE is not warranted for the August 18, 2019 outage on SWEPCO's transmission system, which was caused by vegetation contact with a SWEPCO transmission line. The evidence does not show the outage was due to negligent vegetation management practices, or indicative of overall poor quality of service or management.

101. A downward adjustment to the ROE is not warranted for SWEPCO's worsening System Average Interruption Duration Index and System Average Interruption Frequency Index scores. These changing metrics can result from many factors, including weather. The evidence does not show these metrics were indicative of overall poor quality of service or management.

102. SWEPCO's proposed 4.18% cost of debt is reasonable.

103. A capital structure composed of 50.63% long-term debt and 49.37% equity is reasonable in light of SWEPCO's business and regulatory risks.

104. A capital structure composed of 50.63% long-term debt and 49.37% equity will be sufficient to attract capital from investors.

105. SWEPCO's overall rate of return should be as follows:

COMPONENT	CAPITAL STRUCTURE	COST OF CAPITAL	WEIGHTED AVERAGE COST OF CAPITAL
LONG-TERM DEBT	50.63%	4.18%	2.12%
COMMON EQUITY	49.37%	9.45%	4.67%
TOTAL	100.00%		6.79%

Financial Integrity (Ring-Fencing Protections)

106. AEP is a large corporation with several subsidiaries in multiple states, including both regulated and non-regulated entities. The effects of financial instability or weakness in one of these entities could affect not only AEP as the parent company, but also its subsidiaries, including SWEPCO.

107. Ring-fencing measures have been used to protect utilities from risky parents or other affiliates to protect the utility's financial integrity and to ensure the utility can continue to operate and serve its customers.

108. Ordering the following financial protections is reasonable and necessary to protect SWEPCO's financial integrity and to ensure SWEPCO's ability to provide reliable service at just and reasonable rates:

a. SWEPCO will work to ensure that its credit ratings at Standard and Poor's (S&P) and Moody's remain at or above SWEPCO's current credit ratings.

b. SWEPCO will notify the Commission if its credit issuer rating or corporate rating as rated by either S&P or Moody's falls below investment-grade level.

c. SWEPCO will take the actions necessary to ensure the existence of a SWEPCO stand-alone credit rating.

d. SWEPCO will not share a credit facility with any unregulated affiliates.

e. SWEPCO's debt will not be secured by non-SWEPCO assets.

f. SWEPCO's assets will not secure the debt of AEP or its non-SWEPCO affiliates. SWEPCO's assets will not be pledged for any other entity.

g. SWEPCO will not hold out its credit as being available to pay the debt of any AEP affiliates.

h. Except for access to the utility money pool and the use of shared assets governed by the Commission's affiliate rules, SWEPCO will not commingle its assets with those of other AEP affiliates.

i. SWEPCO will not transfer any material assets or facilities to any affiliates, other than a transfer that is on an arm's-length basis in accordance with the Commission's affiliate standards applicable to SWEPCO, regardless of whether such affiliate standards would apply to the particular transaction.

j. Without prior approval of the Commission, neither AEP nor any affiliate of AEP (excluding SWEPCO) will incur, guaranty, or pledge assets in respect of any incremental new debt that is dependent on: (1) the revenues of SWEPCO in more than a proportionate degree than the other revenues of AEP; or (2) the stock of SWEPCO.

k. SWEPCO will not seek to recover from customers any costs incurred as a result of a bankruptcy of AEP or any of its affiliates.

109. These financial protections are similar to those agreed to by SWEPCO affiliate AEP Texas in Docket No. 49494, which were approved by the Commission. SWEPCO already abides by most of the ring-fencing measures approved for AEP Texas and confirmed that SWEPCO is amenable to similar measures.

110. The evidence shows substantial benefit, and does not show a significant cost or harm, to ordering SWEPCO to employ the financial protections listed above.

Transmission O&M Expense

111. SWEPCO's test year transmission O&M expenses were $46,683,319, of which $8,636,052 were affiliate expenses.

112. SWEPCO's transmission O&M expenses were not contested by any party and are reasonable.

Transmission Expenses and Revenues under FERC-Approved Tariff

113. 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.

Proposed Deferral of SPP Wholesale Transmission Costs

114. SWEPCO proposes to defer the portion of its approved transmission charges (ATC) that is above or below the test year level into a regulatory asset or liability for recovery in a future TCRF or rate case proceeding.

115. SWEPCO has not shown that the proposed recovery mechanism is needed here.

116. SWEPCO has not demonstrated that the ATC tracker is necessary for it to have a reasonable opportunity to earn a reasonable return above its necessary expenses.

Distribution O&M Expense

117. SWEPCO's adjusted test year distribution O&M expenses including its own costs plus the charges from its service company affiliate, AEP Service Company (AEPSC), for distribution activities necessary to provide safe, reliable distribution services were $93,656,735.

118. The adjusted test year distribution O&M 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.

119. SWEPCO's distribution O&M expenses are reasonable and necessary.

Distribution Vegetation Management

120. SWEPCO's proposal to recover distribution O&M base-rate expenses of $14.57 million, consisting of the test year amount of $9.57 million and an additional amount of $5 million, is reasonable.

121. The additional amount of distribution O&M expense in the amount of $5 million is reasonable and necessary to carry forward SWEPCO's vegetation management program to improve overall reliability on targeted circuits and decrease outages caused by trees.

122. SWEPCO commits to spending the entirety of the increased amount of $5 million for distribution O&M expense solely on vegetation management.

123. A compliance docket should be opened regarding SWEPCO's system reliability, vegetation management, and vegetation management expense.

Generation O&M Expense

124. SWEPCO's proposed rate increase does not adjust the test year (O&M) expense for Dolet Hills to reflect the scheduled retirement of the plant by the end of 2021.

125. During the test year, SWEPCO incurred approximately $12.5 million in non-fuel O&M expense related to its 257 megawatts (MW) (40.28%) ownership share of Dolet Hills.

126. For Dolet Hills, SWEPCO's test year average monthly O&M expense level is approximately $1.04 million per month.

127. After SWEPCO retires Dolet Hills at the end of 2021, SWEPCO will avoid significant non-fuel O&M expenses for operations at Dolet Hills.

128. The reduced utilization and ultimate retirement of Dolet Hills will result in known and measurable changes in the cost to maintain and operate the plant.

129. SWEPCO should recover O&M expense associated with the operation of Dolet Hills from March 18, 2021 (the relate-back date of rates in this proceeding) through December 31, 2021, at a monthly O&M expense level of $1.04 million per month.

130. SWEPCO should not recover O&M expense for Dolet Hills past its retirement in December 2021.

<u>Payroll Expenses</u>

131. 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 (March 2020) plus post-test year pay increases of 3.0% for merit-eligible employees and 2.5% for hourly physical and craft employees, which were implemented in April 2020 and September 2020, respectively.

132. In June and July of 2020, retirement incentive packages were offered to certain SWEPCO and AEPSC employees. One SWEPCO employee and 189 AEPSC employees accepted the retirement incentive package.

133. Staff proposes an adjustment of $544,331 in addition to SWEPCO's requested payroll adjustment based on a more recent time period, October 31, 2020, that was after the retirement incentives were offered.

134. It is appropriate to annualize SWEPCO's base payroll as of October 31, 2020, increasing SWEPCO's base payroll by $544,300 on a total company basis and $199,282 on a Texas retail jurisdiction basis, inclusive of the pay raise actually given by SWEPCO to its employees.

135. SWEPCO requests an increase of $3,804,876 to the test-year payroll expense allocated from AEPSC, based on an annualization of the end of test year headcount and inclusion of a merit increase.

136. Staff proposes an adjustment of ($4,480,512) to the allocated AEPSC payroll, also based on annualization of the October 2020 AEPSC payroll that was after the retirement incentives were offered.

137. The impact of the retirements is reflected in Staff's adjustment of $544,331 to SWEPCO's payroll and an adjustment of ($4,480,512) to SWEPCO's requested AEPSC allocated payroll.

138. SWEPCO failed to show it intended to replace the retired employees or that its employee headcount would recover or vary minimally from the test year. Rather, a material number of employees accepted the retirement package.

139. The retirement package and revised employee headcount is a material known and measurable change that merits an adjustment to payroll.

140. It is appropriate to annualize the base payroll for AEPSC payroll expense as of October 31, 2020, resulting in a decrease to the Company's proposed base rates of $4,480,512 on a total company basis and $1,686,106 on a Texas retail jurisdiction basis.

Short-Term Incentive Compensation

141. SWEPCO's Application excluded financial-based short-term incentive compensation (STI) expense and 50% of the financial-based funding mechanism related to its STI plans.

142. SWEPCO's request to recover STI expense should be adjusted to correct errors in accordance with the testimony of Staff witness Ruth Stark, which SWEPCO does not oppose.

143. SWEPCO's requested STI expense, adjusted in accordance with the testimony of Commission Staff witness Ruth Stark, is approved.

Long-Term Incentive Compensation

144. SWEPCO adjusted its test year long-term incentive compensation (LTI) expenses to remove the 75% of those expenses related to performance units but retained the 25% related to restricted stock units.

145. Restricted stock units are not based on financial measures and are appropriate to include in SWEPCO's rates.

146. SWEPCO's requested LTI expense is approved.

Severance Costs

147. In calendar years 2017 and 2018, SWEPCO incurred $0 in direct severance costs. During the test year, SWEPCO incurred $767,074 in direct severance costs.

148. SWEPCO's $767,074 in direct severance costs during the test year is atypical and does not represent normal levels of direct severance costs.

149. It is appropriate to average three years of direct severance costs to calculate SWEPCO's direct allowable severance costs, which equates to $252,033.

150. AEPSC allocates severance costs to SWEPCO. During the test year relative to calendar year 2017 and 2018, AEPSC charged severance costs to SWEPCO that increased from less than $550,000 for the two years prior to $1,460,876 during the test year.

151. SWEPCO's $1,460,876 in allocated severance costs during the test year is atypical and does not represent normal levels of allocated severance costs.

152. It is appropriate to average three years of allocated severance costs to calculate SWEPCO's allowable allocated severance costs, which equates to $824,300.

<u>Pension Expense</u>

153. SWEPCO's 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 to these 2020 costs to determine the pro forma level of expense to include in the cost of service. SWEPCO's requested cost of service pension expense is reasonable.

<u>Other Post Retirement Benefits Expense</u>

154. SWEPCO's requested Other Post-Employment Benefits (OPEB) 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. SWEPCO's requested OPEB expense is reasonable.

<u>Depreciation and Amortization Expense</u>

<u>Net Salvage/Demolition Study</u>

155. The use of a 10% contingency factor in SWEPCO's demolition study to determine terminal net salvage amounts for SWEPCO's generating plants is reasonable.

156. It is reasonable for SWEPCO to escalate the terminal net salvage amounts in the demolition study (which are stated in year end 2020 dollars) to the expected final retirement date of each plant using a 2.22% inflation rate from the "Livingston Survey" dated December 2019 published by the research department of the Federal Reserve Bank of Philadelphia.

<u>Curve Life Combinations – Mass Property Accounts</u>

157. It is reasonable to apply an S0.0-68 Iowa curve life combination for FERC Account 353, Transmission Station Equipment.

158. It is reasonable to apply an S1.5-74 Iowa curve life combination for FERC Account 354, Transmission Towers and Fixtures.

159. It is reasonable to apply an L1.5-49 Iowa curve life combination for FERC Account 355, Transmission Poles and Fixtures.

160. It is reasonable to apply an R2.0-70 Iowa curve life combination for FERC Account 356, Overhead Conductors and Devices.

161. It is reasonable to apply an S-.5-55 Iowa curve life combination for FERC Account 364, Poles, Towers, and Fixtures.

162. It is reasonable to apply an R4.0-80 Iowa curve life combination for FERC Account 366, Underground Conduit.

163. It is reasonable to apply an R3.0-46 Iowa curve life combination for FERC Account 367, Underground Conductor.

164. It is reasonable to apply an R3.0-59 Iowa curve life combination for FERC Account 369, Services.

165. It is reasonable to apply an L0.0-15 Iowa curve life combination for FERC Account 370, Meters.

<u>Amortization Expense</u>

166. SWEPCO's amortization expense related to an intangible asset that was fully amortized as of the end of the test year should be excluded from SWEPCO's revenue requirement.

<u>Purchased Capacity Expense</u>

167. During the test year, SWEPCO continued to purchase 50 MW of capacity under its long-term purchase power agreement with Louisiana Generating Company (formerly Cajun Electric Power Cooperative) (the Cajun contract). That agreement began in 1992. These capacity costs have been consistently recovered through base rates.

168. During the test year, SWEPCO purchased the product designated as Operating Reserve Capacity under the Cajun contract and counted that capacity in SWEPCO's compliance with SPP's capacity reserve requirements. During the test year SWEPCO did not purchase any Operating Reserve Energy under the Cajun contract.

169. The Operating Reserve Capacity under the Cajun contract is distinguishable from Regulation and Operating Reserve Services procured in the SPP Independent Monitor day-ahead and real-time market.

170. The costs that SWEPCO incurred during the test year under the Cajun contract continue to be properly recovered in base rates.

171. The cost of energy incurred under SWEPCO's wind energy contracts has been collected through SWEPCO's fuel factor and reconciled as energy purchases since their inception, starting with Docket No. 40443 for the Majestic Renewable Energy Purchase Agreements.

172. According to the SPP Planning Criteria, the amount of capacity that may be accredited to a renewable resource is determined by a set of formulas using the historical output of that particular facility and updated over time.

173. The Commission should continue to account for the costs incurred under these wind contracts as energy.

Affiliate Expense

174. SWEPCO incurred a total of $87,634,578 in adjusted total company test year affiliate charges: $85,227,881 in charges from AEPSC and $2,406,697 from other affiliates.

175. Staff proposed an adjustment to SWEPCO's affiliate expense that SWEPCO did not oppose.

176. As adjusted by Staff, SWEPCO's affiliate expenses are reasonable and necessary for each item or class of items, are allowable, and are charged to SWEPCO at a price no higher than was charged by the supplying affiliate to other affiliates, and the rate charged was a reasonable approximation of the cost of providing the service.

Federal Income Tax Expense

177. SWEPCO's method of calculating its federal income tax expense is reasonable.

178. The amount of federal income tax SWEPCO included in its cost of service was calculated in accordance with the provisions of PURA §§ 36.059 and 36.060.

179. No party challenged the inclusion of federal income tax expense in SWEPCO's cost of service.

Ad Valorem Taxes

180. SWEPCO's requested effective ad valorem tax rate excludes Texas jurisdictional differences that would decrease the effective rate but includes Texas jurisdictional differences that increase the effective rate.

181. The effective ad valorem tax rate should be synchronized with the plant to which the rate is to be applied.

182. Including SWEPCO's proposed Texas jurisdictional plant differences related to depreciation and Allowance for Funds Used During Construction (AFUDC) rates in the

plant balance used to calculate ad valorem taxes requires that such jurisdictional differences be included in the determination of the effective ad valorem tax rate.

183. Including SWEPCO's proposed Texas jurisdictional plant differences related to depreciation and AFUDC rates in the determination of the effective ad valorem tax rate does not result in other states subsidizing Texas customers.

184. The appropriate effective ad valorem tax rate that includes the Texas jurisdictional differences in the determination of the rate is 0.961262%.

Payroll Taxes

185. It is reasonable to synchronize payroll taxes with adjustments to SWEPCO's payroll expenses.

186. Incentive compensation is part of SWEPCO's payroll expenses.

187. A potential offset of incentive compensation with additional base pay by SWEPCO in the future is speculative.

188. Payroll tax on disallowed incentive compensation is properly borne by shareholders.

189. An adjustment of ($258,162) to SWEPCO's payroll tax expense is appropriate. This synchronizes payroll taxes with the adjustments to payroll and incentive compensation expenses as recommended by Staff.

Gross Margin Tax

190. SWEPCO calculates the Texas gross receipts (margin) tax amount using an effective rate derived from test year payments and test year Texas retail base and fuel revenues.

191. Revenue related taxes should be updated and synchronized with the final revenue requirement set in this case.

Allocated Transmission Expenses Related to Retail Behind-the-Meter Generation

192. To serve its retail and wholesale customers, SWEPCO purchases Network Integration Transmission Service (NITS) from SPP for the use of SPP's transmission system.

193. SPP charges for NITS pursuant to its FERC-approved OATT.

194. 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.

195. SPP allocates the cost of using its transmission system to NITS customers (referred to as Network Customers in the OATT) based on the load ratio share of each customer's monthly Network Load to the total system load at the time of the monthly system peak.

196. To obtain the data necessary to make this allocation, SPP requires Network Customers, such as SWEPCO, to submit their monthly Network Load data to SPP.

197. In October 2018, SWEPCO changed how it reports its monthly Network Load to SPP by adding load served by retail behind-the-meter generation (BTMG).

198. In this context, BTMG refers to a generation unit that is behind the transmission system meter—*i.e.*, not directly connected to the bulk transmission system—and is intended to serve all or part of the capacity or energy needs for the load behind the meter without withdrawing energy from the SPP transmission system.

199. Retail BTMG (in contrast to wholesale BTMG) is on-site generation operated by a retail end-use customer to serve its own local load requirements. Retail BTMG may be large scale, such as an industrial customer with a cogeneration facility, or small scale, such as a residential rooftop solar facility.

200. When retail BTMG is excluded from a Network Customer's monthly load report, it is reported on a "net" basis, whereas when retail BTMG is included, it is reported on a "gross" basis.

201. SPP provided educational information to its stakeholders, including SWEPCO, clarifying that FERC policy and the SPP OATT do not exclude or "net" BTMG from the Network Load calculation.

202. At this time, SWEPCO is only reporting the retail BTMG load of one customer, Eastman, which is located in SWEPCO's Texas service area.

203. Eastman operates an on-site cogeneration facility that generates approximately 150 MW of power to supply the full load requirements of Eastman's operations. Eastman is a "qualifying facility" under the Public Utility Regulatory Policies Act of 1978.

204. During scheduled maintenance outages and forced/unscheduled outages when Eastman's generation is not operating, Eastman purchases standby electricity service from SWEPCO under SWEPCO's Supplementary, Backup, Maintenance and As-Available Power Service Tariff. Eastman coordinates routine maintenance outages with SWEPCO to avoid system peaks.

205. Due to the configuration of Eastman's campus and BTMG, Eastman uses a SWEPCO-owned transmission line to serve all the load at its campus, but its use of the line is incidental and is not imposing new costs on SWEPCO's system.

206. During the test year, the Network Load that SWEPCO reported to SPP included 146 MW of load served by Eastman's BTMG. The higher reported Network Load resulted in SPP allocating a higher share of its transmission system costs to SWEPCO, which was reflected in SWEPCO's NITS charges in the test year.

207. There is a lack of consensus among SPP and its Network Customers regarding how to report retail BTMG load to SPP under the OATT.

208. Determining whether SWEPCO's NITS charges are pursuant to the OATT necessarily requires an interpretation of the OATT.

209. FERC has exclusive jurisdiction to resolve disputes involving the interpretation of a FERC-approved tariff, such as SPP's OATT.

210. SWEPCO's role in providing the data to SPP on which SPP relied to allocate NITS charges does not remove the issue from FERC's jurisdiction because the determination of monthly Network Load is addressed in SPP's OATT and the resulting rates are wholesale rates.

211. SPP has Network Customers in multiple states, including Texas, and conflicting interpretations of the OATT would undermine FERC's ability to ensure that a filed rate is uniform across different states.

212. SWEPCO's test year NITS charges from SPP are reasonable under the filed rate doctrine.

213. The NITS charges are part of SWEPCO's overall transmission costs, which SWEPCO allocates jurisdictionally among Texas, Arkansas, and Louisiana.

214. SWEPCO did not identify the increase in NITS charges attributable to reporting Eastman's BTMG load.

215. To recover the additional cost, SWEPCO proposed to change how it allocates its transmission costs by imputing Eastman's BTMG load to the Texas jurisdiction for jurisdictional allocation and to the Large Lighting and Power-Transmission (LLP-T) class for class allocation.

216. Adding Eastman's BTMG load to the Texas jurisdiction would increase Texas's share of SWEPCO's transmission costs by $5.7 million, with corresponding reductions to the Arkansas and Louisiana jurisdictions.

217. Adding Eastman's BTMG load to the LLP-T class would have a larger impact, increasing that class's share of SWEPCO's transmission costs by $7.5 million, with corresponding reductions to the remainder of SWEPCO's classes.

218. Adjusting the jurisdictional and class allocators for SWEPCO's overall transmission costs results in a shift of not just the SPP-related costs, but also the non-SPP-related costs.

219. SWEPCO did not explain why adjusting the allocations was the appropriate method to recover its increased NITS charges, or why reporting Eastman's BTMG load would impact non-SPP-related costs.

220. SWEPCO has 187 retail BTMG customers in Texas, including Eastman. Of these customers, at least three have cogeneration facilities (including Eastman) and the rest are commercial or residential solar facilities.

221. SWEPCO has retail BTMG customers in Arkansas and Louisiana, including at least one industrial retail BTMG customer (a paper mill) in Arkansas, and solar retail BTMG customers in both Arkansas and Louisiana.

222. Adding retail BTMG load solely to Texas likely results in the Texas jurisdiction receiving a higher allocation of SWEPCO's transmission costs than if the Company had treated each jurisdiction consistently. This inconsistency is not attributable to SPP requiring Network Customers to report retail BTMG load, as SWEPCO presented evidence that all retail BTMG load should be reported.

223. SWEPCO's decision to increase the Texas jurisdictional allocator, but not the Arkansas and Louisiana jurisdictional allocators, is unreasonable and results in unreasonably discriminatory rates for Texas customers.

224. SWEPCO's corresponding change to the LLP-T class allocator is unreasonable and results in unreasonably discriminatory rates among SWEPCO's Texas customers.

225. SWEPCO's proposals to allocate transmission costs at both the jurisdictional and class levels by adding Eastman's BTMG load to the Texas jurisdiction and LLP-T class, respectively, are not reasonable, necessary, and non-discriminatory.

226. Eastman's BTMG load should be removed when performing the jurisdictional and class allocations of transmission costs.

Billing Determinants

227. The Commission's RFP accepts the use of estimated billing units.

228. SWEPCO used estimated billing determinants to address potential customer migration among rate classes between rate cases.

229. SWEPCO's initial filing included pro forma adjustments to the test year billing determinants for all of the known and measureable items at the time this case was filed.

230. The ongoing effects, if any, of the COVID-19 pandemic on SWEPCO's billing determinants are not known and measurable and do not reflect conditions that are likely to prevail when the rates approved in this case are in effect.

231. ETSWD's proposal that SWEPCO should update its class cost of service study (CCOSS) to incorporate new data and account for the "enduring 'work from home'" shift and other effects of COVID-19 is not reasonable because the effects of COVID-19 are not known and measurable.

232. ETSWD's alternative proposal that the Commission instruct SWEPCO to recalculate and adjust its CCOSS using the data provided in SWEPCO's response to ETSWD Request for Information 3-1 also is not reasonable because the effects of COVID-19 are not known and measurable.

233. A pro forma adjustment to billing determinants should not be used to address a temporary event, because a pro forma adjustment is intended to ensure that test year data better represents a utility's ongoing operations.

234. Customers who permanently left SWEPCO during the test year should be removed from SWEPCO's proposed billing determinants.

235. Except in an extraordinary event not present in this case, a pro forma adjustment to remove a customer that permanently left SWEPCO after the close of the test year should not be made because that event was not known or measureable during the test year.

236. SWEPCO's adjusted test year billing determinants are reasonable and should be used in designing rates resulting from this case.

Functionalization and Cost Allocation

237. The allocation methodologies and processes used in SWEPCO's jurisdictional cost of service study and CCOSS reflect criteria generally used to determine the appropriateness of allocation methodologies.

238. The allocation methodologies and processes used in SWEPCO's jurisdictional cost of service study and CCOSS are consistent with the development of the jurisdictional cost of service study and CCOSS ordered by the Commission in Docket No. 46449 and with the base rates approved by the Commission in that docket and updated in the Company's related compliance filing in Docket No. 48233.

Jurisdictional Allocation

239. Until this rate case, SWEPCO has not proposed to include the self-served load of any retail customer in allocating transmission costs in any of its jurisdictions.

240. SWEPCO's proposal to increase the allocation to Texas customers by $5.7 million through the inclusion of the self-served load of a single customer is unreasonable.

241. The jurisdictional allocation of transmission costs to Texas retail customers should be established by using the actual load served by SWEPCO in each of its jurisdictions.

242. SWEPCO's allocation of Eastman's load served by its retail BTMG should be removed from the jurisdictional cost of service study.

243. SWEPCO appropriately removed the allocation of certain distribution investments from the wholesale class.

<u>Class Allocation</u>

244. SWEPCO corrected its CCOSS in rebuttal testimony to use a system load factor based on the single annual coincident peak in the average and excess demand four-coincident peak methodology.

245. The use of the single annual coincident peak in calculating the system load factor is consistent with Commission precedent and cost causation.

246. SWEPCO properly accounted for customer prepayments in its rebuttal CCOSS.

247. SWEPCO appropriately does not allocate major account representative costs to the residential class.

248. In its rebuttal CCOSS, SWEPCO appropriately corrected an error regarding its allocation of line transformer costs.

249. SWEPCO's correction to the line transformer allocation is not contrary to the Commission's decision in Docket No. 46449.

250. Staff's proposal for a four-year phase-in of rate increases to move all classes to their relative rate of return ignores that customers' consumption patterns change year-to-year and would cause some classes to incur significant rate increases each year for four years.

251. The Cotton Gin class, with its customers located in the Texas Panhandle, is markedly different from SWEPCO's other commercial classes located in northeast Texas because, among other things, they operate primarily on a seasonal basis in the winter months, their vegetation management requirements are different than those located in northeast Texas, and they typically are served directly from line transformers, rather than from secondary lines.

252. Three customer classes historically have been well below their relative rates of return as shown though SWEPCO's CCOSS, including its rebuttal CCOSS: the Cotton Gin class, the Oilfield Secondary class, and the Public Street and Highway Lighting class.

253. It is appropriate to require SWEPCO to provide direct testimony in its next base rate case addressing why these three classes continue to be well below unity and address whether there are measures that can be taken in the class allocation (or rate design) process to address this situation, other than simply applying gradualism.

254. Based on the evidence in this case, SWEPCO's proposed class allocation to address classes that are not at a unitary relative rate of return is reasonable.

255. None of the $5.7 million in transmission costs SWEPCO allocated to the Texas retail jurisdiction and in its CCOSS through its retail BTMG proposal should be allocated to any Texas retail customers.

Municipal Franchise Fees

256. SWEPCO develops the effective rate for municipal franchise fees based on test year actual municipal franchise taxes paid, less the amount in excess of the base amount and test year actual kWh sales.

257. SWEPCO applies the effective rate for municipal franchise fees to the test year-adjusted kWh sales to determine the pro forma amount to include in SWEPCO's cost of service.

258. SWEPCO's allocation of municipal franchise fees was not contested by any party and is reasonable.

Revenue Distribution

259. The class revenue distribution is the rate design mechanism by which a utility's approved annual revenue requirement is assigned to the customer classes.

260. The revenue distribution also determines the revenue requirement targets for each class.

261. The percent increase in base rates for each class is based on its revenue deficiency as determined by the CCOSS.

262. The revenue deficiency determines the revenue requirement needed to bring each class to an equalized return.

263. The revenue requirement at an equalized return is the amount of revenue needed from each class to recover the full costs of serving that customer class.

264. The equalized revenue requirement and revenue change based on that requirement is the starting place for the revenue distribution. Other factors may also be taken into consideration such as customer migration, and a potential need to moderate a rate increase through rate gradualism.

265. SWEPCO's proposed rebuttal revenue distribution moves all customer classes closer to cost of service.

266. All present base rate-related revenues, inclusive of TCRF and DCRF revenues, are the appropriate starting point for evaluating any rate increase.

267. In Docket No. 46447, SWEPCO was required to present its rate change request in this case such that its then-present revenues show the total present revenues inclusive of the TCRF and DCRF revenues.

Rate Moderation/Gradualism

268. All parties to this case agree that some form and level of rate moderation should be applied to the revenue distribution.

269. The design of rates within each rate schedule should be cost-based and informed by the results of the CCOSS, subject to gradualism.

270. Gradualism and rate moderation are appropriate exceptions to this requirement when a class's proposed rate increase leads to "rate shock."

271. A proposed rate increase of 43% or less in any one class is an appropriate upper percentage to apply in this case for the gradualism/rate moderation evaluation.

272. SWEPCO's approach of grouping major rate classes for purposes of implementing the revenue distribution was approved by the Commission in SWEPCO's two most recent base rate proceedings, Docket Nos. 40443 and 46449.

273. SWEPCO's proposed rate moderation methodology, which reduces the subsidization among individual rate classes, is reasonable and should be adopted.

274. Staff's proposed four-year phased-in method to move all customers to unity does not account for the fact that customers' consumption patterns change year-to-year, and would result in significant rate increases every year over the four-year phase-in period to some customers.

275. Staff's proposed four-year phased-in method should not be accepted.

Rate Design and Tariff Changes

276. In general, SWEPCO's proposed rate design retains the rate structures and relationships approved by the Commission in SWEPCO's two most recent base rate proceedings, Docket Nos. 40443 and 46449.

277. SWEPCO's proposed rate design provides a reasonable basis for establishing rates in this proceeding.

278. SWEPCO has not met its burden of proof to justify removing the 50 kilowatt (kW) maximum demand cap in the GS rate schedule.

279. SWEPCO should not be required to revise its rate schedules in its next rate case to preclude the potential for customer migration between rate schedules or between any other customer classification.

280. SWEPCO should be required to address the customer migration issue in more detail in its next base rate case filing, including which classes are structured to allow migration among classes even if customers' loads or operations do not change, why customers migrate among classes, and how SWEPCO adjusts, or estimates, its billing determinants to account for customer migration among rate classes between base rate cases.

281. SWEPCO has not explained or justified why it is appropriate, in this case, to collect fixed demand-related costs through energy charges in the Large Power Secondary class.

282. SWEPCO offers a rate option for Cotton Gin customers that allows the application of the minimum monthly bill only during the ginning season as defined as November through February.

283. In SWEPCO's prior fuel reconciliation proceeding, Docket No. 47553, SWEPCO agreed to impute the value of renewable energy credits (RECs) and treat them as a base-rate expense.

284. SWEPCO should revise the REC Rider to allow a customer to link its RECs to specific renewable resources.

285. SWEPCO must implement a REC opt-out tariff that would refund REC costs to transmission-voltage customers who have opted out.

286. The REC opt-out charge should be calculated based on an energy allocator for REC costs, consistent with how RECs are generated, and set at a credit of 0.064 cents per kWh.

287. SWEPCO did not perform or provide a study justifying its proposal to increase the reactive demand charge by 29.4%.

288. SWEPCO has not met its burden of demonstrating that there is a cost basis for increasing the reactive demand charge in the Large Lighting and Power (LLP) rate schedule.

289. Under the Company's residential plug-in electric vehicles (PEV) rider, an installed sub-meter separately measures PEV kWh usage while a standard meter measures total residence kWh usage.

290. SWEPCO has met its burden of proof regarding the residential PEV rider.

291. ETSWD's request that the Commission direct SWEPCO to implement a retail choice pilot project is moot based on the Commission's denial of ETSWD's request for a declaratory ruling on this matter in Docket No. 51257.

Transmission Rate for Retail Behind-the-Meter Generation

292. Because SWEPCO's proposal to allocate to any customer or class the SPP charges related to Eastman's load served by its retail BTMG should be rejected, it is not appropriate for SWEPCO to implement a Synchronous Self-Generation Load rate schedule or rate.

Baselines for Cost-Recovery Factors

293. A TCRF is a rate mechanism that allows an electric utility outside of the Electric Reliability Council of Texas to periodically update its recovery of transmission costs.

294. SWEPCO is eligible under 16 TAC § 25.239 to have a TCRF.

295. TCRF baseline values should be set during the compliance phase of this docket, after the Commission makes final rulings on the various contested issues that may affect this calculation.

296. A DCRF is a rate mechanism that allows an electric utility to periodically adjust its rates for changes in certain distribution costs.

297. The Commission has adopted 16 TAC § 25.243 to implement PURA § 36.210. The rule allows an electric utility not offering customer choice (*e.g.*, SWEPCO) to file an application for a DCRF at any time other than April and May.

298. DCRF baseline values should be set during the compliance phase of this docket, after the Commission makes final rulings on the various contested issues that may affect this calculation.

299. A Generation Cost Recovery Rider (GCRR) is a rate mechanism authorized under PURA § 32.213 that allows an electric utility to recover its investment in a power generation facility outside of a base rate proceeding.

300. The baseline values for a subsequent implementation of the GCRR should be established during the compliance phase of this docket, after the Commission makes final rulings on the various contested issues that may affect this calculation.

Rate Case Expenses

301. SWEPCO and CARD sought to recover a total of $3,769,007 in RCEs for this docket as well as Docket Nos. 49042, 46449, 40443, 47141, and 50997, consisting of $2,740,315 for SWEPCO's own RCEs and $1,028,692 in RCEs paid or to be paid by SWEPCO to CARD for its participation in these dockets and reflected on SWEPCO's and CARD's RCE reports.

302. The Commission's order in Docket No. 47141 authorized CARD to collect up to an additional $2,500 in RCEs in that docket after April 13, 2020.

303. In this docket, CARD originally requested to recover $6,321 in RCEs incurred in Docket No. 47141 after April 13, 2020.

304. CARD's request to recover $6,321 for Docket No. 47141 RCEs should be reduced to $2,500.

305. SWEPCO seeks to recover $65,167 in RCEs in Docket Nos. 51415 and 40443 that are computed based on paying two outside attorneys in those dockets rates in excess of $550 per hour.

306. The Office of the Attorney General (OAG) issued a memorandum in 2016 that limited the maximum outside counsel per-hour fee to $525, but allowing the Deputy Attorney General to authorize a higher fee. This memorandum was addressed to, among others, state agencies and addressed "Outside Counsel Contract Rules and Templates."

307. The OAG issued a follow-up memorandum, in 2019 that did not increase the $525 per-hour fee cap. This follow-up memorandum also was directed to state agencies and addressed Outside Counsel Contract Rules and Templates.

308. SWEPCO did not meet its burden of proof to show that the nature, extent, and difficulty of the work performed by the attorneys who charged in excess of $550 per hour justified hourly rates in excess of $550 in this base rate case.

309. The rates SWEPCO paid to outside attorneys in excess of $550 per hour are excessive and not reasonable.

310. The fact that other entities may be willing to pay an attorney a rate in excess of $550 per hour does not mean that the rate is reasonable and not excessive in the context of a Commission electric utility rate proceeding.

311. SWEPCO's request to recover $65,167 in RCEs related to outside attorney fees billed in excess of $550 per hour should be denied.

312. The total amount of RCEs that SWEPCO and CARD should recover in this docket is $3,700,021.

313. SWEPCO should reimburse CARD for its requested rate case expenses, except that CARD's recovery related for Docket No. 47141 is $2,500, not $6,321.

314. It is reasonable for SWEPCO to recover the $3,700,021 in rate case expenses authorized in this docket through its proposed Rate Case Surcharge Rider.

315. Any trailing RCEs related to Docket No. 51415 that are incurred after the dates of the RCEs addressed in the final reports filed in this docket should be recorded as a regulatory asset and deferred for analysis in a future SWEPCO docket.

Other Issues

316. It is uncontested and reasonable that the final approved return on equity should be included in the factoring rate calculation to synchronize factoring expense properly to the approved revenue requirement.

317. Staff's proposed adjustments of ($1,164,427) to remove carrying charges paid by SWEPCO associated with affiliate or shared assets and ($530,384) to remove carrying charges the Company received from its affiliates is uncontested and reasonable.

318. Staff's adjustment to update the customer deposit interest amount to incorporate the Commission-approved 2021 interest rate is uncontested and reasonable. In this case that is 0.61%, which results in an adjustment of ($1,041,156) to SWEPCO's request.

319. In accordance with the Commission's decisions in Docket Nos. 40443 and 46449, SWEPCO removed Supplement Executive Retirement Plan expense from its requested cost of service, which is reasonable.

320. In accordance with the Commission's decisions in Docket Nos. 40443 and 46449, Staff recommended an adjustment for executive perquisites. Based on Staff's adjustment, SWEPCO agreed to remove $20,595 from its revenue requirement related to executive perquisites. This adjustment is reasonable.

321. SWEPCO has announced that the Welsh plant will cease coal-fired operations in 2028 in light of the Coal Ash Combustion Residual Rule and the Effluent Limitations Guidelines.

322. SWEPCO has not yet determined whether natural gas conversion of the Welsh plant is in customers' best interest.

323. If such a conversion to natural gas were to occur in the future, SWEPCO will request Commission authorization to include the costs associated with that conversion in customer rates in a future proceeding.

324. SWEPCO has not included any Construction Work in Progress in its requested rate base.

325. RFP Schedule E-4 contains the calculation of SWEPCO's cash working capital allowance included in rate base.

326. The lead-lag study used in this proceeding is the one approved in SWEPCO's last base rate case, Docket No. 46449.

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

328. At the time the current proceeding was filed, less than five years had passed since SWEPCO's last lead-lag study. By using the last approved study, SWEPCO estimates that it saved around $75,000 in rate case expenses.

329. It is uncontested and reasonable that cash working capital should be updated and synchronized with the final revenue requirement.

330. Staff's adjustment of ($46,306) to administrative and general O&M expense, specifically for regulatory commission expense, is not contested and is reasonable.

331. SWEPCO's federal income taxes were calculated consistent with PURA § 36.059 including treatment of tax savings derived from liberalized depreciation and amortization, investment tax credit, or similar methods.

332. SWEPCO's expenditures for advertising, contributions, memberships, and donations included in its cost of service meet the standard and thresholds set forth in 16 TAC § 25.231(b)(1)-(2).

333. SWEPCO uses advertising to convey information regarding safety and reliability to its customers and to support local initiatives.

334. SWEPCO did not include any prohibited advertising expenses in its request.

335. SWEPCO makes charitable contributions toward education, community service, and economic development in and for the benefit of the communities in which it operates. These costs are reasonable and consistent with the Commission's requirements and thresholds for recovery

336. SWEPCO membership expenses are reasonable and comply with the Commission's standards.

337. No party raised an issue with respect to SWEPCO's competitive affiliates.

338. SWEPCO is not seeking to include in rates any costs previously deferred by a Commission order.

339. SWEPCO's request to defer the portion of its ongoing net SPP OATT bill that is above or below the net test year level is not reasonable and should be denied.

340. SWEPCO proposed an optional Residential Time-of-Use rate schedule as a pilot available to residential customers.

341. SWEPCO proposed a Commercial Time-of-Use rate schedule for commercial loads of 100 kW or greater.

342. The pilot projects will gauge interest and utilization of the time-of-use format by customers that do not qualify for SWEPCO's Off-Peak Rider for the Lighting and Power, LLP, and Metal Melting Service classes. Participating customers can manage certain energy costs by shifting energy consumption to off-peak periods.

343. The proposed time-of-use rate schedule and design is reasonable and appropriate under 16 TAC § 25.234.

344. SWEPCO proposes to update its economic development rider.

345. SWEPCO's proposed tariff revisions to attract loads from a variety of businesses with different load requirements in order to spur economic growth in its service territory and provide long-term benefits to SWEPCO customers are reasonable and appropriate.

346. The proposed tariff revisions are consistent with the Commission's standards including 16 TAC § 25.234.

347. SWEPCO is not filing a fuel reconciliation proceeding in this docket; therefore, the schedules dealing with fuel reconciliation proceedings are not applicable. Accordingly, SWEPCO's requested waiver of the portions of the RFP that request information related to fuel reconciliation proceedings should be granted.

348. SWEPCO obtained authorization in Docket No. 50917 to waive the requirement that it file an RFP Schedule S in this base rate case.

349. Ordering Paragraph 10 of the Order on Rehearing in Docket No. 46449 states, "[t]he regulatory treatment of any excess deferred taxes resulting from the reduction in the

federal-income-tax rate will be addressed in SWEPCO's next base-rate case." The treatment of SWEPCO's excess deferred taxes has been addressed in this case.

B. Conclusions of Law

1. SWEPCO is subject to PURA. Tex. Util. Code §§ 11.001-66.016.

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

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

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

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

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

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

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

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

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

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

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

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

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

15. SWEPCO's STI payments to collectively bargained employees should not be reduced to remove financially-based STI. PURA § 14.006.

16. Upon completion of this base rate case, SWEPCO's TCRF should be set to zero. 16 TAC § 25.239(f).

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

18. The Commission has authority to order SWEPCO to adopt the financial protections listed in Finding of Fact No. 108. PURA §§ 11.002, 14.001, 14.003, 14.154(a), 14.201, 36.003(a).

19. Prudence is the exercise of that judgment and the choosing of one of that select range of options which a reasonable utility manager would exercise or choose in the same or similar circumstances given the information or alternatives available at the point in time such judgments is exercised or option is chosen. *Gulf States Util. Co. v. Public Util. Comm'n*, 841 S.W.2d 459, 476 (Tex. App—Austin 1992, writ denied).

20. There may be more than one prudent option within the range available to a utility in a given context. Any choice within the select range of reasonable options is prudent, and the Commission should not substitute its judgment for that of the utility. The reasonableness of an action or decision must be judged in light of the circumstances, information, and available options existing at the time, without benefit of hindsight. Docket No. 40443, Order on Rehearing at 5 (citing *Nucor Steel v. Public Utility Commission of Texas*, 26 S.W.3d 742, 752 (Tex. App.—Austin 2000, pet. denied)).

21. A utility may demonstrate the prudence of its decision making through contemporaneous evidence. Alternatively, the utility may obtain an independent, retrospective analysis that demonstrates that a reasonable utility manager, having investigated all relevant factors and alternatives, as they existed at the time the decision was made, would have found the utility's actual decision to be a reasonably prudent course. *Gulf States*, 841 S.W.2d at 476.

22. The utility does not enjoy a presumption that the expenditures reflected in its books have been prudently incurred merely by opening the books to inspection. But while the ultimate

burden of persuasion on the issue of prudence remains with the utility, its initial burden of production (*i.e.*, to come forward with evidence) is shifted to opponents if the utility establishes a prima facie case of prudence. This is a "Commission-made" rule, intended "to aid in the trial of utility prudence reviews" and facilitate "efficient hearings," allowing the utility to establish prudence "by introducing evidence that is comprehensive, but short of proof of the prudence of every bolt, washer, pipe hanger, cable tray, I-beam, or concrete pour." *Entergy Gulf States, Inc. v. Public Util. Comm'n*, 112 S.W.3d 208, 214-15, and n.5 (Tex. App.—Austin 2003, pet. denied).

23. The rate year is defined as the 12-month period beginning with the first date that rates become effective. 16 TAC § 25.5(101).

24. The rates approved by this order are effective for consumption on and after March 18, 2021 in accordance with PURA § 36.211(b) and 16 TAC § 25.246(d)(1).

25. The Commission's Cost of Service Rule permits post-test year adjustments for known and measurable decreases to test year data under conditions that include a plant being removed from service, mothballed, sold, or removed from the electric utility's books prior to the rate year. 16 TAC § 25.231(c)(2)(F)(iii).

26. The Commission has discretion to make exceptions to its substantive rules applicable to electric-service providers, including its Cost of Service Rule, for good cause. 16 TAC § 25.3.

27. While the Commission's Cost of Service Rule generally requires that depreciation expense shall be computed on a straight-line basis, other methods may be used when it is determined that such depreciation methodology is a more equitable means of recovering the cost of the plant. 16 TAC § 25.231(b)(1)(B).

28. PURA § 36.064 requires SWEPCO to prove that: (1) its proposed self-insurance reserve coverage is in the public interest; (2) the plan, considering all costs, would be a lower cost alternative to purchasing commercial insurance; and (3) customers would receive the benefits of the savings. Tex. Util. Code § 36.064(b).

29. For SWEPCO to establish that its self-insurance plan is in the public interest, SWEPCO "must present a cost benefit analysis performed by a qualified independent insurance consultant who demonstrates that, with consideration of all costs, self-insurance is a lower-cost alternative than commercial insurance and the customers will receive the benefits of the self insurance plan." Further, "[t]he cost benefit analysis shall present a detailed analysis of the appropriate limits of self insurance, an analysis of the appropriate annual accruals to build a reserve account for self insurance, and the level at which further accruals should be decreased or terminated." 16 TAC § 25.231(b)(1)(G).

30. SWEPCO did not meet its burden of proof to show that its proposed self-insurance reserve would be in the public interest. Tex. Util. Code § 36.064(b); 16 TAC § 25.231(b)(1)(G).

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

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

33. A lead-lag study is performed to determine the reasonableness of a cash working capital allowance. 16 TAC § 25.231(c)(2)(B)(iii)(IV) and (V).

34. 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. *Entergy Louisiana, Inc. v. Louisiana Pub. Serv. Comm'n*, 539 U.S. 39, 47 (2003).

35. FERC has exclusive jurisdiction over the wholesale sale or transmission of electricity in interstate commerce. 16 U.S.C. § 824(b).

36. Pursuant to its exclusive jurisdiction over wholesale rates, FERC is the appropriate arbiter of disputes involving the interpretation of a FERC-approved tariff, such as SPP's OATT. *AEP Texas North Co. v. Texas Indus. Energy Consumers*, 473 F.3d 581, 585-86 (5th Cir. 2006).

37. The reasonableness of a utility's jurisdictional allocation is a matter within the state's jurisdiction to determine in setting the utility's retail rates, even when it impacts the allocation of costs charged pursuant to a FERC-approved tariff. *Entergy Texas, Inc. v. Nelson*, 889 F.3d 205, 209-10 (5th Cir. 2018).

38. A transmission-voltage customer that submits an opt-out notice to the Commission is not required to pay costs incurred by the utility to acquire RECs. 16 TAC § 25.173(j).

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

40. Except for charges by attorneys and consultants in excess of $550 per hour and the $2,500 cap on CARD's expenses in Docket No. 47141, the RCEs SWEPCO is seeking to recover in this case for itself and CARD are recoverable pursuant to PURA § 36.061(b).

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

C. Proposed Ordering Paragraphs

In accordance with these Findings of Fact and Conclusions of Law, the Commission issues the following orders:

1. The Proposal for Decision issued by the SOAH ALJs is adopted to the extent consistent with this order.

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

3. SWEPCO shall implement and adhere to the financial protections listed in Finding of Fact No. 108. No later than 90 days from the date of this Order, SWEPCO shall have implemented, and be adhering to, all of those financial protections.

4. In its direct testimony in its next base rate case, SWEPCO shall address why some of its customer classes, including the Cotton Gin class, the Oilfield Secondary class, and the Public Street and Highway Lighting class, historically are far below their relative rates of return produced by the Company's CCOSS, and whether adjustments, other than gradualism, can and should be made to address this recurring situation.

5. In its direct testimony in its next base rate case, SWEPCO shall address why customers can or should be allowed to migrate from class-to-class without experiencing a change in load or operations. In that testimony, SWEPCO should explain how it accounts for these future migrations through its adjusted billing determinants, and either justify its existing relatively open class structure, or propose rate schedule revisions that more closely group similarly situated customers into rate schedules.

6. SWEPCO may recover its authorized RCEs through its proposed Rate Case Surcharge Rider.

7. SWEPCO and CARD may seek to recover in a future proceeding any trailing RCEs not already presented in their July 6, 2021 rate case expense reports for this case.

8. SWEPCO's TCRF and DCRF are set to zero at the conclusion of this base rate case. The baseline values for SWEPCO's TCRF, DCRF, and GCRR shall be developed and set during the compliance phase of this docket in *Compliance Tariff for Final Order in Docket No. 51415 (Application of Southwestern Electric Power Company for Authority to Change Rates)*, Control No. _____.

9. SWEPCO shall file tariffs consistent with this order within 20 days of the date of this order in *Compliance Tariff for Final Order in Docket No. 51415 (Application of Southwestern Electric Power Company for Authority to Change Rates)*, Control No. _____. No later than ten days after the date of the tariff filings, Staff shall file its comments recommending

approval, modification, or rejection of the individual sheets of the tariff proposal. Responses to Staff's recommendation shall be filed no later than 15 days after the filing of the tariff. The Commission shall by letter approve, modify, or reject each tariff sheet, effective the date of the letter.

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

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

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

Signed: August 27, 2021.

ANDREW LUTOSTANSKI
ADMINISTRATIVE LAW JUDGE
STATE OFFICE OF ADMINISTRATIVE HEARINGS

STEVEN H. NEINAST
ADMINISTRATIVE LAW JUDGE
STATE OFFICE OF ADMINISTRATIVE HEARINGS

ROBERT H. PEMBERTON
ADMINISTRATIVE LAW JUDGE
STATE OFFICE OF ADMINISTRATIVE HEARINGS

CASSANDRA QUINN
ADMINISTRATIVE LAW JUDGE
STATE OFFICE OF ADMINISTRATIVE HEARINGS

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415
COMPANY NAME Southwestern Electric Power Company
TEST YEAR END 31-Mar-20

PFD Schedule I
Total Company Revenue Requirement

	Company Test Year Total	Company Adjustments To Test Year	REBUTTAL Co Requested Test Year Total Electric	PFD Adj To Company Request	PFD Adjusted Total Electric
	(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)
REVENUE REQUIREMENT					
Operations & Maintenance	1,096,640,498	(545,239,261)	551,401,239	(23,625,522)	527,775,717
Loss on Disposition of Utility Property	653,208	(490,000)	163,208	0	163,208
Accretion Expense	3,484,561	0	3,484,561	0	3,484,561
Amortization Expense	17,994,221	5,940,656	23,934,877	3,310,118	27,244,995
Depreciation Expense	236,316,513	1,872,435	238,188,948	(6,258,253)	231,930,695
Taxes Other Than Income Taxes	100,527,332	(566,762)	99,960,570	(6,106,245)	93,854,325
Federal Income Taxes	7,262,011	65,052,207	65,052,207	(18,584,325)	46,467,882
Return on Invested Capital	263,445,627	123,780,532	387,226,159	(58,606,702)	328,619,457
Other State Income Taxes	(1,364,764)	1,364,764	0		
TOTAL	**1,724,959,207**	**(348,285,429)**	**1,369,411,769**	**(109,870,929)**	**1,259,540,840**

SOAH DOCKET NO. **473-21-0538**
PUC DOCKET NO. **51415**
COMPANY NAME **Southwestern Electric Power Company**
TEST YEAR END **31-Mar-20**

OPERATIONS AND MAINTENANCE EXPENSE	Acct. No	**Company Test Year Total (a)**	**Company Adjustments To Test Year (b)**	**REBUTTAL Co Requested Test Year Total Electric (c)**	**PFD Adj To Company Request (d)**	**PFD Adjusted Total Electric (e) = (c) + (d)**
Operations & Maintenance:						
Prod. Operation and Supr	500	21,645,237	(1,299,105)	20,346,132	(2,711,267)	17,634,865
Fuel-Reconcilable	501	399,631,093	(382,531,543)	17,099,550	(49,336)	17,050,214
Fuel-Non Reconcilable	501	0	0	0	(3,266,584)	(3,266,584)
Steam Expenses	502	19,098,323	(8,212,796)	10,885,527	(1,319,045)	9,566,482
Electric Expenses	505	10,576,275	(532,822)	10,043,453	(431,460)	9,611,993
Misc Steam Power Expenses	506	16,480,428	2,024,792	18,505,220	(3,831,596)	14,673,624
Rents	507	3,339	0	3,339	(634)	2,705
Allowance Expense	509	333,862	(41,727)	292,135	0	292,135
Maintenance Supv and Eng	510	5,221,988	(367,421)	4,854,567	(391,247)	4,463,320
Maintenance of structures	511	5,930,496	(99,368)	5,831,128	(235,335)	5,595,793
Maintenance of boiler plant	512	36,899,429	(769,067)	36,130,362	(3,976,004)	32,154,358
Maintenance of electric plant	513	8,232,373	(192,019)	8,040,354	(184,768)	7,855,586
Maintenance of misc steam plant	514	7,151,128	(164,156)	6,986,972	(1,095,596)	5,891,376
Operation supervision and engineering	517	0	0	0	(456)	(456)
Maintenance Supv and Eng	541	0	0	0	(355)	(355)
Operation Supv and Eng	546	4,833	(8,710)	(3,877)	(368)	(4,245)
Operation Fuel	547	10,520,437	(10,520,437)	0	(64)	(64)
Operation Generation Exp	548	257,827	(11,366)	246,461	1,512	247,973
Misc. Other Power Gen Exp	549	6,031	0	6,031	(3)	6,028
Operation Rents	550	0	0	0	0	0
Maintenance Supv and Eng	551	(35)	0	(33)	1	(32)
Maintenance of structures	552	961	60	1,021	7	1,028
Maintenance of generating and ele	553	827,970	(17,633)	810,337	1,500	811,837
Maint of Misc Other power gen plant	554	81,759	0	81,759	0	81,759
Purchased Power	555	207,609,120	(200,987,454)	6,621,666	0	6,621,666
System Control & Load Dispatch	556	1,494,472	(103,460)	1,391,012	(99,295)	1,291,717
System Control & Dispatch Other	557	1,822,709	1,255,487	3,078,196	(194,920)	2,883,276
Transmission Ops Supr & Engr	560	10,546,443	(565,371)	9,981,072	(527,202)	9,453,870
Transmission Load Dispatching -reliability	5611	0	0	0	0	0
Monitor and operate transmission-sys	5612	1,073,774	(43,835)	1,029,939	(66,502)	963,437
Trans service and scheduling	5613	417	0	417	0	417
Schedule system controland disatch ser	5614	11,545,148	0	11,545,148	0	11,545,148
Reliabiility planning and standards deve	5615	251,831	(9,586)	242,245	(15,744)	226,501
Reliability planning and standards deve s	5618	914,530	0	914,530	0	914,530
Transmission Station Equipment	562	1,235,007	(22,879)	1,212,128	1,318	1,213,446
Trans OH Line Expense	563	430,199	(2,044)	428,155	(1,111)	427,044
Underground Line Expenses	564	1,573	19	1,592	0	1,592
Transmission of Electricity by Others	565	73,241,705	79,285,200	152,526,905	0	152,526,905
Misc. Transmission Expenses	566	2,924,908	452,807	3,377,715	(92,286)	3,285,429
Rents	567	25,508	(1)	25,507	(9)	25,498
SPP Admin - MAM&SC	5757	2,366,891	0	2,366,891	0	2,366,891
Maint. Supv. And Eng.	568	15,702	(864)	14,838	(617)	14,221
Maint. of Structures	569	36,341	(195)	36,146	32	36,178
Maint. of computer hardware	5691	9,937	(312)	9,625	(621)	9,004
Maint. of computer software	5692	642,128	(5,624)	636,504	(9,777)	626,727
Maint. of computer equip	5693	56,944	0	56,944	0	56,944
Transmission Maint Station Equip	570	2,651,013	(78,372)	2,572,641	(6,307)	2,566,334
Transmission Maint OH Line Exp	571	14,533,315	(27,704)	14,505,611	1,206	14,506,817
Maint. of Underground Lines	572	11,239	111	11,350	0	11,350
Maint. of Misc. Transmission	573	85,869	(4,658)	81,211	(82)	81,129
Distribution Ops Supr & Engr	580	2,632,859	(167,391)	2,465,468	(154,371)	2,311,097
Distribution Load Dispatching	581	62,791	(1,291)	61,500	0	61,500
Distribution Station Expenses	582	749,112	(21,825)	727,287	(2,564)	724,723
Distribution OH Line Expenses	583	1,752,384	(223,813)	1,528,571	(10,170)	1,518,401
Underground Line Expenses	584	1,383,497	(46,597)	1,336,900	3,632	1,340,532
Street Lighting & Signal Sys	585	162,030	(3,872)	158,158	189	158,347
Meter Expenses	586	3,819,316	(302,033)	3,517,283	6,241	3,523,524
Customer Installations	587	410,742	(20,716)	390,026	1,916	391,942
Miscellaneous Distribution Exp	588	20,017,606	2,087,692	22,105,298	(4,186)	22,101,112
Rents	589	889,843	0	889,843	0	889,843
Distribution Maint Supr & Engr	590	166,883	(13,911)	152,972	337	153,309
Maint. of Structures	591	39,491	(209)	39,282	51	39,333
Distribution Maint Station Equip	592	2,040,674	(46,290)	1,994,384	(908)	1,993,476
Distribution Maint OH lines	593	57,550,019	(1,092,825)	56,457,194	38,430	56,495,624
Underground Line Expenses	594	660,415	(15,706)	644,709	1,351	646,060
Dist Maint Line Trnf, Regulators	595	140,636	(8,001)	132,635	533	133,168
MaintStreet Light & Signal Sys	596	303,595	(18,992)	284,603	978	285,581
Maintenance of Meters	597	442,928	(28,138)	414,790	2,491	417,281
Maint of Misc Distr Plant	598	371,393	(15,560)	355,833	1,488	357,321
Supervision - Customer Accts	901	781,491	(60,532)	720,959	(1,997)	718,962
Meter Reading Exp	902	2,614,840	(145,207)	2,469,633	3,185	2,472,818
Customer Records & Collection	903	17,797,556	(75,924)	17,721,632	(595,255)	17,126,377
Customer Deposit Interest	903.2	0	0	0	0	0
Uncollectible Accounts	904	724,395	0	724,395	0	724,395
Miscellaneous	905	101,498	(323)	101,175	(1,972)	99,203
Factoring Expense	426.5	9,711,825	(1,296,219)	8,415,606	0	8,415,606
Factoring Expense on Revenue Deficiency			1,117,582	1,117,582	(567,072)	550,510
Factoring Rate on Revenue Deficiency				0.0048258000000		0.0051612600000
Customer Service and Information	906	0	0	0	0	0
Supervision	907	7,429,119	(6,739,057)	690,062	(1,311)	688,751
Customer Assistance	908	15,029,496	(12,749,804)	2,279,692	8,601	2,288,293
Information & Instr Advertising	909	0	0	0	0	0
Misc. Cust. Service and Information	910	27,409	(1,365)	26,044	(965)	25,079
Sales Supervision	911	2,198	0	2,198	0	2,198
Demonstrating & Selling Exp	912	265,976	(6,786)	259,190	(200)	258,990
Advertising Expense	913	0	0	0	0	0
Misc. Sales Expense	916	0	0	0	0	0
Sales Expense	917	0	0	0	0	0
		0	0	0	0	0
TOTAL Operations & Maintenance		**1,024,512,494**	**(543,499,166)**	**481,013,330**	**(19,774,563)**	**461,238,767**

Attachment A

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415
COMPANY NAME Southwestern Electric Power Company
TEST YEAR END 31-Mar-20

OPERATIONS AND MAINTENANCE EXPENSE	Acct. No	Company Test Year Total (a)	Company Adjustments To Test Year (b)	REBUTTAL Co Requested Test Year Total Electric (c)	PFD Adj To Company Request (d)	PFD Adjusted Total Electric (e) = (c) + (d)
Administrative & General: (WP/A)						
Admin & General Salaries	920	32,325,718	(4,055,803)	28,269,915	(1,457,325)	26,812,590
Office Supplies & Exp	921	2,947,644	(1,212,661)	1,734,983	(54)	1,734,929
Admin Expenses Transferred	922	(4,430,969)	(59,256)	(4,490,225)	(15,049)	(4,505,274)
Outside Services	923	9,712,500	7,253	9,719,753	(70)	9,719,683
Property Insurance	924	2,428,223	1,689,700	4,117,923	(2,132,274)	1,985,649
Injuries & Damages	925	3,657,677	(29,527)	3,628,150	493	3,628,643
Employee Pensions & Benefits	926	13,373,091	2,799,757	16,172,848	(1,638)	16,171,210
Regulatory Commission Exp	928	2,624,761	(2,540,746)	84,015	(231,756)	(147,741)
Duplicate Charges	929	0	0	0	0	0
General Advertising Exp	9301	318,019	(1,129)	316,890	(24)	316,866
Miscellaneous	9302	1,724,290	1,732,377	3,456,667	(12,049)	3,444,618
Rents	931	1,008,537	(585)	1,007,952	0	1,007,952
Maint. Of General Plant	935	6,436,014	(69,422)	6,366,592	(1,213)	6,365,379
TOTAL Administrative & General		72,125,505	(1,740,042)	70,385,463	(3,850,959)	66,534,504
TOTAL O & M EXPENSE		**1,096,637,999**	**(545,239,208)**	**551,398,793**	**(23,625,522)**	**527,773,271**
	8140	53	-53	0		0
Gains/Losses Disposition Allowances	4118, 4119	4	0	4		4
Operations Expense - Non associated	4010	2442	0	2,442		2442
TOTAL		**1,096,640,498**	**(545,239,261)**	**551,401,239**		**527,775,717**

SOAH DOCKET N 473-21-0538
PUC DOCKET NO 51415
COMPANY NAME Southwestern Electric Power Company
TEST YEAR END 31-Mar-20

PFD Schedule III
Invested Capital

	Acct. No	Company Test Year Total (a)	Company Adjustments To Test Year (b)	REBUTTAL Co Requested Test Year Total Electric (c)	PFD Adj To Company Request (d)	PFD Adjusted Total Electric (e) = (c) + (d)
INVESTED CAPITAL						
Plant in Service	101	9,262,354,949	59,960,988	9,322,315,937	(339,874,755)	8,982,441,182
Accumulated Depreciation	108	(3,329,123,077)	104,944,688	(3,224,178,389)	316,560,953	(2,907,617,436)
Net Plant In Service		5,933,231,872	164,905,676	6,098,137,548	(23,313,802)	6,074,823,746
Construction Work in Progress	107	226,392,894	(226,392,894)	0	0	0
Plant Held for Future Use	105	1,044,101	(823,186)	220,915	0	220,915
Dolet Hills Mine FAS 143 ARO Asset	101.6	61,976,617	(61,976,617)	0	0	0
Capitalized leases	1011	105,842,819	(105,842,819)	0	0	0
Accumulated Provision - Leased Assets		(31,065,524)	31,065,524	0		
Completed Construction Not Classified	106	319,647,154	0	319,647,154	0	319,647,154
Plant Acquisition	114	18,043,976	(18,043,976)	0	0	0
Accumulated Provision - Plant Acquisition		(18,043,976)	18,043,976	0	0	0
Other Electric Plant Adjustments	116				0	0
Turk Impairments		(51,821,999)		(51,821,999)		(51,821,999)
Tx Trans Veg Mgmt Cost Writeoff		(1,471,585)		(1,471,585)		(1,471,585)
Tx Dist Veg Mgmt Cost Writeoff		(3,993,357)		(3,993,357)		(3,993,357)
SERP		(637,842)		(637,842)		(637,842)
CWIP Fin Based Incentive		(12,432,748)	42,000	(12,390,748)	(84,000)	(12,474,748)
RWIP Fin Based Incentive		(499,903)		(499,903)		(499,903)
Working Cash Allowance		(145,220,159)	0	(145,220,159)	3,058,346	(142,161,813)
Materials and Supplies	154	70,436,747	(913,340)	69,523,407	0	69,523,407
Fuel Inventories	151/152	105,918,091	(19,211,748)	86,706,343	(28,528,383)	58,177,960
Prepayments	165	17,148,962	83,452,444	100,601,406	0	100,601,406
SFAS #109 Regulatory Assets & Liabilities	1823/254	(412,675,887)	35,506,181	(377,169,706)	0	(377,169,706)
Accumulated DFIT - Reg Assets and Liabilities		412,675,897	(35,506,191)	377,169,706	0	377,169,706
Accumulated Deferred Federal Income Taxes		(1,270,549,476)	291,719,543	(978,829,933)	(455,122,490)	(1,433,952,423)
Rate Base - Other		0	0	0		0
IPP Credit	2530067	(7,532,556)	0	(7,532,556)	0	(7,532,556)
Trading Deposits	1340018/1340	2,092,064	0	2,092,064	0	2,092,064
Excess Earnings Deferral	2540052	(2,453,476)	0	(2,453,476)	0	(2,453,476)
T.V. Pole Attachments	2530050	(831,313)	0	(831,313)	0	(831,313)
Sabine Mine Reclamation	2420059	0	(64,960,236)	(64,960,236)	0	(64,960,236)
Investment in Oxbow		0	16,576,181	16,576,181	(16,576,181)	0
Electric Plant Purchased or Sold		64,005	(64,005)	0		
SFAS #106 Medicare Subsidy		2,533,221	0	2,533,221		2,533,221
Customer Deposits		(65,072,259)	0	(65,072,259)	0	(65,072,259)
TOTAL INVESTED CAPITAL (RATE BASE)		**5,252,746,360**	**107,576,513**	**5,360,322,873**	**(520,566,510)**	**4,839,756,363**
RATE OF RETURN		**5.02%**		**7.22%**		**6.79%**
RETURN ON INVESTED CAPITAL		**263,445,627**	**123,780,532**	**387,226,159**	**(58,606,702)**	**328,619,457**

Attachment A

	Acct. No	Company Test Year Total (a)	Company Adjustments To Test Year (b)	REBUTTAL Co Requested Test Year Total Electric (c)	PFD Adj To Company Request (d)	PFD Adjusted Total Electric (e) = (c) + (d)
AMORTIZATION EXPENSE						
Amortization Exp	404	17,421,930	3,435,169	20,857,099	0	20,857,099
Amort of Elec Plt Aqui	406	0	0	0	0	0
Amort Exp (Reg Debit)	4073	860,876	2,288,902	3,149,778	3,310,118	6,459,896
Amort Exp (Reg Credit)	4074	(288,585)	216,585	(72,000)	0	(72,000)
Total Amortization		17,994,221	5,940,656	23,934,877	3,310,118	27,244,995
ACRETION EXPENSE						
Acretion Expense	4111	3,484,561	0	3,484,561	0	3,484,561
DEPRECIATION EXPENSE						
Production	4030.1	118,198,563	1,104,459	119,303,022	(3,335,777)	115,967,245
Transmission	4030.2	49,421,354	(1,487,507)	47,933,847	(1,926,373)	46,007,474
Distribution	4030.3	61,585,051	2,596,244	64,181,295	(996,103)	63,185,192
General	4030.4	7,111,545	(340,761)	6,770,784	0	6,770,784
Total Depreciation Expense		236,316,513	1,872,435	238,188,948	(6,258,253)	231,930,695
TOTAL DEPRECIATION, ACRETION & AMT EXP		257,795,295	7,813,091	265,608,386	(2,948,135)	262,660,251
Loss on Disposition Util Prop	411	653,208	(490,000)	163,208		163,208
TOTAL		**$ 258,448,503**	**$ 7,323,091**	**$ 265,771,594**	**$ (2,948,135)**	**$ 262,823,459**

Attachment A

SOAH DOCKET NO. **473-21-0538**
PUC DOCKET NO. **51415**
COMPANY NAME **Southwestern Electric Power Company**
TEST YEAR END **31-Mar-20**

PFD Schedule V
Taxes Other Than FIT
Page 1 of 1

		Company Test Year Total (a)	Company Adjustments To Test Year (b)	REBUTTAL Co Requested Test Year Total Electric (c)	PFD Adj To Company Request (d)	PFD Adjusted Total Electric (e) = (c) + (d)
TAXES OTHER THAN FIT						
Non Revenue Related						
Ad Valorem Taxes-Texas		19,752,787	1,626,874	21,379,661	(3,255,645)	18,124,016
Ad Valorem Taxes-Other States		42,662,719	3,422,126	46,084,845	0	46,084,845
Total Property		62,415,506	5,049,000	67,464,506	(3,255,645)	64,208,861
Payroll Taxes						
FICA		6,971,664	45,867	7,017,531	(258,162)	6,759,369
FUTA		40,193	0	40,193	0	40,193
SUTA		40,777	0	40,777	0	40,777
Total Payroll		7,052,634	45,867	7,098,501	(258,162)	6,840,339
Franchise Taxes Texas	408.33	0	0	0	0	0
Other States		4,393,405	(4,393,405)	0	0	0
Total Franchise		4,393,405	(4,393,405)	0	0	0
Other Sales and Use Tax		39,720	(39,720)	0	0	0
Other		85,990	(84,295)	1,695	0	1,695
Total Other		125,710	(124,015)	1,695	0	1,695
TOTAL NON REVENUE RELATED TAXES		**73,987,255**	**577,447**	**74,564,702**	**(3,513,807)**	**71,050,895**
Revenue Related						
State Gross Receipts - Texas		6,215,215	2,454,209	8,669,424	(1,231,432)	7,437,992
State Gross Receipts - Other		8	0	8	0	8
Local Gross Receipts - Texas		9,357,340	(3,757,069)	5,600,271	(792,642)	4,807,629
Local Gross Receipts - Other		8,327,064	0	8,327,064	0	8,327,064
PUC Assessment - Texas		989,177	390,598	1,379,775	(195,988)	1,183,787
PUC Assessment - Other		1,188,520	0	1,188,520	0	1,188,520
State Gross Margins - Texas		462,753	(231,947)	230,806	(372,377)	(141,571)
TOTAL REVENUE RELATED TAXES		**26,540,077**	**(1,144,209)**	**25,395,868**	**(2,592,438)**	**22,803,430**
TOTAL TAXES OTHER THAN INCOME TAXES		**100,527,332**	**(566,762)**	**99,960,570**	**(6,106,245)**	**93,854,325**

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415
COMPANY NAME Southwestern Electric Power Company
TEST YEAR END 31-Mar-20

FEDERAL INCOME TAXES - METHOD 1

	113,324,648	(10,903,917)	102,420,731
	1,458,080	0	1,458,080
	3,719,670	4,664,032	8,383,702
Return	0	0	0
	0	0	0
Less:	0	0	0
Snynchronized Interest	73,596	0	73,596
DITC Amortization	0	0	0
Amortization of Protected Excess DFIT	16,602,098	0	16,602,098
Preferred Dividend Exclusion	0	0	0
Medicare Subsidy	135,178,092	(6,239,885)	128,938,207
AFUDC		0	0
Restricted Stock Plan - Tax Deduction		0	0
Prior Year T/R Adjustment	542,023	0	542,023
Accelerated Book Depletion	10,069,545	0	10,069,545
Parent Company Tax Loss Saving	1,538,774	0	1,538,774
TOTAL	0	0	0
Plus:		0	0
AFUDC			0
Business Meals not Deductible	12,150,342	0	12,150,342
Additional Depreciation			
Stock based Compensation			
AFUDC-BIP Amortization			
FAS 106 (Medicare Reimbursement)			
Business Meals Not Deductible			
TOTAL			

REBUTTAL

Co Requested Test Year Total Electric	**PFD Adj To Company Request**	**PFD Adjusted Total Electric**
(a)	**(b)**	**(c) = (a) + (b)**
387,226,159	(58,606,702)	328,619,457

TAXABLE COMPONENT OF RETURN	264,198,409	(52,366,816)	211,831,592
TAX FACTOR (1/1-.21)(.21)	26.582278%	26.582278%	26.582278%
TOTAL FIT BEFORE ADJUSTMENTS	**70,229,957**	**(13,920,293)**	**56,309,664**
Adjustments:			
Amortization of DITC	(1,458,080)	0	(1,458,080)
Amortization of Excess DFIT	(3,719,670)	(4,664,032)	(8,383,702)
	0	0	0
Prior Year T/R Adjustment	0	0	0
		0	0
TOTAL	(5,177,750)	(4,664,032)	(9,841,782)
		0	
TOTAL FEDERAL INCOME TAXES	**65,052,207**	**(18,584,325)**	**46,467,882**

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD JURISDICTIONAL & FUNCTIONAL MODEL
FOR TEST YEAR JUNE 30, 2020

	TOTAL COMPANY			TEXAS RETAIL		
DESCRIPTION	**TOTAL COMPANY REQUESTED AMOUNT**	**PFD ADJUSTMENT**	**PFD ADJUSTED TOTAL COMPANY**	**COMPANY REQUESTED TEXAS RETAIL**	**PFD ADJUSTMENT TO TEXAS RETAIL**	**PFD ADJUSTED TEXAS RETAIL**
SUMMARY - EQUALIZED RETURN						
RATE BASE	5,360,322,879	(520,566,509)	4,839,756,370	2,025,542,720	(238,979,972)	1,786,562,748
RETURN	387,226,159	(58,606,701)	328,619,458	146,323,859	(25,016,248)	121,307,611
RATE OF RETURN ON RATE BASE	7.22%	-0.43%	6.79%	7.22%		6.79%
PRESENT O&M EXP	550,283,659	(23,625,522)	526,658,137	215,193,067	(14,433,904)	200,759,163
INCR IN 903-CUST ACCT & COLL FACTC	1,117,582		1,117,582	548,442	(26,200)	522,242
TOT OPERATION & MAINT EXP	551,401,241	(23,625,522)	527,775,719	215,741,509	(14,460,104)	201,281,405
DEPRECIATION & AMORTIZATION EXP	265,771,594	(2,948,135)	262,823,459	105,928,834	(3,999,442)	101,929,392
SO2 ALLOWANCE	4	0	4	1	0	1
NON-REVENUE TAXES OTHER THAN INC	74,564,702	(3,513,807)	71,050,895	28,266,008	(1,680,382)	26,585,626
REVENUE RELATED TAXES ARK	0	0	0	0	0	0
REVENUE RELATED TAXES LA	9,515,593	0	9,515,593	0	0	0
REVENUE RELATED TAXES TX	10,821,602	(2,592,438)	8,229,164	10,821,602	(935,821)	9,885,781
TOTAL TAXES OTHER THAN INCOME	94,901,897	(6,106,245)	88,795,652	39,087,610	(2,616,203)	36,471,407
REV RELATED TAX ON REVENUE DEFCIENCY	5,058,674		5,058,674	2,482,493	(118,595)	2,363,898
FED INCOME TAX LIABILITY	65,052,207	(18,584,325)	46,467,882	24,601,826	(7,502,124)	17,099,702
TOTAL OPERATING EXPENSES	982,185,617	(51,264,227)	930,921,390	387,842,273	(28,696,469)	359,145,805
COST OF SERVICE	1,369,411,776	(109,870,929)	1,259,540,848	534,166,132	(53,712,717)	480,453,415
TOTAL PROPOSED CEEDITS	(195,477,466)	0	(195,477,466)	(82,636,594)	4,826,353	(77,810,240)
BASE REVENUE REQUIREMENT	**1,173,934,310**	**(109,870,929)**	**1,064,063,381**	**451,529,538**	**(48,886,363)**	**402,643,175**

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD CLASS-FUNCTIONAL SUMMARY
FOR TEST YEAR JUNE 30, 2020

	Generation Energy	Total Capacity				Total Capacity	Distribution Customer	Total Rate Base Revenue Requirement
		Generation Demand	Transmission Demand	Distribution Primary	Distribution Secondary			
1 Basic Residential	10,430,079	73,170,363	34,220,198	22,903,082	18,528,481	**148,822,124**	13,166,421	**172,418,624**
2								
3 General Service with Demand	1,018,314	7,812,815	3,644,839	3,046,980	2,466,402	**16,971,037**	1,492,041	**19,481,392**
4 General Service without Demand	322,184	2,511,009	1,172,995	1,201,655	974,293	**5,859,952**	1,123,696	**7,305,832**
5								
6 Cotton Gin	23,978	66,716	31,788	193,256	157,295	**449,056**	2,074	**475,107**
7								
8 Lighting and Power-Secondary	10,268,402	54,254,095	25,425,582	17,730,844	14,344,762	**111,755,284**	2,656,917	**124,680,603**
9 Lighting and Power-Primary	2,995,901	11,031,478	5,176,150	3,953,772	433,126	**20,594,525**	380,793	**23,971,220**
10								
11 Large Lighting and Power-Primary	734,000	3,315,901	1,550,824	244,304	133,551	**5,244,581**	217,532	**6,196,112**
12 Large Lighting and Power-Transmission	3,394,016	11,263,027	5,403,989	1,924	1,526	**16,670,465**	310,437	**20,374,918**
13								
14 Oilfield Primary	1,660,069	5,259,127	2,470,116	2,289,579	217,297	**10,236,119**	351,585	**12,247,773**
15 Oilfield Secondary	85,085	434,857	204,328	145,899	116,319	**901,402**	3,502	**989,989**
16								
17 Metal Melting-Primary	172,980	537,910	250,419	527,623	51,025	**1,366,977**	86,404	**1,626,361**
18 Metal Melting-Transmission	238,287	735,426	342,783	9,626	6,363	**1,094,198**	47,505	**1,379,990**
19 Metal Melting-Secondary	9,231	30,676	14,120	69,194	56,269	**170,259**	5,707	**185,197**
20								
21 Municipal Pumping	277,854	860,492	404,293	438,718	355,114	**2,058,617**	75,002	**2,411,473**
22 Municipal Service	129,406	529,183	246,432	222,058	178,929	**1,176,601**	170,688	**1,476,695**
23								
24 Municipal Lighting	130,007	391,774	178,231	337,876	273,149	**1,181,030**	1,136,591	**2,447,628**
25 Public Street and Highway	4,859	15,636	7,262	13,500	10,979	**47,377**	38,016	**90,252**
26								
27 Private, Outdoor, Area	237,573	734,190	334,465	637,573	515,915	**2,222,144**	2,055,495	**4,515,211**
28 Customer-Owned Lighting	32,476	97,873	44,872	91,950	74,565	**309,261**	27,165	**368,902**
29								
35 **Total**	**32,164,699**	**173,052,547**	**81,123,687**	**54,059,414**	**38,895,359**	**347,131,007**	**23,347,572**	**402,643,278**

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD CLASS MODEL SUMMARY
FOR TEST YEAR JUNE 30, 2020

DESCRIPTION	RESIDENTIAL BASIC	RESIDENTIAL DG	GS W/ DEMAND	GS WO/ DEMAND	COTTON GIN	GS DG	LIGHT & POWER SEC	LIGHT & POWER PRI	LIGHT & POWER DG	LLP PRI
SUMMARY - EQUALIZED RETURN										
RATE BASE	761,788,151	605,497	86,016,949	31,250,884	1,934,195	50,400	558,732,246	105,446,858	704,730	28,092,780
RETURN	51,725,415	41,113	5,840,551	2,121,935	131,332	3,422	37,937,920	7,159,842	47,851	1,907,500
RATE OF RETURN ON RATE BASE	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
PRESENT O&M EXP	85,733,514	69,338	9,622,527	3,720,438	203,037	5,458	60,804,955	12,384,861	170,899	3,177,117
INCR IN 903-CUST ACCT & COLL FACTC	217,946	88	20,769	12,165	1,436	13	183,554	12,280	805	7,374
TOT OPERATION & MAINT EXP	85,951,460	69,426	9,643,297	3,732,603	204,473	5,472	60,988,509	12,397,142	171,704	3,184,491
DEPRECIATION & AMORTIZATION EXP	43,618,367	36,563	4,947,105	1,803,624	118,284	2,997	31,694,871	6,003,504	39,302	1,538,383
SO2 ALLOWANCE	1	0	0	0	0	0	0	0	0	0
NON-REVENUE TAXES OTHER THAN INC	11,415,708	9,239	1,300,959	479,384	29,559	765	8,255,095	1,546,269	11,904	408,611
REVENUE RELATED TAXES ARK	0	0	0	0	0	0	0	0	0	0
REVENUE RELATED TAXES LA	0	0	0	0	0	0	0	0	0	0
REVENUE RELATED TAXES TX	4,129,943	3,010	470,080	146,868	5,905	399	3,493,852	689,394	4,614	270,009
TOTAL TAXES OTHER THAN INCOME	15,545,651	12,248	1,771,039	626,253	35,463	1,164	11,748,947	2,235,663	16,518	678,620
REV RELATED TAX ON REVENUE DEFCIENCY	986,520	398	94,011	55,064	6,501	59	830,845	55,587	3,646	33,377
FED INCOME TAX LIABILITY	7,458,685	5,850	851,988	312,542	18,902	498	5,336,705	953,740	6,942	258,236
TOTAL OPERATING EXPENSES	153,560,684	124,485	17,307,439	6,530,085	383,624	10,190	110,599,878	21,645,635	238,112	5,693,106
COST OF SERVICE	205,286,099	165,598	23,147,990	8,652,020	514,955	13,612	148,537,798	28,805,477	285,963	7,600,606
TOTAL PROPOSED CREDITS	(33,013,458)	(19,616)	(3,678,284)	(1,346,188)	(39,848)	(1,927)	(24,120,664)	(4,834,257)	(22,494)	(1,404,493)
BASE REVENUE REQUIREMENT	**172,272,641**	**145,983**	**19,469,706**	**7,305,832**	**475,107**	**11,685**	**124,417,134**	**23,971,220**	**263,469**	**6,196,112**

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD CLASS MODEL SUMMARY
FOR TEST YEAR JUNE 30, 2020

LLP TRAN	OILFIELD PRI	METAL MELTING PRI	METAL MELTING TRANS	METAL MELTING SEC	OILFIELD SEC	PUMPING SERVICE	MUNICIPAL SERVICE	MUNICIPAL LIGHTING	PUBLIC HIGHWAY	PRIVATE AREA LIGHTING	CUST-OWNED LIGHTING	TOTAL
93,058,024	53,016,721	6,467,541	5,902,818	735,800	4,561,234	10,310,226	6,271,826	10,778,186	392,491	18,950,263	1,494,930	1,786,562,748
6,318,640	3,599,835	439,146	400,801	49,961	309,708	700,064	425,857	731,839	26,650	1,286,723	101,506	121,307,611
6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
11,378,422	6,474,063	815,817	745,991	81,324	493,053	1,195,292	745,067	907,436	35,619	1,819,455	175,478	200,759,163
40,150	12,957	1,875	44	282	2,575	1,778	(263)	1,923	351	3,613	543	522,260
11,418,572	6,487,021	817,692	746,035	81,606	495,628	1,197,070	744,804	909,359	35,971	1,823,068	176,022	201,281,423
5,154,647	3,007,261	377,988	328,323	45,931	254,608	601,634	368,021	674,108	23,373	1,201,754	88,744	101,929,392
0	0	0	0	0	0	0	0	0	0	0	0	1
1,342,528	787,288	97,053	85,539	11,517	66,781	153,247	94,413	165,013	6,014	296,089	22,651	26,585,626
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
19,148	197,437	66,314	75,628	4,221	2,584	59,928	49,162	73,877	1,512	111,698	10,199	9,885,781
1,361,676	984,725	163,366	161,167	15,738	69,365	213,176	143,575	238,889	7,526	407,787	32,851	36,471,407
181,735	58,651	8,489	198	1,277	11,657	8,050	(1,192)	8,704	1,590	16,355	2,460	2,363,982
796,535	468,832	59,225	50,027	7,179	42,859	93,918	59,629	108,856	3,926	190,550	14,078	17,099,702
18,913,165	11,006,489	1,426,760	1,285,749	151,731	874,118	2,113,848	1,314,837	1,939,917	72,387	3,639,515	314,154	359,145,907
25,231,805	14,606,325	1,865,906	1,686,550	201,692	1,183,825	2,813,912	1,740,694	2,671,756	99,037	4,926,237	415,660	480,453,518
(4,856,887)	(2,358,552)	(239,545)	(306,561)	(16,495)	(193,837)	(402,439)	(264,000)	(224,128)	(8,785)	(411,026)	(46,758)	(77,810,240)
20,374,918	**12,247,773**	**1,626,361**	**1,379,990**	**185,197**	**989,989**	**2,411,473**	**1,476,695**	**2,447,628**	**90,252**	**4,515,211**	**368,902**	**402,643,278**

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD TCRF BASELINES
FOR TEST YEAR JUNE 30, 2020

DESCRIPTION	TCRF BASELINE	RESIDENTIAL BASIC	RESIDENTIAL DG	GS W/ DEMAND	GS WO/ DEMAND	COTTON GIN	GS DG	LIGHT & POWER SEC	LIGHT & POWER PRI	LIGHT & POWER DG	LLP PRI
TIC	487,591,029	205,962,749	111,753	21,938,119	7,060,969	128,601	11,163	152,470,678	31,266,158	130,684	9,268,154
ROR	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
RTIC	33,107,431	13,984,871	7,588	1,489,598	479,440	8,732	758	10,352,759	2,122,972	8,873	629,308
TDEPR	18,861,569	7,967,293	4,323	848,636	273,141	4,975	432	5,898,050	1,209,474	5,055	358,522
TFIT	5,130,407	2,166,109	1,175	231,085	74,378	871	118	1,606,050	329,340	1,376	97,626
TOT	6,095,885	2,574,917	1,397	274,281	88,280	1,590	140	1,906,260	390,904	1,634	115,875
TCRED	(70,834,945)	(29,929,943)	(16,240)	(3,183,747)	(1,024,716)	(26,750)	(1,620)	(22,127,153)	(4,537,470)	(18,965)	(1,345,031)
revreqt	(7,660,103)	(3,236,753)	(1,756)	(344,388)	(110,843)	(2,520)	(175)	(2,393,504)	(490,822)	(2,052)	(145,493)
ATC	67,409,237	28,474,256	15,450	3,032,935	976,176	17,779	1,543	21,079,001	4,322,532	18,067	1,281,318
ALLOC		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
ClassALLOC		42.24%	0.02%	4.50%	1.45%	0.03%	0.00%	31.27%	6.41%	0.03%	1.90%
RR	**59,749,134**	**25,237,502**	**13,694**	**2,688,547**	**865,333**	**15,259**	**1,368**	**18,685,498**	**3,831,710**	**16,015**	**1,135,825**
BD		2,163,595,580	2,013,476	205,483,534	66,333,658	5,234,123	114,497	6,522,773	1,370,803	8,452	358,160
BD BASIS		kWh	kWh	kWh	kWh	kWh	kWh	kW	kW	kW	kW

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD TCRF BASELINES
FOR TEST YEAR JUNE 30, 2020

LLP TRAN	OILFIELD PRI	METAL MELTING PRI	METAL MELTING TRANS	METAL MELTING SEC	OILFIELD SEC	PUMPING SERVICE	MUNICIPAL SERVICE	MUNICIPAL LIGHTING	PUBLIC HIGHWAY	PRIVATE AREA LIGHTING	CUST-OWNED LIGHTING	TOTAL
32,360,709	14,983,459	1,467,947	2,041,182	80,097	1,044,089	2,438,406	1,486,875	1,056,355	20,673	1,991,867	270,340	487,591,029
6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
2,197,292	1,017,377	99,674	138,596	5,439	70,894	165,568	100,959	71,726	1,404	135,248	18,356	33,107,431
1,251,815	579,608	56,785	78,959	3,098	40,389	94,325	57,517	40,863	800	77,052	10,458	18,861,569
340,857	157,828	15,462	21,500	844	9,062	25,869	15,774	11,208	84	20,950	2,843	5,130,407
404,589	187,330	18,353	25,520	1,001	12,983	30,493	18,594	13,210	254	24,902	3,380	6,095,885
(4,696,315)	(2,174,459)	(213,034)	(296,225)	(11,624)	(178,056)	(351,732)	(214,477)	(152,375)	(6,273)	(289,453)	(39,285)	(70,834,945)
(508,017)	(235,213)	(23,045)	(32,043)	(1,258)	(18,397)	(38,088)	(23,225)	(16,499)	(463)	(31,301)	(4,248)	(7,660,103)
4,473,853	2,071,456	202,943	282,193	11,073	144,345	337,109	205,560	146,041	2,858	275,375	37,374	67,409,237
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
6.64%	3.07%	0.30%	0.42%	0.02%	0.21%	0.50%	0.31%	0.22%	0.00%	0.41%	0.06%	100%
3,965,836	**1,836,244**	**179,899**	**250,149**	**9,816**	**125,948**	**299,021**	**182,335**	**129,541**	**2,395**	**244,073**	**33,126**	**59,749,134**
1,433,918	765,088	194,231	220,660	24,392	40,837	60,026,735	26,943,781	26,004,489	1,070,584	49,398,122	6,704,408	
kW	kW	kW	kW	kW	kW	kWh	kWh	kWh	kWh	kWh	kWh	

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD DCRF BASELINES
FOR TEST YEAR JUNE 30, 2020

DESCRIPTION	DCRF BASELINE	RESIDENTIAL BASIC	RESIDENTIAL DG	GS W/ DEMAND	GS WO/ DEMAND	COTTON GIN	GS DG	LIGHT & POWER SEC	LIGHT & POWER PRI	LIGHT & POWER DG	LLP PRI
DIC_{RC}	411,184,963	185,511,173	288,996	24,256,526	11,132,747	1,547,765	19,802	129,122,916	16,476,754	274,234	1,613,289
ROR_{AT}	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
$DEPR_{RC}$	24,342,308	10,964,970	17,117	1,436,387	658,121	58,388	1,175	7,664,097	983,494	16,118	95,408
FIT_{RC}	4,207,614	1,898,758	2,966	248,200	113,827	11,328	204	1,326,484	169,317	2,747	16,374
OT_{RC}	5,442,530	2,458,138	3,832	321,841	147,691	13,000	263	1,715,051	218,808	3,617	21,355
$ALLOC_{CLASS}$		45.13%	0.07%	5.90%	2.71%	0.34%	0.00%	31.44%	4.01%	0.07%	0.39%
$DISTREV_{RC}$	61,911,911	27,918,075	43,538	3,653,446	1,675,552	187,809	2,986	19,473,078	2,490,390	41,102	242,680
$BD_{RC\text{-}CLASS}$		2,163,595,580	2,013,476	205,483,534	66,333,658	5,234,123	114,497	6,522,773	1,370,803	8,452	358,160
$BD_{RC\text{-}CLASS}$ BASIS		kWh	kWh	kWh	kWh	kWh	kWh	kW	kW	kW	kW

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD DCRF BASELINES
FOR TEST YEAR JUNE 30, 2020

LLP TRAN	OILFIELD PRI	METAL MELTING PRI	METAL MELTING TRANS	METAL MELTING SEC	OILFIELD SEC	PUMPING SERVICE	MUNICIPAL SERVICE	MUNICIPAL LIGHTING	PUBLIC HIGHWAY	PRIVATE AREA LIGHTING	CUST-OWNED LIGHTING	TOTAL
91,751	9,887,949	2,207,512	15,772	512,979	1,142,741	3,324,019	1,991,028	7,760,859	313,483	12,982,668	709,999	411,184,963
6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
4,991	589,309	131,735	872	30,466	55,093	198,891	118,657	466,740	7,637	800,572	42,069	24,342,308
739	101,321	22,661	133	5,275	10,110	34,377	20,512	80,336	1,589	133,070	7,287	4,207,614
1,146	131,209	29,306	199	6,815	12,296	44,525	26,645	103,959	1,688	171,732	9,414	5,442,530
0.02%	2.41%	0.54%	0.00%	0.12%	0.27%	0.81%	0.49%	1.89%	0.07%	3.15%	0.17%	100.00%
13,106	1,493,230	333,592	2,276	77,387	155,091	503,494	301,004	1,177,997	32,200	1,986,897	106,980	61,911,911
1,433,918	765,088	194,231	220,660	24,392	40,837	60,026,735	26,943,781	26,004,489	1,070,584	49,398,122	6,704,408	
kW	kW	kW	kW	kW	kW	kWh	kWh	kWh	kWh	kWh	kWh	

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD REVENUE DISTRIBUTION
FOR TEST YEAR JUNE 30, 2020

Class	Present Base Revenue	Present Base + TCRF + DCRF Revenue	Cost-Based Electric Revenue	PFD Cost Based Gross Bill Change	Cost-Based % Change	PFD Target Gross Bill Change	PFD Target Gross % Change	PFD Target Net Bill Change	PFD Target Net % Change	PFD Revenue Requirements
Residential	**147,077,995**	**153,227,969**	**172,418,624**	**25,340,629**	**17.23%**	**25,340,629**	**17.23%**	**19,190,655**	**12.52%**	**172,418,624**
General Service w/ Demand	16,998,369	17,638,468	19,481,392	2,483,022	14.61%	2,508,967	14.76%	1,868,869	10.60%	19,507,337
General Service w/o Demand	5,669,225	5,875,817	7,305,832	1,636,607	28.87%	1,646,337	29.04%	1,439,745	24.50%	7,315,562
Lighting & Power Sec	100,037,248	104,243,548	124,680,603	24,643,355	24.63%	24,809,402	24.80%	20,603,103	19.76%	124,846,650
Lighting & Power Pri	23,827,679	24,896,460	23,971,220	143,541	0.60%	175,465	0.74%	(893,316)	-3.59%	24,003,144
Cotton Gin	231,688	249,858	475,107	243,419	105.06%	100,228	43.26%	82,058	32.84%	331,916
Large Lighting & Power Pri	5,298,104	5,538,446	6,196,112	898,008	16.95%	906,260	17.11%	665,918	12.02%	6,204,364
Large Lighting & Power Tran	22,387,847	23,470,723	20,374,918	(2,012,929)	-8.99%	(1,985,795)	-8.87%	(3,068,670)	-13.07%	20,402,053
Metal Melting-Sec	143,749	151,026	185,197	41,448	28.83%	41,695	29.01%	34,418	22.79%	185,444
Metal Melting-Pri	1,402,858	1,496,310	1,626,361	223,503	15.93%	225,669	16.09%	132,217	8.84%	1,628,527
Metal Melting-Tran	1,498,929	1,672,408	1,379,990	(118,939)	-7.93%	(117,102)	-7.81%	(290,581)	-17.37%	1,381,827
Oilfield Pri	10,636,387	11,134,950	12,247,773	1,611,386	15.15%	1,627,698	15.30%	1,129,134	10.14%	12,264,084
Oilfield Sec	588,848	591,392	989,989	401,140	68.12%	254,736	43.26%	252,193	42.64%	843,584
Total Commercial & Industrial	**188,720,933**	**196,959,406**	**218,914,493**	**30,193,561**	**16.00%**	**30,193,561**	**16.00%**	**21,955,087**	**11.15%**	**218,914,493**
Municipal Pumping	2,279,333	2,390,468	2,411,473	132,140	5.80%	150,041	6.58%	38,905	1.63%	2,429,373
Municipal Service	1,650,219	1,701,604	1,476,695	(173,524)	-10.52%	(162,563)	-9.85%	(213,948)	-12.57%	1,487,656
Municipal Lighting	2,267,085	2,351,444	2,447,628	180,543	7.96%	198,712	8.77%	114,353	4.86%	2,465,797
Public Street & Hwy Lighting	30,170	33,447	90,252	60,082	199.14%	13,051	43.26%	9,775	29.22%	43,221
Total Muni & Muni Lighting	**6,226,806**	**6,476,962**	**6,426,047**	**199,241**	**3.20%**	**199,241**	**3.20%**	**(250,156)**	**-3.86%**	**6,226,806**
Private, Outdoor, Area Lighting	4,150,616	4,307,444	4,515,211	364,595	8.78%	364,595	8.78%	207,767	4.82%	4,515,211
Customer-Owned Lighting	293,022	324,093	368,902	75,880	25.90%	75,880	25.90%	44,809	13.83%	368,902
Total Lighting	**4,443,639**	**4,631,537**	**4,884,113**	**440,474**	**9.91%**	**440,474**	**9.91%**	**252,576**	5.45%	**4,884,113**
Total Firm Retail	**346,469,372**	**361,295,874**	**402,643,278**	**56,173,905**	**16.21%**	**56,173,905**	**16.21%**	**41,347,404**	**11.44%**	**402,643,278**

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD RATES SUMMARY
FOR TEST YEAR JUNE 30, 2020

RATE SHEET	RATE CLASS	TYPE OF RATE	Current Rates	SWEPCO Proposed Rates	Staff Proposed Rates	
IV-1	Residential	Customer Charge	$ 8.00	$ 10.00	$ 9.44	per customer
		Net Metering Admin Fee	$ 8.00	$ 10.00	$ 9.44	per customer
		kWh Charge (on peak)	$ 0.072266	$ 0.092448	$ 0.084717	per kWh
		Block 1 kWh Charge	$ 0.053589	$ 0.068555	$ 0.062835	per kWh
		Block 2 kWh Charge	$ 0.043789	$ 0.056855	$ 0.051354	per kWh
IV-2	General Service W/D	Customer Charges	$ 11.59	$ 15.00	$ 13.30	per customer
		Net Metering Admin Fee	$ 8.00	$ 10.00	$ 9.44	
		Block 2 kW Charge	$ 4.87	$ 2.95	$ 5.59	per kW
		kWh Charge	$ 0.061302	$ 0.075419	$ 0.070526	per kWh
IV-2	General Service Wo/D	Customer Charges	$ 11.59	$ 15.00	$ 13.30	per customer
		kWh Charge	$ 0.061302	$ 0.089950	$ 0.082768	per kWh
IV-3	Lighting & Power Secondary	Block 2 kW Charge	$ 9.38	$12.48	$ 9.23	per kW
		kWh Charge	$ 0.016155	$ 0.022038	$ 0.015610	per kWh
	Lighting & Power Primary	Block 2 kW Charge	$ 9.16	$ 12.18	$ 9.23	per kW
		kWh Charge	$ 0.014904	$ 0.020470	$ 0.015610	per kWh
IV-4	Large Lighting & Power Primary	Block 2 kW Charge	$ 10.02	$ 13.32	$ 11.73	per kW
		kWh Charge	$ 0.010382	$ 0.013816	$ 0.012166	per kWh
IV-4	Large Lighting & Power Transmission	Block 2 kW Charge	$ 6.87	$ 7.93	$ 6.26	per kW
		kWh Charge	$ 0.010382	$ 0.012212	$ 0.010075	per kWh
Various		kVAR charge	$ 0.51	$ 0.66	$ 0.51	per kVAR
		Additional Transformer Cap	$ 1.60	$ 2.08	$ 1.86	per kVAR
IV-6	Metal Melting-Secondary	Block 2 kW Charge	$ 4.63	$ 6.16	$ 5.27	per kW
		kWh Charge	$ 0.015014	$ 0.019925	$ 0.020074	per kWh
	Metal Melting-Primary	Block 2 kW Charge	$ 4.54	$ 6.04	$ 5.33	per kW
		kWh Charge	$ 0.014613	$ 0.019422	$ 0.015868	per kWh
IV-7	Metal Melting-69kV	Block 2 kW Charge	$ 3.42	$ 4.55	$ 3.15	per kVA
		kWh Charge	$ 0.010211	$ 0.013569	$ 0.009425	per kWh
IV-8	Off Peak Rider	Customer Charge	$ 81.14	$ 107.90	$ 94.12	per customer
IV-13	Oilfield Service	Primary kW Charge	$ 7.93	$ 10.55	$ 9.14	per kW
		Primary kWh Charge	$ 0.01155	$ 0.015507	$ 0.013236	per kWh
		Secondary kW Charge	$ 8.29	$ 11.02	$ 11.88	per kW
		Secondary kWh Charge	$ 0.01209	$ 0.016109	$ 0.017226	per kWh
IV-14	Cotton Gin Service	Customer Charge	$ 29.21	$ 38.84	$ 41.85	per customer
		Per kWh (May-Oct)	$ 0.097105	$ 0.129129	$ 0.139113	per kWh
		Per kWh (Nov - Apr)	$ 0.050171	$ 0.066717	$ 0.061343	per kWh
IV-19	Municipal Pumping	kWh Charge	$ 0.036899	$ 0.041875	$ 0.039328	per kWh
IV-20	Municipal Service	kWh Charge	$ 0.058369	$ 0.066241	$ 0.052619	per kWh
IV-21/22	Recreational Lighting and	Customer Charge	$ 7.35	$ 10.01	$ 9.25	per customer
	Customer-Supplied Lighting	kWh Charge	$ 0.040229	$ 0.055472	$ 0.050752	per kWh

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
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PFD RATES SUMMARY
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IV-23	MUNICIPAL STREET LIGHTING					
IV-24	Rate Code 521					
IV-25	175W Mercury Vapor	Wood/Overhead	$ 8.71	$ 6.84	$ 9.00	per fixture
IV-31	400W Mercury Vapor	Wood/Overhead	$ 14.82	$ 11.63	$ 15.32	
	400W Mercury Vapor	Non-Wood/Overhead	$ 16.44	$ 12.91	$ 16.99	
	400W Mercury Vapor	Base-Mounted/Overhead	$ 18.24	$ 14.32	$ 18.85	
	400W Mercury Vapor	Base-Mounted/Underground	$ 20.44	$ 16.05	$ 21.13	
	70W High Pressure Sodium	Wood/Overhead	$ 10.51	$ 8.25	$ 10.86	
	70W High Pressure Sodium	Non-Wood/Overhead	$ 12.13	$ 9.52	$ 12.54	
	70W High Pressure Sodium	Base-Mounted/Overhead	$ 13.92	$ 10.93	$ 14.39	
	70W High Pressure Sodium	Non-Wood/Underground	$ 14.34	$ 11.26	$ 14.82	
	70W High Pressure Sodium	Base-Mounted/Underground	$ 16.12	$ 12.65	$ 16.66	
	150W High Pressure Sodium	Wood/Overhead	$ 19.21	$ 15.08	$ 19.85	
	150W High Pressure Sodium	Non-Wood/Overhead	$ 20.84	$ 16.36	$ 21.54	
	150W High Pressure Sodium	Base-Mounted/Overhead	$ 22.65	$ 17.78	$ 23.41	
	150W High Pressure Sodium	Non-Wood/Underground	$ 23.05	$ 18.09	$ 23.82	
	150W High Pressure Sodium	Base-Mounted/Underground	$ 24.84	$ 19.50	$ 25.67	
	250W High Pressure Sodium	Wood/Overhead	$ 22.31	$ 17.51	$ 23.06	
	250W High Pressure Sodium	Non-Wood/Overhead	$ 23.94	$ 18.79	$ 24.74	
	250W High Pressure Sodium	Base-Mounted/Overhead	$ 25.72	$ 20.19	$ 26.58	
	250W High Pressure Sodium	Non-Wood/Underground	$ 26.14	$ 20.52	$ 27.02	
	250W High Pressure Sodium	Base-Mounted/Underground	$ 27.93	$ 21.93	$ 28.87	
	300W High Pressure Sodium	Wood/Overhead	$ 32.58	$ 25.58	$ 33.67	
	300W High Pressure Sodium	Non-Wood/Overhead	$ 34.21	$ 26.85	$ 35.36	
	300W High Pressure Sodium	Base-Mounted/Overhead	$ 36.00	$ 28.26	$ 37.21	
	300W High Pressure Sodium	Non-Wood/Underground	$ 36.41	$ 28.58	$ 37.63	
	300W High Pressure Sodium	Base-Mounted/Underground	$ 38.20	$ 29.99	$ 39.48	
	500W High Pressure Sodium	Wood/Overhead	$ 36.65	$ 28.77	$ 37.88	
	500W High Pressure Sodium	Non-Wood/Overhead	$ 38.28	$ 30.05	$ 39.56	
	500W High Pressure Sodium	Base-Mounted/Overhead	$ 40.07	$ 31.45	$ 41.41	
	500W High Pressure Sodium	Non-Wood/Underground	$ 40.48	$ 31.78	$ 41.84	
	500W High Pressure Sodium	Base-Mounted/Underground	$ 42.26	$ 33.17	$ 43.68	
	35W Low Pressure Sodium	Wood/Overhead	$ 10.67	$ 8.38	$ 11.03	
	55W Low Pressure Sodium	Wood/Overhead	$ 10.67	$ 8.38	$ 11.03	
	55W Low Pressure Sodium	Non-Wood/Overhead	$ 12.29	$ 9.65	$ 12.70	
	55W Low Pressure Sodium	Base-Mounted/Overhead	$ 14.09	$ 11.06	$ 14.56	
	90W Low Pressure Sodium	Wood/Overhead	$ 20.36	$ 15.98	$ 21.04	
	90W Low Pressure Sodium	Non-Wood/Overhead	$ 21.99	$ 17.26	$ 22.73	
	90W Low Pressure Sodium	Base-Mounted/Overhead	$ 23.79	$ 18.68	$ 24.59	
	90W Low Pressure Sodium	Non-Wood/Underground	$ 24.19	$ 18.99	$ 25.00	
	90W Low Pressure Sodium	Base-Mounted/Underground	$ 25.99	$ 20.40	$ 26.86	
	180W Low Pressure Sodium	Wood/Overhead	$ 34.61	$ 27.17	$ 35.77	
	180W Low Pressure Sodium	Non-Wood/Overhead	$ 36.24	$ 28.45	$ 37.46	
	180W Low Pressure Sodium	Base-Mounted/Overhead	$ 38.04	$ 29.86	$ 39.32	
	180W Low Pressure Sodium	Non-Wood/Underground	$ 38.44	$ 30.18	$ 39.73	
	180W Low Pressure Sodium	Base-Mounted/Underground	$ 40.24	$ 31.59	$ 41.59	
	Rate Code 529-(CLOSED)					
	75W Mercury Vapor		$ 4.18	$ 5.27	$ 4.32	per fixture
	100W Mercury Vapor		$ 4.61	$ 5.81	$ 4.76	
	400W Mercury Vapor		$ 9.39	$ 11.83	$ 9.71	
	Rate Code 528 (OPEN)					
	100W Mercury Vapor		$ 2.01	$ 2.53	$ 2.08	per fixture
	175W Mercury Vapor		$ 2.75	$ 3.46	$ 2.84	
	250W Mercury Vapor		$ 3.80	$ 4.79	$ 3.93	
	150W Mercury Vapor		$ 5.60	$ 7.06	$ 5.79	
	400W Metal Halide		$ 4.96	$ 6.25	$ 5.13	
	400W Metal Halide		$ 6.45	$ 8.13	$ 6.67	
	1000W Metal Halide		$ 15.00	$ 18.90	$ 15.50	
	70W High Pressure Sodium		$ 2.11	$ 2.66	$ 2.18	
	100W High Pressure Sodium		$ 2.75	$ 3.46	$ 2.84	
	150W High Pressure Sodium		$ 3.07	$ 3.87	$ 3.17	
	250W High Pressure Sodium		$ 4.54	$ 5.72	$ 4.69	
	400W High Pressure Sodium		$ 6.45	$ 8.13	$ 6.67	
	1000W High Pressure Sodium		$ 14.90	$ 18.77	$ 15.40	

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD RATES SUMMARY
FOR TEST YEAR JUNE 30, 2020

	Rate Code 538 (CLOSED)								
	6,000L Incandescent		$	8.71	$	10.97	$	9.00	per fixture
	16000L Mercury Vapor Wood		$	9.05	$	11.40	$	9.35	
	Rate Code 535 (OPEN)								
	100W Mercury Vapor		$	2.53	$	3.19	$	2.61	
	175W Mercury Vapor		$	3.49	$	4.40	$	3.61	
	250W Mercury Vapor		$	4.80	$	6.05	$	4.96	
	400W Mercury Vapor		$	7.06	$	8.89	$	7.30	
	1000W Mercury Vapor		$	15.83	$	19.94	$	16.36	
	150W Metal Halide		$	6.26	$	7.89	$	6.47	
	400W Metal Halide		$	8.14	$	10.26	$	8.41	
	1000W Metal Halide		$	18.92	$	23.84	$	19.55	
	70W High Pressure Sodium		$	2.66	$	3.35	$	2.75	
	100W High Pressure Sodium		$	3.48	$	4.38	$	3.60	
	150W High Pressure Sodium		$	3.87	$	4.88	$	4.00	
	250W High Pressure Sodium		$	5.73	$	7.22	$	5.92	
	400W High Pressure Sodium		$	8.14	$	10.26	$	8.41	
	1000W High Pressure Sodium		$	18.75	$	23.62	$	19.38	
IV-26	PUBLIC STREET & HIGHWAY LIGHTING								
IV-27	Rate Codes 534,539,739 (OPEN)								
	100W Mercury Vapor		$	1.38	$	1.57	$	2.15	per fixture
	175W Mercury Vapor		$	2.12	$	2.41	$	3.30	
	250W Mercury Vapor		$	3.20	$	3.63	$	4.98	
	400W Mercury Vapor		$	5.01	$	5.69	$	7.79	
	1000W Mercury Vapor		$	11.73	$	13.31	$	18.25	
	400W Metal Halide		$	5.00	$	5.67	$	7.78	per fixture
	1000W Metal Halide		$	12.01	$	13.63	$	18.68	
	70W High Pressure Sodium		$	1.08	$	1.23	$	1.68	
	100W High Pressure Sodium		$	1.60	$	1.82	$	2.49	
	150W High Pressure Sodium		$	1.92	$	2.18	$	2.99	
	250W High Pressure Sodium		$	3.41	$	3.87	$	5.30	
	400W High Pressure Sodium		$	5.34	$	6.06	$	8.31	
	1000W High Pressure Sodium		$	12.46	$	14.14	$	19.38	
IV-28	PRIVATE, OUTDOOR & AREA LIGHTING								
IV-29	Private 2500L	Incandescent	$	4.54	$	6.15	$	5.27	per fixture
IV-30	Private 7700	Mercury Vapor	$	6.05	$	8.19	$	7.02	
IV-32	Private 7700 w/Pole	Mercury Vapor	$	6.05	$	8.19	$	7.02	
IV-33	Area 100W	Mercury Vapor	$	5.42	$	7.34	$	6.30	per fixture
	Area 175W	Mercury Vapor	$	6.05	$	8.19	$	7.03	
	Area 250W	Mercury Vapor	$	6.84	$	9.26	$	7.95	
	Area 400W	Mercury Vapor	$	8.17	$	11.06	$	9.50	
	Area 1000W	Mercury Vapor	$	13.43	$	18.18	$	15.60	
	Area 400W	Metal Halide	$	4.79	$	6.48	$	5.57	
	Area 1000W	Metal Halide	$	11.14	$	15.08	$	12.94	
	Area 100W	High Pressure Sodium	$	2.05	$	2.78	$	2.38	
	Area 250W	High Pressure Sodium	$	3.38	$	4.58	$	3.93	
	Area 400W	High Pressure Sodium	$	4.79	$	6.48	$	5.56	
	Area 1000W	High Pressure Sodium	$	11.07	$	14.99	$	12.85	
	Outdoor 175W	Mercury Vapor	$	8.14	$	11.02	$	9.46	per fixture
	Outdoor 400W	Mercury Vapor	$	11.37	$	15.39	$	13.20	
	Outdoor 70W	High Pressure Sodium	$	8.60	$	11.64	$	9.99	
	Outdoor 150W	High Pressure Sodium	$	12.00	$	16.24	$	13.93	
	Floodlighting 250W	Metal Halide	$	9.26	$	12.53	$	10.75	per fixture
	Floodlighting 400W	Metal Halide	$	10.53	$	14.25	$	12.23	
	Floodlighting 1000W	Metal Halide	$	18.97	$	25.68	$	22.03	
	Floodlighting 150W	High Pressure Sodium		$7.98		$10.80	$	9.27	
	Floodlighting 250W	High Pressure Sodium		$9.16		$12.40	$	10.64	
	Floodlighting 400W	High Pressure Sodium		$10.37		$14.04	$	12.04	
	Floodlighting 1000W	High Pressure Sodium		$18.82		$25.48	$	21.85	

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD RATE CASE EXPENSES
FOR TEST YEAR JUNE 30, 2020

RESIDENTIAL	$	0.000244	$/kWh
TOTAL COMMERCIAL & SMALL INDUSTRIAL C	$	0.000174	$/kWh
TOTAL MUNICIPAL CLASS	$	0.000117	$/kWh
TOTAL LIGHTING CLASS	$	0.000249	$/kWh
TOTAL INDUSTRIAL CLASS		0.306%	% of Base Revenues

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD RATE CASE EXPENSES
FOR TEST YEAR JUNE 30, 2020

Docket No. 51415 REC Costs	$ 1,281,301
TX Retail Allocation (ENERGY)	36.96%
TX Retail Allocated REC Costs	$ 473,593

	Class ENERGY	REC Costs in Base Rates	kWh at Meter	REC Opt Out Credit/kWh
Residential	31.72%	$ 150,230.47		
Commercial	45.13%	$ 213,749.07	3,105,486,129	$ 0.000069
Industrial	20.65%	$ 97,810.06	1,481,924,742	$ 0.000066
Municipal	1.67%	$ 7,911.46		
Lighting	0.82%	$ 3,891.89		

STATE OFFICE OF ADMINISTRATIVE HEARINGS

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SERVICE LIST

AGENCY:	**Public Utility Commission of Texas (PUC)**
STYLE/CASE:	**SOUTHWESTERN ELECTRIC POWER COMPANY**
SOAH DOCKET NUMBER:	**473-21-0538**
REFERRING AGENCY CASE:	**51415**

STATE OFFICE OF ADMINISTRATIVE HEARINGS	**ADMINISTRATIVE LAW JUDGE** **ALJ STEVEN NEINAST**
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