Control Number: 51415

Item Number: 324

Addendum StartPage: 0

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

WORKPAPERS TO THE

DIRECT TESTIMONY AND EXHIBITS OF BILLIE S. LACONTE

ON BEHALF OF
TEXAS INDUSTRIAL ENERGY CONSUMERS

April 1, 2021

324

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIRST REQUEST FOR INFORMATION

Question No. TIEC 1-16:

Referring to page 6:

a. Please provide all documents surrounding the settlement(s) in which SWEPCO agreed to retire the Dolet Hills Power Station.

b. Please provide a schedule of the net book value of SWEPCO's share of the environmental investments at the Dolet Hills Power Station that SWEPCO sought and received approval from the PUCT in Docket No. 46449.

c. Please confirm that in Docket No. 46449, Dolet Hills was projected to retire in the year 2046. If not confirm, please state why not.

Response No. TIEC 1-16:

a. The 2019 SWEPCO Arkansas rate case settlement is publicly available at: http://www.apscservices.info/pdf/19/19-008-U_301_1.pdf

b. Please see attachment TIEC 1-16b Attachment 1.xlsx

c. Confirmed.

Prepared By: Michael A. Baird | Title: Mng Dir Acctng Policy & Rsrch
Prepared By: Christopher N. Martel | Title: Regulatory Consultant Sr

Sponsored By: Thomas P. Brice | Title: VP Regulatory & Finance

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

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

ORDER ON REHEARING

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

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

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

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

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

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

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

Production Plant Net Salvage

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

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

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

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

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

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

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

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

Transmission Plant

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

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

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

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

Distribution Plant

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

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

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

General Plant

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

Depreciation Reserve

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

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

Payroll

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

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

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

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

Incentive Compensation

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

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR AUTHORITY TO CHANGE RATES

DIRECT TESTIMONY OF

THOMAS P. BRICE

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

OCTOBER 2020

Q. HAS SWEPCO PROVIDED ALL THE SCHEDULES AND WORKPAPERS TO COMPLY WITH THE COMMISSION'S REQUIREMENTS FOR BASE RATE PROCEEDINGS?

A. Yes. However, SWEPCO requests a waiver of the portions of the Rate Filing Package (RFP) that requests information related to fuel reconciliation proceedings. SWEPCO is not filing a fuel reconciliation proceeding in this docket; therefore, the schedules dealing with fuel reconciliation proceedings are not applicable. Schedule V of the RFP will provide more detail on specific schedules that are not required in this proceeding related to fuel reconciliation, as well as certain other waivers requested by SWEPCO.

Additionally, SWEPCO requested a waiver of the requirement to file Schedule S (Independent Audit of the Application) in Docket No. 50917. No objection to SWEPCO's waiver application has been raised, and the Commission Staff recommended approval of the request. SWEPCO and Commission Staff filed an agreed proposed notice of approval on August 12, 2020.

V. DOLET HILLS POWER STATION RATEMAKING TREATMENT

Q. PLEASE DESCRIBE THE DOLET HILLS POWER STATION.

A. The Dolet Hills Power Station (Dolet Hills) is located southeast of Mansfield, Louisiana and is a 650 net MW lignite fueled generating unit. Lignite for Dolet Hills is mined from the adjacent Dolet Hills and the Oxbow reserves (collectively referred to as DH Mines), located in Desoto Parish and Red River Parish, respectively.

Dolet Hills is owned by Cleco Power, LLC (CLECO), SWEPCO, Northeast Texas Electric Cooperative, Inc. (NTEC), and Oklahoma Municipal Power Authority

(OMPA). SWEPCO's ownership interest is 262 MW or 40.234% of the unit's total capacity. 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.

Q. HAS THE ECONOMICALLY USEFUL LIFE OF DOLET HILLS CHANGED SINCE THE COMMISSION LAST REVIEWED ITS USEFUL LIFE?

A. Yes. In May 2020, lignite production operations at the DH Mines ceased based on SWEPCO's and CLECO's determination that all economically recoverable lignite had been depleted. Dolet Hills will continue to operate for the benefit of customers through the peak energy use season in 2021 with lignite that has been mined and has been or will be delivered to the plant this year and into 2021. Dolet Hills will retire no later than December 31, 2021.

Q. HOW DID CIRCUMSTANCES CHANGE AT DOLET HILLS AND THE DH MINES SINCE THE COMMISSION LAST REVIEWED THE USEFUL LIFE OF THE PLANT?

A. Due to *force majeure* events in 2017 and 2018 and increases in lignite production costs, in 2019 SWEPCO reduced operations at the mine to engage a single dragline excavator instead of the three dragline excavators previously used. Despite diligent efforts to reduce mining costs, SWEPCO determined early in 2020 that the economically recoverable reserves were depleted and that mining activities should cease and the plant be retired by the end of 2021. The Company evaluated mining operations and costs of operating Dolet Hills beyond 2021. That analysis, which is included in my workpapers, demonstrates that retirement of Dolet Hills will result in up to $180 million in estimated fuel savings.

Q. ACCORDING TO GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (GAAP) AND STANDARD REGULATORY PRACTICE, OVER WHAT TIME PERIOD WILL THE REMAINING UNDEPRECIATED VALUE OF DOLET HILLS BE DEPRECIATED?

A. Consistent with GAAP and standard regulatory practice, the remaining undepreciated value of Dolet Hills will be depreciated through 2021. SWEPCO realizes that depreciation of Dolet Hills over its 2021 economically useful life for ratemaking purposes would have a significant impact on SWEPCO's base rates that are to be set in this proceeding.

Q. DOES SWEPCO HAVE A PROPOSAL THAT WILL SIGNIFICANTLY MITIGATE THE RATE IMPACT OF DEPRECIATING THE PLANT OVER ITS ECONOMICALLY USEFUL LIFE?

A. Yes. When the United States Congress reduced the federal corporate income tax rate to 21% in 2018, an excess of Accumulated Deferred Income Taxes (ADIT) was created for SWEPCO. In SWEPCO's previous general rate case, Docket No. 46449, the Commission ordered that excess deferred taxes resulting from the reduction in the federal income tax rate would be addressed in SWEPCO's next base-rate case. SWEPCO proposes that the balance of the unprotected excess ADIT and the refund provision associated with the protected excess ADIT (SWEPCO has been amortizing the protected excess ADIT in accordance with the Tax Cuts and Jobs Act of 2017 and setting up the Texas portion as a provision for refund) be used to offset the

PUC DOCKET NO. 46449
SOAH DOCKET NO. 473-17-1764

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

ORDER ON REHEARING

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

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

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

625

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

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

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

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

Rate Base

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

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

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

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

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

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

Dolet Hills

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

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

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

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

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

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

30. [Deleted.]

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

PUC DOCKET NO. 46449

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR AUTHORITY TO CHANGE RATES

DIRECT TESTIMONY OF

PAUL W. FRANKLIN

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

DECEMBER 2016

than retiring Dolet Hills and replacing it with alternative capacity, based on the analyses upon which Cleco relied.

Q. ARE THE DOLET HILLS RETROFITS USED AND USEFUL?

A. Yes, they are. The SNCR at Dolet Hills entered service in March 2013. The ACI, DSI, baghouse and ID fan systems were completed in June 2014, and began continuous operation by the MATS compliance date of April 16, 2015. The retrofits have allowed Dolet Hills to continue to be a valuable source of electricity for SWEPCO and its customers.

V. EXPECTED USEFUL LIVES OF SWEPCO'S GENERATING UNITS

Q. HOW ARE THE EXPECTED USEFUL LIVES OF THE POWER PLANTS IN THE SWEPCO GENERATION FLEET DETERMINED?

A. The expected life of a power plant depends on many factors, including the original design, the current condition of the unit, and the potential cost in the future to replace the generation with another source. The expected useful lives of SWEPCO's generation units are listed in Table 2 above.

Q. HAVE YOU PRESENTED TESTIMONY ON THE USEFUL LIVES OF SWEPCO'S POWER PLANTS IN PAST DOCKETS BEFORE THIS COMMISSION?

A. Yes. In Docket No. 40443 before this Commission I supported the expected lives for SWEPCO's generating units based on the in-service year, generating technology, fuel type, and unit-specific conditions.

SOAH DOCKET NO. 473-20-4204
PUC DOCKET NO. 50997

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' TWELFTH REQUEST FOR INFORMATION

The following questions refer to the Direct Testimony of Thomas P. Brice:

Question No. TIEC 12-26:

Referring to pages 10-11:

a. Please provide all documents provided to the Commission in Docket No. 46449 concerning the independent economic unit disposition analysis SWEPCO presented.
b. Please confirm that this unit disposition analysis assumed that Dolet Hills Power Station would operate until 2046. If not confirm, please state what the assumed retirement date for DHPS was.
c. Please confirm that the 2011 Life of Mine plan assumed that the Oxbow mine would cease producing lignite in 2026. If not confirm, please state in what year the 2011 Life of Mine plan assumed that the Oxbow mine would stop producing lignite.
d. How did this unit disposition analysis assume SWEPCO and CLECO would obtain the lignite necessary to run DHPS in the period after mining activities at Oxbow mine ceased and before the retirement date of DHPS? In responding, please provide all documents, studies, and analyses supporting the assumed method of obtaining lignite during that period.

Response No. TIEC 12-26:

a. Please see the following items in Docket No. 46449 on the PUC Interchange: Rebuttal Testimony of Kurt C. Strunk for Southwestern Electric Power Company filed May 19, 2017; Workpapers for Rebuttal Testimony of Kurt C. Strunk filed May 22, 2017; and SWEPCO discovery responses to OPUC's 17th filed May 31, 2017, OPUC's 18th filed June 1, 2017, and Sierra Club's 4th filed June 2, 2017. See also live supplemental testimony of Kurt C. Strunk on June 15, 2017.
b. Confirm. The analysis utilized the depreciable life for Dolet Hills power station of 2046, as approved by the PUC in Docket Nos. 40443 and 46449. In Docket No. 40443, the Company advocated changing the depreciable life of the plant to 2026, but the PUC adopted the position of intervenors recommending a 2046 depreciable life for Dolet Hills power station.
c. The 2011 Life of Mine plan assumed DHLC produced and delivered lignite to Dolet Hills during the period 2011 through 2026.
d. Details of lignite deliveries were not quantified by SWEPCO and CLECO beyond 2026. For lignite prices beyond 2026, the unit disposition analysis inflated costs from the DHLC 2011 Life of Mine plan. It was known at the time of the Oxbow acquisition that

the total mining permit area contained an additional 80 million tons of lignite not yet under lease. The Company thus expected the Oxbow reserves to provide sufficient lignite to operate Dolet Hills power station through the station's PUC-approved depreciable life.

Prepared By: Jonathan M. Griffin	Title: Regulatory Consultant Staff
Sponsored By: Thomas P. Brice	Title: VP Regulatory & Finance

PUC DOCKET NO. 37364

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR AUTHORITY TO CHANGE RATES

DIRECT TESTIMONY OF

DAVID A. DAVIS

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

AUGUST 28, 2009

salvage into a gross removal component and a gross salvage component. Thus, for SEC financial reporting purposes, the amount of gross removal costs included in depreciation rates and accruals and the actual removal cost charges to accumulated depreciation can readily be determined and reclassified to a regulatory liability account.

Q. HAS THE COMMISSION PREVIOUSLY ADDRESSED THE ARO ACCOUNTING THAT SWEPCO PROPOSES TO USE?

A. Yes. As I mentioned previously, SWEPCO's proposed treatment of AROs in this filing is identical to that used by TCC, which the Commission approved in Docket No. 33309.

Q. WERE ANY ADJUSTMENTS MADE TO ACCUMULATED DEPRECIATION AS A RESULT OF SWEPCO TEXAS GENERATION PLANT RE-REGULATION FOLLOWING PASSAGE OF SENATE BILL 547 BY THE TEXAS LEGISLATURE?

A. Yes. The Depreciation Study adjusts generation plant accumulated depreciation to add back (increase accumulated depreciation) removal costs accrued net of removal costs incurred through December 31, 2007. The net removal cost was deducted from generation accumulated depreciation in accordance with SWEPCO's implementation of FASB ASC 410 in 2003. In total, this adjustment adds $13,538,188 to generation accumulated depreciation at December 31, 2007 and treats SWEPCO generation property as regulated for the Depreciation Study.

VI. STUDY RESULTS

Q. PLEASE EXPLAIN THE RESULTS OF YOUR STUDY FOR PRODUCTION PLANT.

A. For Steam Production Plant, the composite rate decreased from 2.90% to 1.44%. For purposes of this rate comparison, the steam production depreciation rate used for Pirkey and Dolet Hills generating stations, which were placed in-service in 1985 and 1986, was 2.90%. The 2.90% equals the Total Steam rate authorized by the PUCT in Docket No. 5301 in 1984. Rates for Pirkey and Dolet Hills generating stations are being requested for Commission initial approval in this rate proceeding.

In addition, rates for Other Production Plant (Mattison Plant) are being requested for initial approval in this rate proceeding, therefore a comparison to current rates is not meaningful.

As previously mentioned, the average service lives that were used to calculate SWEPCO's current depreciation rates are not determinable since the rates the Commission Staff witness recommended in Docket No. 5301 were composite rates that did not separately set out the life parameters and net salvage parameters. Using generation plant unit lives from the Gilbert Associates, Inc. February 1983 Depreciation Study in Docket No. 5301 and comparing those lives with this filing's study indicates that Steam Production rates decreased primarily due to the increase in life estimates used in the this filing's study. A comparison of the life estimate increase (excluding the Mattison Plant) is shown below:

	Average Service Life (Years) From Gilbert Associates in Docket No. 5301	Life Span (Years) From Exhibit DAD-1, Page 25
Gas and Oil Units	**24 to 44**	**65**
Coal and Lignite Units	**36 to 39**	**60**

Q. PLEASE EXPLAIN THE RESULTS OF YOUR STUDY FOR TRANSMISSION PLANT.

A. For Transmission Plant, the composite rate decreased from 3.08% to 2.18%. As previously mentioned, the average service lives and net salvage percentages that were used to calculate SWEPCO's current depreciation rates are not available from Docket No. 5301. Using depreciation parameters from Gilbert Associates, Inc. February 1983 Depreciation Study in Docket No. 5301 and comparing these parameters to the depreciation parameters in this filing's study indicates that the decrease was caused by an increase in the average service life for five accounts (352, 353, 354, 355, and 356), partially offset by a decrease in the net salvage ratio for four accounts (353, 354, 355, and 356).

Q. PLEASE EXPLAIN THE RESULTS OF YOUR STUDY FOR DISTRIBUTION PLANT.

A. For Distribution Plant, the composite rate decreased from 4.17% to 2.17%. As previously mentioned, the average service lives and net salvage percentages that were used to calculate SWEPCO's current depreciation rates are not available from Docket

SCHEDULE IV

SOUTHWESTERN ELECTRIC POWER COMPANY
Generating Unit Retirement Dates

Station & Unit	Capability MW	Year Installed	Year Retired	Life Span (Years)
GAS & OIL UNITS				
Arsenal Hill				
Unit 5	110	1960	2025	65
Knox Lee				
Unit 2	25	1950	2015	65
Unit 3	25	1952	2017	65
Unit 4	77	1956	2021	65
Unit 5	344	1974	2039	65
Lieberman				
Unit 1	25	1947	2012	65
Unit 2	26	1949	2014	65
Unit 3	112	1957	2022	65
Unit 4	110	1959	2024	65
Lone Star				
Unit 1	50	1954	2019	65
Mattison				
Unit 1	85	2007	2052	45
Unit 2	85	2007	2052	45
Unit 3	85	2007	2052	45
Unit 4	85	2007	2052	45
Wilkes				
Unit 1	175	1964	2029	65
Unit 2	357	1970	2035	65
Unit 3	348	1971	2036	65
COAL & LIGNITE UNITS				
Dolet Hills				
Unit 1	262	1986	2046	60
Flint Creek				
Unit 1	264	1978	2038	60
Pirkey				
Unit 1	580	1985	2045	60
Welsh				
Unit 1	528	1977	2037	60
Unit 2	528	1980	2040	60
Unit 3	528	1982	2042	60

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR AUTHORITY TO CHANGE RATES

DIRECT TESTIMONY OF

MICHAEL A. BAIRD

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

OCTOBER 2020

Southwestern Electric Power Company
Dolet Hills Recommendation

Description	Utility Account	Month	Gross Plant	Accum. Depr.	Allocated CWIP	Gross Plant + Allocated CWIP	Depreciation Rates	Depreciation July 2020 - Mar-21	Total Company Net Book	Texas Net Book	Total Company Depreciation	Texas Net Book
Dolet Hills Plant	31100 - Structures, Improvemnt-Coal	06/2020	57,127,514	51,966,358	686,515	57,814,029	2.00%	867,210	4,293,946	1,586,330	528,106	195,100.28
Dolet Hills Plant	31200 - Boiler Plant Equip-Coal	06/2020	211,216,144	139,942,797	2,538,234	213,754,378	2.36%	3,783,452	67,489,895	24,933,071	8,300,477	3,066,479.62
Dolet Hills Plant	31400 - Turbogenerator Units-Coal	06/2020	39,735,805	33,443,811	477,515	40,213,320	2.13%	642,408	5,649,586	2,087,150	694,834	256,695.35
Dolet Hills Plant	31500 - Accessory Elect Equip-Coal	06/2020	12,575,554	10,578,211	151,123	12,726,678	2.10%	200,445	1,796,898	663,836	220,998	81,644.10
Dolet Hills Plant	31600 - Misc Pwr Plant Equip-Coal	06/2020	16,666,082	13,644,739	200,280	16,866,362	2.39%	302,330	2,719,013	1,004,496	334,407	123,541.45
Dolet Hills Plant	31700 - ARO Steam Production Plant	06/2020	1,257,350	548,720	-	1,257,350	37.57%	354,315	354,315	130,896	43,577	16,098.71
Dolet Hills Plant	31700 - ARO Steam Production Plant	06/2020	(26,693)	(1,937)	-	(26,693)	61.83%	(12,378)	(12,378)	(4,573)	(1,522)	(562.41)
			338,551,758	250,122,699	4,053,667	342,605,425			82,291,276	30,401,206	10,120,876	3,738,997
				CWIP	4,053,667							
								Account 1080161	29,763,258	10,995,563		
								Demo Estimate	10,740,383	3,967,864		
								Total Dolet NBV	**122,794,917**	**45,364,633**		
								Excess ADIT Off-Set	**(82,311,412)**	**(30,408,645)**		
								Remaining Value	40,483,505	14,955,988		
								4 Year Amortization	10,120,876	3,738,997		

624

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S FIFTH REQUEST FOR INFORMATION

Question No. OPUC 5-7:

Please refer to the Direct Testimony of Mr. Michael Baird, page 23. Please provide a calculation of the amount by which the retirement of Dolet Hills and the proposal to recover the unrecovered undepreciated balance (after the TCJA refund offset) impacts the revenue requirement for Texas customers by customer class. Please provide the same analysis of the impact to the Texas revenue requirement by customer classes if the unrecovered undepreciated balance is not allowed to be recovered over four years, but continues to be recovered using the currently approved depreciation rates.

Response No. OPUC 5-7:

Please see OPUC 5-7 Attachment 1 for the requested revenue requirement by customer class for SWEPCO's proposed recovery of Dolet Hills over four years including supporting calculations. SWEPCO has not performed a calculation for recovery of Dolet Hills using the currently approved depreciation rates.

Prepared By: Earlyne T. Reynolds	Title: Reg Pricing & Analysis Mgr
Prepared By: Randall W. Hamlett	Title: Dir Regulatory Acctg Svcs
Sponsored By: Jennifer L. Jackson	Title: Reg Pricing & Analysis Mgr
Sponsored By: John O. Aaron	Title: Dir Reg Pricing & Analysis
Sponsored By: Michael A. Baird	Title: Mng Dir Acctng Policy & Rsrch

UNITED STATES DISTRICT COURT
FOR THE WESTERN DISTRICT OF ARKANSAS
TEXARKANA DIVISION

Sierra Club, et al., Plaintiffs, v. United States Army Corps of Engineers, et al., Defendants.	))))))))))	Civil No. 4:10-cv-04017-RGK Electronically Filed

<u>CONSENT DECREE</u>

WHEREAS, the Sierra Club, National Audubon Society, and Audubon Arkansas (collectively "Plaintiffs") filed a Complaint on February 11, 2010, and a First Amended Complaint on July 16, 2010 (collectively, "Complaints") against the United States Army Corps of Engineers and the District Engineer of the Vicksburg District (the "COE") challenging a permit issued on December 17, 2009 (the "COE Permit") to Southwestern Electric Power Company ("SWEPCO") (Plaintiffs and SWEPCO are collectively referred to as the "Parties") for certain work associated with the construction of the John W. Turk, Jr. Power Plant (the "Turk Plant"); and

WHEREAS, the Complaints alleged claims for injunctive and declaratory relief pursuant to the Administrative Procedure Act, 5 U.S.C. § 701 *et seq.*, ("APA") based on allegations that the COE permit failed to conform to the requirements of the National Environmental Policy Act, 42 USC §§ 4321-70a ("NEPA"), and its implementing regulations, and the Federal Water Pollution Control Act, 33 USC § 1344 (the "CWA"), and its implementing regulations; and

18. "Turk Air Permit" shall mean the permit issued to the Turk Plant under the Prevention of Significant Deterioration and the Title V Operating Permit Programs of the Clean Air Act and which is identified as Permit No. 2123-AOP-R0.

19. "Turk NPDES Permit" shall mean the permit issued to the Turk Plant under the CWA to authorize wastewater discharges and which is identified as Permit No AR0051136.

20. "Turk Solid Waste Permit" shall mean the permit issued to the Turk Plant under the Arkansas Solid Waste Management Act that allows the disposal of coal combustion byproducts at the Turk Plant and which is identified as Permit No. 0311-S3N.

21. "Welsh Unit 2" shall mean Unit 2 at SWEPCO's Welsh Power Station in Titus County, Texas.

22. "Wind Energy Resources" shall mean any new wind generating resource interconnected to the bulk electric system or SWEPCO's distribution system for which a wind resource analysis has been performed that specifies a long-term average annual capacity factor of forty (40) percent or greater and, if the resource will be secured through a long-term power purchase agreement, provides for the payment of liquidated damages if minimum annual deliveries of energy consistent with that long-term average are not satisfied.

IV. FUTURE ENERGY RESOURCES

A. Future Development at the Turk Plant Site

23. SWEPCO shall not construct any additional generating units on the site of the Turk Plant. In addition, during the operation of the Turk Plant, SWEPCO shall not construct any new coal-fired units at any location in Arkansas that is within a 30-mile radius of the Turk Plant site.

B. Welsh Unit 2

24. Beginning on the date that the Turk Plant commences Commercial Operation, SWEPCO will limit the Annual Capacity Factor of Welsh Unit 2 to no more than sixty (60) percent.

25. SWEPCO will seek all necessary regulatory approvals, and will permanently retire Welsh Unit 2 by December 31, 2014, unless SPP has identified and approved transmission mitigation measures that must be completed prior to the retirement of Welsh Unit 2 that have in-service dates beyond December 31, 2014, in which case SWEPCO will permanently retire Welsh Unit 2 as soon as all required approvals have been issued and all necessary transmission mitigation measures have been completed, but no later than December 31, 2016.

C. Clean Energy Resources

26. During the period from October 30, 2011 through December 31, 2014, SWEPCO and its affiliates, including any entities that own an interest in any coal-fired generating unit operated by SWEPCO or its affiliates that is located in Arkansas, Louisiana, Oklahoma or Texas, will construct or secure the energy from a total of 400 MW (nameplate rating) of new Clean Energy Resources. Power purchase agreements to secure the energy from Clean Energy Resources shall have a minimum term of 20 years. Renewable Energy Certificates (RECs) or other clean energy attributes from these resources shall not be sold or transferred to any third party, or used to meet any existing requirements for clean or renewable energy. Nothing in this Consent Decree shall preclude SWEPCO from relying on investments made, or power purchases contracted, pursuant to this Consent Decree to demonstrate compliance with, seek RECs for, or otherwise satisfy the requirements of or participate in any federal, state, or local statutory or regulatory programs related to Clean Energy Resources or climate change related requirements, so long as those programs are promulgated after the effective date of this Consent Decree.

27. New wind projects developed to satisfy this commitment must be sited consistent with the U.S. Fish and Wildlife Service Interim Guidance for minimizing impacts from wind development on birds and wildlife, dated May 13, 2003, and be located outside of any Important Bird Areas identified by the National Audubon Society (*see* http://iba.audubon.org/iba/siteSearch.do) as of the date of this Consent Decree.

V. TURK PLANT OPERATIONS

A. Total PM_{10} Emission Rate

28. SWEPCO shall determine compliance with the Total PM_{10} Emission Rate established in the Turk Air Permit via a stack test each year performed pursuant to the requirements established in the Turk Air Permit using the reference testing and monitoring methods and procedures specified in 40 C.F.R. Part 60, Appendix A1, Method 5 or Method 17 (filterable only), and Method 202 (condensable only), as of the Effective Date of this Consent Decree. At its option, SWEPCO may use any method that is approved by EPA subsequent to the Effective Date of this Consent Decree. Use of any particular method shall conform to the EPA requirements specified in 40 C.F.R. Part 60, Appendix A, or any federally approved method contained in the Arkansas SIP.

29. SWEPCO will examine the Total PM_{10} Emission Rate measured during stack tests performed within the first three years after commencement of Commercial Operation of the Turk Plant. Within 120 days after completion of the annual stack test required in the third year of Commercial Operation, SWEPCO shall evaluate the data to determine whether a lower Total PM_{10} Emission Rate can be established pursuant to this Paragraph that would apply during normal operation of the Turk Plant, without including periods of start-up, shut down or Malfunction. If the highest measured total PM_{10} Emission Rate measured during the stack tests is 0.022 lb/MMBtu or higher, no lower Total PM_{10} Emission Rate will be established. If the

REDACTED

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

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

TABLE OF CONTENTS

depreciation expense of $1.114 million and a reduction to the Company's proposed revenue requirement of $1.152 million.[608]

For the same reasons advocated by Cities, CARD rejects SWEPCO's proposal to reduce the life span of the Dolet Hills Plant from 60 years to 40 years. Like Cities, CARD argues that SWEPCO failed to show that Dolet Hills would have no remaining reserves after 2026, nor does SWEPCO provide any analysis of whether alternative fuel sources are available to supplement the lignite from Oxbow Mine.

ALJs' Analysis

The ALJs do not find that SWEPCO has supported its proposal to reduce the life span of the Dolet Hills Plant from 60 years to 40 years. SWEPCO offers a single argument to support its request—that the Dolet Hills plant must match the availability of its specific fuel source. The availability of the fuel from the one source should not determine a plant's service life because it is very likely that SWEPCO can obtain fuel from other sources. When SWEPCO recently purchased the Oxbow mine, for example, the fuel resources were extended under the contract for the Dolet Hills plant to at least 2026.[609] It is important in determining the service life of the Dolet Hills Plant to note SWEPCO's Pirkey Plant, which closely resembles the Dolet Hills Plant, has a 60-year service life.

Additionally, the ALJs agree with Cities that the settlement approved by the LPSC is not binding in this case. Furthermore, that settlement did not determine the service life for the unit; it required only that SWEPCO and CLECO extend the service life through 2026 at a minimum for depreciation purposes. The language suggests a minimum service life, not the maximum service life.

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[608] Cities Ex. 3 (Kollen Direct) at 53 and Schedule LK-9.

[609] Cities Ex. 3 (Kollen Direct) at 50.

In SWEPCO's last Texas base rate case, filed August 28, 2009, SWEPCO proposed a 60-year service life. That proceeding recommended a 60-year life span for the Dolet Hills Plant.[610] Other than the fuel source argument, SWEPCO has not shown a justifiable reason to shorten the useful life of the Dolet Hills Plant to 40 years in this proceeding. Therefore, the ALJs recommend that the Dolet Hills Plant's current expected service life of 60 years remain. This results in a reduction in depreciation expense of $1.114 million and a reduction to the Company's proposed revenue requirement of $1.152 million.[611]

d. Welsh Unit 2 Life

As discussed previously, as part of its settlement on the Turk Plant, SWEPCO agreed to retire Welsh Unit 2 in 2016. Accordingly, SWEPCO performed depreciation studies with a useful life for Welsh Unit 2 ending 2016.

Cities and CARD reject SWEPCO's proposal to retire Welsh Unit 2 in 2016. Cities and CARD advocate that Welsh Unit 2's original useful life of 60 years be maintained. They propose that if the unit is ultimately retired, SWEPCO can request rate treatment to accommodate that retirement in a future rate case. Meanwhile, they contend that the Commission in this case should continue to assume that the useful life of Welsh 2 for ratemaking purposes is consistent with that of Welsh Units 1 and 3. Assuming that 2040 is reasonable retirement for Welsh 2, the effect of Cities' and CARD's recommendation is a reduction to depreciation expense of $1.042 million and a reduction in revenue requirement of $1.079 million.[612]

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[610] Cities Ex. 3 (Kollen Direct) at 50.

[611] Cities Ex. 3 (Kollen Direct) at 53 and Schedule LK-9.

[612] Cities Ex. 3, (Kollen Direct) at 45-46 and Schedule LK-8.

ALJs' Analysis

The ALJs recommend a disallowance for the Turk Plant. However, regardless of whether the Commission accepts the ALJs' recommendation, the retirement date for Welsh Unit 2 should remain at 2040 (the original useful life of 60 years). As part of its settlement on the Turk Plant, SWEPCO agreed to retire Welsh Unit 2 in 2016. The issue of whether to retire Welsh Unit 2 was not fully addressed in this proceeding. The ALJs agree with the intervenors that a separate proceeding should be initiated to consider the retirement of Welsh Unit 2 along with SWEPCO's plans to replace the capacity from Welsh Unit 2. Accordingly, SWEPCO's proposal to accelerate recovery of the remaining undepreciated plant costs as part of this proceeding should be rejected. Because Welsh Unit 2 remains operational (although at a reduced capacity), and until the Commission has had an opportunity to evaluate the retirement of Welsh Unit 2, the ALJs recommend that the retirement date for Welsh Unit 2 be 2040. If SWEPCO eventually retires Welsh Unit 2 in 2016, it can request that retirement date in a future rate proceeding. A 2040 retirement date results in a reduction to depreciation expense of $1.042 million and a reduction in revenue requirement of $1.079 million.[613]

e. Production Plant Net Salvage

SWEPCO requested an overall production plant net salvage rate of negative 3.4%. The contested issues related to production plant net salvage include: (i) the plant demolition studies conducted for SWEPCO's power plants; (ii) the escalation of production plant removal costs to the expected retirement date; and (iii) the inclusion of interim retirements and net salvage on interim retirements in the production net salvage calculation.

i. SWEPCO Plant Demolition Studies

Rather than using a generic production plant net salvage rate or one that historically has been used, SWEPCO calculated its production plant net salvage using engineering studies of the

[613] Cities Ex. 3, (Kollen Direct) at 45-46 and Schedule LK-8.

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cost to demolish and remove each of its power plants. These calculations took into account the specific attributes of each plant and were performed by Sargent & Lundy, LLC (S&L), a recognized power plant engineering firm.[614] SWEPCO witness David A. Davis testified that many utilities over the past 10 to 15 years have begun using demolition studies based on data specific for their power plants, instead of relying on generic net salvage values or historically used ratios.[615] Demolition studies take into account the specific, unique characteristics of the depreciable power plant. Mr. Davis asserted that this approach is better than using historical ratios or generic net salvage values.[616] The methodologies and approaches used by S&L in conducting the plant demolition studies were sponsored by SWEPCO witness Steven R. Bertheau, Senior Vice President and Project Director with S&L.[617] The overall net salvage rate of negative 3.4% requested by SWEPCO is inclusive of: (i) the removal costs and salvage in the S&L studies; (ii) the escalation of the S&L removal costs and salvage for each plant to the expected retirement date of the plant; and (iii) net salvage on interim retirements. Mr. Davis testified that SWEPCO's net salvage rate of negative 3.4% is reasonable compared to the Intervenors who simply made recommendations without any quantifiable connection between the objections they raised and their overall net salvage recommendations.[618]

Cities' Position

Cities claim that the Commission should exclude SWEPCO's proposed dismantling costs included in its requested depreciation rates.[619] The Company's estimated dismantlement costs are based on an assumed *total* dismantlement plus a 15% contingency.[620] However, Mr. Kollen testified that SWEPCO never fully dismantles its plants, rather, it sporadically conducts partial

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[614] SWEPCO Ex. 43 (Davis Direct) at 11-12, Exhibit DAD-1 at 10; SWEPCO Ex. 44 (Bertheau Direct) at 5-11, Exhibit SRB-1; SWEPCO Ex. 81 (Davis Rebuttal) at 17-24; SWEPCO Ex. 82 (Bertheau Rebuttal) at 4-8, Exhibit SRB-1R.

[615] SWEPCO Ex. 81 (Davis Rebuttal) at 20.

[616] SWEPCO Ex. 81 (Davis Rebuttal) at 18-19.

[617] SWEPCO Ex. 44 (Bertheau Direct) at 6-8; SWEPCO Ex. 82 (Bertheau Rebuttal) at 6-7, 10-33, Exhibit SRB-1R.

[618] SWEPCO Ex. 81 (Davis Rebuttal) at 21-23.

[619] Cities Ex. 3 (Kollen Direct) at 58, 61.

[620] Cities Ex. 3 (Kollen Direct) at 59.

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

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

ORDER ON REHEARING

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

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

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

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

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

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

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

Production Plant Net Salvage

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

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

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

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

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

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

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

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

Transmission Plant

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

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

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

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

Distribution Plant

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

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

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

General Plant

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

Depreciation Reserve

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

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

Payroll

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

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

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

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

Incentive Compensation

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

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

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

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

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

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

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

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

F. Welsh Unit 2

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

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

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

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

G. Rate of return

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

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

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[30] PFD at 62.

[31] PFD at 139.

[32] PFD at 141.

[33] PFD at 145.

[34] PFD at 140.

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

H. Consolidated Tax Savings Adjustment

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

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

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

I. Pirkey (Sabine) Mine Reclamation Costs

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

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

Turk CCN Costs Cap

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

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

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

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

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

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

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

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

117. DELETED.

118. DELETED.

Welsh Unit 2

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

120. DELETED.

121. DELETED.

122. DELETED.

123. DELETED.

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

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

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

Turk Plant – Other Issues

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

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

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

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

Prepaid Pension Asset and ADFIT Impacts

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

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

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

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

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

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

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

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

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

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

Oxbow Investment

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

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

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

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

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

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

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

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

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

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

The Appropriate Ratemaking Treatment for the Retirement of Welsh Unit 2

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

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

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

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

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

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

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

Turk Power Plant Cost Cap

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

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

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

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

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

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

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

Materials and Supplies Adjustment

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

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

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

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

Accumulated Deferred Federal Income Taxes

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

Pensions

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

Rate of Return and Cost of Capital

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

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

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

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

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

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

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

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

Cost of Service

Welsh Unit 2 O&M

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

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

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

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

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

Production Maintenance Expense

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

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

170. [Deleted.]

171. [Deleted.]

172. [Deleted.]

173. [Deleted.]

174. [Deleted.]

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

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

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

Adjustment to Accumulated Depreciation

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

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

Adjustment to Accumulated Depreciation Production Plant

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

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

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

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

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

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

Transmission Plant

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

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

BEFORE THE LOUISIANA PUBLIC SERVICE COMMISSION

RECEIVED
OCT 06 2020
LA Public Service Commission

JOINT APPLICATION OF CLECO POWER LLC AND SOUTHWESTERN ELECTRIC POWER COMPANY FOR: (I) AUTHORIZATION TO CLOSE THE OXBOW MINE; (II) AUTHORIZATION TO INCLUDE AND DEFER CERTAIN ACCELERATED MINE CLOSING COSTS IN FUEL AND RELATED RATE MAKING TREATMENTS; AND (III) EXPEDITED TREATMENT	)))))))))	DOCKET NO. U-35753

DIRECT TESTIMONY OF

MICHAEL A. BAIRD

ON BEHALF OF

SOUTHWESTERN ELECTRIC POWER COMPANY

OCTOBER 2020

based on forecasted land payments for the Dolet Hills and Oxbow Mines (the Mines) and their mining areas while reclamation activities are completed.

Q. HOW ARE LONG-TERM ASSET COSTS BILLED TO SWEPCO AS FUEL EXPENSE?

A. These costs are billed in accordance with two agreements related to the Dolet Hills mining operations. First, the Lignite Mining Agreement (LMA) among SWEPCO and CLECO, as joint owners of the DHPS, and DHLC, as miner, determines billing amounts related to the mining operations (Exhibit MB-1). Next, the Lignite Ownership and Mining Joint Operating Agreement (JOA) among SWEPCO, CLECO and Oxbow determines billing amounts related to mineral and land operations (Exhibit MB-2). Generally, the LMA Article 9.3 requires that costs, as defined under Generally Accepted Accounting Principles (GAAP), are accumulated as incurred, and billed to SWEPCO and CLECO as lignite is delivered to DHPS. This is further supported by Article IV (D) (7) of the JOA. This means the long-term asset costs described above are depreciated and amortized as incurred as depreciation and amortization expenses related to the mining activities. Under GAAP, depreciation and amortization expenses are incurred and allocated to the accounting periods during the productive useful life of the related asset. The mining-related depreciation and amortization expenses are included with other accumulated mining-related costs as unbilled lignite costs, and are billed to SWEPCO as the lignite is delivered to DHPS. These billings for deliveries are then accumulated as fuel inventory and charged to fuel expense as the lignite is burned to generate electricity at the DHPS.

Q. HOW DOES THIS IMPACT SWEPCO FUEL EXPENSE?

A. This will increase the Dolet Hills mine costs billed to SWEPCO and correspondingly, fuel expense. Previously, these long-term assets had a productive life that ended as late as 2036. With the decision to close the mine in 2021, SWEPCO will incur fuel expense related to the remaining long-term asset costs shown above over the remaining period of two years versus up to seventeen years. This means that the Dolet Hills fuel expense will increase significantly in 2020 and 2021. This additional fuel expense is consistent with GAAP, the LMA Article 9.3.1 (C) and the JOA Article IV (D) (6).

This can be illustrated with a simplified example. Assume that long-term assets had a remaining value of $170. Prior to the decision to close the mine in 2021, $10, or $170 over 17 years, would be depreciated each year. After the decision to close the mine in 2021, the depreciation expense would increase to $85, or $170 over 2 years. As discussed above, this increased depreciation expense relating to mining activities would be billed as the lignite is delivered and would be included in fuel expense as the fuel is burned to generate electricity.

Q. WHAT IS THE ESTIMATED INCREASE IN DOLET HILLS DEPRECIATION AND AMORTIZATION EXPENSE RELATED TO LONG-TERM ASSET MINING COSTS?

A. During 2020 and 2021, the estimated increase in Dolet Hills depreciation and amortization expense related to long-term asset mining costs is:

Description	Increase
Property, Plant and Equipment – owned	$103,460,000
Property, Plant and Equipment - leased	25,680,000
Asset Retirement Cost	98,459,000
Oxbow Mining Rights and related	26,968,000
Land leases and related (Estimated)	16,710,000
Total	$271,277,000

Q. WHAT IS SWEPCO'S SHARE OF THIS INCREASE?

A. SWEPCO owns 40.234% of DHPS and, therefore, is responsible for 40.234% of $271,277,000 or $109,146,000.

Q. DOES THIS MEAN THAT SWEPCO'S FUEL EXPENSE WILL INCREASE EQUALLY OVER 2020 AND 2021?

A. No, it does not. SWEPCO uses an average cost of fuel inventory to record fuel expense based on the lignite burned at DHPS. Since the beginning balance of fuel inventory on hand contains lignite billed using a 2036 mine life, it will reflect a much lower cost than the amounts to be billed after the decision to close the Mines in 2021 was made. Thus, after the decision was made to retire the Mines, it takes a while for the decision to be fully reflected in SWEPCO's average fuel expense. Because of this, the cost of lignite per ton expensed will be higher in 2021.

Q. WOULD YOU PLEASE DESCRIBE THE ASSET RETIREMENT OBLIGATION (ARO) AND ASSET RETIREMENT COST (ARC)?

A. Yes. Under GAAP, AROs represent the estimated liability for costs of a legal obligation associated with retiring an asset. An example of this type of legal obligation would be the final mine reclamation costs for the Dolet Hills Mine. DHLC has recorded the present value of the estimated cost of the legal obligation associated with retiring the asset as a component of the cost of the asset itself when the asset is placed into service, also referred to as the ARC, and recorded a corresponding credit to ARO liability. During the life of the asset, the DHLC adjusts the ARC for increases and decreases in the estimated ARO liability. DHLC depreciates the ARC, as adjusted, prospectively over the useful life of related asset. In addition, each accounting period, accretion expense is recorded and

5 Nov, 2020

AEP to retire more than 1,600 MW of coal capacity

Author Darren Sweeney

Theme Energy

American Electric Power Co. Inc. announced Nov. 5 that it will shut down more than 1,600 MW of coal capacity at two power plants in Texas by the end of 2028 to meet federal environmental regulations.

AEP said it plans to retire the 721-MW Pirkey coal plant in Hallsville, Texas, in 2023 and stop burning coal at the 1,053-MW Welsh coal plant in Pittsburg, Texas, in 2028. AEP utility Southwestern Electric Power Co., or SWEPCO, owns an 86% interest in the Pirkey coal plant, representing about 580 MW of capacity. SWEPCO also owns and operates the Welsh coal plant.

AEP said these moves are part of compliance plans that it will file this month to meet the requirements of the U.S. Environmental Protection Agency's Coal Combustion Residuals, or CCR, rule.

"Dry bottom ash handling systems or new lined ash ponds that meet the requirements of the EPA's CCR and Effluent Limitation Guidelines (ELG) rules will be built and operational in 2023 at four other power plant sites," the company said in a news release. "Existing ash ponds at these sites will be closed, and the ash will be moved to regulated landfills."

AEP said it plans to make the necessary investments to continue operating Appalachian Power Co.'s 2,930-MW John E. Amos and 1,330-MW Mountaineer coal plants in West Virginia, as well as the 1,560-MW Mitchell coal plant in West Virginia owned by AEP subsidiaries Kentucky Power Co. and Wheeling Power Co. The company also expects the 528-MW Flint Creek coal plant in Arkansas to meet environmental regulations. SWEPCO owns a 50% interest in the Flint Creek coal plant, with the remaining interest owned by Arkansas Electric Cooperative Corp.

In addition, AEP expects to make the necessary upgrades to the ash pond system at its 1,310-MW Rockport Unit 1 in Indiana to allow the coal unit to continue operating until its planned retirement in 2028. The Rockport unit, operated by AEP subsidiary Indiana Michigan Power Co., is among the largest coal units in the nation.

AEP also announced that it "will not renew the lease" for the 1,310-MW Rockport Unit 2 when it expires in 2022.

"As we look at the future of our power plant fleet, we've balanced the remaining life and economic viability of each of our coal-fueled generating units with other options for delivering power to our customers. We continue to add lower cost, cleaner resources, like renewables and natural gas, as we diversify our generating fleet to benefit our customers and the environment," AEP Chairman, President and CEO Nicholas Akins said in the news release. "We have retired or sold nearly 13,500 MW of coal-fueled generation in the last decade."

The Pirkey coal plant received nearly 2.6 million tons of lignite coal from Sabine Mining Co.'s South Hallsville No. 1 Mine in 2019, according to S&P Global Market Intelligence data. Meanwhile, the Welsh coal plant received more than 3 million tons of coal from Peabody Energy Corp.'s North Antelope Rochelle Mine in 2019.

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR A PROPOSED TARIFF REVISION REGARDING THE REQUEST FOR APPROVAL OF A TAX ADJUSTMENT RIDER TO PROVIDE TAX BENEFITS TO ITS RETAIL CUSTOMERS	)))))))	DOCKET NO. 18-014-TF ORDER NO. 2

ORDER

On February 27, 2018, Entergy Arkansas, Inc. (EAI) filed with the Arkansas Public Service Commission (Commission) a *Request for Approval of a Tax Adjustment Rider to Provide Tax Benefits to its Retail Customers* (Request) along with the Direct Testimony of Myra L. Talkington and the proposed Tax Adjustment Rider (Rider TA) as an exhibit to her testimony. On March 2, 2018, the Office of the Attorney General Leslie Rutledge (AG) filed a notice of intent to participate in this docket. On March 14, 2018, Arkansas Electric Energy Consumers, Inc. (AEEC) filed a Petition to Intervene which was granted by this Commission on March 16, 2018, by Order No. 1. On March 16, 2018, the General Staff (Staff) of the Commission filed the Direct Testimony of Jeff Hilton. On March 19, 2018, the AG filed the Responsive Testimony of Donna Gray and AEEC filed the Direct Testimony of Billie S. LaConte. On March 23, 2018, EAI filed the Supplemental Direct Testimony of Myra L. Talkington.

Positions of the Parties

Ms. Talkington testifies on behalf of EAI that the Tax Cut and Jobs Act of 2017 (TCJA), among other things, reduces the maximum federal corporate income tax rate from 35 percent to 21 percent creating excess Accumulated Deferred Income Tax (ADIT) amounts. She states that proposed Rider TA would flow back to retail customers the

11

excess ADIT amounts not related to the depreciation of assets and not subject to normalization provision of the Internal Revenue Code (Unprotected excess ADIT). Talkington Direct at 2-4.

Ms. Talkington describes excess ADIT as being classified into two categories: 1) the portion subject to the normalization requirements of the Internal Revenue Code, or "Protected" excess ADIT, and 2) the portion not subject to such normalization provision, or "Unprotected" excess ADIT. She explains that Rider FRP provides the means for customers to realize the benefits of the TCJA with respect to the Protected excess ADIT and expense changes, consistent with the Commission's expressed desire in Docket No. 18-006-U, on an ongoing basis. She further states that EAI does not believe that Rider FRP would accomplish the return of the Unprotected excess ADIT amounts as expeditiously as desired by the Governor of Arkansas in his letter to the Commission dated January 11, 2018, and the AG as indicated in her Notice of Intent filed in this docket. Ms. Talkington states that Rider TA accomplishes this shared objective and results in customers realizing significant savings almost immediately. Ms. Talkington testifies that she believes that the implementation of Rider TA meets the Commission's expressed objectives in Order No. 1 in Docket No. 18-006-U as she previously explained. *Id.* at 5-6.

Ms. Talkington describes the methodology by which the Unprotected excess ADIT would be provided to retail customers. She states that Rider TA amounts will offset customers' bills by reducing monthly base rate billings by the applicable rate class percentage. She states that Rider TA would go into effect the first billing cycle of April 2018 through the last billing cycle of December 2018 for customers in the Small General

Service (SGS), Large General Service (LGS), and Lighting rate classes. For Residential customers, Rider TA would begin with the first billing cycle of April 2018 through the last billing cycle of December 2019. She explains that the length of the effective period for Rider TA for residential customers is longer than that of other customers because EAI is proposing a longer return period for residential customers to avoid adverse rate effects upon the expiration of Rider TA. She explains that using a 21-month refund period for residential customers creates an estimated $20 per month bill reduction per 1,000 kWh of usage. She further explains that if the same time period that is proposed for all other rate classes is also used for the residential class, the bill impact would almost double, creating the potential for rate shock at the end of the year when the Rider TA would expire. She states that rate stability for residential customers was a factor in determining the treatment of refunds in response to the tax reform in 1986. *Id.* at 7-8.

Ms. Talkington testifies that it is preferred and in the public interest to provide the refund of Unprotected excess ADIT through a separate rider from Rider FRP because these refunds represent significant credits to customers and such credits would be constrained by statutory restrictions on annual revenue requirement increases or decreases pursuant to Rider FRP. She explains that utilizing Rider TA allows these refunds to begin in April 2018 – nine months before it would be possible through Rider FRP and without a limitation on the level of refund. *Id.* at 8.

Ms. Talkington provides Table 1 which shows the Rider TA Rate Calculation for all the classes and indicates that the retail customer amount of approximately $466 million has been allocated to the retail classes based on base rate revenues from EAI's last approved cost of service in Docket No. 15-015-U. She states that the allocated class amounts were then divided by the forecasted base rate revenues for the months of April through December 2018 to arrive at the Rider TA billing rates for 2018. She testifies that for the Residential class, one-half of the amount would be returned to the customers in 2018 with the other half being returned in 2019. She states that there would be a redetermination of Rider TA billing percentage on or before December 1, 2018, when EAI would determine the revised Rider TA percentage rate for residential customers based on the most recent revenue forecast (to be used in the 2018 Rider FRP filing). She states that this revised rate would be effective for Residential customers' bills rendered on and after the first billing cycle of January 2019 and that it would be filed with the Commission, along with the redetermination calculation, by December 1, 2018. Ms. Talkington testifies that EAI will not include carrying charges on the redetermined Rider TA amount for the Residential rate class because it would only be equitable in the scenario wherein EAI carries forward un-refunded amounts, but otherwise reflects the full impact of the revalued ADIT in its cost of capital calculation. She explains that because ADIT is treated as cost-free capital, the revaluation has the effect of increasing EAI's rate of return and that under the proposal, all refunds, except for true-ups, will have concluded by the end of 2019. She notes that in the 2019 Rider FRP, EAI will include an offsetting amount in Current Accrued and Other Liabilities for the un-refunded balance for 2019. She states that this offsetting amount would continue to give customers the benefit of cost-free capital associated with the un-refunded amount in rates until the refund has concluded. *Id.* at 9-11.

Ms. Talkington states that on or before December 1, 2019, EAI would file a true-up calculation using the final Unprotected excess ADIT amounts based upon its 2017

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Consideration of the stipulation and settlement agreement between Gulf Power Company, the Office of Public Counsel, Florida Industrial Power Users Group, and Southern Alliance for Clean Energy regarding the Tax Cuts and Jobs Act of 2017.	DOCKET NO. 20180039-EI ORDER NO. PSC-2018-0180-FOF-EI ISSUED: April 12, 2018

The following Commissioners participated in the disposition of this matter:

ART GRAHAM, Chairman
JULIE I. BROWN
DONALD J. POLMANN
GARY F. CLARK
ANDREW GILES FAY

APPEARANCES:

JEFFREY A. STONE and RUSSELL A. BADDERS, ESQUIRES, One Energy Place, Pensacola, Florida 32520-0100; Beggs & Lane, P. O. Box 12950, Pensacola, Florida 32576-2950
On behalf of Gulf Power Company (Gulf).

J.R. KELLY and CHARLES REHWINKEL, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

JON MOYLE and KAREN PUTNAL, ESQUIRES, Moyle Law Firm, PA, The Perkins House, 118 North Gadsden Street, Tallahassee, Florida 32301
On behalf of the Florida Industrial Power Users Group (FIPUG).

SUZANNE BROWNLESS, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Florida Public Service Commission (Staff).

MARY ANNE HELTON, ESQUIRE, Deputy General Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
Advisor to the Florida Public Service Commission.

KEITH HETRICK, ESQUIRE, General Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
Florida Public Service Commission General Counsel.

FINAL ORDER APPROVING JOINT MOTION TO APPROVE STIPULATION AND SETTLEMENT AGREEMENT

BY THE COMMISSION:

BACKGROUND

On February 14, 2018, Gulf Power Company (Gulf) filed a Stipulation and Settlement Agreement (SSA) between Gulf and the Office of Public Counsel (OPC), the Florida Industrial Power Users Group (FIPUG), and the Southern Alliance for Clean Energy (SACE) regarding the Tax Cuts and Jobs Act of 2017 in Docket Nos. 20180013-PU,[1] the generic tax docket, and 20160186-EI,[2] Gulf's last base rate case proceeding. The SSA addresses the effects of the passage of the Tax Cuts and Jobs Act of 2017 (Act), signed into law by President Trump on December 22, 2017. The signatories to the SSA are OPC, FIPUG and SACE, all of whom were signatories to Gulf's last rate case stipulation.[3]

The SSA implements paragraph 6 of Gulf's 2017 Stipulation and Settlement Agreement (2017 Settlement) approved by Order No. PSC-17-0178-S-EI.[4] There are six basic parts to the SSA: 1) base rate reduction of $18.2 million per year commencing on April 1, 2018;[5] 2) establishment of a regulatory liability to account for the tax rate reduction from January 1, 2018 until the effective date of the base rate reduction;[6] 3) refund of $69.4 million by the end of 2018 through the fuel cost recovery clause for the unprotected excess deferred tax regulatory liability as of December 31, 2017;[7] 4) reduction of $15.6 million to Environmental Cost Recovery Clause (ECRC) recovered by the end of 2018;[8] 5) establishment of a 53.5% equity ratio cap for all retail regulatory purposes, e.g., earnings surveillance reporting, interim rate determinations, cost recovery clauses;[9] and 6) initiation of a limited scope proceeding by May 1, 2018, for the purpose of determining the amount and flow back period for protected excess deferred taxes through a prospective reduction in base rates, should one be warranted.[10] The SSA is intended to resolve all of Gulf's outstanding tax issues associated with the Act.

On February 19, 2018, pursuant to Section 366.076(1), Florida Statutes, this docket was opened to expedite consideration of the SSA as requested by the signatories so that the base rate reduction agreed to by the parties, if appropriate, can be implemented in April 2018. On February 26, 2018, Gulf filed a Joint Motion to Approve Stipulation and Settlement Agreement (Motion) requesting that the SSA be approved in its entirety and that this Commission take final

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[1] Docket No. 20180013-PU, In re: Petition to establish a generic docket to investigate and adjust rates for 2018 tax savings, by Office of Public Counsel.
[2] Docket No. 20160186-EI, In re: Petition for rate increase by Gulf Power Company.
[3] Order No. PSC-17-0178-S-EI, issued on May 16, 2017, in Docket No. 160186-EI, In re: Petition for rate increase by Gulf Power Company.
[4] Id.
[5] Paragraphs 2, 4.
[6] Paragraphs 5, 8.
[7] Paragraph 7.
[8] Paragraph 9.
[9] Paragraph 11.
[10] Paragraph 13.

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PUC DOCKET NO. 48371
SOAH DOCKET NO. 473-18-3733

ENTERGY TEXAS, INC.'S STATEMENT OF INTENT AND APPLICATION FOR AUTHORITY TO CHANGE RATES	§ § § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

This Order addresses the application of Entergy Texas, Inc. for authority to change its rates. ETI filed an unopposed settlement agreement that resolves certain issues between the parties in this proceeding. The Commission approves ETI's request for authority to change its rates, as modified by the settlement agreement, to the extent provided in this Order.

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

I. Findings of Fact

Applicant

1. ETI generates, transmits, distributes, and sells electricity through facilities and equipment that it owns and operates in Texas under CCN number 30076.

Application

2. On May 15, 2018, ETI filed an application requesting authority to change its rates. The application included the schedules of information required by the Commission's rate filing package for generating utilities (except as described in findings of fact 8 and 9) as well as the pre-filed direct testimony of 32 witnesses.

3. In its application, ETI requested an increase in base and rider rates designed to collect a total non-fuel retail amount of approximately $1.027 billion per year, an increase of $117.5 million, not including a Tax Cuts and Jobs Act[1] (TCJA) rider designed to flow to customers approximately $201.7 million of unprotected excess accumulated deferred

[1] Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution on the Budget for Fiscal Year 2018, Pub. L. No. 115-97, 131 Stat. 2054 (Dec. 22, 2017).

60. The extension of the San Jacinto purchased-power agreement is reasonable and necessary and was entered into prudently.

Regulatory Assets

61. The signatories agreed for ETI to establish a Hurricane Harvey regulatory asset totaling \$20,527,124 and to amortize it over 12 years.

62. It is appropriate for ETI to establish a Hurricane Harvey regulatory asset totaling \$20,527,124 and to amortize it over 12 years.

63. The signatories agreed for ETI to establish regulatory assets—one each for the remaining Sabine 2 and Neches Station investments—to recover a return of, but not on, the remaining Sabine 2 and Neches Station investments over a period of 10 years.

64. It is appropriate for ETI to establish regulatory assets—one each for the remaining Sabine 2 and Neches Station investments—to recover a return of, but not on, the remaining Sabine 2 and Neches Station investments over a period of 10 years.

65. As part of the settlement agreement, ETI withdrew its request to establish a new regulatory asset for the \$21.3 million unrecovered capital cost of the Spindletop asset and agreed not to seek recovery of such costs in any future proceeding.

Tax Cuts and Jobs Act (TCJA)

66. The signatories agreed for ETI to establish a rider to credit to customers the sum of \$25 million and eliminate the regulatory liability established under Project No. 47945.[6] The regulatory liability reflects the difference between (a) the amount ETI actually collected in rates (including base rates, the TCRF, and the DCRF) from January 25, 2018, through the date that new base rates are implemented in this docket, based on a federal income tax rate of 35%; and (b) the actual federal income tax rate in 2018 of 21%. The rider, which is identified as the federal-income-tax-credit rider, is attached as part of exhibit A to ETI's agreed motion for interim rates filed on October 5, 2018.

[6] *Proceeding to Investigate and Address the Effects of the Tax Cuts and Jobs Act of 2017 on the Rates of Texas Investor-Owned Utility Companies,* Project No. 47945, Order (Jan. 25, 2018).

67. The signatories agreed for the portion of the $25 million allocable to the large industrial power service, large general, and general rate classes to be credited over a period of 10 months and for the portion of the $25 million allocable to all other classes to be credited over a period of 4 years.

68. The signatories agreed that the federal-income-tax-credit rider described in this Order addresses tax-related amounts recorded in the TCRF and DCRF balances and extinguishes the underlying regulatory liability established in Project No. 47945.

69. The amount of $25 million for the federal-income-tax-credit rider is within the range of the parties' litigation positions.

70. It is appropriate for ETI to establish and implement the federal-income-tax-credit rider, as described in this Order.

71. The signatories agreed for ETI's protected excess ADFIT in the amount of $242.5 million (which includes a tax gross-up) to be flowed to customers through base rates under the average rate assumption method (ARAM).

72. It is appropriate for ETI's protected excess ADFIT in the amount of $242.5 million (which includes a tax gross-up) to be flowed to customers through base rates under the ARAM method.

73. The signatories agreed for ETI's unprotected excess ADFIT in the amount of $185.2 million (which includes a tax gross-up) to be flowed to ETI customers using a separate rider. That rider, which is identified as the TCJA rider, was included in exhibit A to ETI's agreed motion for interim rates. ETI also agreed to pay carrying charges on the unamortized balance to ETI customers at a weighted average cost of capital of 7.73%.

74. The signatories agreed, with respect to the TCJA rider, for the portion allocable to the large industrial power service, large general, and general rate classes to be flowed back to those classes over a period of 12 months and for the portion allocable to the other rate classes to be flowed back to those classes over a period of 4 years.

75. It is appropriate for ETI to establish and implement the TCJA rider as described in this Order.

76. The federal-income-tax-credit rider and the TCJA rider will extinguish the regulatory liabilities established under Project No. 47945, except for the portion of the regulatory liability associated with ETI's advanced metering system tariff, which is not addressed in this docket.

77. The rates approved in this Order reflect the reduction in federal income tax rates from 35% to 21% under the TCJA.

Allocation and Rate Design

78. The signatories agreed on using the class revenue allocation and rate design reflected in attachment B to the settlement agreement.

79. The provisions of the settlement agreement regarding class revenue allocation and rate design and the terms and conditions of service included in the settlement agreement are just and reasonable.

80. The signatories agreed that ETI's proposed line-loss factors—as corrected on page three of ETI's errata to its rate-filing-package schedules and direct testimony, filed on July 9, 2018—are reasonable.

81. ETI's proposed line-loss factors, as corrected, are appropriate.

82. ETI withdrew its request for Commission approval of its proposed changes to schedules for interruptible service and standby metering service.

Customer Charge

83. The signatories agreed for the customer charge applicable to the residential class to be raised from $7.00 to $10.00 per month.

84. The signatories agreed for the customer charge applicable to the small general class to be raised from $10.20 to $14.19 per month.

85. The agreed-to changes in customer charges are within the range of the parties' litigated positions and are appropriate.

86. The agreed-to customer charges are just and reasonable rates.

PUC DOCKET NO. 49494
SOAH DOCKET NO. 473-19-4421

PUBLIC UTILITY COMMISSION OF TEXAS
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APPLICATION OF AEP TEXAS INC. FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

This Order addresses the application of AEP Texas Inc. for authority to change its rates. On February 13, 2020, AEP Texas filed an unopposed agreement between the parties to this proceeding. The Commission approves the rates, terms, and conditions set forth in the agreement to the extent provided in this Order.

I. Background

On May 1, 2019, AEP Texas filed an application for authority to change its rates. AEP Texas initially sought to increase its annual transmission and distribution revenues by approximately $35.18 million, inclusive of a rider to refund to customers the balance of excess tax revenue that resulted from the Tax Cuts and Jobs Act of 2017.[1] AEP Texas requested an overall rate of return of 7.08% based on a cost of debt of 4.2758%, a return on equity of 10.5%, and a capital structure of 55% long-term debt and 45% equity. AEP Texas's application also included proposals to consolidate the rates of its formerly separate central and north divisions, eliminate a surcharge associated with its deployment of advanced meters, begin to recover in base rates the ongoing costs to provide advanced metering service, and move the recovery of all costs to provide transmission service into a transmission cost recovery factor.

The Commission referred this docket to the State Office of Administrative Hearings (SOAH) on May 2, 2019. Parties filed testimony and engaged in discovery. After holding a hearing on the merits, the SOAH administrative law judges (ALJs) filed a proposal for decision on November 12, 2019. In the proposal for decision, the SOAH ALJs recommended a decrease of $59,741,451 to AEP Texas's current total base-rate revenue requirement. The SOAH ALJs also

[1] Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution on the Budget for Fiscal Year 2018, Pub. L. No. 115-97, 113 Stat. 2054 (Dec. 22, 2017).

S32

Agreement – Cash Working Capital

127. The signatories agreed that, for purposes of AEP Texas's earnings monitoring reports for reporting years beginning in 2020, AEP Texas's total company cash working capital is negative $13,408,892, as shown in exhibit D to the agreement.

128. AEP Texas's total company cash working capital of negative $13,408,892 is reasonable and is appropriate to use in AEP Texas's earnings monitoring reports.

Agreement – Capitalized Incentive Compensation

129. The signatories agreed that all parties to the docket reserve the right to take any position with respect to prospective treatment of incentive compensation capitalized after the close of the test year (December 31, 2018) in AEP Texas' next base-rate proceeding.

130. The signatories agreed that, unless legislation is passed permitting the recovery of incentive compensation, the incremental investment included in AEP Texas's interim transmission cost of service and DCRF proceedings will exclude any financially based incentive compensation capitalized after the close of the test year (December 31, 2018) until AEP Texas's next base-rate case.

Agreement – Vegetation Management Capitalization Policy

131. Since the end of the test year in AEP Texas's last rate case (July 1, 2006) through December 31, 2018, AEP Texas capitalized, rather than expensed, $25,612,338 incurred to expand an existing right-of-way or to remove trees with a diameter of greater than 18 inches from the originally cleared right-of-way.

132. The signatories agreed that AEP Texas will remove the above-described $25,612,338 from rate base and defer these costs as a regulatory asset to be amortized through a rider over a five-year period.

133. The signatories agreed that AEP Texas will defer amounts capitalized under its vegetation management capitalization policy in 2019 into a regulatory asset to be addressed in a future proceeding.

134. The signatories agreed that going forward from January 1, 2020, AEP Texas will treat only the initial clearing of land for a right-of-way as capital.

Agreement – Income Taxes

135. The signatories agreed that, to address the effects of the Tax Cuts and Jobs Act of 2017, AEP Texas will refund a total of $108,020,034, which reflects the following: the difference between the revenues collected under existing rates and the revenues that would have been collected had the existing rates been set using the 21% tax rate enacted under the Tax Cuts and Jobs Act of 2017 until the new rates are implemented; amounts associated with the change in the amortization of protected excess deferred federal income taxes (EDIT) as a result of the Tax Cuts and Jobs Act of 2017 from January 1, 2018 until the date the protected EDIT is included in new rates; and unprotected EDIT associated with the change in tax rates under the Tax Cuts and Jobs Act of 2017.

136. The amount of $108,020,034 is being refunded through separate riders for distribution and transmission customers. The signatories agreed that AEP Texas will refund $76,531,681 to distribution customers through its proposed income tax refund rider over a one-year period. The rider will be implemented separately for each division. AEP Texas will refund $31,488,353 to transmission customers as a one-time credit through its transmission cost of service.

137. The agreement's treatment of the federal income tax issues discussed in findings of fact 135 and 136 is appropriate.

138. The signatories agreed not to initiate a proceeding to review AEP Texas's or its affiliate's accumulated deferred federal income tax balances on AEP Texas's or its affiliate's bonds associated with the securitization of transition to competition costs and not to raise issues related to the appropriate treatment of EDIT amounts associated with those bonds in future Commission proceedings related to AEP Texas or its affiliates.

Agreement – Rate-Case Expenses

139. The signatories agreed that AEP Texas will reimburse Cities for all rate-case expenses incurred in all dockets for which the recovery of rate-case expenses was sought in this docket.

140. The signatories agreed that Cities will provide AEP Texas with invoices for all rate-case expenses incurred within ten days of the date of this Order.

141. The signatories agreed that AEP Texas will reimburse Cities for rate-case expenses included on invoices submitted in accordance with this timeline within 30 days of this Order.

142. The signatories agreed that AEP Texas will not seek recovery of rate-case expenses in Docket No. 49556, including expenses incurred by Cities or AEP Texas associated with this proceeding.

143. The signatories agreed that AEP Texas will reimburse Cities for any appeals of this Order.

144. The signatories agreed that AEP Texas will move to dismiss Docket No. 49556 within 30 days of this Order.

145. The agreement's treatment of rate-case expenses is appropriate.

Agreement – Affiliate Expenses

146. The signatories agreed that the affiliate amounts included in the rates developed through the agreement are reasonable and necessary, are allowable, and are charged to AEP Texas at a price no higher than was charged by the supplying affiliate to other affiliates.

147. Each signatory reserved the right, in a future AEP Texas proceeding and for prospective application, to dispute whether and in what amount AEP Texas may include in rate base or expense amounts related to affiliate services.

Agreement – Self-Insurance Reserve

148. The signatories agreed that AEP Texas's proposed annual accrual of $4.27 million to the storm reserve is reasonable. The annual accrual of $4.27 million accounts for annual expected operations and maintenance losses from storm damage in excess of $500,000 and builds towards a new target reserve of $13.3 million that consists of $10.6 million for the central division and $2.7 million for the north division.

149. The agreement's treatment of the self-insurance reserve is appropriate.

150. AEP Texas's self-insurance reserve is in the public interest and is a lower-cost alternative to purchasing commercial insurance.

151. AEP Texas's self-insurance reserve results in savings that benefit ratepayers.

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR AUTHORITY TO CHANGE RATES

DIRECT TESTIMONY OF

GREGORY S. WILSON

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

OCTOBER 2020

A. Insurance companies include provisions in their premiums for all costs associated with the transfer of the insurance risk. Hence, they include provisions for losses, loss adjustment expenses, non-loss related expenses, premium taxes, and a profit.

A self-insurance reserve, such as SWEPCO's reserve, does not need to include many of the provisions other than those for losses and loss-related expenses. For example, a self-insurance reserve does not need to pay premium taxes and other state-imposed fees. An insurance company needs to make a profit on the business it transacts. A self-insurance reserve, on the other hand, is not intended to generate a profit and, hence, no provision for profit needs to be included in the accrual provisions. Insurance companies also incur costs associated with the acquisition of insured risks. The largest of these expenses is that associated with the payment of commissions to insurance agents or brokers to place the business. A self-insurance reserve does not include any provision for commissions. Finally, an insurance company must expend resources to underwrite risks, market its products, and maintain overhead expenses. A self-insurance reserve does not need to provide for these costs.

In summary, self-insurance saves the costs of premium taxes, commissions, profit, and many of the general expenses associated with the operation of an insurance company.

Q. WHAT OTHER COST-BENEFIT ANALYSIS HAVE YOU RELIED UPON TO SHOW THAT THE COST FOR THE SELF-INSURED LAYER IS LOWER THAN THE COST OF COMMERCIAL INSURANCE FOR THE SAME LAYER OF INSURANCE AND IS IN THE INTEREST OF THE COMPANY'S CUSTOMERS?

A. 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. SWEPCO's experience is that this type of coverage is significantly more expensive than self-insurance. 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.

VII. CONCLUSION

Q. WHAT DO YOU CONCLUDE REGARDING SWEPCO'S REQUEST FOR SELF-INSURANCE RESERVE TO T&D PROPERTY LOSSES?

A. I have conducted an analysis that meets the Commission's rule requirements and have demonstrated that self-insurance is necessary and desirable given the lack of reasonably priced commercial insurance. My conclusion is that SWEPCO should accrue $1,689,700, which is composed of $799,700 each year to provide for the year's annual expected losses from storms with at least $500,000 in T&D damages and $890,000 to build the total self-insurance reserve up to the $3,560,000 level. In addition, I conclude that the requested self-insurance plan is a lower cost alternative to purchasing commercial insurance, when considering all costs. Finally, I conclude that the plan is in the best interests of SWEPCO's customers and that SWEPCO's customers will receive the benefits of the savings produced by the plan.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

GREGORY S. WILSON, FCAS, MAAA
Vice President and Principal

CURRENT POSITION

Mr. Wilson is a Vice President and Principal with Lewis & Ellis, Inc.

EXPERIENCE:

Mr. Wilson's responsibilities include evaluating the adequacy of insurance company reserve levels in conjunction with actuarial certification for the annual statement as well as state insurance department examinations. He also evaluates the adequacy of loss reserves for several self-insured companies. In addition, he performs rate level analyses for insurance companies and helps them prepare filings for the state insurance departments, as well as self-insured analyses for electric utilities and prepares testimony for the Public Utility Commission.

Prior to joining the firm, Mr. Wilson was a Principal Consultant at PricewaterhouseCoopers LLP. His responsibilities were similar to his current responsibilities. In addition, he reviewed retrospective rating calculations for several companies involved in class action litigation in Texas. He also performed several funding analyses for governmental entities.

Prior to joining PricewaterhouseCoopers LLP, Mr. Wilson was Vice President of Amica Mutual Insurance Company in Providence, Rhode Island.

N. Costs of Processing Refunds or Credits

Q. AS DESCRIBED IN PURA § 36.062, HAS SWEPCO INCLUDED IN ITS COST OF SERVICE ANY COST OF PROCESSING A REFUND OR CREDIT UNDER SECTION 36.110 OF PURA?

A. No, it has not.

O. Profit or Loss from the Sale or Lease of Merchandise

Q. DOES SWEPCO'S FILING INCLUDE ANY PROFIT OR LOSS FROM THE SALE OR LEASE OF MERCHANDISE AS DESCRIBED IN PURA § 36.063?

A. No, it does not.

P. Self-Insurance

Q. HAS THE COMPANY HAD A SELF-INSURANCE RESERVE IN THE PAST AS DESCRIBED IN PURA § 36.064?

A. No, it has not.

Q. IS SWEPCO REQUESTING ESTABLISHMENT OF A SELF-INSURANCE RESERVE FOR TEXAS STORM RESTORATION COSTS IN THIS CASE?

A. Yes, it is. SWEPCO witness Greg Wilson addresses the scope of the self-insurance reserve. His analysis establishes that a self-insurance reserve is beneficial to customers. Later in my testimony, I address the specific pro forma adjustment associated with SWEPCO's request.

Q. IS THIS STORM RESERVE REQUEST PATTERNED AFTER A CATASTROPHE RESERVE THAT HAS BEEN APPROVED BY THE COMMISSION?

A. Yes, it is. SWEPCO patterned this request after the catastrophe reserve approved for AEP Texas in various rate cases. What this means is that SWEPCO will utilize the reserve for a major storm for which incremental expenses exceed $500 thousand for a single event. Thus, the reserve will not include small storms, but is available for larger storms that cost at least $500 thousand and relate to SWEPCO's Texas retail operations. For example, if there is a $1 million storm in Northwest Arkansas, that would not qualify. However, if that storm related to East Texas, then it would qualify.

Q. WHY IS A SELF-INSURANCE RESERVE WARRANTED?

A. Major storm costs are outside the control of SWEPCO and SWEPCO cannot predict such costs. Such expenditures are by their nature unpredictable, as confirmed by the Commission's rule, which requires that the utility design the reserve to recover expenses that cannot reasonably be included in base rates.

Q. PLEASE EXPLAIN THE ACCOUNTING SWEPCO WILL IMPLEMENT FOR THE PROPOSED MAJOR STORM CATASTROPHE RESERVE FOR TEXAS.

A. On a monthly basis, SWEPCO will charge $140,808 (1/12 of $1,689,700) to Operations and Maintenance expense and credit FERC Account 228.1 Accumulated Provision for Property Insurance. If incremental operations and maintenance (O&M) losses for major storms (i.e., eligible expenses) exceed $500,000 from a single event, SWEPCO will charge the losses against the reserve (FERC Account 228.1).

Q. HOW WILL SWEPCO DETERMINE THE ELIGIBLE LOSSES OR INCREMENTAL O&M EXPENSES TO CHARGE TO THE RESERVE?

. SWEPCO captures storm restoration costs by project. Eligible losses to charge against the reserve would exclude capitalized costs and regular labor expenses incurred. Since SWEPCO recovers regular labor in its base rate revenue requirement, SWEPCO will not charge these expenses against the storm reserve. The remaining O&M expense (i.e., incremental and not capitalized) includes materials and supplies charged directly to the storm work order, charges from other AEP operating companies, charges from outside contractors, and overtime that is not recovered in SWEPCO's base rates. As required by the FERC Uniform System of Accounts, SWEPCO will maintain adequate records according to the year the loss occurred. This will permit the Commission to review charges to the reserve account for reasonableness.

Q. HOW WILL SWEPCO TREAT THE CATASTROPHE RESERVE IN FUTURE RATE FILINGS?

A. In future rate filings, SWEPCO will treat the catastrophe reserve amount as a reduction to its Texas jurisdictional rate base if the amounts credited to the reserve exceed the charges against the reserve (an excess or regulatory liability). If the charges to the reserve exceed the amounts credited to the reserve (a shortage or regulatory asset), SWEPCO will add the regulatory asset to rate base. This is the treatment required in PURA §36.064 (d)(2).

Q. Pension and Other Postemployment Benefits

Q. HAS THE COMPANY INCLUDED PENSION AND OTHER POSTEMPLOYMENT BENEFITS IN COMPLIANCE WITH PURA § 36.065?

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to offer an independent opinion of the reasonableness of the approach Southwestern Electric Power Company (SWEPCO or the Company) proposes to take with respect to protecting its transmission and distribution (T&D) assets through self-insurance. The specific purpose of my testimony is: (1) to estimate the annual accruals needed to provide for the expected property losses incurred by SWEPCO for the storm damage losses that are not covered by insurance and for which Section 36.064 of the Public Utility Regulatory Act (PURA) permits a provision to be made; and (2) to estimate a target amount to accumulate in the self-insurance reserve along with a recommended time period over which these accruals are to be made.

My testimony also includes a cost-benefit analysis demonstrating that self-insurance at the levels proposed by SWEPCO is a lower cost alternative to purchasing insurance and is in the public interest, consistent with 16 Tex. Admin. Code (TAC) § 25.231(b)(1)(G).

Q. WHAT DOES 16 TAC § 25.231(b)(1)(G) PROVIDE REGARDING SELF-INSURANCE?

A. This rule provides as follows:

> Accruals credited to reserve accounts for self-insurance under a plan requested by an electric utility and approved by the commission. The commission shall consider approval of a self-insurance plan in a rate case in which expenses or rate base treatment are requested for a such a plan. For the purposes of this section, a self-insurance plan is a plan providing for accruals to be credited to reserve accounts. The reserve accounts 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. The commission will approve a self-insurance plan to the extent it finds it to be in the 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.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I propose an annual accrual of $1,689,700 and a target property loss self-insurance reserve of $3,560,000 for storm damage losses. As I explain subsequently, the $1,689,700 million accrual is composed of two elements. The first is $799,700 to provide for average annual expected losses from storms with T&D losses of at least $500,000. The second is $890,000 accrued over four years to achieve the target reserve of $3,560,000.

III. SELF-INSURANCE RESERVE BACKGROUND

Q. PLEASE STATE THE PURPOSE OF A SELF-INSURANCE RESERVE AND EXPLAIN HOW IT WOULD OPERATE.

A. The purpose of SWEPCO's self-insurance reserve is to provide for occurrences resulting in storm-related T&D losses of at least $500,000.

Each year, an amount of money would be accrued in the self-insurance reserve to provide for losses expected to occur in the calendar year. In addition to this amount, an accrual would be made to raise the self-insurance reserve to a level that would serve as a financial buffer in the event that actual losses exceed the accrued annual expected loss amount.

Q. WHAT HAPPENS IF THE ANNUAL AGGREGATE LOSSES EXCEED THE AMOUNT ACCRUED IN ANY GIVEN YEAR?

A. If the annual aggregate losses exceed the amount accrued in any given year, the remaining reserve would be drawn upon to provide the needed additional amounts. If the annual aggregate losses are less than the amount accrued for that purpose, the excess annual accrual would remain in the self-insurance reserve, serving to bring the self-insurance reserve closer to its target level.

Q. WHY IS IT NECESSARY TO BUILD THE SELF-INSURANCE RESERVE UP TO A CERTAIN TARGETED LEVEL?

A. The range of expected losses from storm damage covered by the self-insurance reserve varies considerably from year to year, as will the actual losses that SWEPCO will incur. The self-insurance reserve needs to be sufficient to cover the losses for each year, knowing that any given year's actual losses may be very different from the average expected losses. Hence, a reserve large enough to provide for some variation in the annual aggregate amount of losses is needed.

Q. IS SWEPCO'S SELF-INSURANCE PROGRAM IN THE CUSTOMERS' INTEREST?

A. Yes. SWEPCO's self-insurance program is in the best interest of the Company's customers. As will be shown later, the program provides a lower cost alternative than purchasing insurance for all losses. At the same time, it provides for utility rate stability

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S FOURTH REQUEST FOR INFORMATION

Question No. OPUC 4-3:

Please refer to the Direct Testimony of Mr. Gregory S. Wilson at page 11.
a. Please provide the analysis that was conducted by Mr. Wilson concerning the cost benefit of self-insurance for SWEPCO.

b. Please admit or deny that SWEPCO currently has commercial insurance to cover storm losses. If admit, please provide the terms and cost of such insurance. If deny, please provide an explanation of how SWEPCO currently covers the costs of major storm damage.

Response No. OPUC 4-3:

a. Mr. Wilson's analysis is described in his testimony.

b. SWEPCO maintains property insurance subject to various terms, conditions and exclusions for potential property loss. Storm losses could be a cause of property loss. However, the policy excludes coverage for transmission and distribution lines, conductors, poles, towers, and attachments thereon, unless within 1,000 feet of a covered facility.

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SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S FOURTH REQUEST FOR INFORMATION

Question No. OPUC 4-4:

Please refer to the Direct Testimony of Mr. Gregory S. Wilson, Exhibit GSW-3. Please provide the details concerning the storm costs for the year 2000. When did this storm or storms occur?

Response No. OPUC 4-4:

This storm was an ice storm that occurred in late December 2000. The details of the storm costs were included in Mr. Wilson's direct testimony in Docket No. 37364, which is publicly available on the Commission's Interchange.

Prepared By: Gregory S. Wilson Title: Vice President & Principal

Sponsored By: Gregory S. Wilson Title: Vice President & Principal

PUC DOCKET NO. 37364

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR AUTHORITY TO CHANGE RATES

DIRECT TESTIMONY OF

GREGORY S. WILSON

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

AUGUST 28, 2009

annual basis for SWEPCO for 5,000 iterations of annual experience. A statistical distribution is estimated from SWEPCO's trended loss experience and input into the model. The program is run 5,000 times, each time simulating a possible outcome. From these 5,000 iterations of simulated experience I was able to determine that the expected annual loss is $2.35 million.

Q. HOW DOES THE EXPECTED ANNUAL LOSS COMPARE TO THE COMPANY'S ACTUAL HISTORICAL LOSS?

A. The actual average annual loss for the nine-year period was $3.45 million. This calculation can be seen on EXHIBIT GSW-2. I recommend that the Company accrue the lower number from the simulation because in my opinion, the historical amount is skewed towards the high end by the ice storm that occurred in 2000. This storm caused the average to be far higher than would normally be expected, and since there are only nine years of data available, its impact cannot be offset by several good years of results.

EXHIBIT GSW-3 contains an example showing how each historic loss was adjusted to reflect the current cost levels using the Handy-Whitman index of cost trends of electric utility construction for the South Central Region. The Handy-Whitman index data is a standard type of database used to measure cost changes for utility companies. The loss in the example occurred on September 23, 2005, for $1,544,036. The Handy-Whitman index on July 1, 2005, was 377; on January 1, 2006, it was 401. Interpolating between these two points to September 23, 2005, produces an expected index of 387.957. As of January 1, 2009, the

Handy-Whitman index was 535. Thus, the change from September 23, 2005 to January 1, 2007, was 535 dived by 387.957, or 1.379 (37.9% increase). Multiplying the loss of $1,544,036 by 1.379 gives a cost-adjusted loss of $2,129,255. This procedure was used for each loss of $50,000 or greater that occurred during the experience period. This approach is reasonable because it adjusts historic costs to current dollar levels.

Q. WHY WERE THE LOSSES FOR 2000 AND 2004 ESTIMATED?

A. The Company does not have detailed data for storm damage going back as far as 2000. They only have the total amount paid, not broken out by storm. We know that there was a large ice storm at the end of 2000, and a series of large thunderstorms in 2004. I believe that it is appropriate to include these storms in the data when trying to estimate the expected annual loss.

Q. HOW WERE THE LOSSES FOR 2000 AND 2004 ESTIMATED?

A. It appears that the largest total loss for any year without a severe storm was approximately $281,000. We took the total amount paid out in those years with unusually large payments, and subtracted $281,000 from the total. The remaining losses were considered to be the impact of the storms noted above. By subtracting the largest recorded estimate for the normal losses, we believe that we have a conservative estimate of the total amount paid for the storms in 2000 and 2004, which makes our estimate of the annual accrual a minimum that we would recommend be approved.

VI. TARGET RESERVE

Q. WHAT IS THE TARGET AMOUNT OF MONEY NEEDED TO PROVIDE FOR AN ADEQUATE SELF-INSURANCE RESERVE?

A. The recommended total target amount of the reserve is $11.0 million, which is the amount of O&M damages expected to result from a 25-year storm. Given its geographic location and its past history, SWEPCO should expect to incur the occasional extraordinary loss due to severe weather.

Q. HOW WAS YOUR TARGET RESERVE OF $11.0 MILLION DEVELOPED?

A. As noted above, I ran a Monte Carlo simulation on the loss history of SWEPCO. From the results of the simulation, I determined that the largest expected loss in any 25-year period is approximately $11 million.

Q. WHY IS THIS RESERVE LEVEL APPROPRIATE?

A. This reserve level is the amount that should be carried by SWEPCO to make an actuarially sound provision for coverage of the self-insured losses. The target reserve will be sufficient if annual losses are equal to or less than the target in a given year provided the reserve is already in place at its target amount; but if the actual losses exceed the amount accrued for the expected annual amount for several years in a row, the self-insurance reserve may be depleted.

For example, once the reserve level has been reached, if there are several years with losses of approximately $2,350,000, then the reserve will remain unused. However, if there are two consecutive years with annual aggregate losses of more

SPP Southwest Power Pool

SPP PLANNING CRITERIA

Revision 2.3

Maintained by:

TRANSMISSION WORKING GROUP
SYSTEM PROTECTION AND CONTROLS WORKING GROUP
SUPPLY ADEQUACY WORKING GROUP

Published on 1/11/2021

calculation of the temperature levels as defined in the Criteria. Site specific data shall contain both dry- bulb and wet-bulb temperatures.

6) Temperatures for summer rating of equipment should be taken from Handbook Table 1B: Cooling and Dehumidification Design Conditions - Cooling DB/MWB for 0.4% DB (dry-bulb) and MWB (mean wet-bulb) (Column 2a and 2b, respectively). According to the 2001 Handbook Page 27.2, "The 0.4% annual value is about the same as the 1.0% summer design temperature in the 1993 ASHRAE Handbook." In older Handbooks, the dry-bulb temperature for summer rating of equipment shall be taken as that which is equaled or exceeded 1% of the total hours during the months of June through September for the plant's geographical location. The wet-bulb temperature for the summer rating shall be the "mean coincident wet-bulb" temperature corresponding to the above dry-bulb temperature.
7) The temperature for winter rating of equipment should be taken from Handbook Table 1A: Heating and Wind Design Conditions-United States - Heating Dry Bulb 99% (Column 2b). According to the 2001 Handbook Page 27.3, "Annual 99.6% and 99.0% design conditions represent a slightly colder condition than the previous cold season design temperatures, although there is considerable variability in this relationship from location to location." In older Handbooks, the minimum dry-bulb temperature for winter testing and net generating capacity shall be taken as that which is equaled or exceeded 99% of the total hours during the months of December through February (per Handbook definition) for the plant's geographical location. The wet-bulb temperature is not significant for the winter rating and can be disregarded.
8) Standard barometric pressure for a plant site shall be determined for each plant elevation from the equation provided in Section 9.
9) For those units using a lake or river as a source of condenser cooling water, the summer standard inlet temperature is the highest water inlet temperature during the month concurrent with the member's peak load of the year, averaged over the past ten years.
10) Ambient wet-bulb temperature and condenser cooling water temperature are generally not significant factors in adjusting cold weather capability of generating units. Shall special situations arise in which these temperatures are required, reasonable estimates for temperatures occurring coincidentally with the winter rating dry-bulb temperature as defined in the Criteria shall be used.

7.1.2 NET GENERATING CAPACITY AND DEMAND RESPONSEADJUSTMENTS

1) The rated net capability of a unit may be above or below the actual tested net capability as a result of adjustments for Net generating capacity Conditions, with the exception of units with winter season net capacity greater than their summer net capacity. For these units, the winter season rated net capability shall be no greater than the actual tested net capacity. No net generating capacity adjustment for ambient conditions shall be made.
2) Seasonal net capability shall not be reduced to provide regulating margin or spinning reserve. It shall reflect operation at the power factor level at which the generating equipment is normally expected to be operated over the daily peak load period.
3) Extended capability of a unit or plant obtained through bypassing of feed-water heaters, by utilizing other than normal steam conditions, by abnormal operation of

auxiliaries in steam plants, or by abnormal operation of combustion turbines or diesel units may be included in the seasonal net capability if the following conditions are met; a) the extended capability based on such conditions shall be available for a period of not less than four continuous hours when needed and meets the other restrictions, and b) appropriate procedures have been established so that this capability shall be available promptly when requested by the system operator.

4) The seasonal net capability established for nuclear units shall be determined taking into consideration the fuel management program and any restrictions imposed by governmental agencies.
5) The seasonal net capability established for hydroelectric plants, including pumped storage projects, shall be determined taking into consideration the reservoir storage program and any restrictions imposed by governmental agencies and shall be based on median hydro conditions.
6) The seasonal net capability established for run-of-the-river hydroelectric plants shall be determined using historical hydrological data on a monthly basis.
7) The seasonal net capability established for Demand Response Programs shall be adjusted in accordance with the Demand Response Programs Reporting and Documentation Procedures givin in SPP Business Practice.
8) The seasonal net capability established for Behind-The-Meter Generation, which does not have firm delivery beyond a discrete point of delivery, shall be adjusted in accordance with Behind The Meter Generation Reporting and Documentation Procedures given in SPP Business Practice.
9) The recommended methodology to evaluate the net planning capability established for wind or solar facilities shall be determined on a monthly basis, as stated below. If a member's desire to use a more restrictive methodology to evaluate the net capability of wind or solar they may do so, however net capability determined by the alternative methodology employed cannot credit the wind or solar with a capability greater than determined with the methodology stated below:
10) Assemble all available hourly net power output (MWH) data measured at the system interconnection point.

    (a) Select the hourly net power output values occurring during the top 3% of load hours for the SPP Load Serving Entity for each month of each year for the evaluation period.

    (b) Select the hourly net power output value that can be expected from the facility 60% of the time or greater. For example, for a 5 year period with the 110 hourly net power output values ranked from highest to lowest, the capacity of the facility will be the MW value in the 65th data point.

    (c) A seasonal or annual net capability may be determined by selecting the appropriate monthly MW values corresponding to the Load Serving Entity's peak load month of the season of interest (e.g., 22 hours for a typical 30 day month and110 hours for a 5 year period).

    (d) Facilities in commercial operation 3 years or less:

        (i) The data must include the most recent 3 years.

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S FIRST SET OF REQUESTS FOR INFORMATION

Question No. CARD 1-12:

Provide a copy of SWEPCO's integrated resource plan report that governed capacity planning decisions during the test year period.

Response No. CARD 1-12:

Please see CARD 1-12 Attachment 1 (provided electronically on the PUC Interchange) for the 2019 SWEPCO IRP that was filed with the Louisiana Public Service Commission on August 15, 2019.

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Sponsored By: Scott E. Mertz	Title: Regulatory Consultant Staff

3.0 Resource Evaluation

3.1 Current Resources

An initial step in the IRP process is the demonstration of the capacity resource requirements. This aspect of the traditional "needs" assessment must consider projections of:

- existing capacity resources—current levels and anticipated changes;
- anticipated changes in capability due to efficiency and/or environmental considerations;
- changes resulting from decisions surrounding unit disposition evaluations;
- regional and sub-regional capacity and transmission constraints/limitations;
- load and peak demand;
- current DR/EE; and
- SPP capacity reserve margin and reliability criteria.

3.2 Existing SWEPCO Generating Resources

The underlying minimum reserve margin criterion to be utilized in SWEPCO's resource needs assessment is based on the current SPP minimum capacity margin of 10.7 percent.[4] As a function of peak demand this converts to an equivalent "reserve margin" of 12.0 percent.[5] The reserve margin is the result of SPP's own system reliability assessment. Table 1 displays key parameters for SWEPCO's current supply-side resources.

[4] Per Section 4.1.9 of the "Southwest Power Pool Planning Criteria" (Latest Revision: July 25, 2017).

[5] $0.107 / (1 - 0.107) = 0.12$.

Table 1. Current Supply-Side Resources, as of June 2019

Plant	Unit	Output Net MW Capability	In-Service Year	Expected Useful Life	Primary Fuel	State	Retirement Date (1)
Arsenal Hill	5	110	1960	65	Natural Gas	LA	2025
Dolet Hills (2)	1	650**	1986	60	Lignite	LA	2046
Flint Creek	1	528*	1978	60	Coal	AR	2038
Knox Lee	2	30	1950	69	Natural Gas	TX	2020
Knox Lee	3	31	1952	67	Natural Gas	TX	2020
Knox Lee	5	348	1974	65	Natural Gas	TX	2039
Lieberman	2	26	1949	70	Natural Gas	LA	2019
Lieberman	3	109	1957	65	Natural Gas	LA	2022
Lieberman	4	108	1959	65	Natural Gas	LA	2024
Lone Star	1	50	1954	65	Natural Gas	TX	2019
Mattison	1	76	2007	45	Natural Gas (CT)	AR	2052
Mattison	2	76	2007	45	Natural Gas (CT)	AR	2052
Mattison	3	76	2007	45	Natural Gas (CT)	AR	2052
Mattison	4	76	2007	45	Natural Gas (CT)	AR	2052
Pirkey	1	675***	1985	60	Lignite	TX	2045
Stall	6A, 6B, 6S	511	2010	40	Natural Gas (CC)	LA	2050
Turk	1	650	2012	55	Coal	AR	2067
Welsh	1	528	1977	60	Coal	TX	2037
Welsh	3	528	1982	60	Coal	TX	2042
Wilkes	1	177	1964	65	Natural Gas	TX	2029
Wilkes	2	362	1970	65	Natural Gas	TX	2035
Wilkes	3	362	1971	65	Natural Gas	TX	2036
Majestic	1	80 (A)	2009		Wind (PPA)	TX	2029
High Majestic	1	80 (A)	2012		Wind (PPA)	TX	2032
Flat Ridge	1,2	109 (A)	2013		Wind (PPA)	KS	2032
Canadian Hills	1,2,3	201 (A)	2012		Wind (PPA)	OK	2032

* SWEPCO's Share is 264 MW
** SWEPCO's Share is 262 MW
*** SWEPCO's Share is 580 MW
(1) Based on the latest Commission approved depreciation rates in the respective SWEPCO state jurisdictions.
(2) Dolet Hills has transitioned to seasonal operations and the Company is continuing to evaluate operations.

For purposes of establishing a modeling "baseline," it is necessary to establish assumptions pertaining to all of the capacity and energy resources available to SWEPCO. Figure 10 depicts SWEPCO's current generation resources along with their current age. For IRP purposes, each generating unit has an assumed planned retirement date based on the latest Commission approved depreciation rates in the respective SWEPCO state jurisdictions, which is shown in Table 1 and reflected in the Capacity, Demand, and Reserves summary (CDR) found in Exhibit F of the appendix. As depicted in the figure, the gas-steam units are the oldest units on the

SWEPCO system. These older units are of a less efficient design than newer Natural Gas Combined Cycle (NGCC) units and therefore are dispatched far less frequently in the SPP market, resulting in much lower expected capacity factors. As a result, while these units have relatively low fixed costs and provide capacity value, should either a catastrophic failure occur or a very expensive component fails that would require replacing, there is a higher degree of probability that such gas-steam units would not be economic to repair. In such a case, the unit would likely be retired.

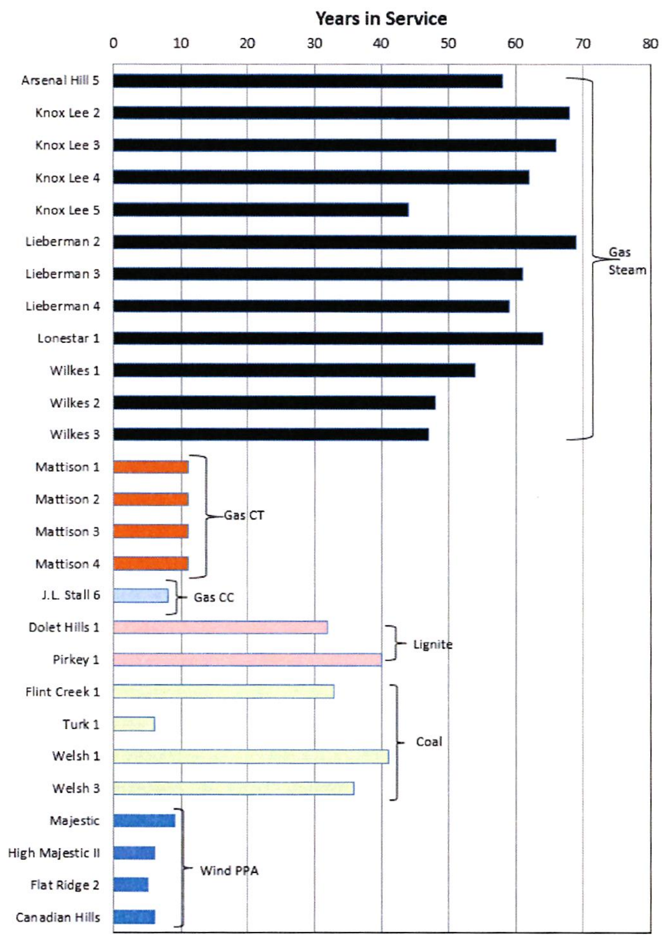

Figure 10. Current Resource Fleet (Owned and Contracted) with Years in Service, as of July 1, 2019

With the exception of Lieberman 2, Lone Star and Knox Lee Units 2 & 3, no firm commitment has been made to retire the balance of the gas-steam assets, however, given the age and the potential of such expensive component failures, this IRP assumes that some of these

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PUC DOCKET NO. 26195
SOAH DOCKET NO. 473-02-3473

JOINT APPLICATION OF TEXAS GENCO, LP AND CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC TO RECONCILE ELIGIBLE FUEL REVENUES AND EXPENSES PURSUANT TO SUBST. R. 25.236	§ § § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the joint application of CenterPoint Energy Houston Electric, LLC and Texas Genco, LP (collectively, CenterPoint) to reconcile fuel expenses and revenues for the period from August 1, 1997, through January 30, 2002. This is CenterPoint's final fuel reconciliation pursuant to PURA[1] § 39.202(c). Except as provided in this Order, the Commission adopts the findings of fact and conclusions of law contained in the Commission's Interim Order[2] and the proposal for decision (PFD), including findings of fact and conclusions of law, issued by the administrative law judge (ALJ) for the State Office of Administrative Hearings (SOAH) on March 4, 2004 and modified by the ALJ's April 1, 2004 letter. As discussed below, the Commission modifies or reverses the ALJ on the following three issues: out-of-merit capacity costs, above-market Kerr McGee coal costs, and capacity costs in purchased power. In addition, after considering the initial PFD and remanding to SOAH the issue of capacity costs in purchased power, the Commission adopts the unopposed stipulation resolving all issues identified in the Commission's Order on Remand.[3] CenterPoint's application, as modified by this Order, is approved.

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[1] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§ 11.001-64.158 (Vernon 1998 & Supp. 2004) (PURA).

[2] Interim Order (Apr. 25, 2003).

[3] Order on Remand (Apr. 20, 2004). *See also* Remand Order No. 5 (May 18, 2004).

Moreover, the Commission finds that CenterPoint's request is distinguishable from Docket No. 27576, Texas-New Mexico Power Company's (TNMP's) fuel reconciliation case. First, this issue was presented differently in the TNMP case. TNMP sought to include OOMC charges, as well as other charges for ancillary services, that were incurred under its purchased-power contract with Constellation. Constellation supplied TNMP with OOMC services (and various ancillary services) at a fixed dollar per megawatt-hour price. The ALJ found that TNMP did not explain whether OOMC payments from ERCOT would be off-set against the fee. Other costs associated with the Constellation contract were also disallowed. In contrast, CenterPoint's request is not associated with a third-party transaction, and it is only seeking recovery of OOMC charges net of any payments it received for providing OOMC service. In addition, the ALJ in the TNMP case ultimately concluded that TNMP failed to carry its burden of proof on this issue.[14] In contrast, the evidence in this proceeding clearly supports a determination that OOMC costs are identical to re-dispatch fees and are not related to purchased power. And as discussed above, P.U.C. SUBST. R. 25.236(a)(5) expressly allows recovery of re-dispatch fees as an eligible fuel expense.

Therefore, consistent with this discussion, the Commission reverses the ALJ on the treatment of OOMC costs and modifies FOF 56, 57 and 60 and Conclusion of Law (COL) 14 and 22; deletes FOF 58 and 59 and COL 13 and 15; and adds new FOF 58A and 59A.

C. Capacity Costs in Purchased Power

This issue relates to whether certain purchased-power expenses for firm power included capacity costs that are not an eligible fuel expense.[15] Intervenors and Staff asserted that although the contracts at issue were priced on an "energy-only" basis (i.e., $/MWh) and did not have a separately stated demand or capacity charge, the contracts

[14] Docket No. 27576, Proposal for Decision at 74 (Nov. 11, 2003).

[15] *See* P.U.C. SUBST. R. 25.236(a)(4).

had an implicit capacity component because they had capacity attributes of reliability and firmness of supply and were used to meet CenterPoint's load obligations without increasing its generating capacity. CenterPoint argued, however, that it did not purchase capacity but instead purchased replacement energy when faced with outages and other temporary conditions. CenterPoint asserted that the essential element of a capacity purchase is that it is made as part of the system planning process to provide flexibility to meet expected future requirements of the system.[16] According to CenterPoint, this flexibility is obtained through the right to call on energy for the reserved capacity, if and when needed.

1. PFD Findings and Remand

The ALJ recommended that the Commission follow its precedent from Entergy's last fuel reconciliation case[17] and find that CenterPoint's purchased-power contracts had a capacity component. The ALJ found that CenterPoint was short on capacity during certain times throughout the reconciliation period and that it purchased power to compensate for loss of generating units, to augment reserves, and to preserve reliability.[18] Although the purchases were not part of the utility's capacity planning process, the ALJ determined that they were made to maintain reliability and would therefore be considered capacity purchases under the Commission's definition in the Entergy case.

Consistent with its recent ruling in El Paso's fuel reconciliation, Docket No. 26194,[19] the Commission rejects the portions of the PFD in this proceeding that recommend disallowing capacity costs in purchased power using the methodology proposed by the Office of Public Utility Counsel.[20] In the El Paso and Entergy cases,[21] the Commission found capacity in certain purchased-power contracts based, in part, on

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[16] CenterPoint Ex. 12, Mitcham Rebuttal Testimony at 25 (Bates).

[17] *Application of Entergy Gulf States, Inc. for the Authority to Reconcile Fuel Costs*, Docket No. 23550, Final Order (Aug. 2, 2002).

[18] *See* Proposal for Decision at 15.

[19] Docket No. 26194, Final Order at 2-7.

[20] Proposal for Decision at 13.

[21] Docket No. 23550, Final Order.

specific contract language and other documents in the evidentiary record that indicated the utility was purchasing capacity. However, in this proceeding, based on the evidentiary record, the Commission was unable to determine whether specific contracts or other documents at issue contain language that would indicate that the utility was purchasing capacity. Further, no evidence was presented regarding how to quantify any such capacity in a manner that is generally consistent with the El Paso case.[22] Therefore, at its April 15, 2004 open meeting, the Commission remanded this issue to SOAH to determine whether CenterPoint's purchased-power expenses included capacity costs and, if so, to quantify those costs.

2. Settlement Agreement on Remand Issues

On May 10, 2004, CenterPoint, City of Houston, GCCC, OPC, Staff, and TIEC filed an unopposed stipulation resolving all issues among these parties relating to the Commission's Order on Remand. The remand stipulation provides that a total of $4.7 million, inclusive of interest, shall be considered as payments for capacity, and not energy, in connection with purchased-power contracts entered into by HL&P during the reconciliation period. According to the remand stipulation, the $4.7 million shall be excluded from eligible fuel expense in this proceeding.

The Commission finds that this remand stipulation is an appropriate compromise to this difficult issue and is in the public interest. Accordingly, the Commission approves the stipulation. The Commission adds new FOF 55A-55G and COL 11A-11B, deletes FOF 42 and 52-54 and COL 10 and 12, and modifies FOF 48 and 51 and COL 11 to reflect the Commission's changes to the PFD and its adoption of the stipulation.

D. ERCOT Resettlements

At the time the March 2003 stipulation was signed, the Electric Reliability Council of Texas (ERCOT) was still resettling transactions for the month of January 2002. Because there was no disagreement among the parties concerning the need to reflect the resettlements in the final fuel balance in this proceeding, the parties agreed that

[22] *See* Docket No. 26194, Final Order at 2-7.

CenterPoint would make a filing showing the amount of money received or paid by CenterPoint as a result of all resettlements through the date of its 2004 stranded cost true-up filing. On April 2, 2004, pursuant to the Interim Order, CenterPoint made this filing in the form of a notice with an affidavit and schedules attached.[23] No party challenged the amounts set forth in this notice. The Commission admits the notice into evidence as Commission Exhibit No. 1 and includes FOF 17A, 17E, and 17L to reflect the notice and its effect on the stipulated fuel balance.

III. Findings of Fact

A. Procedural History

1. Reliant Energy HL&P (HL&P), an unincorporated division of Reliant Energy, Incorporated (Reliant Energy), was an investor-owned electric utility providing retail electric service within the State of Texas from August 1, 1997, through January 30, 2002 (the reconciliation period).

2. On July 1, 2002, Reliant Energy timely filed its petition to reconcile eligible fuel revenues and expenses (petition), which included revenues and expenses for the reconciliation period, with the Public Utility Commission of Texas (PUC or Commission).

3. Reliant Energy sought reconciliation of an under-recovery fuel balance of $144,339,069 (including interest through May 31, 2002) consisting of a beginning under-recovery fuel balance of $93,670,073; eligible fuel expenses of $8,495,938,826; eligible fuel revenues of $8,478,310,066; and a cumulative negative interest balance of $33,040,236.

4. Reliant Energy published notice of this proceeding once each week for two consecutive weeks in a newspaper having general circulation in each county of the service area of HL&P. In addition, Reliant Energy provided direct notice, by

[23] Notice Concerning Adjustment to Final Fuel Balance Related to January 2002 Resettlements (Apr. 2, 2004).

PUC DOCKET NO. 27035
SOAH DOCKET NO. 473-03-1282

APPLICATION OF CENTRAL POWER AND LIGHT COMPANY FOR AUTHORITY TO RECONCILE FUEL COSTS	§ § § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER ON REHEARING

This Order addresses the request of AEP Texas Central Company (TCC) (formerly Central Power and Light Company) to reconcile fuel costs for the period from July 1, 1998 through December 31, 2001. This is TCC's final fuel reconciliation as an integrated utility.

Except as provided in this Order, the Commission adopts the proposal for decision (PFD) and the PFD on Remand, including findings of fact and conclusions of law, filed on February 3, 2004 and January 13, 2005, respectively, by the administrative law judges (ALJs) of the State Office of Administrative Hearings (SOAH). As discussed below, the Commission reverses the ALJs on the following issues: (1) the substitution of actual for estimated revenue and expense for that part of the reconciliation period extending beyond January 1, 2002; (2) the treatment of capacity revenues TCC received from the Electric Reliability Council of Texas (ERCOT); (3) the identification and quantification of implicit capacity costs contained in TCC's "firm energy only" purchased-power contracts (the subject of the remanded proceeding); (4) the disallowance of a set of replacement-power costs associated with one outage at the South Texas Project (STP); (5) the deduction of $3,548,048 from TCC's fuel expenses because of its suit against the U.S. Department of Energy (DOE) for overcharges; and (6) the prudence of TCC's spot-market purchases of coal from Oxbow Minings, Inc.

340

Commission further notes that no party responded to TCC's renewed argument for using the booked figures made in its exceptions.

In accordance with the preceding discussion, the Commission deletes finding of fact 15 and modifies findings of fact 14, 16, and 17.

III. Capacity Revenues TCC Received from ERCOT

Noting that P.U.C. SUBST. R. 25.236(a)(7)(C) provides that "eligible fuel expenses shall be offset by . . . revenues from off-system sales in their entirety [subject to margin sharing]," the ALJs found that TCC should offset its fuel expenses by including the $2,826,370 in revenues it received from ERCOT as compensation for bringing offline capacity online and making it available for spinning at ERCOT's request. TCC excepted to the ALJs' determination, arguing that crediting ERCOT capacity revenues against fuel expenses would violate the principle of symmetrical treatment of costs and revenues. (P.U.C. SUBST. R. 25.236(a)(4) excludes capacity costs recorded in FERC Account 555 (*i.e.*, for purchased power) from fuel expenses.) Therefore, TCC maintained, because it excluded $6.1 million spent during the reconciliation period in explicit capacity costs, it also should be allowed to exclude the ERCOT capacity revenues. Nevertheless, TCC stated that it did *not* object to the finding that TCC should offset its eligible fuel expenses by the ERCOT capacity revenues, because TCC agreed in Docket No. 15900[5] to treat all off-system sales margins (which would include capacity revenues) as a fuel item with the phase-in of bonded rates in Docket No. 14965.[6] It proposed amending conclusion of law 16 to reflect TCC's agreement to do so. (It also proposed deleting finding of fact 38.)

The Commission finds it appropriate to adopt TCC's alternative proposal. Doing so will benefit ratepayers even more than would the ALJs' recommended finding, as the latter would result in a sharing of only 50% of the capacity revenues with ratepayers pursuant to the margin-sharing provisions of its Integrated Stipulation and Agreement

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[5] *Application of Central Power and Light Company for Authority to Reconcile Fuel Costs*, Docket No. 15900, Order at 18, Finding of Fact 75 (June 28, 1996).

[6] *Application of Central Power and Light Company for Authority to Change Rates*, Docket No. 14965, Second Order on Rehearing (Oct. 16, 1997).

(ISA).[7] Thus, the Commission finds it unnecessary to make a determination as to whether the ERCOT capacity revenues TCC received should be considered offsets to its off-system energy sales outside of the offset agreed to in Docket No. 15900. The Commission deletes finding of fact 38 and modifies conclusion of law 16 to reflect its decision.

III. Implicit Capacity Costs in TCC's Purchased-Power Contracts

At its May 13, 2004 open meeting, the Commission declined to adopt the ALJs' original recommendation in this case to find that $29.6 million of TCC's purchased-power expenses were actually implicit capacity costs.[8] The Commission's decision was consistent with the Commission's prior ruling in El Paso Electric Company's fuel reconciliation, Docket No. 26194.[9] In that case, the Commission declined to adopt the methodology proposed by OPC for identifying and quantifying implicit capacity costs, involving a comparison of power prices in "firm energy only" contracts with the cost of supplying power from TCC's least efficient gas-fired generating plants. (Any excess in the contract price over the utility's generating cost was deemed to reflect a capacity payment.[10]) In this case, the Commission stated that, unlike in the El Paso case, it found no evidence in the record of specific contracts or other documents indicating that TCC was buying capacity through "firm energy only" contracts.[11] Consequently, the Commission remanded the imputed-capacity issue to SOAH for further evidence to determine whether TCC's claimed purchased-power expenses included capacity costs, and to quantify any such costs.[12] The Order on Remand stated that the Commission

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[7] Subsection 3.G. of the ISA stipulates that TCC's annual off-system sales margins above $2.62 million are to be shared on a 50/50 basis with customers.

[8] *See* Order on Remand (May 25, 2004).

[9] *Petition of El Paso Electric Company to Reconcile Fuel Costs*, Docket No. 26194, Order (May 5, 2004).

[10] PFD at 6, 64-65, and 67-68 (Feb. 3, 2004); Docket No. 26194, Order at 3 and 5-6 (May 5, 2004).

[11] Order on Remand at 1-2 (May 25, 2004).

[12] *Id.* at 3.

could not determine whether "specific contracts or other documents contain language indicating that CPL was purchasing capacity"[13] in any of its "firm energy only" contracts.

In the PFD on Remanded Issues, the ALJ identified nine contracts that appeared to contain implicit capacity costs, and quantified those costs at $1,619,750, using a method proposed by TCC. The Commission adopts the ALJs' recommendation on contract identification. With respect to quantification, the Commission adopts the ALJ's basic recommendation, but with one of the modifications proposed by the Texas Industrial Energy Consumers (TIEC) to correct a "math error" in calculating the proxy capacity charges for 1999 and 2000.[14] For each of those years, the adjustment set forth by TIEC recognizes that the one of the benchmark contracts was for four months only (June-September), rather than the entire year. Dividing the annual cost of the contract(s) by the proper (lower) level of capacity purchased (in megawatt-months) yields somewhat higher proxy capacity charges for the two years: $2.50 instead of $1.53 for 1999 and $2.57 instead of $2.31 for 2000. When the corrected figures are applied to the capacity purchased under the "firm energy only" contracts for each year, the sum of the annual products is $1,962,750, rather than $1,619,750.[15]

Because the PFD on Remand contains a complete set of findings of fact and conclusions of law, the Commission deletes the entire set of findings of fact and conclusions of law contained in the original (pre-remand) PFD regarding this issue. Thus, findings of fact 40-53 are deleted, and are replaced by new findings of fact R6-R15, which are located at the end of the non-remand findings of fact. (Findings of fact R6 and R7 exactly duplicate deleted findings of fact 40 and 41.) In addition, new findings of fact R1-R5, relating to the procedural history of the remanded issues in this case, immediately precede findings of fact R6-R15. Similarly, conclusions of law 18-20 are deleted, and are replaced by new conclusions of law R1-R2, at the end of the non-remand conclusions of law.

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[13] *Id.*

[14] TIEC's Exceptions at 2-3 (Jan. 26, 2005).

[15] *See Id.* at 2, fn. 4.

IV. Disallowance of Replacement-Power Costs for One Outage at STP

The ALJs recommended disallowances totaling $2,901,654 associated with six power outages and one power reduction at STP during the reconciliation period. The Commission adopts the ALJs' recommendations on all but one of these instances, namely, the $820,162 outage at STP Unit 2 on May 8-11, 2001. In the latter case, which the ALJs admitted was a "close question,"[16] STP personnel used a computer to record data regarding the operation of the Unit 2 feedwater regulating valves, which were monitored through a "Hart" (a protocol standard) adapter. When STP personnel had asked the vendor whether the Hart adapter was polarity-sensitive, the vendor said that polarity did not matter. STP personnel successfully tested the Hart adapter using a laptop computer with a 2-prong AC adapter. When they performed the actual monitoring, however, they used a laptop with a 3-prong AC adapter. (The third prong was for connecting to ground.) During the monitoring, STP personnel also decided to plug the computer into a utility outlet to conserve the computer's batteries. The AC adapter's ground plug shorted the signal wires, resulting in a process that caused the valve to close and the reactor to trip.

The Commission finds that TCC STP personnel exhibited appropriate caution in asking the vendor about the polarity sensitivity of the Hart adapter and in running a test of the monitoring equipment. The ALJs applied an unduly high standard in finding that the STP employees should have reviewed documentation from the manufacturer or vendor to confirm the latter's reassurance regarding polarity sensitivity. Accordingly, the Commission reverses the ALJs' recommended disallowance, and modifies findings of fact 76(b) and 76(c), as well as conclusion of law 30.

V. Deduction of $3,548,048 from Fuel Expenses Because of TCC's Suit Against U.S. Department of Energy

Pursuant to a contract with STP owners, the Department of Energy (DOE) provided uranium-enrichment services to STP between 1986 and 1993. STP and other utilities have filed suit against the DOE, seeking to recover a refund for overcharges for

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PUC DOCKET NO. 29408
SOAH DOCKET NO. 473-04-3640

APPLICATION OF ENTERGY GULF STATES, INC. FOR AUTHORITY TO RECONCILE FUEL COSTS	§ § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the application of Entergy Gulf States, Inc. (EGSI) to reconcile approximately $3.7 billion in total-company fuel and purchased-power costs (over $1.4 billion of which are assigned to Texas retail customers) for the 36-month period of September 2000 through August 2003. After an evidentiary hearing, the State Office of Administrative Hearings (SOAH) administrative law judges (ALJs) issued a proposal for decision (PFD) on January 31, 2005, and issued corrections to the PFD on February 22, 2005.[1] In the PFD, the ALJs recommended disallowing costs associated with energy attributed to the 30% of EGSI's River Bend nuclear plant not included in its rate base, as well as costs for capacity that was not explicitly priced in EGSI's purchased-power contracts.[2] But the ALJs further recommended that those implicit capacity costs incurred during the summer of 2003 be allowed due to special circumstances.[3] The ALJs did not, however, find special circumstances to allow costs for explicitly priced capacity[4] or the profits and non-fuel costs associated with the power from the 30% of the River Bend plant.[5] The ALJs otherwise recommended approval of EGSI's application.

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[1] Letter from Lilo Pomerleau and Travis Vickery, ALJs, SOAH, to Stephen Journeay, Director, Policy Development Division (Feb. 22, 2005).

[2] PFD at 4, 10-24 (Jan. 31, 2005).

[3] *Id.* at 4, 76-77.

[4] *Id.* at 68-73.

[5] *Id.* at 77-81.

and is treated as an unregulated asset. The Commission adopted a non-unanimous settlement agreement and ratified EGSI's treatment of the River Bend 30% as an unregulated asset for all purposes in all proceedings in *Application of Entergy Gulf States for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule* 25.344, Docket No. 22356, Interim Order at 7-8 (May 29, 2001).

42. During the summer of 2001, EGSI used power from its River Bend 30% to serve retail customers.

43. EGSI sought to recover $13,568,045 (total Company) or $5,283,539 (Texas jurisdictional) for energy from the River Bend 30% used to serve EGSI's retail customers during the months of June, July and August 2001.

44. Included in the $5,283,539 (Texas jurisdictional) are fuel costs, other expenses and profit.

45. Included in the "other expenses" of the River Bend 30%, incurred in addition to nuclear-fuel costs, are depreciation, coolants and water, steam expenses, miscellaneous nuclear-power expenses, rents, maintenance, administrative and general salary expenses, office supplies, insurance expenses, miscellaneous general expenses, and taxes, among others.

46. Of the $13,568,045 (total Company) or $5,283,539 (Texas jurisdictional) sought by EGSI as purchased power from the River Bend 30%, actual nuclear-fuel costs to the River Bend 30% are $1,066,384 (total Company) or $412,694 (Texas jurisdictional). EGSI booked the $13,568,045 (total Company) or $5,283,539 (Texas jurisdictional) to FERC Account 555 (Purchased Power).

47. The energy from the River Bend 30% used to serve EGSI's retail customers was generated by EGSI, not purchased by EGSI. There was no transfer of title between EGSI and Entergy Services, Inc, and EGSI did not buy back the River Bend 30% power from Entergy Services, Inc.

48. An internal corporate accounting transfer between EGSI's unregulated and regulated business activities does not amount to a sale. Therefore, it is not

reasonable for EGSI to re-record its expenses and profit related to this transaction as a purchased-power expense in FERC Account 555 (Purchased Power).

F. Imputed Capacity Costs

49. Upon deregulation of the electric industry, the pricing in many purchased-power contracts changed, in that often there is no capacity cost stated in firm purchased-power contracts.

50. During the Reconciliation Period, the Entergy Operating Committee directed that the ISB reflect imputed capacity costs for certain firm-energy purchases in order to comply with Louisiana Public Service Commission (LPSC) cost-recovery rules.

51. To comply with the LPSC order that requires implicit capacity costs to be excluded from fuel, the Entergy Operating Committee evaluated summer firm-energy purchases made during the reconciliation period to determine whether there was an implicit capacity value. These firm-energy purchases (contracts) are the same purchases at issue in this reconciliation.

52. In 2001 and 2002, the Operating Committee determined that energy purchases include an imputed capacity value of 24% and 10%, respectively. For 2003, the Operating Committee was presented with an analysis showing an imputed level of 6% but found that unique circumstances in the market at that time merited no imputed capacity value.

53. In the years 2001, 2002, and 2003, the Operating Committee was presented with different methodologies for the basis of their imputed capacity-value determinations of the summer purchases in each respective year.

54. LPSC agreed with the Operating Committee's determination of 24% in 2001. However, for 2002, LPSC adopted, pursuant to settlement, a capacity imputation level of 14%. For 2003, LPSC ordered an imputation level of 11%.

55. A level of 24% capacity imputation for the year 2001 is reasonable based on the Operating Committee's determination as accepted by the LPSC.

56. A level of 14% capacity imputation for the year 2001 is reasonable based on EGSI's agreement that such a level was acceptable in both this case and in the LPSC case.

57. EGSI bought over 760 megawatts (MW) of purchased power in the summer of 2003 that contained an explicit capacity charge.

58. The analysis used to derive a 6% level of capacity imputation, presented to the Operating Committee in 2003, was reasonably based on contracts purchased for the same time period, summer 2003, that included a separately stated capacity cost.

59. Imputation levels should only apply to purchased power assigned to serve EGSI's native load.

G. Reasonableness and Necessity of Fuel Expenses (Uncontested Findings)

60. EGSI incurred $2,124,980,405 in natural-gas expenses during the Reconciliation Period.

61. EGSI purchased natural gas in the monthly and daily markets. EGSI also transported gas on its own account and negotiated operational balancing agreements with various pipeline companies.

62. EGSI employed a diversified portfolio of gas supply and transportation agreements to meet its natural-gas requirements, and EGSI prudently managed its gas-supply contracts.

63. EGSI's gas expenses compare favorably to recognized market indices.

64. EGSI's natural-gas expenses were reasonable and necessary expenses incurred to provide reliable electric service to retail customers.

65. EGSI incurred $147,617,558 in coal expenses during the Reconciliation Period.

66. During the Reconciliation Period, EGSI negotiated the Test Burn, Storage, and Proposal Extension Agreement with Arch Coal, Inc. for coal supply at Nelson

Station. The coal transportation agreements for Nelson Station were the same agreements reviewed by the Commission in Docket No. 23550.

67. EGSI prudently managed its coal and coal-related contracts during the Reconciliation Period.

68. EGSI monitored and audited coal invoices from Louisiana Generating, LLC for coal burned at Big Cajun II, Unit 3.

69. EGSI's coal expenses compare favorably to the coal expenses reported by other Texas and Louisiana generators that use Powder River Basin coal.

70. EGSI's coal expenses were reasonable and necessary expenses incurred to provide reliable electric service to retail customers.

71. EGSI incurred $16,326,352 in fuel-oil expenses during the Reconciliation Period.

72. Fuel oil was used as a start-up and flame-stabilization fuel at a few units, as an emergency back-up fuel at one station, and as an economic alternative to natural gas on two occasions.

73. All of the fuel oil was purchased on a short-term basis from spot-market sources after solicitation of offers from multiple suppliers.

74. EGSI's fuel-oil expenses were reasonable and necessary expenses incurred to provide reliable electric service to retail customers.

75. EGSI incurred $81,789,291 in nuclear-fuel expenses for the River Bend nuclear plant during the Reconciliation Period.

76. EGSI's nuclear-fuel expenses during the Reconciliation Period are under the applicable performance-based ratemaking (PBR) nuclear-fuel targets, and compare favorably to industry nuclear-fuel costs.

77. EGSI's nuclear-fuel expenses were reasonable and necessary expenses incurred to provide reliable electric service to retail customers.

78. EGSI proposed a line-item adjustment (credit) to fuel expense of $9,830, which no party challenged.

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' NINTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 9-2:

Please quantify the imputed capacity costs associated with SWEPCO's wind and solar PPAs in Excel format with all formulas and links intact.

Response No. TIEC 9-2:

SWEPCO has not quantified any imputed capacity costs associated with SWEPCO's wind and solar PPAs.

Prepared By: Scott E. Mertz	Title: Regulatory Consultant Staff
Sponsored By: Scott E. Mertz	Title: Regulatory Consultant Staff

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