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SOAH DOCKET NO. 473-22-1073
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APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY TO AMEND ITS CERTIFICATE OF CONVENIENCE AND NECESSITY TO CONVERT HARRINGTON GENERATING STATION FROM COAL TO NATURAL GAS	§ § § § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

REDACTED

DIRECT TESTIMONY

OF

KARL NALEPA

ON BEHALF OF THE

OFFICE OF PUBLIC UTILITY COUNSEL

MARCH 25, 2022

SOAH DOCKET NO. 473-22-1073
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REDACTED DIRECT TESTIMONY OF KARL NALEPA

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LIST OF ACRONYMS

Acronym	Description
CCCT	Combined Cycle Combustion Turbine
CCGT	Combined Cycle Gas Turbine
CT	Combustion Turbine
kWh	Kilowatt-hour
Mcf	Thousand Cubic Feet
MISO	Midcontinent Independent System Operator
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-hour
NPV	Net Present Value
RICE	Reciprocating Internal Combustion Engine
SO_2	Sulphur Dioxide

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Karl J. Nalepa. I am a partner in, and President of, ReSolved Energy Consulting, LLC ("REC"), an independent utility consulting company. My business address is 11044 Research Boulevard, Suite A-420, Austin, Texas 78759.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am presenting testimony on behalf of the Office of Public Utility Counsel ("OPUC").

Q. PLEASE OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a Master of Science degree in Petroleum Engineering from the University of Houston, and a Bachelor of Science degree in Mineral Economics from The Pennsylvania State University. I am also a certified mediator.

I have been a partner in REC since July 2011, since having joined R.J. Covington Consulting, its predecessor firm, in June 2003. I lead our firm's regulated market practice, where I represent the interests of clients in utility regulatory proceedings, prepare client cost studies, and develop client regulatory filings. Before joining REC, I served for more than five years as an Assistant Director with the Railroad Commission of Texas ("RRC"). In this position, I was responsible for overseeing the economic regulation of natural gas utilities in Texas, which included supervising staff casework, advising Commissioners on regulatory issues, and serving as a Technical Rate Examiner in regulatory proceedings. Prior to joining the RRC, I worked as an independent consultant advising clients on a broad range of electric and natural gas industry issues, and before that I spent five years as a supervising consultant with Resource Management International, Inc. I also served for four years as a Fuels Analyst with the Public Utility Commission of Texas ("PUC" or the "Commission"), where I evaluated fuel issues in electric utility rate filings and fuel reconciliation filings, participated in electric utility-related rulemaking proceedings, and took part in the review of electric utility resource plans. My professional career began with eight years in the reservoir engineering department of Transco Exploration Company, which was an affiliate of Transco Gas Pipeline Company, a major interstate pipeline company. My Statement of Qualifications is included as Attachment A.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. [1] I have testified many times before the Commission, as well as the RRC, on a variety of regulatory issues. I have also provided testimony before the Louisiana Public Service Commission, Arkansas Public Service Commission, and Colorado Public Utilities Commission. A summary of my previously filed testimony is included as Attachment B. In addition, I have provided analyses and recommendations in many city-level regulatory proceedings that resulted in decisions without written testimony.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE AND SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

[1] Note: All page number references in my testimony are to the native page numbers unless indicated otherwise.

A. The purpose and scope of my testimony is to evaluate Southwestern Public Service Company's ("SPS" or "Company") Application ("Application") to amend its certificate of convenience and necessity ("CCN") to convert the Harrington Generating Station from coal to natural gas.[2] My testimony specifically focuses on whether the proposed facility is necessary for the service, accommodation, convenience, or safety of the public.[3]

Additionally, my testimony evaluates the purported costs and benefits of the proposed facility presented in the Application.

Q. UNDER WHAT AUTHORITY IS SPS REQUESTING TO AMEND ITS CCN?

A. SPS is requesting to amend its CCN under Public Utility Regulatory Act ("PURA") §§ 37.053 and 37.056.[4]

III. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS IN THIS PROCEEDING.

A. Based on my evaluation of the Application, I have made the following findings and recommendations:

1. SPS has already entered into an Agreed Order[5] to cease coal operations at the Harrington Station, so scenarios included its 2021 Analysis reflecting investment in environmental controls are irrelevant in the analysis of options. These scenarios provide a false sense of support for the natural gas conversion scenarios as the

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[2] *Application of Southwestern Public Service Company to Amend its Certificate of Convenience and Necessity to Convert Harrington Generating Station from Coal to Natural Gas*, Docket No. 52485 (Aug. 27, 2021). ("SPS' Application").

[3] Public Utility Regulatory Act, Tex. Util. Code Ann. § 37.056(a) (West 2007) (PURA).

[4] SPS' Application at 2.

[5] *In the Matter of an Agreed Order Concerning Southwestern Public Service Company, dba XCEL Energy Harrington Station Power Plant*, Docket No. 2020-0982-MIS, Agreed Order (Oct. 27, 2020).

opportunity to install environmental controls on the Harrington units are no longer an option;

2. SPS scenarios incorporating retirement of some or all of the Harrington units assume accelerated recovery of depreciation, which leads to front-end loading of the associated NPVs but is contrary to Commission precedent for rate treatment of early plant retirements. If the Commission approves an option that incorporates the retirement of Harrington units, the Commission should reject accelerated recovery of the remaining depreciation expense and treat the retirement of the unit(s) consistent with the treatment adopted in SWEPCO Docket Nos. 51415[6] and 46449[7]; and

3. SPS does not recognize any extension of the service life of Harrington after converting to natural gas operation. This is especially important because the pipeline SPS seeks to construct makes up much of the incremental investment and should have a service life on the order of 70 years, far longer than SPS' current remaining service life for Harrington Station of 12 to 16 years. If the Commission approves SPS' request to convert the Harrington Station to natural gas operation, the rate treatment of such approval should require that the pipeline cost be separately booked to plant and recovered over 70 years or some other reasonable period commensurate with operation of a natural gas pipeline.

Q. BASED ON YOUR FINDINGS AND RECOMMENDATIONS, IS THE PROPOSED NATURAL GAS CONVERSION IN THE PUBLIC INTEREST?

A. Yes, SPS has shown that the proposed conversion of the Harrington Station to natural gas operation is necessary for the service, accommodation, convenience, or safety of the public under PURA § 37.056. The Agreed Order with the Texas Commission on Environmental Quality ("TCEQ") requires SPS to cease coal operations at Harrington by the end of 2024,[8] and since the boilers are designed for natural gas operations, the conversion is cost

[6] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 51415, (Oct. 14, 2020).

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

[8] Docket No. 2020-0982-MIS, Agreed Order.

effective. However, support for the conversion should be subject to the conditions described above for future ratemaking treatment.

IV. OVERVIEW OF APPLICATION

Q. WHAT IS SPS REQUESTING IN ITS APPLICATION?

A. SPS is seeking the following approvals from the Commission:[9]

1. Grant an amendment to its CCN authorizing SPS to convert all three units at Harrington Generating Station from coal generation to natural gas generation;[10]
2. Authorize the Company to construct, own, and operate a new pipeline to supply natural gas to Harrington Generating Station;[11] and
3. Any other relief to which it may be entitled.[12]

Q. PLEASE DESCRIBE SPS' REQUEST.

A. The Harrington Power Station consists of three coal-powered steam turbine units, located in Potter County, Texas, with a total net capacity of 1,050 MW.[13] Harrington Unit 1 has a net capacity of 340 MW; Harrington Unit 2 has a net capacity of 355 MW; and Harrington Unit 3 has a net capacity of 355 MW.[14] All three of the plant's boilers were designed to burn both coal and natural gas.[15] SPS is seeking approval to amend its existing CCN to convert Harrington from coal generation to natural gas generation.[16]

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[9] SPS' Application at 5-6 and 10.

[10] SPS' Application at 10.

[11] *Id.*

[12] *Id.*

[13] Direct Testimony of William A. Grant on Behalf of Southwestern Public Service Company at 9:3-2. ("Grant Testimony").

[14] *Id.* at 9:4-6.

[15] *Id.* at 9:6-7.

[16] *Id.* at 9:9-11.

Q. WHY DOES SPS SEEK TO CONVERT HARRINGTON TO NATURAL GAS?

A. Monitoring by the Texas Commission on Environmental Quality ("TCEQ") in 2016 indicated that the Harrington Station was exceeding the National Ambient Air Quality Standards ("NAAQS") for SO_2.[17] SPS was required to develop an implementation plan to comply with the NAAQS and show that Harrington will achieve compliance with the standards by 2025.[18] SPS presented its plan for complying with the emissions standard to the TCEQ, and entered into an Agreed Order with the TCEQ in 2020 to cease coal operations at Harrington by December 31, 2024.[19]

Q. PLEASE DESCRIBE SPS' COMPLIANCE PLAN.

A. SPS conducted an economic analysis in 2019 (the "2019 Analysis") to evaluate compliance solutions that included: (1) maintaining coal operations at Harrington by installing environmental controls to comply with NAAQS; or (2) ceasing coal operations, by either converting the units to operate on natural gas or by retiring the units.[20] SPS also considered a combination of these solutions, for example, installing environmental controls on two units and retiring the remaining unit.[21] SPS also evaluated ways to maximize the use of existing generator interconnection rights, such as locating solar generation at the Harrington site.[22]

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[17] *Id.* at 11:6-12.

[18] *Id.* at 11:12-14.

[19] *Id.* at 12:8-9.

[20] Direct Testimony of Ben Elsey on Behalf of Southwestern Public Service Company at 24:3-7. ("Elsey Testimony").

[21] *Id.* at 24:8-11.

[22] *Id.*

Q. WHAT DID THE 2019 ANALYSIS CONCLUDE?

A. According to SPS, the 2019 Analysis demonstrated that installing the necessary capital-intensive environmental controls required to maintain coal operations on one or more units at Harrington was among the highest cost options.[23] Thus, SPS concluded that coal operations at Harrington should cease before 2025.[24] Of the remaining compliance options—to convert Harrington to operate on natural gas, or retire Harrington by end of 2024 and seek other resources to replace the capacity, SPS determined to convert the Harrington units to operate on natural gas.[25]

Q. DID SPS UPDATE ITS ANALYSIS?

A. Yes. SPS updated its economic analysis in 2021 (the "2021 Analysis").[26] SPS explains that its 2021 Analysis uses a similar approach to its 2019 Analysis.[27] However, the 2021 Analysis incorporated several changes:[28]

1. It was conducted in SPS's new production cost modeling software, EnCompass;[29]
2. It incorporated updated modeling inputs and assumptions, including an updated gas forecast and load forecast;[30]
3. The cost of replacement resources incorporated pricing received from SPS' recently issued Request for Information ("RFI");[31] and

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[23] *Id.* at 24:14-17.

[24] *Id.* at 24:17-18.

[25] *Id.* at 24:18-21.

[26] *Id.* at 26:1-2.

[27] *Id.* at 26:9-13.

[28] *Id.* at 26:13-14.

[29] *Id.* at 26:14-15.

[30] *Id.* at 26:16-18.

[31] *Id.* at 26:18-19

4. It included the oversight of an Independent Evaluator.[32]

Q. WHAT SCENARIOS DID SPS EVALUATE?

A. SPS evaluated six scenarios in its 2021 Analysis:[33]

Scenario 1 - Retire all three Harrington Units by year end 2024;[34]

Scenario 2 - Convert all three Harrington Units to operate on natural gas by year end 2024;[35]

Scenario 3 - Install Dry Sorbent Injection ("DSI") on all three Harrington Units by year end 2024;[36]

Scenario 4 - Install Spray Dryer Absorber ("SDA") on all three Harrington Units by year end 2024;[37]

Scenario 5 - Retire Harrington Units 1 & 2 / Convert Harrington Unit 3 to operate on natural gas by year end 2024;[38] or

Scenario 6 - Retire Harrington Unit 1 / Convert Harrington Units 2 & 3 to operate on natural gas by year end 2024.[39]

SPS conducted sensitivity analyses on natural gas price forecasts, market energy price forecasts, load forecasts, and transmission network upgrade costs for each scenario.[40]

Q. WHAT NEEDS TO BE DONE TO CONVERT HARRINGTON FROM COAL TO NATURAL GAS?

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[32] *Id.* at 26:19-20.

[33] *Id.* at 29:1-3.

[34] *Id.* at 29:4.

[35] *Id.* at 29:5-6.

[36] *Id.* at 29:7.

[37] *Id.* at 24:8.

[38] *Id.* at 24:9-10.

[39] *Id.* at 24:11-12.

[40] *Id.* at 24:18-21.

A. SPS needs to install additional natural gas burners and associated piping and control equipment to convert each unit to run on natural gas only.[41] SPS must increase the plant's common gas distribution header size to deliver a larger natural gas flow to the three units.[42] Finally, SPS must acquire additional natural gas supply to run the units solely on natural gas.[43] To do that, SPS proposes to construct a new 20-inch diameter natural gas supply line from Harrington to northwest of the plant to tap into two different gas supplier transmission lines approximately twenty miles away.[44]

Q. WHAT PIPELINES DOES SPS INTEND TO USE FOR GAS SUPPLY TO THE NEWLY CONVERTED FACILITY?

A. The pipelines are El Paso Natural Gas and Natural Gas Pipeline Company of America.[45]

Q. WHAT IS THE ESTIMATED CAPITAL COST TO CONVERT THE HARRINGTON STATION TO NATURAL GAS?

A. SPS estimates the cost to convert the Harrington Station from coal to natural gas to be between $65 million and $75 million or $62/kW to $71/kW.[46]

Q. HOW DOES THIS COST COMPARE TO OTHER OPTIONS?

A. SPS Witness Ben Elsey testified that SPS evaluated two different environmental control solutions: Dry Sorbent Injection and Spray Dryer Absorber.[47] DSI and SDA are two

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[41] Direct Testimony of Mark Lytal on Behalf of Southwestern Public Service Company at 8:5-7. ("Lytal Testimony").

[42] *Id.* at 8:7-10.

[43] *Id.* at 8:7-10.

[44] *Id.* at 8:10-12.

[45] *Id.* at 14:3-5.

[46] Elsey Testimony at 28:1-3.

[47] *Id.* at 28:4-5.

methods used to remove acid gases (including SO_2) from the combustion process.[48] SPS estimated the cost of installing DSI on all three Harrington units be $255 million to $270 million, or $243/kW to $257/kW.[49] SPS estimated the cost of installing SDA to be $510 million to $555 million, or $486/kW to $529/kW.[50]

In the alternative, SPS expects that retiring all three Harrington units would likely require acquisition of replacement firm peaking generation, or battery energy storage.[51] SPS estimates that firm peaking generation, such as a 200 MW combustion turbine, would cost $100 million, or $500/kW, and battery energy storage would cost approximately $1,500/kW.[52]

Q. WHAT DID THE 2021 ANALYSIS CONCLUDE?

A. SPS reached the same conclusion as it did in its 2019 Analysis.[53] It concluded that coal operations at Harrington should cease before 2025.[54] Of the remaining compliance options to convert Harrington to operate on natural gas or retire Harrington by end of 2024 and seek other resources to replace the capacity, SPS determined to convert the Harrington

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[48] *See* EPA, Air Pollution Control Cost Manual, Seventh Edition (Apr. 2021), available at https://www.epa.gov/sites/ default/files/2021-05/documents/wet_and_dry_scrubbers_section_5_chapter_1_control_cost_manual_7th_edition.pdf (Mar. 21, 2022).

[49] Elsey Testimony at 28:5-6.

[50] *Id.* at 28:6-7 at 28:6-7.

[51] *Id.* at 28:8-12.

[52] *Id.* at 28:9-12.

[53] *Id.* at 33:12-13.

[54] *Id.* at 33:14-16.

units to operate on natural gas.[55] Table 1 summarizes the results of the scenario analyses under SPS' planning load forecast:[56]

Table 1

Scenario	Delta ($000)	NPV ($000) 2022-2024	Delta ($000)	NPV ($000) 2022-2041
2	$0	$2,450	$0	$11,949
1	$168	$2,618	$123	$12,072
3	($10)	$2,440	$439	$12,388
4	($10)	$2,440	$695	$12,644
5	$92	$2,542	$62	$12,011
6	$39	$2,490	($5)	$11,944

Table 1 is organized so that Scenario 2, which reflects SPS' request to convert all three Harrington units to operate on natural gas by year end 2024, is at the top. The alternative scenarios, as I described earlier, are shown below Scenario 2. The short-term and long-term total NPV of each Scenario, and the difference in NPV from Scenario 2, are summarized below Scenario 2.

Q. WHAT DO THE RESULTS SHOW?

A. The results of SPS' analyses compare scenarios over both the short term (2022-2024) and long term (2022-2041). Over the 20-year forecast period, Scenario 2—converting all three Harrington units to operate on natural gas by year end 2024—results in a lower NPV than all other scenarios, aside from Scenario 6—retiring Harrington Unit 1 / converting Harrington Units 2 & 3 to operate on natural gas by year end 2024. But Scenario 6 reflects a higher NPV in the short-term. This is because SPS assumes the early retirement of Harrington Unit 1 will result in accelerating the collection of the remaining depreciation

[55] *Id.* at 31:12-14.

[56] *Id.* at 32:2.

expense and any decommissioning costs associated with the unit.[57] Conversely, Scenarios 3 and 4 maintain Harrington coal operations and avoid the accelerated recovery of depreciation expense in the short-term but incur significant capital costs related to environmental controls that make the scenarios more costly on an NPV basis over the 20-year forecast period.

Q. WHAT IS THE IMPACT OF SPS' SENSITIVITY ANALYSIS?

A. SPS tested both its planning load forecast and its financial load forecast.[58] SPS' planning load forecast incorporates an additional margin for the uncertainty of oil and gas load growth,[59] so it is somewhat higher than SPS' financial load forecast. However, SPS' relative ranking of scenarios is not affected by using the financial load forecast.[60]

SPS tested its base, high, and low natural gas price forecasts. Low natural gas prices strengthen Scenario 2 - converting all three Harrington units to operate on natural gas by year end 2024 - while also improving the relative NPV of Scenarios 5 and 6.[61] Conversion to natural gas operation was still the lowest NPV even under high natural gas prices, although the differences were less.[62]

SPS tested its transmission network upgrade costs assuming a base cost of $400/kW, a low-cost case of $200/kW and a high-cost case of $600/kW.[63] The low-cost

57 *Id.* at 33:21-34:2.

58 *Id.* at 31:5-6.

59 *Id.* at 31:6-9.

60 *Id.* at 35:1-3.

61 *Id.* at Attachment BRE-1.

62 *Id.*

63 *Id.*

case lowers the NPV of Scenario 2, improves the relative NPV of Scenarios 5 and 6, and in fact, makes Scenario 1 —retire all three Harrington units by year end 2024— the lowest NPV over the 20-year forecast period under the low-cost case / high gas price case.[64] The high-cost case strengthens Scenario 2.[65]

Q. DID SPS ESTIMATE THE BILL IMPACTS TO CONSUMERS OF CONVERTING HARRINGTON FROM COAL TO NATURAL GAS OPERATION?

A. No. SPS' position is that this is not a proceeding to change rates and does not have all the necessary inputs in the record to calculate bill impacts.[66]

V. BASIS FOR EVALUATION

Q. WHAT STANDARD DID YOU APPLY IN YOUR EVALUATION OF SPS' APPLICATION?

A. I have applied the standard set out in PURA § 37.056, whereby the Commission may approve an application and grant a certificate *only* if the commission finds that the certificate is necessary for the service, accommodation, convenience, or safety of the public.[67] Specifically, SPS must show that the proposed acquisition will result in the probable improvement of service or lowering of cost to consumers in the area if the certificate is granted.[68]

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[64] *Id.*

[65] *Id.*

[66] Southwestern Public Service Company's Response to Commission Staff's Fifth Request for Information Question Nos. 5-1 Through 5-5 at 5 (Feb. 24, 2022). ("Staff RFI 5").

[67] *See* PURA § 37.056(a) (emphasis added).

[68] *See* PURA § 37.056(c)(4)(E).

VI. ISSUES WITH THE HARRINGTON CONVERSION

Q. DO YOU HAVE ANY ISSUES WITH SPS' REQUEST TO CONVERT THE HARRINGTON STATION TO NATURAL GAS OPERATION?

A. Yes. I have the following issues with SPS' request:

First, as SPS has already entered into an Agreed Order to cease coal operations at the Harrington Station, scenarios included in its 2021 Analysis reflecting investment in environmental controls related to continued coal operations are irrelevant in the analysis of options;

Second, scenarios incorporating retirement of some or all of the Harrington units assume accelerated recovery of depreciation, which leads to front-end loading of the associated NPVs which is contrary to Commission precedent for rate treatment of early plant retirements; and

Third, SPS does not recognize any extension of the service life of Harrington after converting the facilities to natural gas operation. This is especially important because the pipeline SPS seeks to construct makes up much of the incremental investment and should have a service life on the order of 70 years, far longer than SPS' current remaining service life for Harrington Station of 12 to 16 years.

Q. PLEASE EXPLAIN YOUR FIRST ISSUE.

A. The scenarios included in the 2019 Analysis conducted by SPS included options to install environmental controls on the Harrington units and maintaining coal operations.[69] The results of the 2019 Analysis found that installing the capital-intensive environmental controls was among the highest cost options and, therefore, least favorable solutions.[70] Based on its findings, SPS concluded it should cease coal operations at Harrington before

[69] Elsey Testimony at 24:3-6.

[70] *Id.* at 24:14-17.

2025.[71] Consequently, SPS entered into its Agreed Order with the TCEQ in October 2020 to cease coal operations at Harrington.[72]

However, in its updated 2021 Analysis, SPS again included scenarios to install environmental controls on the Harrington units and maintain coal operations.[73] As SPS had already committed to ceasing coal operations at Harrington under the Agreed Order, the scenarios to evaluate the NPV of maintaining coal operations are not realistic.

Q. WHAT IS THE IMPACT OF INCLUDING THESE SCENARIOS IN THE 2021 ANALYSIS?

A. SPS' analyses show that the scenarios adding environmental controls have NPVs $439,000 to $695,000 higher than the scenario converting all units to natural gas operation. But the scenarios provide a false sense of support for the natural gas conversion scenarios as the opportunity to install environmental controls on the Harrington units is no longer an option.

Q. PLEASE EXPLAIN YOUR SECOND ISSUE.

A. In scenarios that assumed retirement of one or more of the Harrington units, SPS pointed out that the high customer rate impact in the first three years is due to the need to accelerate collection on the remaining depreciation expense and any decommissioning costs associated with Harrington 12 to 16 years earlier than currently planned.[74]

Q. DO YOU AGREE WITH SPS' ASSUMPTION TO ACCELERATE DEPRECIATION EXPENSE AND DECOMMISSIONING COSTS?

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[71] *Id.* at 24:17-18.

[72] *Id.* at 6:18-19.

[73] *Id.* at 29:3-12.

[74] *Id.* at 33:18-34:2.

A. No, I do not.

Q. PLEASE EXPLAIN WHY NOT.

A. The Commission has recent precedent for the treatment of remaining depreciation expense on a generating unit retired early by the utility. In Docket No. 51415, Southwestern Electric Power Company ("SWEPCO") sought approval to retire its Dolet Hills power plant well before the end of its approved service life.[75] The Commission found that:

> With respect to the period after December 31,2021 (the post-retirement phase of the Dolet Hills rate rider), the remaining net book values of Dolet Hills should be placed in a regulatory asset to be amortized without a return. All other cost recovery for Dolet Hills, the Oxbow investment, or DHLC under the Dolet Hills rate rider should cease, as the assets will no longer be providing service.[76]
>
> SWEPCO's recovery of Dolet Hills' remaining net book value (whether through depreciation during the operative-plant phase or recovery from the regulatory asset during the post-retirement phase) should be amortized in accordance with the asset's useful life ending in 2046.[77]
>
> Amortizing these assets in accordance with Dolet Hills' useful life ending in 2046 equitably balances the interests of SWEPCO and both its current and future customers.[78]
>
> It would be inequitable to SWEPCO's current customers to accelerate SWEPCO's recovery of these assets, as SWEPCO proposes to do, through offsetting the excess accumulated deferred federal income taxes (ADFIT) SWEPCO owes to its current customers and amortizing the balance over only four years.[79]

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[75] *Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 51415, Petition and Statement of Intent to Change Rates at 12-13 (Oct. 14, 2020).

[76] *Application of Southwestern Electric Power Company for Authority to Change Rates,* Docket No. 51415, Order at FOF 60(Jan. 14, 2022).

[77] *Id.* at FOF 61.

[78] *Id.* at FOF 63.

[79] *Id.* at FOF 64.

And prior to the Dolet Hills decision, the Commission issued a similar decision on SWEPCO's Welsh Unit 2:

> 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.[80]
>
> 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.[81]
>
> 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.[82]
>
> 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.[83]

Q. DID SPS CONSIDER THIS PRECEDENT IN ITS ANALYSIS?

A. No, it did not.[84]

Q. SHOULD THE ORDERS IN DOCKET NOS. 51415 AND 46449 BE APPLIED TO SPS' ANALYSIS?

A. Yes. SPS intends to retire Harrington by the end of 2024 and accelerate collection on the remaining depreciation expense and any decommissioning costs on the units. However, consistent with Docket Nos. 51415 and 46449, the remaining expense should be recovered over the units' remaining approved service lives of 12 to 16 years.

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[80] Docket No. 46449, Order on Rehearing at FOF 68 (Mar. 19, 2018).

[81] *Id.* at FOF 69.

[82] *Id.* at FOF 70.

[83] *Id.* at FOF 71.

[84] Southwestern Public Service Company's Response to Office of Public Utility Counsel's First Request for Information Question Nos. 1-1 through 1-17 RFI 1-17 at 23, (Jan. 20, 2022). ("SPS Response to OPUC 1").

Q. WHAT IS THE IMPACT ON SPS' ANALYSIS IF THE EXPENSES ARE RECOVERED OVER 12 TO 16 YEARS?

A. Table 2 shows the impact of removing the accelerated recovery of remaining depreciation expense on SPS' base case analysis using its planning load forecast. For simplicity, I removed the entire amount of depreciation booked in 2024. In practice, this amount would be amortized over the remaining life of the Harrington units.

Table 2

Scenario	Depreciation[85] 2024 ($000)	Delta ($000)	Delta ($000)	NPV ($000) 2022-2024	Delta ($000)	NPV ($000) 2022-2041
2	[redacted]	[redacted]	$0	$2,450	$0	$11,949
1	[redacted]	[redacted]	$168	$2,618	$123	$12,072
3	[redacted]	[redacted]	($10)	$2,440	$439	$12,388
4	[redacted]	[redacted]	($10)	$2,440	$695	$12,644
5	[redacted]	[redacted]	$92	$2,542	$62	$12,011
6	[redacted]	[redacted]	$39	$2,490	($5)	$11,944

Table 2 is organized so that Scenario 2, which reflects SPS' request to convert all three Harrington Units to operate on natural gas by year end 2024, is at the top. The alternative scenarios, as I described earlier, are shown below Scenario 2. The first year depreciation for each Scenario, and the difference from Scenario 2, are summarized below Scenario 2.

Q. WHAT DO THE RESULTS SHOW?

A. The result show that impact of removing the accelerated recovery of remaining depreciation expense improves the NPV for scenarios where units are retired, relative to the base case.

Q. WHAT DO YOU RECOMMEND?

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[85] Southwestern Public Service Company's Confidential – Exhibit SPS-Sierra Club RFI 1-3(I) (SUPP 1) (HSPM), (Nov.12, 2021).

A. I recommend, if the Commission approves an option that incorporates the retirement of Harrington units, the Commission should reject accelerated recovery of the remaining depreciation expense and treat the retirement of the unit(s) consistent with the treatment adopted in SWEPCO Docket Nos. 51415 and 46449. As shown in Table 2, this could reduce the NPV by [redacted] depending on the scenario implemented.

Q. PLEASE EXPLAIN YOUR THIRD ISSUE.

A. SPS is not requesting a modification to the Commission approved retirement dates for Harrington in this case, and it is leaving the service lives of the boilers at 60 years, corresponding to ending service years 2036, 2038, 2040—which means remaining lives of 12, 14, and 16 years, respectively—if the boilers are converted to natural gas operation by 2024.[86]

Q. WHY IS THIS IMPORTANT?

A. This is important because more than three-fourths of the anticipated cost of the natural gas conversion is related to installation of the supporting natural gas pipeline.[87]

Q. WHAT SERVICE LIFE WOULD YOU EXPECT FOR A NATURAL GAS PIPELINE?

A. The pipeline should have a useful life of as much as 70 years, based on comparisons to other transmission pipelines in Texas.[88]

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[86] Southwestern Public Service Company's Response to Office of Public Utility Counsel's Third Request for Information Question Nos. 3-1 through 3-5 OPUC RFI 3-4 at 8 (Mar. 14, 2022).

[87] Lytal Testimony at Attachment ML-1 showing ($57.3 million / $74.6 million = 77%), (Aug. 27, 2021); SPS Response to OPUC 1 RFI 1-11 at 17 showing ($49.6 million / $65.0 million = 76%), (Jan. 20, 2022).

[88] Texas Railroad Commission, *Atmos Pipeline Texas*, Docket No. 10580, Direct Testimony of Dane Watson, Exhibit DAW-2 at 31-32 (Mr. Watson recommended a survivor curve with an average service life of 70 years for FERC Account 367, Transmission Mains.) (Dec. 18, 2020).

Q. WHAT IS THE IMPACT OF APPLYING THE REMAINING SERVICE LIFE OF THE HARRINGTON UNITS TO THE NEW PIPELINE INVESTMENT?

A. The impact of applying the remaining service life is that the annual depreciation expense will be significantly overstated if the pipeline is depreciated over 12 to 16 years rather than over 70 years. Conversely, if the pipeline is depreciated over 70 years, SPS will have a significant amount of unrecovered pipeline plant at the time that the Harrington Station is retired. Table 3 compares the annual depreciation of the pipeline assuming a 12 year service life and a 70 year service life:

Table 3

Service Life (Years)	Annual Depreciation ($65 million)[89]	Annual Depreciation ($75 million)[90]
12[91]	$4.13 million	$4.77 million
70[92]	$0.71 million	$0.82 million
Difference	$3.42 million	$3.95 million

As can be seen in Table 3, depreciating the pipeline over 70 years reduces annual depreciation expense by $3.42 million to $3.95 million compared to depreciating the pipeline over 12 years.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that, if the Commission approves SPS' request to convert the Harrington Station to natural gas operation, the rate treatment of such approval requires the pipeline

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89 SPS Response to OPUC 1 (The $65 million project cost includes $49.6 million related to pipeline construction).

90 Lytal Testimony at Attachment ML-1 (The $75 million project cost estimate includes $57.3 million related to pipeline construction).

91 $49.6 million / 12 = $4.13 million and $57.3 million / 12 = $4.77 million, assuming no salvage cost.

92 $49.6 million / 70 = $0.71 million and $57.3 million / 70 = $0.82 million, assuming no salvage cost.

cost to be separately booked to plant and recovered over 70 years or some other reasonable period commensurate with operation of a natural gas pipeline. SPS may be able to recover more of the pipeline cost if it is able to extend the lives of the Harrington units beyond the current retirement dates or use the site to install future gas-fired generation served by the pipeline if it is economically prudent to do so.

Q. IS SPS' REQUEST TO CONVERT THE HARRINGTON STATION FROM COAL TO NATURAL GAS OPERATION IN THE PUBLIC INTEREST?

A. The conversion of the Harrington Station is in the public interest, with two important conditions—that the retirement of any Harrington assets be treated consistent with the Commission's Orders in Docket Nos. 51415 and 46449, and the proposed natural gas pipeline be depreciated over the appropriate service life for a natural gas transmission pipeline and not limited to the current remaining lives of the Harrington Units.

Q. WHAT IS THE BASIS FOR YOUR CONCLUSION?

A. My conclusion is based on the following:

- SPS entered into an Agreed Order with TCEQ to end coal operations at the Harrington Station by the end of 2024.
- The Settlement in Docket No. 51802[93] supports SPS' request to retire the coal-specific assets at the Harrington Station in 2024.[94]
- The proposal to convert the units from coal to natural gas operation has the lowest initial capital investment, compared to installation of environmental controls or new build capacity.
- The proposal to convert the units from coal to natural gas operations under most sensitivities is the lowest cost NPV alternative to replace the retired capacity.

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[93] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 51802, Unopposed Stipulation at 5 (January 26, 2022).

[94] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 51802, Application at 4 (February 8, 2021).

- The option to convert two Harrington units and retire one unit reflects a small long-term NPV advantage over conversion of all three units, but still requires the same natural gas pipeline investment[95] and increases the uncertainty that the retired unit capacity can be timely replaced.[96]

Q. HOW DO THE CONDITIONS YOU RECOMMEND IMPACT COST TO CUSTOMERS?

A. As I discussed, retirement of any Harrington assets should be treated consistent with the Commission's Orders in Docket Nos. 51415 and 46449. I determined that this could reduce the NPV by [redacted] depending on the scenario implemented. Furthermore, the proposed natural gas pipeline should be depreciated over the appropriate service life for a natural gas transmission pipeline and not limited to the current remaining lives of the Harrington Units. I found that depreciating the pipeline over 70 years reduces annual depreciation expense by $3.42 million to $3.95 million compared to depreciating the pipeline over 12 years.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, at this time.

[95] Lytal Testimony at 11.

[96] Elsey Testimony at 19.

ATTACHMENTS

ATTACHMENT A

STATEMENT OF QUALIFICATIONS

KARL J. NALEPA

Mr. Nalepa is an energy economist with more than 40 years of private and public sector experience in the electric and natural gas industries. He has extensive experience analyzing utility rate filings and resource plans with particular focus on fuel and power supply requirements, quality of fuel supply management, and reasonableness of energy costs. Mr. Nalepa developed peak demand and energy forecasts for public utilities and has forecast the price of natural gas in ratemaking and resource plan evaluations. He led a management and performance review of the Texas Public Utility Commission and has conducted performance reviews and valuation studies of municipal utility systems. Mr. Nalepa previously directed the Railroad Commission of Texas' Regulatory Analysis & Policy Section, with responsibility for preparing timely natural gas industry analysis, managing ratemaking proceedings, mediating informal complaints, and overseeing consumer complaint resolution. He has prepared and defended expert testimony in both administrative and civil proceedings and has served as a technical examiner in natural gas rate proceedings.

EDUCATION

1998	Certificate of Mediation Dispute Resolution Center, Austin
1989	NARUC Regulatory Studies Program Michigan State University
1988	M.S. - Petroleum Engineering University of Houston
1980	B.S. - Mineral Economics Pennsylvania State University

PROFESSIONAL HISTORY

2011 -	ReSolved Energy Consulting Partner
2003 - 2011	RJ Covington Consulting Managing Director
1997 – 2003	Railroad Commission of Texas Asst. Director, Regulatory Analysis & Policy
1995 – 1997	Karl J. Nalepa Consulting Principal
1992 – 1995	Resource Management International, Inc. Supervising Consultant
1988 – 1992	Public Utility Commission of Texas Fuels Analyst
1980 – 1988	Transco Exploration Company Reservoir and Evaluation Engineer

AREAS OF EXPERTISE

Regulatory Analysis

Electric Power: Analyzed electric utility rate, certification, and resource forecast filings. Assessed the quality of fuel supply management, and reasonableness of fuel costs recovered from ratepayers. Projected the cost of fuel and purchased power. Estimated the impact of environmental costs on utility resource selection. Participated in regulatory rulemaking activities. Provided expert staff testimony in a number of proceedings before the Texas Public Utility Commission.

As a consultant, represent interests of municipal clients intervening in large utility rate proceedings through analysis of filings and presentation of testimony before the Public Utility Commission. Also assist municipal utilities in preparing and defending requests to change rates and other regulatory matters before the Public Utility Commission.

Natural Gas: Directed the economic regulation of gas utilities in Texas for the Railroad Commission of Texas. Responsible for monitoring, analyzing and reporting on conditions and events in the natural gas industry. Managed Commission staff representing the public interest in contested rate proceedings before the Railroad Commission, and acted as technical examiner on behalf of the Commission. Mediated informal disputes between industry participants and directed handling of customer billing and service complaints. Oversaw utility compliance filings and staff rulemaking initiatives. Served as a policy advisor to the Commissioners.

As a consultant, represent interests of municipal clients intervening in large utility rate proceedings through analysis of filings and presentation of testimony before the cities and Railroad Commission. Also assist small utilities in preparing and defending requests to change rates and other regulatory matters before the Railroad Commission.

Litigation Support

Retained to support litigation in natural gas contract disputes. Analyzed the results of contract negotiations and competitiveness of gas supply proposals considering gas market conditions contemporaneous with the period reviewed. Supported litigation related to alleged price discrimination related to natural gas sales for regulated customers. Provided analysis of regulatory and accounting issues related to ownership of certain natural gas distribution assets in support of litigation against a natural gas utility. Supported independent power supplier in binding arbitration regarding proper interpretation of a natural gas transportation contract. Provided expert witness testimony in administrative and civil court proceedings.

Utility System Assessment

Led a management and performance review of the Public Utility Commission. Conducted performance reviews and valuation studies of municipal utility systems. Assessed ability to compete in the marketplace, and recommended specific actions to improve the competitive position of the utilities. Provided comprehensive support in the potential sale of a municipal gas system, including preparation of a valuation study and all activities leading to negotiation of contract for sale and franchise agreements.

Energy Supply Analysis

Reviewed system requirements and prepared requests for proposals (RFPs) to obtain natural gas and power supplies for both utility and non-utility clients. Evaluated submittals under alternative demand and market conditions, and recommended cost-effective supply proposals. Assessed supply strategies to determine optimum mix of available resources.

Econometric Forecasting

Prepared econometric forecasts of peak demand and energy for municipal and electric cooperative utilities in support of system planning activities. Developed forecasts at the rate class and substation levels. Projected price of natural gas by individual supplier for Texas electric and natural gas utilities to support review of utility resource plans.

Reservoir Engineering

Managed certain reserves for a petroleum exploration and production company in Texas. Responsible for field surveillance of producing oil and natural gas properties, including reserve estimation, production forecasting, regulatory reporting, and performance optimization. Performed evaluations of oil and natural gas exploration prospects in Texas and Louisiana.

PROFESSIONAL MEMBERSHIPS

Society of Petroleum Engineers
International Association for Energy Economics
United States Association for Energy Economics

SELECT PUBLICATIONS, PRESENTATIONS, AND TESTIMONY

"Summary of the USAEE Central Texas Chapter's Workshop entitled 'EPA's Proposed Clean Power Plan Rules: Economic Modeling and Effects on the Electric Reliability of Texas Region,'" with Dr. Jay Zarnikau and Mr. Neil McAndrews, USAEE Dialogue, May 2015

"Public Utility Ratemaking," EBF 401: Strategic Corporate Finance, The Pennsylvania State University, September 2013

"What You Should Know About Public Utilities," EBF 401: Strategic Corporate Finance, The Pennsylvania State University, October 2011

"Natural Gas Markets and the Impact on Electricity Prices in ERCOT," Texas Coalition of Cities for Fair Utility Issues, Dallas, October 2008

"Natural Gas Regulatory Policy in Texas," Hungarian Oil and Gas Policy Business Colloquium, U.S. Trade and Development Agency, Houston, May 2003

"Railroad Commission Update," Texas Society of Certified Public Accountants, Austin, April 2003

"Gas Utility Update," Railroad Commission Regulatory Expo and Open House, October 2002

"Deregulation: A Work in Progress," Interview by Karen Stidger, *Gas Utility Manager*, October 2002

"Regulatory Overview: An Industry Perspective," Southern Gas Association's Ratemaking Process Seminar, Houston, February 2001

"Natural Gas Prices Could Get Squeezed," with Commissioner Charles R. Matthews, *Natural Gas*, December 2000

"Railroad Commission Update," Texas Society of Certified Public Accountants, Austin, April 2000

"A New Approach to Electronic Tariff Access," Association of Texas Intrastate Natural Gas Pipeline Annual Meeting, Houston, January 1999

"A Texas Natural Gas Model," United States Association for Energy Economics North American Conference, Albuquerque, 1998

"Texas Railroad Commission Aiding Gas Industry by Updated Systems, Regulations," *Natural Gas,* July 1998

"Current Trends in Texas Natural Gas Regulation," Natural Gas Producers Association, Midland, 1998

"An Overview of the American Petroleum Industry," Institute of International Education Training Program, Austin, 1993

Direct testimony in PUC Docket No. 10400 summarized in *Environmental Externality,* Energy Research Group for the Edison Electric Institute, 1992

"God's Fuel - Natural Gas Exploration, Production, Transportation and Regulation," with Danny Bivens, Public Utility Commission of Texas Staff Seminar, 1992

"A Summary of Utilities' Positions Regarding the Clean Air Act Amendments of 1990," Industrial Energy Technology Conference, Houston, 1992

"The Clean Air Act Amendments of 1990," Public Utility Commission of Texas Staff Seminar, 1992

ATTACHMENT B

SUMMARY OF PREVIOUSLY FILED TESTIMONY

KARL J. NALEPA
TESTIMONY FILED

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
Before the Public Utility Commission of Texas					
52487	Mar 22	Office of Public Counsel	Entergy Texas Inc.	CCN	Public Interest Review
52195	Oct 21	City of El Paso	El Paso Electric	Cost of Service	Cost of Service Model
52194	July 21	Cities	CenterPoint Energy Houston	EECRF	EECRF Methodology
52178	July 21	Cities	Oncor Electric Delivery	EECRF	EECRF Methodology
52081	July 21	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
52067	July 21	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
51997	Aug 21	Office of Public Counsel	Entergy Texas, Inc.	System Restoration Costs	Cost Review
51802	Aug 21	Xcel Municipalities	Southwestern Public Service	Cost of Service	Cost Allocation
51415	Mar 21	CARD	SWEPCO	Cost of Service	Cost Allocation
51381	Dec 20	Entergy Cities	Entergy Texas Inc.	GCRR	GCRR Methodology
51345	Oct 20	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
51215	Mar 21	Office of Public Counsel	Entergy Texas Inc.	CCN	Public Interest Review
51100	Nov 20	Office of Public Counsel	Lubbock Power & Light	TCOS	Wholesale Transmission Rate
50997	Jan 21	CARD	SWEPCO	Fuel Reconciliation	Fuel Cost Recovery
50790	Jul 20	Office of Public Counsel	Entergy Texas, Inc.	Sale, Transfer, Merger	Public Interest Review
50714	May 20	Cities	Entergy Texas Inc.	DCRF	DCRF Methodology
50110	Dec 19	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
49831	Feb 20	Xcel Municipalities	Southwestern Public Service	Cost of Service	Cost Allocation

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
49737	Jan 20	Office of Public Counsel	SWEPCO	CCN	Public Interest Review
49594	Jul 19	Oncor Cities	Oncor Electric Delivery	EECRF	EECRF Methodology
49592	Jul 19	AEP Cities	AEP Texas Inc.	EECRF	EECRF Methodology
49586	Jul 19	TNMP Cities	Texas-New Mexico Power	EECRF	EECRF Methodology
49583	Aug 19	Gulf Coast Coalition	CenterPoint Energy Houston	EECRF	EECRF Methodology
49496	Jun 19	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
49494	Jul 19	AEP Cities	AEP Texas Inc.	Cost of Service	Plant Additions
49421	Jun 19	Office of Public Counsel	CenterPoint Energy Houston	Cost of Service	Cost of Service
49395	May 19	City of El Paso	El Paso Electric	DCRF	DCRF Methodology
49148	Apr 19	City of El Paso	El Paso Electric	TCRF	TCRF Methodology
49042	Mar 19	SWEPCO Cities	SWEPCO	TCRF	TCRF Methodology
49041	Feb 19	SWEPCO Cities	SWEPCO	DCRF	DCRF Methodology
48973	May 19	Xcel Municipalities	Southwestern Public Service	Fuel Reconciliation	Fuel / Purch Power Costs
48963	Dec 18	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
48420	Aug 18	Gulf Coast Coalition	CenterPoint Energy Houston	EECRF	EECRF Methodology
48404	Jul 18	Cities	Texas-New Mexico Power	EECRF	EECRF Methodology
48371	Aug 18	Cities	Entergy Texas Inc.	Cost of Service	Cost of Service
48231	May 18	Cities	Oncor Electric Delivery	DCRF	DCRF Methodology
48226	May 18	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
48222	Apr 18	Cities	AEP Texas Inc.	DCRF	DCRF Methodology
47900	Dec 17	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
47527	Apr 18	Xcel Municipalities	Southwestern Public Service	Cost of Service	Cost of Service
7461	Dec 17	Office of Public Counsel	SWEPCO	CCN	Public Interest Review
47236	Jul 17	Cities	AEP Texas	EECRF	EECRF Methodology
47235	Jul 17	Cities	Oncor Electric Delivery	EECRF	EECRF Methodology
47217	Jul 17	Cities	Texas-New Mexico Power	EECRF	EECRF Methodology
47032	May 17	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
46936	Oct 17	Xcel Municipalities	Southwestern Public Service	CCN	Public Interest Review
46449	Apr 17	Cities	SWEPCO	Cost of Service	Cost of Service
46348	Sep 16	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
46238	Jan 17	Office of Public Counsel	Oncor Electric Delivery	STM	Public Interest Review
46076	Dec 16	Cities	Entergy Texas Inc.	Fuel Reconciliation	Fuel Cost
46050	Aug 16	Cities	AEP Texas	STM	Public Interest Review
46014	Jul 16	Gulf Coast Coalition	CenterPoint Energy Houston	EECRF	EECRF Methodology
45788	May 16	Cities	AEP-TNC	DCRF	DCRF Methodology
45787	May 16	Cities	AEP-TCC	DCRF	DCRF Methodology
45747	May 16	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
45712	Apr 16	Cities	SWEPCO	DCRF	DCRF Methodology
45691	Jun 16	Cities	SWEPCO	TCRF	TCRF Methodology
45414	Feb 17	Office of Public Counsel	Sharyland	Cost of Service	Cost of Service
45248	May 16	City of Fritch	City of Fritch	Cost of Service (water)	Cost of Service
45084	Nov 15	Cities	Entergy Texas Inc.	TCRF	TCRF Methodology

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
45083	Oct 15	Cities	Entergy Texas Inc.	DCRF	DCRF Methodology
45071	Aug 15	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
44941	Dec 15	City of El Paso	El Paso Electric	Cost of Service	CEP Adjustments
44677	Jul 15	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
44572	May 15	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
44060	May 15	City of Frisco	Brazos Electric Coop	CCN	Transmission Cost Recovery
43695	May 15	Pioneer Natural Resources	Southwestern Public Service	Cost of Service	Cost Allocation
43111	Oct 14	Cities	Entergy Texas Inc.	DCRF	DCRF Methodology
42770	Aug 14	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
42485	Jul 14	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
42449	Jul 14	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
42448	Jul 14	Cities	SWEPCO	TCRF	Transmission Cost Recovery Factor
42370	Dec 14	Cities	SWEPCO	Rate Case Expenses	Rate Case Expenses
41791	Jan 14	Cities	Entergy Texas Inc.	Cost of Service	Cost of Service/Fuel
41539	Jul 13	Cities	AEP Texas North	EECRF	EECRF Methodology
41538	Jul 13	Cities	AEP Texas Central	EECRF	EECRF Methodology
41444	Jul 13	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
41223	Apr 13	Cities	Entergy Texas Inc.	ITC Transfer	Public Interest Review
40627	Nov 12	Austin Energy	Austin Energy	Cost of Service	General Fund Transfers
40443	Dec 12	Office of Public Counsel	SWEPCO	Cost of Service	Cost of Service/Fuel
40346	Jul 12	Cities	Entergy Texas Inc.	Join MISO	Public Interest Review

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
39896	Mar 12	Cities	Entergy Texas Inc.	Cost of Service/ Fuel Reconciliation	Cost of Service/ Nat Gas/ Purch Power
39366	Jul 11	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
38951	Feb 12	Cities	Entergy Texas Inc.	CGS Tariff	CGS Costs
38815	Sep 10	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
38480	Nov 10	Cities	Texas-New Mexico Power	Cost of Service	Cost of Service/Rate Design
37744	Jun 10	Cities	Entergy Texas Inc.	Cost of Service/ Fuel Reconciliation	Cost of Service/ Nat Gas/ Purch Power/ Gen
37580	Dec 09	Cities	Entergy Texas Inc.	Fuel Refund	Fuel Refund Methodology
36956	Jul 09	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
36392	Nov 08	Texas Municipal Power	Texas Municipal Power	Interim TCOS	Wholesale Transmission Rate
35717	Nov 08	Cities Steering Committee	Oncor Electric Delivery	Cost of Service	Cost of Service/Rate Design
34800	Apr 08	Cities	Entergy Gulf States	Fuel Reconciliation	Natural Gas/Coal/Nuclear
16705	May 97	North Star Steel	Entergy Gulf States	Fuel Reconciliation	Natural Gas/Fuel Oil
10694	Jan 92	PUC Staff	Midwest Electric Coop	Revenue Requirements	Depreciation/ Quality of Service
10473	Sep 91	PUC Staff	HL&P	Notice of Intent	Environmental Costs
10400	Aug 91	PUC Staff	TU Electric	Notice of Intent	Environmental Costs
10092	Mar 91	PUC Staff	HL&P	Fuel Reconciliation	Natural Gas/Fuel Oil
10035	Jun 91	PUC Staff	West Texas Utilities	Fuel Reconciliation Fuel Factor	Natural Gas Natural Gas/Fuel Oil/Coal
9850	Feb 91	PUC Staff	HL&P	Revenue Req. Fuel Factor	Natural Gas/Fuel Oil/ETSI Natural Gas/Coal/Lignite

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
9561	Aug 90	PUC Staff	Central Power & Light	Fuel Reconciliation Revenue Requirements Fuel Factor	Natural Gas Natural Gas/Fuel Oil Natural Gas
9427	Jul 90	PUC Staff	LCRA	Fuel Factor	Natural Gas
9165	Feb 90	PUC Staff	El Paso Electric	Revenue Requirements Fuel Factor	Natural Gas/Fuel Oil Natural Gas
8900	Jan 90	PUC Staff	SWEPCO	Fuel Reconciliation Fuel Factor	Natural Gas Natural Gas
8702	Sep 89 Jul 89	PUC Staff	Gulf States Utilities	Fuel Reconciliation Revenue Requirements Fuel Factor	Natural Gas/Fuel Oil Natural Gas/Fuel Oil Natural Gas/Fuel Oil
8646	May 89 Jun 89	PUC Staff	Central Power & Light	Fuel Reconciliation Revenue Requirements Fuel Factor	Natural Gas Natural Gas/Fuel Oil Natural Gas
8588	Aug 89	PUC Staff	El Paso Electric	Fuel Reconciliation	Natural Gas

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
Before the Railroad Commission of Texas					
07061	Sep 21	Texas Cities Alliance	Multiple	Gas Cost Securitization	Prudence Determination
05509	Dec 20	LDC, LLC	LDC, LLC	Cost of Service	Cost of Service/Rate Design
10928	Mar 20	TGS Cities	Texas Gas Service	Cost of Service	Cost of Service/Rate Design
10920	Feb 20	East Texas Cities Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10900	Nov 19	Cities Steering Committee	Atmos Energy Triangle	Cost of Service	Cost of Service
10899	Sep 19	NatGas, Inc.	NatGas, Inc.	Cost of Service	Cost of Service/Rate Design
10737	Jun 18	T&L Gas Co.	T&L Gas Co.	Cost of Service	Cost of Service/Rate Design
10622	Apr 17	LDC, LLC	LDC, LLC	Cost of Service	Cost of Service/Rate Design
10617	Mar 17	Onalaska Water & Gas	Onalaska Water & Gas	Cost of Service	Cost of Service/Rate Design
10580	Mar 17	Cities Steering Committee	Atmos Pipeline Texas	Cost of Service	Cost of Service/Rate Design
10567	Feb 17	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10506	Jun 16	City of El Paso	Texas Gas Service	Cost of Service	Cost of Service/Energy Efficiency
10498	Feb 16	NatGas, Inc.	NatGas, Inc.	Cost of Service	Cost of Service/Rate Design
10359	Jul 14	Cities Steering Committee	Atmos Energy Mid Tex	Cost of Service	Cost of Service/Rate Design
10295	Oct 13	Cities Steering Committee	Atmos Pipeline Texas	Revenue Rider	Rider Renewal
10242	Jan 13	Onalaska Water & Gas	Onalaska Water & Gas	Cost of Service	Cost of Service/Rate Design
10196	Jul 12	Bluebonnet Natural Gas	Bluebonnet Natural Gas	Cost of Service	Cost of Service/Rate Design
10190	Jan 13	City of Magnolia, Texas	Hughes Natural Gas	Cost of Service	Cost of Service/Rate Design
10174	Aug 12	Cities Steering Committee	Atmos Energy West Texas	Cost of Service	Cost of Service/Rate Design
10170	Aug 12	Cities Steering Committee	Atmos Energy Mid Tex	Cost of Service	Cost of Service/Rate Design

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
10106	Oct 11	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10083	Aug 11	City of Magnolia, Texas	Hughes Natural Gas	Cost of Service	Cost of Service/Rate Design
10038	Feb 11	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10021	Oct 10	AgriTex Gas, Inc.	AgriTex Gas, Inc.	Cost of Service	Cost of Service/Rate Design
10000	Dec 10	Cities Steering Committee	Atmos Pipeline Texas	Cost of Service	Cost of Service/Rate Design
9902	Oct 09	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
9810	Jul 08	Bluebonnet Natural Gas	Bluebonnet Natural Gas	Cost of Service	Cost of Service/Rate Design
9797	Apr 08	Universal Natural Gas	Universal Natural Gas	Cost of Service	Cost of Service/Rate Design
9732	Jul 08	Cities Steering Committee	Atmos Energy Corp.	Gas Cost Review	Natural Gas Costs
9670	Oct 06	Cities Steering Committee	Atmos Energy Corp.	Cost of Service	Affiliate Transactions/ O&M Expenses/GRIP
9667	Nov 06	Oneok Westex Transmission	Oneok Westex Transmission	Abandonment	Abandonment
9598	Sep 05	Cities Steering Committee	Atmos Energy Corp.	GRIP Appeal	GRIP Calculation
9530	Apr 05	Cities Steering Committee	Atmos Energy Corp.	Gas Cost Review	Natural Gas Costs
9400	Dec 03	Cities Steering Committee	TXU Gas Company	Cost of Service	Affiliate Transactions/ O&M Expenses/Capital Costs

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
Before the Louisiana Public Service Commission					
U-35359	Feb 20 Nov 20	PSC Staff	Dixie Electric Membership Corporation	Cost of Service	Cost of Service / FRP Renewal / AMS Certification Stipulation
U-34344/ U-34717	Apr 18	PSC Staff	Dixie Electric Member Corporation	Formula Rate Plan	Stipulation
U-34344	Jan 18	PSC Staff	Dixie Electric Member Corporation	Formula Rate Plan	Adjusted Revenues
U-33633	Nov 15	PSC Staff	Entergy Louisiana, LLC/ Entergy Gulf States Louisiana	Resource Certification	Prudence
U-33033	Jul 14	PSC Staff	Entergy Louisiana, LLC/ Entergy Gulf States Louisiana	Resource Certification	Revenue Requirement
U-31971	Nov 11	PSC Staff	Entergy Louisiana, LLC/ Entergy Gulf States Louisiana	Resource Certification	Certification/Cost Recovery
Before the Colorado Public Utilities Commission					
18A-0791E	Mar 19	Pueblo County	Black Hills Colorado Electric	Economic Development Rate	Tariff Issues
Before the Arkansas Public Service Commission					
O7-105-U	Mar 08	Arkansas Customers & pipelines serving CenterPoint	CenterPoint Energy, Inc.	Gas Cost Complaint	Prudence / Cost Recovery

RESPONSES

QUESTION NO. Staff 5-1:

Please provide estimated rate class bill impacts if the proposed conversion of Harrington Generating Station from coal to natural gas is put into rates. Please include both base rate and fuel cost impacts.

RESPONSE:

Because this case is not a proceeding to change rates, SPS does not have in the record all the data, inputs and rate design details needed to calculate the bill impacts to the various rate classes that would result from proposed conversion of the Harrington Generation Station to natural gas operations. These rates and customer impacts would be determined in a future SPS rate case. However, for point of reference, if the Harrington Station is *not* converted to natural gas operations and is instead retired, in Ben Elsey's Direct Testimony (Table BRE-2 at page 32) SPS has calculated the net present value ("NPV") increased cost to ratepayers to replace the retired capacity to be $168 million over the 2022–2024 time period (approximately $98.8 million to Texas retail at the jurisdictional allocation factors provided by SPS in pending Docket No. 51802) and $123 million NPV cost over 2022–2041 (approximately $72.3 million to Texas retail at the jurisdictional allocation factors SPS provided in Docket No. 51802). This outcome would certainly result in greater rate impacts for customers than would the proposed conversion.

Preparer: Ben Elsey
Sponsors: William A. Grant, Ben R. Elsey

QUESTION NO. OPUC 1-17:

Please reference the Direct Testimony of Ben Elsey at pages 33-34. Mr. Elsey testifies that the high customer rate impact in the first three years for scenarios where Harrington units are retired early is due to the need to accelerate collection on the remaining depreciation expense and decommissioning costs associated with Harrington 12 to 16 years earlier than currently planned. Please explain if SPS considered any scenarios where the depreciation and decommissioning costs are spread over the projected remaining life of the Harrington Station in the same manner as the retirement of SWEPCO's Dolet Hills Station as described in the proposal for decision in PUC Docket No. 51415.

RESPONSE:

SPS has not conducted such an analysis.

Preparer: Ben R. Elsey
Sponsor: Ben R. Elsey

QUESTION NO. Sierra Club 1-3:

Please refer to the Direct Testimony of Ben R. Elsey at page 13. Please provide all Encompass and all Strategist modeling input and output files supporting SPS/Xcel's application and supporting testimony (in electronic, machine-readable format with formulae intact).

RESPONSE:

Please refer to Exhibit SPS-SC 1-3(i)(HS)(USB) for the EnCompass input and output files.

Please refer to Exhibit SPS-SC 1-3(ii) for the Strategist output files. The structure of the Strategist input files are proprietary to the vendor and can only be provided to active licensees of the Strategist software.

Preparer: Mark Christner, Ben R. Elsey
Sponsor: Ben R. Elsey

RESPONSES

QUESTION NO. Sierra Club 1-3:

Please refer to the Direct Testimony of Ben R. Elsey at page 13. Please provide all Encompass and all Strategist modeling input and output files supporting SPS/Xcel's application and supporting testimony (in electronic, machine-readable format with formulae intact).

NOVEMBER 11, 2021 SUPPLEMENTAL RESPONSE:

The following supplements SPS's initial response filed on November 10, 2021. Please refer to Exhibit SPS-Sierra Club 1-3(i)(SUPP 01)(HS)(USB)

Preparer: Mark Christner, Ben R. Elsey
Sponsor: Ben R. Elsey

HIGHLY SENSITIVE

NATIVE EXCEL FILE

PROVIDED
ELECTRONICALLY

QUESTION NO. OPUC 3-4:

If SPS is not requesting a modification to the Commission approved retirement dates in this case, an inference may be drawn that the service lives of the converted boilers will be between 12 and 16 years. Please explain if SPS believes these service lives are appropriate. If SPS intends to extend the service lives, please provide the new service lives.

RESPONSE:

SPS is not requesting a modification to the Commission approved retirement dates in this case and is leaving the service lives of the boilers at 60 years (corresponding to ending service years 2036, 2038, 2040). Minimal equipment will be installed on the boilers, such as additional gas burners and gas piping, that will be used to increase the gas burning capacity of the boilers. This equipment will have shorter service lives that would run from the time that they are put into service until the boiler (unit) is retired (approximately 12-16 years), or until the equipment has reached the end of its useful life and is replaced as part of an ongoing capital expense.

Preparer: Mark Lytal
Sponsor: Mark Lytal

QUESTION NO. OPUC 1-11:

Please reference the Direct Testimony of Mark Lytal, Attachment ML-1. Please provide a version of Exhibit ML-1 assuming $65 million total project cost.

RESPONSE:

Please see Exhibit SPS-OPUC 1-11.

Preparer: Brian Hudson
Sponsor: Mark Lytal

Southwestern Public Service Company
Harrington Station Conversion Cost at $65 Million

Estimated Cost Table Harrington Coal-to-Gas Conversion							
	Pipeline	**Common Plant**	**Harrington Unit 1**	**Harrington Unit 2**	**Harrington Unit 3**	**Total Plant**	**Total**
Development (Permitting, Engineering, & Survey)	$3,733,498	$720,257	$894,881	$894,881	$894,881	$3,404,900	**$7,138,398**
Land Rights	$1,979,336	$0	$0	$0	$0	$0	**$1,979,336**
Materials	$18,565,189	$314,205	$1,400,190	$1,400,190	$1,400,190	$4,514,776	**$23,079,965**
Labor (Contract)	$21,788,272	$748,084	$1,723,218	$1,723,218	$1,723,218	$5,917,739	**$27,706,011**
SPS Labor and Indirects	$2,365,679	$244,305	$244,305	$244,305	$244,305	$977,218	**$3,342,897**
Estimated Cost Subtotal	**$48,431,975**	**$2,026,850**	**$4,262,594**	**$4,262,594**	**$4,262,594**	**$14,814,632**	**$63,246,607**
Total AFUDC	$1,157,697	$39,535	$299,236	$242,705	$9,450	$590,927	**$1,748,623**
TOTAL COST	**$49,589,671**	**$2,066,386**	**$4,561,830**	**$4,505,299**	**$4,272,044**	**$15,405,559**	**$64,995,231**

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- a proposed long-term debt ratio of 50.63%;
- a proposed cost of long-term debt of 4.18%; and
- a proposed ROE of 10.35%.

B. Dolet Hills Ratemaking Treatment

Dolet Hills is a 650 net MW generating unit fueled by lignite mined from the adjacent Dolet Hills and Oxbow reserves (collectively referred to as the DH Mines). SWEPCO reduced mining operations at the DH Mines in 2019, due to *force majeure* events in 2017 and 2018 and increases in lignite production costs. Despite diligent efforts to reduce mining costs, SWEPCO determined in early 2020 that the economically recoverable lignite reserves had been depleted. Based on this determination, lignite production operations at the DH Mines ceased in May 2020. SWEPCO evaluated mining operations and costs of operating Dolet Hills beyond 2021. That analysis, which is included in the workpapers to SWEPCO witness Thomas P. Brice's direct testimony, demonstrates that retirement of Dolet Hills will result in up to $180 million in estimated fuel savings for SWEPCO customers. Accordingly, Dolet Hills will retire no later than December 31, 2021. 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.

Consistent with GAAP and standard regulatory practice, the remaining undepreciated value of Dolet Hills would be depreciated through 2021—i.e., the plant's economically useful life. SWEPCO realizes the significant impact this would have on SWEPCO's rates that are to be set in this proceeding. To mitigate this impact, SWEPCO proposes to offset Dolet Hills' remaining undepreciated value by the Company's unprotected excess Accumulated Deferred Income Taxes (ADIT) and a tax refund provision. Specifically, when the United States Congress reduced the federal corporate income tax rate to 21% in 2018, excess ADIT was created for SWEPCO. In Docket No. 46449, SWEPCO's most recent base-rate case, 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 reduce the undepreciated value of Dolet Hills. While this will not completely offset the undepreciated value of the Dolet Hills plant, the proposal will significantly mitigate the rate impact on customers. SWEPCO proposes that the remaining net amount of undepreciated value of the Dolet Hills plant be expensed over a four-year period.

C. Request for Declaratory Order Related to Battery Storage

Batteries can perform a variety of beneficial functions on an electric system and can be classified as distribution, transmission, or generation assets under the FERC Uniform System of Accounts, depending on their usage. With the ongoing reduction in the price of battery storage technology, batteries are becoming a cost-effective alternative to traditional distribution, transmission, and generation options. In some instances, a battery installation can avoid or defer the need for a more expensive distribution or transmission system upgrade. As explained in SWEPCO witness Mr. Brice's testimony, SWEPCO plans to evaluate the feasibility of cost-effective battery storage installation on its system.

It is unclear, however, when or even if a certificate of convenience and necessity (CCN) filing is required for a battery installation. For example, batteries installed as distribution assets appear to be exempt from a CCN filing under 16 TAC § 25.101(c)(4). Similarly, a battery used as a transmission asset appears to be exempt if installed in a new high voltage switching station or substation under 16 TAC § 25.101(c)(2).

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57. Good cause exists to make post-test-year reductions to SWEPCO's rate base to reflect, consistent with the Commission's rate treatment of Welsh Unit 2 in Docket No. 46449, that Dolet Hills, the Oxbow investment, and DHLC will cease to provide service to SWEPCO's customers when the plant retires on December 31, 2021.

58. It is appropriate to remove all cost recovery for Dolet Hills, the Oxbow investment, and DHLC from base rates and address these issues instead in a Dolet Hills rate rider.

59. Through the Dolet Hills rate rider, SWEPCO should be permitted, with respect to the period between March 18, 2021 (the date when the rates are effective) and December 31, 2021 (the date of Dolet Hills' retirement) (the operative-plant phase of the Dolet Hills rate rider), to recover the costs ordinarily permitted for an operating generating plant, including a return on the plant's net book value (including applicable accumulated deferred federal income taxes and unused materials and supplies), depreciation, and O&M. SWEPCO should similarly be permitted to continue earning a return on the Oxbow investment and the return on equity and associated taxes for DHLC. The charges in the Dolet Hills Rate Rider should be subject to true-up to reflect an updated-net-book value of Dolet Hills after its retirement and again after the plant is closed and final demolition costs are known.

60. With respect to the period after December 31, 2021 (the post-retirement phase of the Dolet Hills rate rider), the remaining net book values of Dolet Hills should be placed in a regulatory asset to be amortized without a return. All other cost recovery for Dolet Hills, the Oxbow investment, or DHLC under the Dolet Hills rate rider should cease, as the assets will no longer be providing service.

61. SWEPCO's recovery of Dolet Hills' remaining net book value (whether through depreciation during the operative-plant phase or recovery from the regulatory asset during the post-retirement phase) should be amortized in accordance with the asset's useful life ending in 2046.

62. DELETED.

63. Amortizing these assets in accordance with Dolet Hills' useful life ending in 2046 equitably balances the interests of SWEPCO and both its current and future customers.

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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*

GUD NO. 10580

DIRECT TESTIMONY

OF DANE A. WATSON

WITNESS FOR

ATMOS PIPELINE - TEXAS, A DIVISION OF ATMOS ENERGY CORPORATION

JANUARY 6, 2017

GUD NO. 10580
INDEX TO THE DIRECT TESTIMONY
OF DANE A. WATSON, WITNESS FOR
ATMOS PIPELINE - TEXAS, A DIVISION OF ATMOS ENERGY CORPORATION

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I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Dane A. Watson. My business address is 101 E. Park Blvd., Suite 220, Plano, Texas 75074. I am a Partner in Alliance Consulting Group ("Alliance"). Alliance provides consulting and expert services to the utility industry.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Atmos Pipeline - Texas (APT), a division of Atmos Energy Corporation ("Atmos Energy" or the "Company").

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor of Science degree in Electrical Engineering from the University of Arkansas at Fayetteville and a Master's Degree in Business Administration from Amberton University.

Q. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION EXPERT?

A. Yes. The Society of Depreciation Professionals ("the Society") has established national standards for depreciation professionals. The Society administers an examination and has certain required qualifications to become certified in this field. I have met all requirements and am a Certified Depreciation Professional.

Q. PLEASE DESCRIBE YOUR INVOLVEMENT WITH ANY PROFESSIONAL SOCIETIES OR COMMITTEES?

A. I have twice been Chair of the Edison Electric Institute ("EEI") Property Accounting and Valuation Committee and have been Chairman of EEI's Depreciation and Economic Issues Subcommittee. I was the Industry Project Manager for the EEI/AGA effort around the electric and gas industry adoption of FAS 143 and testified before FERC in the hearings leading up to the release of FERC Order 631. I am a Registered Professional Engineer ("PE") in the State of Texas and a Certified Depreciation Professional. I am a Senior Member of the Institute of Electrical and Electronics Engineers. I am also Past President of the Society of Depreciation Professionals.

Q. PLEASE OUTLINE YOUR EXPERIENCE IN THE FIELD OF DEPRECIATION.

A. Since graduation from college in 1985, I have worked in the area of depreciation and valuation. I founded Alliance Consulting Group in 2004 and am responsible for conducting depreciation, valuation and certain other accounting-related studies for utilities in various regulated industries. My duties related to depreciation studies include the assembly and analysis of historical and simulated data, conducting field reviews, determining service life and net salvage estimates, calculating annual depreciation, presenting recommended depreciation rates to utility management for its consideration, and supporting such rates before regulatory bodies.

My prior employment from 1985 to 2004 was with Texas Utilities ("TXU"). During my tenure with TXU, I was responsible for, among other things, conducting valuation and depreciation studies for the domestic TXU companies. During that time, I also served as Manager of Property Accounting Services and Records Management in addition to my depreciation responsibilities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE RAILROAD COMMISSION OF TEXAS?

A. Yes. I conducted depreciation studies, filed written testimony and testified before the Railroad Commission of Texas ("Commission") in Gas Utility Docket ("GUD") Nos. 8976, 9145-9148, 9225, 9313, 9400, 9670, 9762, 9869, and 10000 on behalf of either Atmos Energy Corp., Mid-Tex Division ("Mid-Tex," formerly known as TXU Gas Distribution or "Distribution") and Atmos Pipeline - Texas (formerly known as TXU Lone Star Pipeline or "Pipeline"). I have also filed testimony before the Commission for CenterPoint Energy. A complete listing of my testimony experience is attached as Exhibit DAW-1.

II. PURPOSE AND SUMMARY OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. I sponsor and support the depreciation study and recommended depreciation rate changes for APT and the Company's Shared Services Unit ("SSU").

Q. DO YOU SPONSOR ANY EXHIBITS?

A. Yes. I sponsor the 2016 APT depreciation study and the resulting depreciation rates attached to my direct testimony as Exhibit DAW-2. I also sponsor the 2014 SSU depreciation study and the resulting depreciation rates attached to my direct testimony as Exhibit DAW-3.

Q. WERE THE EXHIBITS YOU ARE SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

Q. PLEASE DESCRIBE THE DEPRECIATION STUDIES ON WHICH APT HAS BASED ITS REQUESTED DEPRECIATION RATES IN THIS CASE.

A. The proposed depreciation rates for APT's assets are based on my depreciation study, which analyzes the life and net salvage percentages for Underground Storage, Transmission, General Plant Depreciated and General Plant Amortized assets that comprise Atmos Energy's APT Division for the period ended September

30, 2016. The proposed depreciation rates for APT-related SSU assets are based on a SSU depreciation study that I performed for the period ended September 30, 2014.

Q. WHAT ANNUAL DEPRECIATION PROVISION IS REFLECTED IN YOUR DEPRECIATION STUDY FOR APT'S ASSETS?

A. Based on the depreciation study, which analyzed APT's depreciable plant in service as of September 30, 2016, I recommend an annualized depreciation provision for APT of approximately $78.5 million dollars. This represents an increase in the annual depreciation provision for APT assets of approximately $19.3 million dollars per year. This amount was determined by comparing the depreciation provision between current rates authorized in APT's last rate case, GUD No. 10000, and the proposed rates as shown in Exhibit DAW-2, Appendix A.

Q. ARE THE RESULTS OF YOUR DEPRECIATION STUDY REFLECTED IN THE TEST YEAR ENDING SEPTEMBER 30, 2016 COST OF SERVICE CALCULATION?

A. Yes. APT Witness Ms. Barbara Myers applies the proposed APT and SSU depreciation rates to the adjusted plant balances as of September 30, 2016.

Q. WHAT DEPRECIATION RATES ARE BEING USED TO CALCULATE SSU DEPRECIATION EXPENSE IN THIS CASE?

A. APT is proposing the SSU depreciation rates provided in my depreciation study attached to my direct testimony as Exhibit DAW-3.

III. OVERVIEW OF DEPRECIATION STUDY METHODOLOGY

Q. WHAT DEFINITION OF DEPRECIATION HAVE YOU USED FOR THE PURPOSES OF CONDUCTING THE DEPRECIATION STUDIES AND PREPARING YOUR TESTIMONY?

A. The term "depreciation," as used herein, is considered in the accounting sense; that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. Depreciation is a process of allocation, not valuation. Depreciation expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. Thus, depreciation is considered an expense or cost, rather than a loss or decrease in value. APT accrues depreciation based on the original cost of all property included in each depreciable plant account. On retirement, the full cost of depreciable property, less the net salvage amount, if any, is charged to the depreciation reserve.

Q. PLEASE DESCRIBE YOUR DEPRECIATION STUDY APPROACH.

A. I conduct a depreciation study in four phases as shown in my Exhibits DAW-2 and DAW-3. The four phases are: Data Collection, Analysis, Evaluation, and Calculation. During the initial phase of the study, I collect historical data to be used in the analysis. After the data is assembled, I perform analyses to determine the life and net salvage percentage for the different property groups being studied. The information obtained from field personnel, engineers, and/or managerial personnel, combined with the study results, are then evaluated to determine how the results of the historical asset activity analysis, in conjunction with the Company's expected future plans, should be applied. Using all of these resources, I then calculate the depreciation rate for each 300-level account and function.

Q. WHAT PROCESS HAVE YOU UNDERTAKEN TO GIVE EFFECT TO BOTH HISTORICAL DATA AND APT-SPECIFIC EXPECTATIONS IN DEVELOPING YOUR SERVICE LIFE RECOMMENDATIONS?

A. In order to achieve a reasonable balance between these critical components of the life analysis, I evaluated the statistical historical data and then applied informed judgment to make the most appropriate service life selections. The objective in any depreciation study is to project the remaining cost (installation, material and removal cost) to be recovered and the remaining periods in which to recover the costs. This requires that the service life selections reflect both APT's historic experience and its current expectations of asset lives. In order to understand APT's expectations regarding asset lives, I interviewed APT engineers working in both operations and maintenance to confirm the historical activity and indications, current and future plans, expectations and the applicability to the future surviving assets. The interview process provides important information regarding changes in materials, operation and maintenance, as well as APT's current expectation regarding the service life of the assets currently in use. This information is then considered along with the historical statistical data to develop the most reasonable and representative expected service lives for APT's assets. The result of all of this analysis is reflected in the service life recommendations set forth in my depreciation study.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE IMPORTANT INFORMATION YOU GLEANED FROM APT PERSONNEL?

A. Yes. As part of the interview process, I interviewed APT engineers in regard to Compressor station equipment. I learned there have been significant projects to upgrade compression on the APT system. There are different characteristics of low-speed and high-speed compressors as well as different life expectations of each, which are important considerations in determining the future life projections of the compressor asset group.

Q. WHAT DEPRECIATION SYSTEM DID YOU USE?

A. The straight-line method, ELG procedure, remaining-life technique comprise the depreciation system that was employed to calculate the annual accrual for depreciation expense in the study.

Q. HAS THIS COMMISSION REPEATEDLY APPROVED THE USE OF ELG DERIVED DEPRECIATION RATES?

A. Yes. The Commission has repeatedly approved the use of the ELG depreciation procedure for APT assets in GUD No. 8664, 8976, 9400, and 10000. The Commission has also approved the use of the ELG methodology to establish deprecation rates for the Atmos' Mid-Tex Division and Atmos' West Texas Division.[1]

Q. HOW ARE DEPRECIATION RATES DEVELOPED UNDER THE ELG SYSTEM?

A. In the ELG system, the annual depreciation expense for each group is computed by dividing the original cost of the asset, less allocated depreciation reserve, less estimated net salvage, by its respective equal life group remaining life. The resulting annual accrual amounts of all depreciable property within an account were accumulated, and the total is divided by the original cost of all account level depreciable property to determine the account-level depreciation rate. The calculated remaining lives and annual depreciation accrual rates are based on attained ages of plant in service and the estimated service life and salvage

[1] *See* Final Orders in GUD Nos. 9145-9148 (FOF No. 111), 9400 (FOF No. 102), 9670, 9762, 9869 and 10170 with respect to Atmos Energy Corp, Mid-Tex Division, and GUD No. 9002-9135 relating to Energas Company, the predecessor to the Atmos Energy Corp., West Texas Division.

characteristics of each depreciable group. The computations of the annual depreciation rates are shown in my Exhibits DAW-2 and DAW-3, Appendix B.

Q. WHAT IS THE SIGNIFICANCE OF AN ASSET'S USEFUL LIFE IN YOUR DEPRECIATION STUDY?

A. An asset's useful life was used to determine the remaining life over which the remaining cost (original cost plus or minus net salvage, minus accumulated depreciation) can be allocated to normalize the asset's cost and spread it ratably over future periods.

Q. HOW DID YOU DETERMINE THE AVERAGE SERVICE LIVES FOR EACH ACCOUNT?

A. The establishment of appropriate average service lives for each account within a functional group was determined by using actuarial analysis methods. The remaining lives, by account, are calculated in my Exhibits DAW-2 and DAW-3, Appendix B. Graphs and tables supporting the actuarial analysis and the chosen Iowa Curves used to determine the average service lives for analyzed accounts are found in the life analysis section and in Appendix C of Exhibit DAW-2 and DAW-3.

Q. WHAT IS NET SALVAGE?

A. While discussed more fully in the study itself, net salvage is the difference between the gross salvage (what is received in scrap value for the asset when retired) and the removal cost (cost to remove and dispose of the asset). Salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the asset.

Q. HOW DID YOU DETERMINE THE NET SALVAGE PERCENTAGES FOR EACH ASSET GROUP?

A. I examined the experience realized by APT by observing the actual net salvage for various bands (or combinations) of years. Using averages (such as the three-year and five-year bands) allows the smoothing of the timing differences between when retirements, removal cost and salvage are booked. By looking at successive average bands ("rolling bands"), an analyst can see trends in the data that would indicate the future net salvage in the account. This examination, in combination with the feedback of APT engineers related to any changes in operations or maintenance that would affect the future net salvage of the asset, allowed the selection of the best estimate of future net salvage for each account. The net salvage as a percent of retirements for various bands (i.e. groupings of years such as the five-year average) for each account are shown in my Exhibit DAW-2 and DAW-3, Appendix D. As with any analysis of this type, expert judgment was applied in order to select a net salvage percentage reflective of the future expectations for each account.

Q. IS THIS A REASONABLE METHOD FOR DETERMINING NET SALVAGE RATES?

A. Yes. The method used to establish appropriate net salvage percentages for each account was determined by using the same methodology that was approved in the last fully litigated case before the Commission in GUD No. 10000. It is also the methodology commonly employed throughout the industry and is the method recommended in authoritative texts.

Q. WHAT FACTORS CAN CAUSE PLANT ASSETS TO EXPERIENCE SIGNIFICANT LEVELS OF NEGATIVE NET SALVAGE?

A. Some plant assets can experience significant negative removal cost percentages due to the timing of the addition versus the retirement. For example, a Transmission asset in FERC Account 367 with a current installed cost of $500 (2016) would have had an installed cost of $24.75 in 1946. Using the Handy-Whitman Bulletin No. 184, G-4, line 27, $24.75 = $500 x 25/505. A removal cost of $50 for the asset on current installed cost would only have a calculated (incorrectly) negative 10 percent removal cost ($50/$500). However, a correct removal cost calculation would show a negative 202 percent removal cost for that asset ($50/$24.75). Inflation from the time of installation of the asset until the time of its removal must be taken into account in the calculation of the removal cost percentage because the depreciation rate, which includes the removal cost percentage, will be applied to the original installed cost of assets. Other factors such as the synchronization of net salvage data can also affect the level of net salvage.

IV. ATMOS PIPELINE - TEXAS DEPRECIATION STUDY

A. Overview

Q. WHEN DID THE LAST CHANGE IN APT'S DEPRECIATION RATES OCCUR?

A. The last change in APT's depreciation rates occurred in 2011. The depreciation rates were established in GUD No. 10000 and were based on a depreciation study of plant in service as of September 30, 2009.

Q. WHAT TYPE OF PROPERTY IS INCLUDED IN THE APT DEPRECIATION STUDY?

A. The APT depreciation study analyzes the property characteristics of APT's underground storage, transmission, and general plant (both depreciated and amortized) and proposes depreciation rates for these assets. The depreciation study is attached to my testimony as Exhibit DAW-2.

Q. WHAT TYPES OF ASSETS ARE CLASSIFIED IN THE GENERAL PLANT DEPRECIATED AND AMORTIZED FUNCTIONS?

A. The General Plant functional group has been split into two groups, depreciated and amortized. The General Plant Depreciated functional group contains facilities and equipment associated with the overall operation of the business, such as office buildings, warehouses, service centers, transportation and power operated equipment. The General Plant Amortized functional group contains assets associated with the overall operation of the business, such as office and computer equipment, stores, tools, and other miscellaneous equipment. All General Plant is used in overall operations of the business rather than with a specific Underground Storage or Transmission classification.

Q. HAS APT EXPERIENCED INCREASED INVESTMENT SINCE ITS LAST RATE CASE?

A. Yes. Since GUD 10000, APT's plant balance has increased from $1.0 billion (9/30/2009) to $2.4 billion (9/30/2016), a change of 140%.

Q. HOW DOES THAT INCREASE IN INVESTMENT AFFECT DEPRECIATION EXPENSE?

A. The increase in investment is a significant factor of the increase in depreciation expense being requested. The prior study balances (at 9/30/2009) with the approved depreciation rates resulted in an annual depreciation expense accrual of $26.1 million. Using the approved rates with the current investment (at 9/30/2016) the annual depreciation expense accrual is $59.2 million. This is an increase of $33.1 million (a change of over 125%) and is nearly 65% of the increase being requested between the 2009 and 2016 study. The increased investment also changes the weighting of the current assets and the theoretical reserve calculations, which are both used in determining the remaining life depreciation accrual and rates.

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS REGARDING THE LIFE PARAMETERS YOU ARE RECOMMENDING IN THE STUDY?

A. Yes. Overall, the lives have primarily remained the same or are increasing. There are a total of 29 accounts; 10 accounts have increasing lives; four accounts have decreasing lives; and 15 remained the same. Underground Storage Accounts 351-Structures and Improvements and Account 356 - Purification Equipment have the largest increases in average service life of seven years and 15 years, respectively. Transmission Account 369 - M&R Station Equipment has the largest decrease in average service life of three years.

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS REGARDING THE NET SALVAGE PARAMETERS YOU ARE RECOMMENDING IN THE STUDY?

A. Yes. First, APT is experiencing negative net salvage as evidenced by the fact that, during the last five years, no accounts in storage or transmission functions have experienced a positive net salvage and a number of accounts have seen increased levels of removal cost resulting in more negative net salvage in nine accounts. Second, in the current depreciation study, historical net salvage data, on an account level, for the past 11 years was available and was relied upon for the net salvage parameters I am recommending in the study. There are a total of 29 accounts; 20 had no change in net salvage; and nine had decreasing (more negative net salvage). There are seven of the nine accounts where the net salvage indications are negative 10 percent or more. These will be discussed later in my testimony and a detailed analysis and discussion of net salvage can be found in Exhibit DAW-2.

B. <u>Service Lives and Net Salvage Depreciation Study Results</u>

Q. WHAT ARE THE PRIMARY FORCES AFFECTING THE DEPRECIATION EXPENSE RECOMMENDED IN THE STUDY?

A. Generally, depreciation expense is affected by three separate factors - changes in average service life, changes in net salvage, and the effect of reserve position, including the impacts of increased investment since the last rate case, which as I discussed above is the primary driver behind the increases in depreciation expense. APT's depreciation expense is no exception.

Q. WHAT IS CAUSING THE HIGHER NEGATIVE NET SALVAGE RATES IN THE ACCOUNTS YOU MENTIONED PREVIOUSLY?

A. The activities related to retirement costs (generally including cutting, capping, and purging of gas for the abandonment of pipe) have increased due to the cost of labor and the increased cost due to compliance with environmental and safety regulations. Performing these activities is more expensive than what has occurred in the past and is definitely more than what has been reflected in the existing depreciation rates. Additionally, there has been very limited or no salvage recorded due to APT's practice of abandoning pipe in place. This practice is expected to continue, so there will be little, if any, salvage recorded for scrap pipe in the future.

Q. WHAT ACCOUNTS WERE MOST IMPACTED BY CHANGES IN THE NET SALVAGE PERCENTAGES?

A. The detailed analysis of each account is described fully in the Salvage Analysis section of Exhibit DAW-2. In my study there are eight accounts where the negative net salvage rate is 10 percent or more: Underground Storage Accounts 351, 352, 354, and 355; and Transmission Accounts 366, 367, 369, and 370. Two accounts in particular, Accounts 367 and 368, are driving the result due to the level of plant investment:

- Account 367, Mains has experienced net salvage from negative 25 percent to negative 35 percent across the most recent full 11 year moving average analysis (excluding the more negative one-year net salvage will not be time synchronized). Since the full 11-year average reflects a negative 25 percent net salvage with modest increases in negative net salvage in shorter bands, my recommendation to retain the existing negative 15 percent is a conservative move and is based on the fact that while there has been an unusually high level of activity over the last five years, the level and mix of activity in the future is not known with reasonable certainty. I recommend retention of the existing net salvage for this account at this time.

- Account 369, M&R Station Equipment has a consistent negative net salvage experience of negative 20 percent across the most recent moving averages. The full 5 year analysis indicates removal costs are approximately negative 22 percent. My recommendation to retain the existing negative 15 percent is a conservative move and is based on the fact that while there has been an unusually high level of activity over the last five years, the level and mix of activity in the future is not known with reasonable certainty. I recommend retention of the existing net salvage for this account at this time.

Q. IS THE LEVEL OF NET SALVAGE APT IS EXPERIENCING A RECENT PHENOMENON?

A. No. However, the level of activity occurring on APT's system is recent and, at this time, it is not known if this level of activity will be sustained for the long term. The net salvage analysis is shown in Exhibit DAW-2, Appendix D. My analysis incorporates this consideration.

Q. PLEASE DESCRIBE THE RESULTS REFLECTED IN YOUR STUDY FOR UNDERGROUND STORAGE PLANT.

A. The functional group depreciation rate for Underground Storage Plant increased from 2.78% to 3.28%. The existing annual depreciation expense accrual at a function level is $8.5 million when compared to the recommended annual depreciation expense accrual using the study proposed rates is $10.0 million or an increase of $1.5 million. The most significant impact in this function is Account 355, M&R Station Equipment and Account 35200, Wells, which reflect over $1.6 million, with some offset (decrease of approximately $200 thousand) in Account 35600, Purification Equipment. The increased investment, along with negative net salvage and the reserve position with some offset due to a longer service lives, is driving the change in this function.

Q. PLEASE DESCRIBE THE RESULTS REFLECTED IN YOUR STUDY FOR TRANSMISSION PLANT.

A. The functional group depreciation rate for Transmission Plant increased from 2.37% to 3.17%. The existing annual depreciation expense accrual is $49.1 million when compared to the recommended annual depreciation expense accrual using the study proposed rates is $65.7 million or an increase of $16.6 million. The account most significantly impacting the results in this function is Account 367, Mains which increased by $13.1 million and is due to the increased investment, along with the reserve position with some offset due to a longer service life.

Q. PLEASE DESCRIBE THE RESULTS REFLECTED IN YOUR STUDY FOR GENERAL PLANT DEPRECIATED.

A. The functional group depreciation rate for General Plant Depreciated increased from 2.93% to 5.81%. The existing annual depreciation expense accrual using the existing rates is $320 thousand when compared to the recommended annual depreciation expense accrual using the study proposed rates is $633 thousand or an increase of approximately $313 thousand. The lives decreased in two accounts (Accounts 392 and 396) by one year each. The same two accounts (Accounts 392 and 396) had existing positive 20 percent net salvage rates which were retained. The primary driver for the change in this function is due to the reserve position of the general plant function.

Q. PLEASE DESCRIBE THE RESULTS REFLECTED IN YOUR STUDY FOR GENERAL PLANT AMORTIZED.

A. The functional group depreciation rate for General Plant Amortized increased from 4.79% to 7.54%. The existing annual depreciation expense accrual using the existing rates is $1.3 million when compared to the recommended annual depreciation expense accrual using the study proposed rates is $2.1 million or an increase of approximately $762 thousand. The driver for this change is the reserve portion of the general plant function. Even though there was no change in lives for these accounts, total expense related to General Plant Amortized accounts has increased due to the reserve true up and the reflection of a whole life amortization rate to be applied going forward. This true up is a necessary component of amortization accounting and ensures the correct amortization will be achieved at the end of the life of each vintage of assets.

Q. ARE YOUR PROPOSED DEPRECIATION RATE RECOMMENDATIONS FOR THE GENERAL PLANT FUNCTION DESIGNED TO ADDRESS THE RESERVE ISSUE?

A. Yes. My proposed depreciation rates accurately reflect current experience and future expectations and also allow for the recovery of the amount of depreciation expense that has been under-accrued.

V. SHARED SERVICE UNIT

Q. DID ALLIANCE PREPARE A DEPRECIATION STUDY FOR ATMOS SHARED SERVICE UNIT?

A. Yes. We have conducted a study as of September 30, 2014. The study recommendations and results are attached to my direct testimony as Exhibit DAW-3.

Q. ARE THE STEPS DESCRIBED ABOVE FOR THE APT DEPRECIATION STUDY THE SAME FOR THE SHARED SERVICES ASSETS?

A. Yes. The same approach and methods were used for both studies.

Q. WHAT PROPERTY IS INCLUDED IN THE SHARED SERVICES UNIT DEPRECIATION STUDY?

A. For Shared Services, there is one general class of depreciable property which is related to general office activities. These assets include office buildings and leasehold improvements, office furniture, communications equipment, transportation equipment, computer software and hardware and other miscellaneous general office assets.

Q. WHAT TIME PERIOD WAS USED TO DEVELOP THE PROPOSED DEPRECIATION RATES?

A. The depreciation rates were developed based on the depreciable property recorded on Shared Services' books at September 30, 2014.

Q. WHAT ARE THE RESULTS OF THE SHARED SERVICES UNIT DEPRECIATION STUDY?

A. The 2014 Shared Services Unit Depreciation Study is found in Exhibit DAW-3. The annual depreciation expense, before allocation, is approximately $21.8 million per year. More details related to the study and results are found in Exhibit DAW-3.

Q. WHAT ARE THE PRIMARY FORCES AFFECTING THE DEPRECIATION RATES RECOMMENDED IN THIS STUDY?

A. Generally, depreciation rates are affected by three separate factors - changes in average service life, changes in net salvage, and the effect of reserve position. SSU's depreciation rates only have two of these affecting the rates—average service life and reserve position.

Q. ARE THERE ANY GENERAL OBSERVATIONS REGARDING THE LIFE AND NET SALVAGE PARAMETERS BEING RECOMMENDED IN THE STUDY YOU WOULD LIKE TO EXPLAIN?

A. Yes. There is significant investment in the SSU related to technology-based assets which generally have shorter life expectations than gas transmission assets. The net salvage analyses for all Shared Services accounts indicate no salvage or cost of removal is being experienced, therefore, a zero percent net salvage rate is recommended for each account in the SSU study. Detailed discussions for each account can be found in Exhibit DAW-3.

Q. WHAT ASSETS WERE ANALYZED FOR THE 2014 SHARED SERVICES UNIT DEPRECIATION STUDY?

A. The SSU assets perform a common service to all of Atmos' divisions, including its regulated utility operations across multiple states, Texas being one of the states. The assets used to perform these common services were analyzed during the depreciation study. As previously stated these assets include, but are not limited to, office buildings, furniture and equipment, communication equipment, and any computer hardware or software utilized. The top three largest investments in SSU are the application software, server hardware, and server software equipment. These assets are primarily located in the Company's home office in Dallas, Texas and the customer service centers in Amarillo, Texas and Waco, Texas.

Q. WHAT DEPRECIATION RATES DOES THE COMPANY PROPOSE TO USE FOR SHARED SERVICES ASSETS?

A. The Company proposes to utilize the depreciation rates proposed in the Alliance depreciation study, which can be found in Exhibit DAW-3 on Appendix A.

Q. HAS THE COMPANY REQUESTED APPROVAL OF THE PROPOSED SHARED SERVICES DEPRECIATION RATES IN ANY OTHER STATES?

A. Yes. The Company has made filings and has received approval of the SSU depreciation rates shown in DAW-3 in Colorado, Kentucky, Virginia, and Tennessee since the Study's completion in March 2015. SSU depreciation rates are pending approval in Louisiana. Atmos will make filings in each of its other jurisdictions according to its regulatory requirements.

Q. WHEN WILL THE COMPANY CONDUCT ANOTHER SHARED SERVICES DEPRECIATION STUDY?

A. The Company has plans to perform a depreciation study on Shared Services assets about every four years. The Company's objective is to have reasonable depreciation rates in place that recognize the expense of those assets over their useful lives. It is important that the depreciation rates be as reasonable as possible, so the cost can be assessed to the proper generation of customer.

VI. CONCLUSION

Q. WHAT ACCOUNT DEPRECIATION RATES ARE YOU PROPOSING, AND HOW DO THEY COMPARE WITH THE CURRENT RATES?

A. The current depreciation rates and the rates I am now proposing related to APT are found in Appendix A of my Exhibit DAW-2. The proposed rates for SSU are in Appendix A of my Exhibit DAW-3. Detailed calculations and comparisons of these rates are found in my studies included in Exhibits DAW-2 and DAW-3.

Q. MR. WATSON, DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. The depreciation studies and analysis performed under my supervision fully support setting depreciation rates for APT and SSU at the levels I have indicated in my testimony. APT and SSU should continue to periodically review the annual depreciation rates for their respective property. In this way, all customers are charged for their appropriate share of the capital expended for their benefit. APT's and SSU's depreciation rates should be set at my recommended amounts in order to recover the total investment in property over the estimated remaining life of the assets.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

STATE OF TEXAS §
§
COUNTY OF COLLIN §

AFFIDAVIT OF DANE A. WATSON

BEFORE ME, the undersigned authority, on this day personally appeared Dane A. Watson who having been placed under oath by me did depose as follows:

1. "My name is Dane A. Watson. I am of sound mind and capable of making this affidavit. The facts stated herein are true and correct based upon my personal knowledge. My current position is Partner for Alliance Consulting Group.

2. I have prepared the foregoing Direct Testimony and the information contained in this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Dane A. Watson
Dane A. Watson

SUBSCRIBED AND SWORN TO BEFORE ME by the said Dane A. Watson on this 19th day of December, 2016.

KARRI L. ALBA
Notary Public
State of Texas
Comm. Expires 01-12-2017

Karri L. Alba
Notary Public

My commission expires: 1/12/17

ATMOS ENERGY CORPORATION

ATMOS PIPELINE TEXAS DIVISION

DEPRECIATION RATE STUDY

As of September 30, 2016

ALLIANCE CONSULTING GROUP

http://www.utilityalliance.com

ATMOS ENERGY CORPORATION - ATMOS PIPELINE TEXAS DIVISION
DEPRECIATION RATE STUDY
EXECUTIVE SUMMARY

Atmos Energy Corporation ("Atmos" or "Company") engaged Alliance Consulting Group to conduct a depreciation study of the Company's Pipeline Texas Division ("APT") natural gas operations depreciable assets as of fiscal year end September 30, 2016.

The existing depreciation rates were based on the straight-line method, equal life group ("ELG") procedure, and remaining-life technique and are retained in this study. This study recommends an increase of $19.3 million in annual depreciation expense when compared to the depreciation rates currently in effect. Life estimates showed the following changes: 10 accounts have an increase in life; four accounts have a decrease in life, and 15 accounts remained unchanged. Net salvage showed the following changes: nine accounts have a decrease in net salvage (more negative) and 20 accounts remained unchanged.

The depreciation study I conducted analyzed and developed depreciation recommendations at an account level. The Company will accrue depreciation expense based on the account level depreciation rates developed in this study. The depreciation study also reflects the continued use of Vintaged Group Amortization for certain General Plant accounts. Appendix A demonstrates the change in depreciation expense.

ATMOS ENERGY CORPORATION
ATMOS PIPELINE TEXAS DIVISION
DEPRECIATION RATE STUDY
As of September 30, 2016
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PURPOSE

The purpose of this study is to develop depreciation rates for the depreciable property as recorded on APT's books at September 30, 2016. The account-based depreciation and amortization rates were designed to recover the total remaining undepreciated investment, adjusted for net salvage, over the remaining life of APT's property on a straight-line basis. Non-depreciable property and property which is amortized, such as intangible software, were excluded from this study.

APT is a Texas intrastate natural gas transmission pipeline network that is connected to three major Texas market centers at Waha, Carthage, and Katy. The APT infrastructure is located at or near existing, new and proposed gas production fields including the Barnett Shale in north Texas and the Bossier Sand in east Texas. APT's system includes approximately 5,400 miles of transmission pipelines within Texas. APT is connected to the largest local distribution company ("LDC") in Texas, serves approximately 80 industrial customers, and is connected to more than 13,000 megawatts ("MW") of natural gas-fired electric generation. APT transports approximately 44 billion cubic feet (Bcf) of natural gas to electric generation power plants and 30 Bcf to industrial customers annually. APT transports approximately 382 Bcf of natural gas per year through pipe-to-pipe infrastructure utilizing more than 100 interconnections with Texas intrastate pipeline, interstate pipeline and plant outlets.

STUDY RESULTS

The existing and current study annual depreciation expense results from the use of Iowa Curve dispersion patterns with average service life, the equal life group ("ELG") procedure and remaining-life technique, and consideration of net salvage in the development of the study recommended depreciation rates. Detailed information for each of these factors will follow in this report.

Overall depreciation rates for APT depreciable property are shown in Appendix A. These rates translate into an annual depreciation accrual of $78.5 million based on APT's depreciable investment at September 30, 2016. The annual equivalent depreciation expense calculated by the same method using the approved functional rates was $59.2 million. The primary driver for the increase in the annual depreciation expense accrual is the increased investment and the recognition of more negative net salvage with some offset due to longer lives.

Appendix A presents a comparison of the existing rates versus the recommended study rates. Appendix B presents the development of the depreciation rates and annual accruals. Appendix C presents a comparison of the existing mortality and net salvage parameters versus the recommended study mortality and net salvage parameters by account. Appendix D shows net salvage history by plant account.

Consistent with the prior study, this depreciation study continues to recognize depreciation expense for Vintaged Group Amortization in Accounts 391 through 399, excluding 392 and 396. This process provides for the amortization of general plant over the same life as approved with a separate amortization to allocate deficit or excess reserve over a five year period. At the end of the amortized life, property will be retired from the books. The FERC, the Public Utility Commission of Texas ("PUCT"), and the Railroad Commission of Texas have approved this approach.

Account 367 Transmission Mains - All (70 L0)

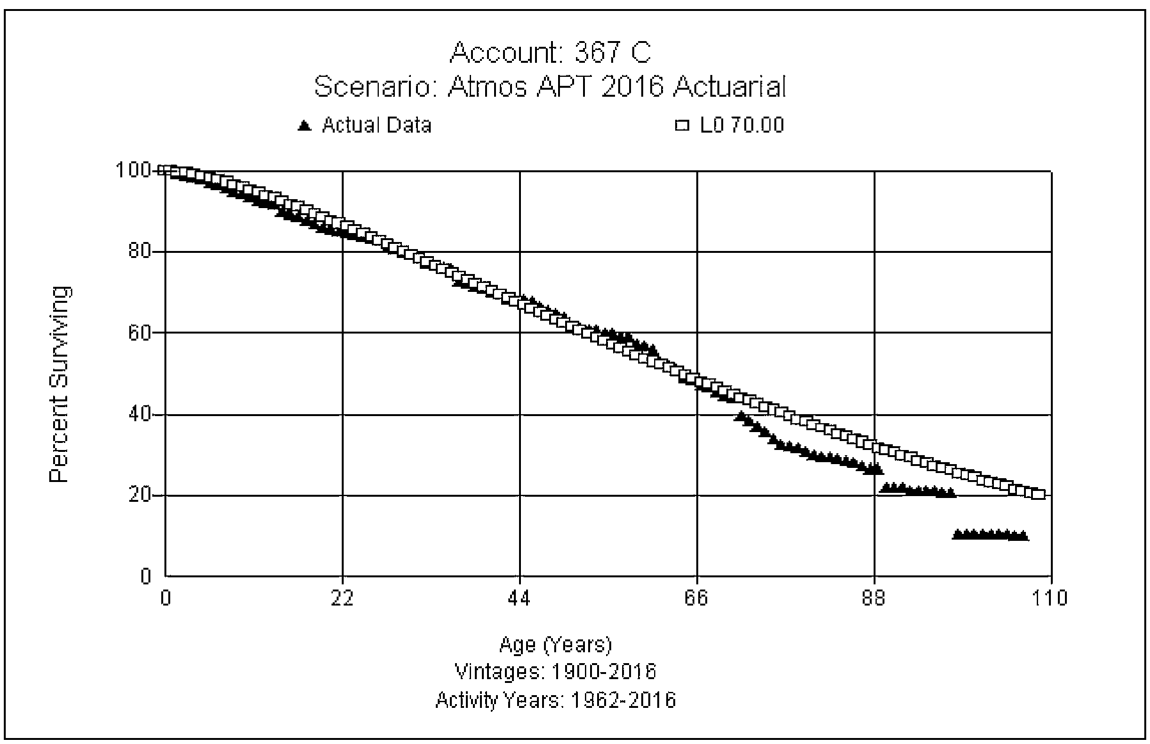
This account includes the cost of transmission system mains including excavation costs, pipe, valves, and other equipment. The plant balance in this account is $1.6 billion, which is an increase of $952 million from the last study. Sixty-seven (67) percent of APT's depreciable property is contained in this account. The existing life for this account is 65 R1.5. This account has a small amount of poly pipe and bare steel pipe.

Operation personnel stated there are three primary activities that create retirements: class changes, relocations and integrity. Company engineers state that pipe installed over the last several years (primarily coated cathodically protected steel) will have a life of at least as long or longer as previous generations of pipe. Company engineers identify factors that will tend to increase the life of pipe: improved quality of manufacturing process and coating processes, installation quality controls are better, cathodic protection systems coupled with fusion epoxy coating, in-line inspections such as chemically treating the gas stream (to mitigate internal corrosion) and installing "clock spring" to combat internal corrosion (permanent wrap) or vessels.

Mitigating the improvements in pipe life, some components in this account will not experience a service life equivalent to that of the pipe. For example, anode cathodic protection will also have a shorter life due to the fact that anodes are used up as they protect the pipe. Company engineers are experiencing anodes lasting 10-15 years, even though the design life is 20 years. However, the Company continues to move from using anodes for hot spots to fully covering with rectifiers so the impact of anodes is decreasing. Also valves are another component in account 367 that are replaced before the pipe in this account. APT is going to consider segregating anodes and leak clamps to separate accounts for amortization to better facilitate retirement reporting in the future. This would be consistent with other Atmos entities.

Typically we would recommend the R dispersion, which would be consistent with the existing, for this account and type of asset but the life indications with the R pattern is at or less than existing. Due to the significant activity taking place on the system, the life indications are less than what the Company expects in the future. The average age of the surviving investment is approximately 11 years. The average age of retirements is 24 years. Early placement bands from 1900-2016 and 1962-2016 with varying experience bands match a 70 L0 with exception at the tail, which is the least important part of the curve to match closely. In more recent placement bands, the life indications appear shorter, which may indicate the impact class relocation or APT integrity projects has had on service lives for this account.

Company field personnel confirm that 70 years is reasonable with normal operation practice, maintenance practice, and system growth. Forces of retirement such as relocations, system growth, and deterioration pressure will continue to act upon this account. Based on visual matching and knowledge of Company operations, a 70 L0 is proposed for this account. A graph of the observed life table versus the proposed life and curve is shown below.



SOAH DOCKET NO. 473-21-1892
PUC DOCKET NO. 51802

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

UNOPPOSED STIPULATION

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ATTACHMENTS:

with usage on and after March 15, 2021. Therefore, the Signatories agree that SPS shall file for a net surcharge to recover the additional amount that SPS would have received for usage on March 15, 2021 through usage on the day before the date that final rates are implemented ("True-up Period"), to recover the revenue that SPS would have received during that period if the tariffs provided in Attachment B had been in effect during that period. The True-up Period consists of two periods: 1) March 15, 2021, the date on which SPS's temporary rates became effective, through July 12, 2021; and 2) July 13, 2021, the relate back date of new rates for SPS in this proceeding until the date that final rates are implemented. SPS shall file for a surcharge to last for a period of 12 months related to the True-up Period within 120 days of a final order.

3. Resolution of Revenue Requirement Issues

This Stipulation is a black box settlement for all revenue requirement issues concerning Texas retail rates except that the Signatories agree to the following specifications:

(A) Financial Structure. Only for the purposes of Allowance for Funds Used During Construction ("AFUDC"), SPS's return on equity ("ROE") shall be 9.35% and SPS's weighted average cost of capital ("WACC") shall be 7.01%. Other than for the purposes of AFUDC, SPS's ROE and WACC are not determined in this proceeding. The ROE and WACC are non-precedential.

(B) Depreciation Expense.

(i) For the SPS Tolk Generating Station ("Tolk"), the depreciation rate (for generating assets) shall be based on a 2034 end-of-life date.

(ii) For the SPS Harrington Generating Station coal assets ("Harrington") and Plant X Unit 3 ("Plant X3"), the depreciation rate will apply SPS's proposed end-of-life dates.

(iii) For all generating units other than Tolk, Harrington, and Plant X3, the depreciation rates will remain unchanged from prior rates.

(iv) All transmission, distribution, general and intangible plant depreciation rates will remain unchanged from prior rates.

(v) The depreciation rates for SPS are set forth in Attachment C.

DOCKET NO. _____

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR AUTHORITY TO CHANGE RATES	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

SOUTHWESTERN PUBLIC SERVICE COMPANY'S STATEMENT OF INTENT AND APPLICATION FOR AUTHORITY TO CHANGE RATES

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Revenue Requirement Phase

1. SPS asks the Commission to approve a total Texas retail base rate revenue requirement (including miscellaneous tariff charges) of $765,521,011 and a base rate increase of $143,365,836, which SPS has calculated based on an overall weighted average cost of capital ("WACC") of 7.56%. That WACC is based on:

   - a proposed equity ratio of 54.60%;
   - a proposed long-term debt ratio of 45.40%;
   - a proposed cost of long-term debt of 4.20%; and
   - a proposed ROE of 10.35%.

2. SPS asks the Commission to find that the capital additions placed into service during the period from July 1, 2019 through December 31, 2020 are reasonable and necessary, and that the costs incurred by SPS for those capital additions are reasonable and prudent.

3. SPS asks the Commission to find that SPS's requested O&M expenses and administrative and general expenses, including native and affiliate expenses, are reasonable and necessary and satisfy the applicable standards under PURA and the Commission's Substantive Rules.

4. SPS asks the Commission to approve SPS's Technical Depreciation Update and resulting depreciation rates, including shorter service lives for: the Tolk Generating Station ("Tolk") Units 1 and 2 based upon a retirement date of 2032; the coal-specific assets at Harrington Generating Station ("Harrington") based on a retirement date of 2024; and Plant X Unit 3 ("Plant X3") based on a retirement date of 2022.

5. SPS asks the Commission to establish SPS's baseline levels for the pension and other post-employment benefits ("OPEB") expenses.

6. SPS asks the Commission to approve the waivers from the Rate Filing Package ("RFP") schedules described in Schedule V to the RFP and Section VIII of this application.

7. SPS asks the Commission to approve SPS's request to maintain the current Attachment Z2 regulatory asset.

8. SPS asks the Commission to approve SPS's request to recover incremental direct costs incurred as a result of the COVID-19 pandemic, establish a tracker for bad debt expense, and seek recovery of the additional bad debt expense in SPS's next base rate case.