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

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

REDACTED

DIRECT TESTIMONY OF
RACHEL S. WILSON

ON BEHALF OF
SIERRA CLUB & DR. LAWRENCE BROUGH

Synapse Energy Economics, Inc.
Cambridge, Massachusetts

April 25, 2017

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EXECUTIVE SUMMARY OF DIRECT TESTIMONY OF RACHEL S. WILSON

Rachel S. Wilson, a Senior Associate at Synapse Energy Economics, has spent the past ten years working within the energy planning sector, focusing on integrated resource planning and the economics of regulatory compliance for electric generating units for a number of different clients across the United States.

Ms. Wilson's testimony evaluates components of the application of Southwestern Electric Power Company ("SWEPCO" or "the Company") to receive rate recovery for investments in pollution control equipment at the Pirkey, Flint Creek, Welsh, and Dolet Hills facilities that were installed with the purpose of meeting obligations under federal environmental regulations. She reviews the economic justification provided by the Company to examine whether the installation of these retrofits is the least cost option for ratepayers, as determined by SWEPCO. Additionally, she evaluates the operating costs of the SWEPCO's solid fuel units as compared to the Company's revenue and the prevailing dispatch prices in the Southwest Power Pool's ("SPP") energy market, to assess the Company's bidding and dispatch practices and the implications of operating those these units.

Ms. Wilson finds that the evidence in this docket indicates that the Company imprudently failed to base its decision to invest in emission controls at Pirkey, Flint Creek, or Welsh units 1 and 3, on a robust analysis that examines detailed costs associated with a carefully selected suite of environmental controls and that compares those costs to a number of reasonable alternatives for replacement capacity. Glaringly, SWEPCO's analyses failed to utilize contemporaneous forecasts of key commodity price inputs. The Company ignored all evidence of falling natural gas prices, and continued using gas price forecasts that were two to three years out of date, which significantly skewed the outcome of its comparison between retrofitting its affected coal units and retiring and replacing them with non-coal capacity and energy. Moreover, SWEPCO did not include costs associated with additional rules environmental rules that were proposed at the time of the Company's analyses, which would lead to increases in the revenue requirements associated with the system costs of the environmental retrofits. In addition to the almost $700 million for which SWEPCO is seeking cost recovery in this docket, the Company should have known that there was the possibility that another $800 million to $1.1 billion might be required at its coal fleet. Further, SWEPCO did not examine replacement options other than new natural gas units, such as market purchases, efficiency, or renewable energy sources (which were foreseeably cost-effective and have proven to be so). These failures by SWEPCO lead me to conclude that the Company's decision to install emission controls at its units was not based on prudent analysis. Meanwhile, with regard to Dolet Hills specifically, SWEPCO seemed to rely solely on the recommendation from Cleco, the co-owner and operator of the Dolet Hills Power Station and did not perform any independent analysis of the economics of the retrofit technologies.

[redacted]

1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and position.

A. My name is Rachel S. Wilson and I am a Senior Associate with Synapse Energy Economics, Incorporated ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 2, Cambridge, Massachusetts 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities. Synapse experts have submitted testimony in more than 350 cases before state Public Utility Commissions since its inception in 1996.

Q. Please summarize your work experience and educational background.

A. I have ten years of experience working within the energy planning sector, including work on integrated resource planning; the economics of regulatory compliance; electric system dispatch; and valuation of environmental externalities from power plants. I am skilled in the use of optimization and electricity dispatch models to perform modeling analyses of electric power systems and have direct experience running the Strategist, PROMOD IV, PROSYM/Market Analytics, PLEXOS, and PCI Gentrader models. I have reviewed input and output data for many other industry models.

I have provided consulting services for a variety of clients, including the U.S. Environmental Protection Agency, the National Association of State Utility Consumer Advocates, the California Division of Ratepayer Advocates, California

Energy Commission, the Massachusetts Department of Energy Resources, the Nova Scotia Utility and Review Board, BC Hydro, the Regulatory Assistance Project, West Virginia Consumer Advocate Division, Vermont Department of Public Service, Iowa Utilities Board, Iowa Office of the Consumer Advocate, Southern Environmental Law Center, Sierra Club, Earthjustice, Natural Resources Defense Council, and Citizens Action Coalition.

I have provided testimony in electricity planning and general rate case dockets in Minnesota, Kentucky, Indiana, Michigan, Oklahoma, Missouri, and Virginia. In addition, I have provided analysis or comments to clients on electricity planning in dockets in West Virginia, Iowa, Vermont, Nova Scotia, and British Columbia.

Prior to joining Synapse in 2008, I worked for the Analysis Group, Inc., an economic and business consulting firm, where I provided litigation support in the form of research and quantitative analyses on a variety of issues relating to the electric industry.

I hold a Master of Environmental Management from Yale University and a Bachelor of Arts in Environment, Economics, and Politics from Claremont McKenna College in Claremont, California.

A copy of my current resume is attached hereto as Exhibit RSW-1.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of joint intervenors the Sierra Club and Dr. Lawrence Brough, to whom I refer collectively as "Sierra Club" throughout this testimony.

Q. Have you testified previously before the Public Utility Commission of Texas?

A. No, I have not.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is twofold. First, my testimony evaluates components of the application of Southwestern Electric Power Company

("SWEPCO" or "the Company") to receive rate recovery for investments in pollution control equipment meant to meet obligations under federal environmental regulations. I review the economic justification provided by the Company to examine whether the installation of these retrofits is the least cost option for ratepayers, as determined by SWEPCO.

Second, I also evaluate the operating costs of the Company's solid fuel units as compared to the Company revenue and of the prevailing market dispatch prices in the Southwest Power Pool ("SPP"), to assess the Company's bidding and dispatch practices and the impact of operation of the units on SWEPCO's net revenue.

[redacted]

2. OVERVIEW OF TESTIMONY AND CONCLUSIONS

Q. What has SWEPCO requested in this case?

A. On June 9, 2011, American Electric Power ("AEP") issued a press release "indicating that Welsh Units 1 and 3, Flint Creek, and Pirkey would have the necessary environmental retrofits installed to allow their continued operation…."[1] Since then, SWEPCO has invested approximately $694.5 million in emission control equipment[2] at five of its generating units—the two units at the Welsh facility (in Texas) and each of Pirkey (Texas), Dolet Hills (Louisiana),[3] and Flint Creek (Arkansas) facilities—to bring those units into compliance with regulations

[1] Direct Testimony of Mark A. Becker at 4:15-17.

[2] SWEPCO Response to TIEC RFI 8-2 (Mar. 20, 2017).

[3] Dolet Hills is co-owned by SWEPCO and Central Louisiana Electric Company ("Cleco"), the latter of which operates the plant.

promulgated by the United States Environmental Protection Agency ("EPA") in order to continue operation. SWEPCO has requested recovery of the costs associated with the installation of these emission controls through increased rates to customers.

Q. In your opinion, do the facts and evidence presented in this case support the Company's request for recovery of the costs of installed emission controls?

A. No, they do not. SWEPCO's analyses, which are intended to provide economic justification for the installed emission control retrofits, are inadequate in a number of ways: they used commodity price forecasts that are two to three years out of date at a time when major shifts were occurring in natural gas markets; they failed to evaluate proposed environmental regulations and their associated costs; they selected an unreasonably limited set of replacement capacity options; and they featured a lack of review and oversight of analyses performed by other parties.

Electric utilities have an obligation to conduct prudent planning with regard to all investments for which they intend to seek rate recovery. This is especially true for major capital additions like the environmental retrofits at issue in this case, due to the magnitude and risk of these expenditures. It is my opinion that SWEPCO acted imprudently when it committed its ratepayers to almost $700 million in investments using an analysis that was clearly flawed.

Q. What is the basis for your conclusion that the Company's analysis was clearly flawed?

A. SWEPCO's analysis contained a number of significant flaws, each of which I will describe in detail in later sections of my testimony:

- **Use of outdated natural gas prices**: SWEPCO used a natural gas price forecast for its analyses that was anywhere from one to three years outdated and thus too high, and assumed an incorrect correlation between coal and natural gas prices under its Reference Case and Low Band sensitivity. Almost without a doubt, the lower gas prices would have cut substantially into the expected margins of the retrofit projects. These lower gas prices would have reduced electricity system market prices as well as the cost of replacement power and/or any alternatives reviewed by SWEPCO. Given the already marginal benefit of the retrofit decision for these relatively large steam units, I would expect that these changed assumptions would have negated any benefit and likely have shown a net liability in retrofitting and continuing to operate SWEPCO's units rather than retiring or replacing them.

- **Failure to evaluate pending environmental regulations**: SWEPCO did not discuss, provide cost estimates for, or model the real costs associated with, compliance with known, proposed environmental rules, including regulations of certain air pollutants, solid waste disposal, or effluents into waterways. These omissions inaccurately skew the Company's analysis in favor of the decision to retrofit to its coal fleet.
- **Failure to analyze appropriate capacity replacement options**: SWEPCO evaluated only new natural gas combined-cycle capacity as a replacement options for its coal units, with the exception of the evaluation of natural gas conversion at Flint Creek. These are appropriate replacement options, but they represent a small subset of the appropriate replacement options that should have been considered by SWEPCO. New fossil-fueled replacement capacity is likely to be the most expensive replacement option, and restricting the types of available resource alternatives to new natural gas-fired resources is unreasonable. SWEPCO should have also considered market purchases of energy and capacity as a replacement option, as well as a portfolio approach that includes energy efficiency and renewable energy technologies.
- **Reliance on third-party analysis with no independent verification**: With regard specifically to Dolet Hills, SWEPCO seems to have relied solely on the retrofit recommendation from Cleco, the co-owner and operator of the facility, and did not perform any independent analysis of the economics of the retrofit technologies.

[redacted]

Q. Is there precedent for other states' utility regulators to deny recovery for environmental retrofits based on poor utility planning?

A. Yes. As discussed more fully in Section 6 of my testimony, public utility regulators in Oregon, Washington, and Indiana have all disallowed portions of environmental retrofit investments where, as here, the company failed to fully and rigorously review alternatives to retrofit and failed to demonstrate that the retrofits made economic sense.

Q. What else, if anything, does your analysis of SWEPCO's bidding and dispatch practices reveal?

A. [redacted]

3. CONDITIONS IN THE ELECTRIC SECTOR IN 2011 THROUGH 2013

Q. What time period is the focus of your analysis of SWEPCO's investment decisions in this docket?

A. I focus on the period from 2011 to 2013—the time period during which SWEPCO decided to invest in the environmental controls at its Pirkey, Flint Creek, Welsh 1 and 3, and Dolet Hills plants at issue in its application—through to 2014, when the retrofit project construction began to accelerate.[4] Construction of the Pirkey retrofits were the first to commence, and began in August 2013.[5] Construction at Flint Creek began in January 2014.[6] Construction on the Welsh 1 and 3 retrofits began in February 2014.[7] Although the exact start date of construction of Dolet Hills is unclear from SWEPCO's application, the co-owner of the plant, Cleco, filed applications for approval of environmental retrofits with the Louisiana Public Service Commission in 2011, and again in 2012.[8]

Q. Please describe the conditions in the electric sector in 2011 that prompted SWEPCO's investments in environmental controls at Pirkey, Flint Creek, Welsh 1 and 3, and Dolet Hills (collectively, in this section, the "SWEPCO Units").

A. In 2011, several environmental regulations had recently been proposed or finalized by the EPA to govern a variety of pollutants to air, water, and land that threaten public health and are emitted by coal-fired generating units. The timeline for these rules is established in the testimony of John C. Hendricks. The rules that prompted the investments in the environmental controls that are at issue in this docket include the Cross-State Air Pollution Rule ("CSAPR"), the Mercury and Air Toxics Standards ("MATS") Rule, and the Regional Haze Rule, which collectively regulated emissions of sulfur dioxide ("SO_2"), oxides of nitrogen ("NOx"), and hazardous air pollutants ("HAPs") such as mercury ("Hg"). Attached hereto as Exhibit RSW-2 is a timeline of these and other pertinent regulations, discussed below, showing the dates of the proposed and final rules and well as the compliance periods.

[4] Direct Testimony of Venita McCellon-Allen at 30:22.

[5] Direct Testimony of Franklin R. Pifer at 26:14.

[6] Direct Testimony of Franklin R. Pifer at 22:6.

[7] Direct Testimony of Franklin R. Pifer at 31:15.

[8] Direct Testimony of Paul W. Franklin at 14-16.

CSAPR, proposed in July 2010 and finalized in July 2011, limited emissions of annual SO_2, annual NOx, and ozone season NOx. Texas was included in both the annual and ozone season NOx programs, while Arkansas and Louisiana were included only in the ozone season NOx programs.[9] According to the Direct Testimony of Mr. John C. Hendricks, the SWEPCO Units comply with CSAPR through their allowance allocations, and thus do not require additional controls, except for Dolet Hills, which installed a Selective Noncatalytic Reduction ("SNCR") system to meet its ozone season obligation.[10]

The MATS Rule, proposed in March 2011 and finalized in February 2012, regulates emissions of mercury, non-mercury heavy metals, various acid gases, and certain organic hazardous air pollutants from coal-fired EGUs.[11] In order to comply with MATS, SWEPCO installed the following controls[12]:

- Flint Creek – Activated carbon injection, dry flue gas desulfurization ("FGD") with integrated baghouse
- Pirkey – Activated carbon injection, calcium bromide
- Welsh 1 and 3 – Activated carbon injection, baghouse
- Dolet Hills – Activated carbon injection, baghouse, dry sorbent injection

Finally, the Regional Haze Rule protects visibility in all areas designated Class I, defined as national parks and wilderness areas that Congress has recognized as significant sites, through the development of a State Implementation Plan ("SIP") or, in certain cases, a Federal Implementation Plan ("FIP") that reduces emissions

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[9] *See generally* 76 Fed. Reg. 48,208, 48,388, 48,414, 48,466 (Aug. 8, 2011).

[10] Direct Testimony of John C. Hendricks at 8:4-9.

[11] 77 Fed. Reg. 9,340 (Feb. 16, 2012).

[12] Direct Testimony of John C. Hendricks at 12: Tbl. 1.

of pollutants that impair visibility. Certain eligible facilities have emissions obligations under this rule, including Flint Creek and Welsh Unit 1.

Q. How are impending environmental regulations important to the case at hand?

A In the 2011-2013 timeframe, there were a suite of other final and proposed EPA regulations, including the MATS and CSAPR rules, that would require coal-burning power plants to install pollution controls or reduce carbon emission.[13] The environmental retrofits at issue in this case are required for compliance with the MATS rule, one of multiple rules expected in the next few years. Just as the MATS rule imposes costs on the existing coal fleet, as made apparent by the retrofits at issue in this docket, other pending rules were also expected to have moderate to significant impacts on the costs of operating and owning coal units.

In evaluating whether to retrofit its coal units, SWEPCO largely ignored the costs of compliance with proposed and pending environmental regulations, effectively assigning them a zero cost. In the current case, the Company does not even address, much less examine the risks of these additional compliance obligations, which, at the time SWEPCO made its decision to install the retrofits, were likely (and remain likely to) impose significant costs on the Company's solid-fuel assets. The Company's MATS controls are unlikely to ensure compliance with additional regulations and unlikely to mitigate most of these future costs. Ignoring these pending and final environmental regulations was simply imprudent: in doing so, the Company both vastly biases its economic analysis and effectively shifts the risk of environmental compliance costs onto the shoulders of its ratepayers.

[13] A proposed rule from the EPA is a draft version of the rule made available for public comment, and is usually a strong indicator that a final rule with similar provisions will follow.

Q. Were there additional proposed environmental regulations in 2011-2013 that may have impacted the SWEPCO Units?

A. Yes. There were a number of other pending rules that were expected to have moderate to significant impacts on the costs of owning and operating coal units. These included: the Coal Combustion Residuals ("CCR") Rule, the Cooling Water Intake Rule, the Effluent Limitations Guidelines ("ELGs"), and revisions to the National Ambient Air Quality Standards ("NAAQS").

Q. Please briefly describe the purpose and impact of the proposed CCR Rule.

A. The CCR Rule governed the disposal of ash and flue gas desulphurization wastes. Coal-fired power plants generate an enormous amount of ash and other residual wastes, commonly placed in dry landfills or slurry impoundments with varying regulations on leakage from these installations. EPA considered two classifications of CCR: (1) under Subtitle C as hazardous waste, requiring siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any correction actions required; or (2) under Subtitle D as solid waste, requiring minimum siting and construction standards for new coal ash ponds, installation of liners on unlined impoundments, and standards for long-term stability and closure care. Proposed in June 2010, and finalized in December 2014, this rule became effective in October 2015.[14]

Q. Please briefly describe the purpose and impact of the proposed Cooling Water Intake Rule.

A. The proposed Cooling Water Intake Rule, designed to reduce impingement and entrainment of aquatic organisms from cooling water intake structures and new and existing electric generating facilities. Proposed in April 2011 and finalized in August 2014, this rule became effective in October 2014.[15]

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[14] 80 Fed. Reg. 21,302 (Apr. 17, 2015).

[15] 79 Fed. Reg. 48,299 (Aug. 15, 2014).

Q. Please briefly describe the purpose and impact of the ELGs.

A. The proposed ELGs are standards for what large industrial sources of water pollution can discharge into nearby waters. EPA issued its *Steam Electric Power Generating Point Source Category: Final Detailed Study Report* in 2009, which reviewed discharges from the electric power industry to determine whether the existing effluent guidelines should be revised. Under the federal Clean Water Act, EPA's final rule was required to make reasonable progress toward the national goal of eliminating toxic water pollution, so utilities knew that the standard would require pollution reductions. Pursuant to a federally enforceable consent decree EPA proposed the ELGs in June 2013; the final rule was due in in 2015, and the Clean Water Act requires compliance within three years of promulgation.[16]

Q. Please briefly describe the purpose and impact of the updates to the NAAQS.

A. Updates to the NAAQS, which are required under the federal Clean Air Act every five years, set maximum air quality limitations for six pollutants that must be met at all locations across the United States. Areas in "nonattainment" for any of the NAAQS are required to set enforceable limits to reduce emissions from sources contributing to that nonattainment.

- In 2010, EPA updated the sulfur dioxide NAAQS, ratcheting down the standard to adequately protect the public against adverse respiratory effects associated with short term exposure.[17] Due both to its shorter averaging time (*i.e.*, 1-hour versus 24-hour) and significantly lower allowable concentration (75 versus 140 parts per billion), the new standard is considerably more stringent than the prior SO_2 NAAQS and would require significant reductions from existing sources. Under the Clean Air Act if an existing source is found to be causing or contributing to nonattainment with the NAAQS, that source is

[16] 80 Fed. Reg. 67,838 (Nov. 3, 2015).

[17] 75 Fed. Reg. 35,520 (June 22, 2010).

- required to install and operate "reasonably available control technology,"[18] which in the context of SO_2 emissions is likely require to a scrubber.
- Similarly, in 2011, EPA was also planning to update and increase the stringency of the ozone NAAQS, which protects against ground-level smog that can cause serious respiratory problems. As with other NAAQS, a source that causes or contributes to ozone nonattainment, must install and operate "reasonably available control technology," which in the context of ozone emissions is likely to mean selective catalytic reduction ("SCR") technology.

Once again, a timeline of these regulations showing the dates of the proposed and final rules, and well as the compliance periods, is included as Exhibit RSW-2 hereto.

Q. Were there other changes to the electric sector underway or reasonably foreseeable at that time, and which were or should have been significant to SWEPCO's analysis?

A. Natural gas prices fell steeply during 2011 through 2013, such that an increasing numbers of coal-fired power plants across the country became uneconomic to operate. Prices had hovered around $4-$5/MMbtu from 2010 to mid-2011[19] and then declined steadily through for the remainder of the year, bottoming out below $2/MMbtu in early 2012. This gas price decline also caused a reduction in wholesale prices for electricity.

As natural gas prices were declining in real time, so too were forecasts of future natural gas prices. Between December 2010 and April 2013, the Energy Information Administration ("EIA") released five versions of its Annual Energy

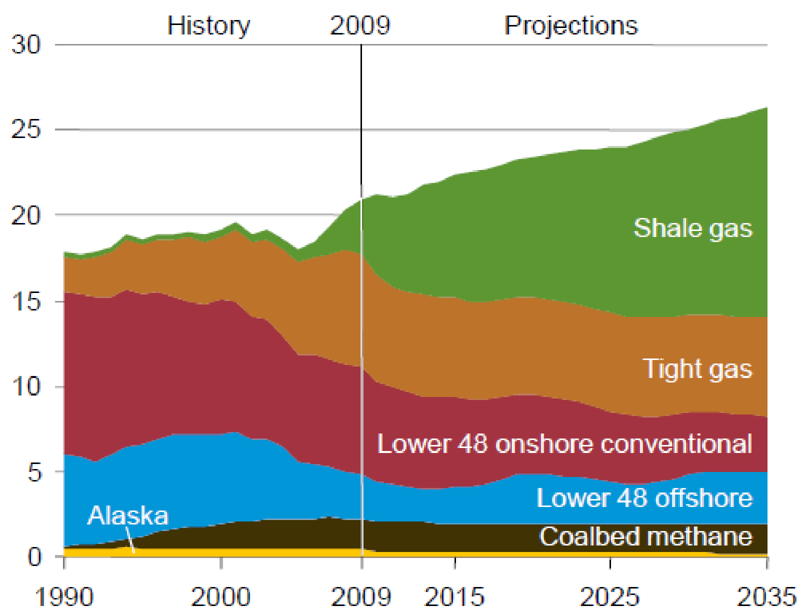
[18] *See, e.g.*, 42 U.S.C. §§ 7502(c)(1); 7410(a)(2)(A); 7410(a)(D)(i)(I).

[19] U.S. Department of Energy, Energy Information Administration (EIA), Henry Hub Prices, available at <http://www.eia.gov/dnav/ng/hist/rngwhhdW.htm>.

Outlook ("AEO"), and each release showed a decrease in the forecast of natural gas prices from the previous year's forecast.

Not only did natural gas prices fall during this time, but the long-term outlook for gas prices fell dramatically. Shale gas was expected to transform the natural gas industry as new gas extraction techniques started to become commonplace. Forecasts predicted that natural gas prices, and thus energy prices, would remain suppressed for years to come. Figure 1, below, shows the EIA's forecast of expected natural gas production through 2035, and the portion of that gas that would come from shale.

Figure 1. U.S. natural gas production, 1990-2035 (trillion cubic feet per year)



Source: EIA AEO 2011

The Southwest Power Pool's ("SPP") *2011 State of the Market Report* noted the acceleration of shale gas development in 2011 that led to natural gas prices below \$2.45/MMBtu in March 2012, "with expectations of further decline. This vast new supply of proven reserves will have reaching implications for the electric utility industry in general and the SPP wholesale electric markets in particular."[20]

Q. Was there evidence in 2011-2013 that these conditions were influencing utility decisions about unit retrofits versus retirements?

A. Yes. Compliance with these regulations was thought to require significant investment in environmental control technologies. Owners and operators of coal-fired units had to analyze the costs associated with the installation of pollution control retrofits at their units compared to the cost of retiring and replacing the units with alternative generation options. During this period, utilities across the country were undertaking similar retrofit versus retirement evaluations to determine the best way to comply with environmental regulations. These energy sector changes would have had a similar effect on their analyses. There is evidence that the number of announced retirements increases in the United States from the beginning of 2011 through 2013, as shown in Table 1. AEP itself recognized this risk in 2011 when it announced that it would retire Welsh 2.[21] The Company also responded to changing market conditions when it decided to retire two additional units in 2013, announcing the retirement of Muskingum River Unit 5 (585 MW) in Beverly, Ohio, on July 11, 2013,[22] and the retirement of Tanners Creek Unit 4 (500 MW) in Lawrenceburg, Indiana, on September 17, 2013.[23]

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[20] SPP Marking Monitoring Unit, *2011 State of the Market* (July 9, 2012), p. 95, *available at* <https://www.spp.org/documents/17582/2011-state-of-the-market-report.pdf>.

[21] Direct Testimony of Venita McCellon-Allen at Exhibit VMA-2.

[22] Press release, American Electric Power, *AEP Expects to Retire 585-Megawatt Coal-Fueled Unit in Ohio* (July 11, 2013), < https://www.aep.com/newsroom/newsreleases/default.aspx?id=1820>.

[23] Press release, American Electric Power, *AEP to Retire Entire Tanners Creek Plant in Indiana* (Sept. 17, 2013), <https://www.aep.com/newsroom/newsreleases/default.aspx?id=1834>.

Table 1. Announced coal retirements in the United States

EIA 860 Original Release Date	Jan 2011	Nov 2011	Sept 2012	Dec 2013
Planned coal retirements in the U.S. (GW)	5.1	12.4	30.1	32.4

Source: EIA 860

State commissions have disallowed portions of the capital costs of the installed retrofits for utilities that failed to do a proper analysis of the economics of its affected coal units or failed to update their analysis as market conditions changed, such as in the examples of Pacific Power and Indianapolis Power & Light that I discuss below in Section 6.

Q. In 2011-2013, how would a reasonable utility have engaged in prudent resource planning, given the uncertainties around environmental regulations and commodity prices?

A. A reasonable utility, utilizing best practices in resource planning, would have done several things to create a robust analysis that evaluates the prudence of retrofitting its coal-fired units with emission controls. The company would:

- **Create a unit-by-unit analysis that compares the costs of installing environmental controls at a single affected unit to the costs of the alternative possibility of retiring and replacing that unit with new or other existing capacity:** A utility acting prudently would evaluate the ongoing capital and operating costs of its system under a scenario that installs the necessary emission control retrofit technologies at its existing units, and compare that to a scenario that values the same costs in a scenario that retires one or more existing units and replaces them with new or purchased capacity and energy.

- **Use up-to-date commodity price forecasts**: Best practices dictate that a prudent utility use the most up-to-date commodity price forecasts. Natural gas price forecasts, and thus also market energy prices, were changing rapidly during the 2011-2013 timeframe, and the use of a forecast that was six or more months out of date would have had a significant effect on the results of a resource planning analysis. Utilities should also include any forecast prices associated with emissions allowances. In 2011-2013, the regulation of CO2 should have been anticipated by a reasonable and prudent utility, and inclusion of a CO_2 cost in a company's Reference Case assumptions would appropriately monetize that risk in a resource planning analysis.

- **Include control costs for all pending environmental rules**: In analyzing environmental regulations and associated control technologies, a prudent utility would include in its analysis the costs related to all proposed or even reasonably anticipated rules. It is simply insufficient to include only the costs necessary for compliance with rules that have been formally finalized. Even if exact costs cannot yet be known, for a utility to include a cost of zero implies that it believes that there will be no rule or that the costs will be zero. It is necessary that a utility include its best estimate of the cost to comply with proposed rules in a resource planning analysis.

- **Make reasonable assumptions about replacement capacity**: Replacement capacity should be equally sized to the retiring unit. It need not be limited to a single unit, or even unit type, but rather could include a combination of natural-gas fired generating units, renewable generating units, and market purchases of capacity and energy. A prudent utility would look at more than one option for replacement, which should include: replacement with new natural gas combined-cycle ("NGCC") capacity, repowering with natural gas, replacement with market purchases, and replacement with renewable energy, and an optimized portfolio replacement which would include both renewable and natural gas-fired capacity.

Q. Did SWEPCO apply these best practices for resource planning you have listed or conduct a robust prudence analysis as you have described?

A. No. As further discussed below, SWEPCO did not conduct a robust analysis or properly evaluate the prudence of retrofitting its coal fired units.

4. DESCRIPTION OF SWEPCO'S ANALYSIS OF ENVIRONMENTAL RETROFITS

Q. What was the basis for SWEPCO's decision to proceed with the installation of environmental retrofits at Pirkey, Flint Creek, Welsh Units 1 and 3, and Dolet Hills?

A. SWEPCO performed a series of what it calls "unit disposition analyses" in January 2011 through May 2011 (hereinafter the "Early 2011 Analyses") that provided the basis for its decision to install environmental retrofits at Pirkey, Flint Creek, and Welsh 1 and 3. The Company used a capacity optimization model called Strategist to perform these analyses. This type of model is designed to compare several resource options and determine the least-cost portfolio of resources to meet capacity and energy needs over time.

Q. How did SWEPCO use the Strategist model to perform the Early 2011 Analyses?

A. For each set of disposition analyses, SWEPCO created two resource portfolios: one that installed emission control retrofits at the unit (or two units, in the case of Welsh 1 and 3) being analyzed;[24] and another that retired the unit and replaced it with new NGCC capacity.[25]

[24] Note that the emission controls evaluated in the Early 2011 Analyses were not limited to those controls that were ultimately installed at the units for which SWEPCO is requesting cost recovery. At Flint Creek, for example, the controls evaluated and included in the cost estimate included SCR and Low NOx burners, which were not part of the suite of controls selected for MATS compliance.

[25] Direct Testimony of Mark A. Becker at 4:1-8.

For each resource portfolio, the Strategist model used its simplified dispatch methodology[26] to calculate the energy production costs of the system between 2011 and 2040, and added those costs to the capital expenditures in that particular portfolio. This stream of values was discounted back to 2011 dollars to arrive at a value called the Cumulative Present Worth of annual revenue requirements ("CPWRR"). The values for the "Retrofit" and "Retirement" portfolios were compared, with the difference representing the savings, or cost, of installing emission control equipment over retiring and replacing the unit being evaluated.

SWEPCO performed this analysis for Pirkey, Flint Creek, and the combined Welsh units 1 and 3 under a Reference commodity price scenario, a Low Band commodity price scenario, and several other scenarios that varied the price on carbon dioxide ("CO_2").[27]

Q. What were the outcomes of the Early 2011 Analyses?

A. The Early 2011 Analyses favored installation of environmental retrofits.[28]

Q. Did SWEPCO continue to evaluate the economics of retrofitting versus retiring the units after this set of Early 2011 Analyses?

A. Yes. SWEPCO performed the analysis again at points in 2012 and 2013 using the Strategist model, and in 2014 and 2015 using the PLEXOS model.[29]

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[26] Production cost models produce dispatch results at an hourly or sub-hourly temporal resolution. Strategist does not have this capability, and instead uses a "typical week" temporal resolution, performing unit dispatch over a single 168-hour week in each month, and extrapolating those results for the remainder of that month.

[27] Direct Testimony of Mark A. Becker at Exhibit MAB-2.

[28] Direct Testimony of Mark A. Becker at 15: Tbl. 6, 18: Tbl. 9, 21: Tbl. 12.

[29] Direct Testimony of Mark A. Becker at 5:24-25, 6:1-12.

Q. How does the PLEXOS model differ from the Strategist model?

A. PLEXOS was created as production cost model (it has since added capacity expansion capability) and simulates more detailed (hourly and sub-hourly) operation of the electric system.

5. ANALYSIS OF THE PRUDENCE OF SWEPCO'S INVESTMENTS IN ENVIROMENTAL CONTROL RETROFITS

Q. Do you believe that SWEPCO's Early 2011 Analyses can be considered an example of prudent resource planning under the criteria you described above?

A. No, I do not—for several reasons.

First, SWEPCO's Early 2011 Analyses are not examples of the type of robust analysis that I reference in Section 3, above, and do not support the investments for which SWEPCO is seeking rate recovery in this docket. At best, they can be considered "screening analyses" designed to inform the Company about potential impacts of different control technologies, but should not form the basis for a decision whether to retrofit or retire an individual unit.

The MATS Rule was not proposed until March 2011, and thus three of SWEPCO's five sets of analyses that make up the Early 2011 Analyses were already completed or in progress before the proposed rule had even been issued. The four analyses performed from January to April of 2011 evaluated the costs of a range of different environmental controls that could lead to the required emissions reductions, but each of those technologies perplexingly had a different cost depending on the month in which the analysis was performed. Further, the four analyses inaccurately assumed that certain environmental controls necessary for MATS compliance are not installed until 2019 or 2020—well beyond the MATS compliance deadline. The only analysis in the set of 2011 Early Analyses that examines a set of controls that resembles those that SWEPCO ultimately decided to install, in the timeframe that would allow for compliance with the

MATS rule, is the May 2011 analysis. However, that analysis also does not support the installation of the environmental controls due to the presence of errors that I describe below.

Second, I believe that there were significant errors in SWEPCO's Early 2011 Analyses that, had they been corrected, would have changed the outcomes for certain units. Specifically, SWEPCO used a natural gas price forecast that was outdated and thus too high, and assumed an incorrect correlation between coal and natural gas prices under its Reference Case and Low Band sensitivity.

Third, the Company failed to account for costs associated with environmental rules beyond MATS, CSAPR, and the CCR Rule.

Fourth, the replacement capacity considered by SWEPCO in its analysis was unnecessarily restricted to new NGCC units.

Finally, with respect to Dolet Hills, SWEPCO's apparent lack of independent review and verification of the analysis done by Cleco was imprudent. I will discuss that further at the end of this section.

I. <u>Welsh Units 1 and 3</u>

Q. Which of the environmental rules described in Section 3 led to SWEPCO emission investments at Welsh Units 1 and 3?

A. Both Welsh units were subject to the CSAPR and MATS rules. Welsh Unit 1 is also a BART-eligible unit under the Clean Air Act's Regional Haze program, and therefore will require "best available retrofit technology" to reduce visibility-impairing emissions.[30]

[30] 42 U.S.C. § 7491(b)(2)(A); 40 C.F.R. § 51.308(e).

Q. Which emission controls did SWEPCO install at Welsh 1 and 3 to bring the units into compliance with these rules?

A. SWEPCO installed ACI and baghouse technologies at the units in order to comply with MATS, at a cost of $388.4 million. In his Direct Testimony, Mr. John C. Hendricks stated that SWEPCO Units comply with CSAPR through their allowance allocations, or through the purchase of additional allowances from the market, if necessary.[31] SWEPCO did not install any emission control equipment specifically for Regional Haze compliance.

Q. What were the errors contained in SWEPCO's analysis of the costs impacts of the environmental retrofits at Welsh 1 and 3?

A. SWEPCO made several material errors in its analysis of the Welsh 1 and 3 retrofits that significantly impact the modeled outcomes. The Company should have:

- Utilized contemporary natural gas price forecasts in its analyses;
- Included costs to comply with all anticipated environmental regulations;
- Separately evaluated the economics of the retrofits or retirement at Welsh Units 1 and 3;
- Evaluated additional options beyond only new natural gas combined-cycle generating units for replacement of Welsh 1 and 3.

I describe these criticisms in more detail below.

[31] Direct Testimony of John C. Hendricks at 8:5-7.

Q. Please describe your concerns with respect to the natural gas price forecast used in the analyses conducted by the Company in support of the retrofits at Welsh 1 & 3?

A. The Company's analysis supporting the decision to retrofit prior to construction was based on an outdated Fundamentals Forecast, with gas prices that appear to be about three years old at the time that the decision to proceed was made.

While the Company announced its intent to pursue retrofits at Welsh 1 and 3 in June 2011, construction did not actually begin until February 2014.[32] During that period, U.S. energy prices and markets changed substantially. Beginning in late 2011 and into 2012, the rapid expansion of shale gas extraction drove down natural gas prices, and the futures expectations for those prices, resulting in the low prices of the last five years. Those substantially lower prices changed the outlook for solid-fuel boilers around the country, and are largely responsible for many of the retirements seen to date. In the midst of this substantial change, the Company appears to have inexplicably maintained an outdated set of fuel price forecasts for the purposes of evaluating Welsh 1 and 3.

Q. The Company produced a series of economic assessments between 2011 and 2015—why isn't it reasonable to rely on those assessments?

A. Those assessments appear to have *all* relied on outdated fuel price forecasts, at least with respect to natural gas prices. And those natural gas prices are extremely high relative to conditions by the time the Company committed financial resources to the retrofits. OPUC asked that the Company "provide copies of the commodity price forecasts…that SWEPCO has used to analyze power purchase and plant investment decisions from 2011 to the present,"[33] a period of six years in which commodity prices have undergone substantial shifts. The Company's response to OPUC (see Exhibit RSW-3 attached hereto) was to refer to Exhibit

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[32] Direct Testimony of Franklin R. Pifer at 31:15.

[33] SWEPCO Response to OPUC RFI 1-11 (Mar. 2, 2017)—attached hereto as Exhibit RSW-3.

MAB-2 for a summary of the commodity prices used between January and May 2011, and the provision of a *single set of forecasts* for the "commodity price forecasts used in Spring 2012, Fall 2012, Summer 2013, Summer 2014, and Summer 2015."[34] That a single forecast, developed between May 2011 and Spring 2012 would be relied upon for analyses three years later, in Summer 2015, is staggering.

Q. What is the magnitude of the gas price difference from SWEPCO's forecasts to the date upon which SWEPCO authorized the retrofits at Welsh?

A. From the early 2011 forecasts provided in Exhibit MAB-2 and the Company's response to OPUC RFI 1-11 to February 2014 is a substantial drop in expected gas prices, particularly during the first ten to fifteen years of the analysis. One useful point of comparison is the EIA's AEO, a critically reviewed and widely used public forecast of the U.S. energy sector. The EIA produces AEO forecasts on an annual basis, with occasional mid-year updates and case studies. The most reliable contemporaneous AEO prior to the February 2014 commencement of construction at Welsh would have been AEO 2013, produced in April 2013.

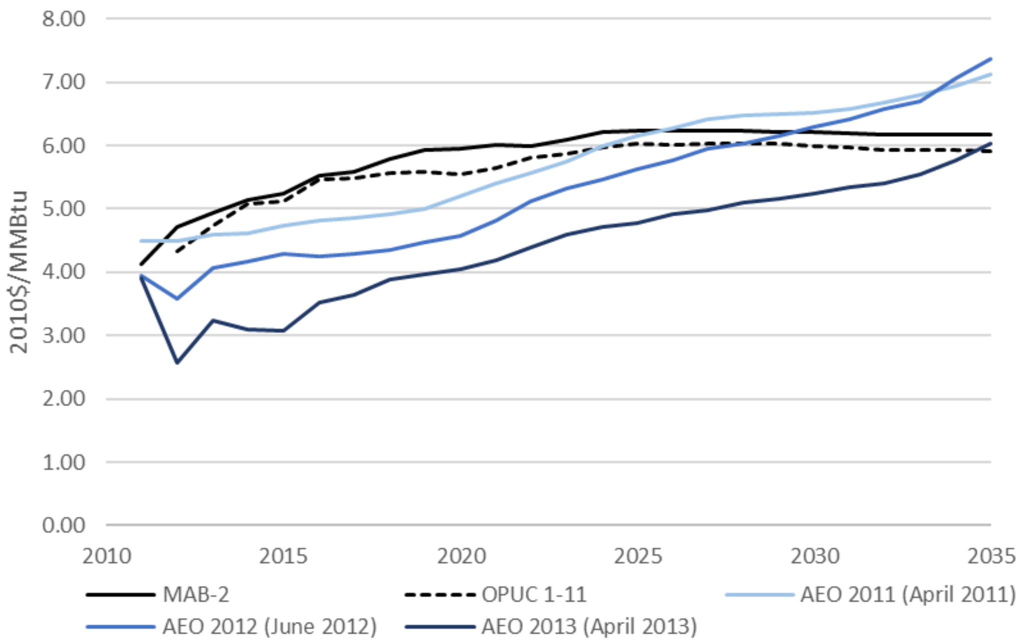
By the time AEO 2013 was released, gas prices in that year were already \$1.50/MMBtu (2010\$) below the outdated forecast being used by SWEPCO. Looking forward, SWEPCO was forecasting gas prices well over 150 percent higher, or up to \$2.0/MMBtu more, than AEO 2013.

Figure 2, below, shows the magnitude of the difference between SWEPCO's gas prices as used and relied upon, and the three AEO forecasts that post-dated SWEPCO's fundamentals forecast but still preceded the decision to retrofit Welsh. By the time we reach the AEO 2013 forecast, it is well below SWEPCO's forecast in every year but 2040. In the key period from 2015 to 2025—after a

[34] SWEPCO Response to OPUC RFI 1-11. (Mar. 2, 2017).

retirement would have been effectuated and highly impactful on net present values – SWEPCO's forecast averages 140 percent, or $1.57/MMBtu (2010$) above AEO 2013.

Figure 2. Natural gas prices (Henry Hub) from SWEPCO 2011 analyses ("MAB-2") and 2012-2015 analyses ("OPUC 1-11") compared against AEO 2011, 2012, and 2013. Inflation adjusted to 2010$/MMBtu.



Q. **How would the use of a more contemporary forecast for natural gas prices have impacted the Company's assessment of the retrofits at Welsh?**

A. Almost without a doubt the lower gas prices would have cut substantially into the expected margins of the retrofit project. These lower gas prices would have reduced electricity system market prices as well as the cost of replacement power and/or any alternatives reviewed by SWEPCO. Given the relatively low benefit for these relatively large steam units and my experience in other similar dockets, I would expect that these changes would have negated any benefit and likely have shown a net liability in maintaining the Welsh units.

Q. Is it reasonable to expect that SWEPCO should have updated their fundamentals forecast used for their Welsh decision sometime between May 2011 and February 2014?

A. Absolutely. The Fundamentals Forecast is produced by AEP Power Service Corporation ("AEPSC") and provided to AEP affiliates. Since 2005, AEPSC has created a Fundamentals Forecast approximately every 18 months, in 2007, 2008, 2009, 2010, 2012, 2013, 2015, and at the end of 2016. The notion that SWEPCO would not have had access to relatively up-to-date information from AEPSC, or could not have requested data validation, updates or quality control from AEPSC, strikes me as extremely unlikely. Irrespective of whether AEPSC had provided a new Fundamentals Forecast to SWEPCO, Mr. Becker and his team still had a responsibility to assess their decision with the best possible information available. Data that is two to three years out of date is not the best information available.

Q. Were there any other errors with respect to commodity prices that are present in SWEPCO's analyses, and how they might affect those analyses?

A. Yes, there were additional flaws that affected those analyses. SWEPCO's Reference and Low Band forecasts assume that natural gas prices are correlated with coal prices, and when natural gas prices decline from the Reference to the Low Band, so too do coal prices. While this may have been true several decades ago, it was not the case at the time the Company was making its retrofit decisions.

The gross margin (on a $/MWh basis) that could be earned by a coal-fired unit relative to market prices is called the "dark spread." The "spark spread" refers to the gross margin for a gas-fired unit. The difference between the dark and the spark spreads simply indicates which units dispatched preferentially, and can be calculated as the difference between the variable cost of a natural gas-fired unit and a coal-fired unit. Prior to 2011, coal units dispatched before natural gas units due largely to lower fuel costs.

In 2012, the average gas-fired combined cycle unit was less expensive than the average coal-fired unit by $3.06/MWh, causing gas units to be dispatched before coal units and inverting the traditional dark/spark spread.[35] This inversion of the dark/spark spread occurred because prices for coal during this time had become more expensive than prices for natural gas, in contrast to SWEPCO's assumption of correlation between the two price forecasts.

This assumption about correlation between coal and natural gas prices means that coal-fired units will always earn a higher gross margin than natural-gas fired units, no matter how much prices for gas decline, skewing the analysis in favor of installing the retrofits at existing coal-fired units.

Q. Do SWEPCO's analyses include costs for environmental controls associated with all the EPA regulations that should have been anticipated at that time?

A. No. The Company included costs for compliance with the MATS Rule, CSAPR, Regional Haze, and the CCR Rule, but it did not include compliance costs for any of the other rules that I discussed in Section 3 of my testimony.[36]

Q Is ignoring the impact of impending rules a valid method of treatment?

A No. In fact, ignoring the economic impact of these impending regulations ascribes a value to them of exactly zero dollars—that is, the Company effectively calculated that there would be no cost at all to comply with any of these regulations. By ignoring the rules, the Company decisively shifted the risk of future costs onto ratepayers.

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[35] This is based on a national average heat rate of 10.15 MMBtu/MWh (coal) and 7.97 MMBtu/MWh (gas) (from EPA Clean Air Markets Division, Air Markets Program Data 2012); annual average fuel prices of $2.38/MMBtu (coal) and $2.75 (gas) (from DOE Energy Information Administration Short Term Energy Outlook historic prices for 2012); and variable O&M costs of $4.25/MWh (coal) and $3.43/MWh (gas) (from Annual Energy Outlook, 2012).

[36] SWEPCO Response to Sierra Club RFI 1-13 (Mar. 20, 2017).

Q. Do you have reason to believe that costs to comply with additional rules could be significant?

A. Yes. For example, the Regional Haze Rule requires states (or EPA, where the state fails to do so) to impose "best available retrofit technology" ("BART") controls for fossil fuel-fired power plants and other major stationary sources that "may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area," and were in existence in 1977, but were not in operation before 1962.[37] When SWEPCO decided on the MATS retrofits, the Company knew or should have known that Welsh Unit 1 would be subject to BART—meaning that the Company could be required to install an emission limitation based on the degree of reduction achievable through the application of the *best* system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility."[38] For coal plants, numerous regional haze plans have concluded that controls such as "scrubbers" for SO_2 emissions or even selective catalytic reduction for NOx emissions are required to meet BART.

Indeed, on January 4, 2017, after Texas failed to submit an approvable regional haze plan, the EPA proposed an emissions obligation at Welsh 1 for SO_2 of 0.04 lb/MMBtu under the Texas Regional Haze FIP, which is based on the installation of a wet FGD.[39] SWEPCO did include a dry FGD in its certain of its analyses; however, the cost to install wet FGD at Welsh 1 is estimated to be $290 million (in 2015 $), while the cost to install dry FGD is estimated to be $264 million.[40] On a levelized basis (taking into account construction costs, the capital carrying

[37] 42 U.S.C. § 7491(b)(2)(A); 40 C.F.R. § 51.308(e).

[38] 40 C.F.R. § 51.301 (emphasis added).

[39] SWEPCO Response to TIEC RFI 8-14 (Mar. 20, 2017); see also 82 Fed. Reg. 912 (proposed Jan. 4, 2017).

[40] Synapse Energy Economics, Inc., Coal Asset Valuation Tool (CAVT) Version 6.0, available at <www.synapse-energy.com>.

cost, and O&M), wet FGD is approximately 8% more expensive than dry FGD for this unit.[41] In its May 2011 analysis, SWEPCO modeled its dry FGD as coming online in 2026.[42] The wet FGD would be required to be operational in 2022. The earlier online date and increased cost of a wet FGD would erode SWEPCO's modeled CPWRR benefits of the retrofit technologies. Costs associated with other regulations, described in Section 3, could put SWEPCO's coal units at a further disadvantage.

Q Were there additional environmental regulations that were known at the time that could affect the Welsh units?

A. Yes, the 8-hour ozone NAAQS presented significant environmental compliance risks to the Welsh units due to the cost of the controls that may be required to help meet compliance obligations.

Q Please briefly describe the 8-hour ozone NAAQS.

A In March 2008, EPA strengthened the 8-hour ozone standard from 84 to 75 parts per billion. The Dallas-Fort Worth area has been designated as being in nonattainment with the 2008 standard, and publicly available modeling show that the Welsh facility contributes to ozone nonattainment in the DFW area.[43] Separately, in 2015, EPA finalized a new NAAQS for ozone, significantly

[41] The calculation is based on data from EIA Form 860 and 923 (years 2013, 2014, and 2015) as well as cost calculations developed by Sargent and Lundy for EPA's IPM Model (version 5.13), specifically Appendix 5-1 and Appendix 5-2.

[42] SWEPCO Response to OPUC RFI 1-8, Attachment 33 (Mar. 2, 2017).

[43] Drs. Mahdi Ahmadi and Kuruvilla John, North Texas Ozone Attainment Initiative Project (Nov. 2015), available at <http://dfwozonestudy.org/>.

strengthening the standard to protect public health.[44] As with the 2008 standard, the DFW area will not attain the more stringent standard.[45]

If EPA or the state were to find that the Welsh plant caused or contributed to nonattainment in the DFW area, this could drive significant additional NOx emission reduction requirements. Specifically, it could require one or both Welsh units to install selective catalytic reduction technology ("SCRs") to comply with the ozone standard. I cannot estimate the costs of additional regulations with absolute certainty, but I can provide a range estimates for the capital and fixed O&M that might be incurred by each of the SWEPCO Units. Those proxy cost estimates are shown in Table 2.

Table 2. Additional environmental compliance capital costs for the SWEPCO Units (M$2015).[46]

Applicable Rule	Technology	Welsh 1	Welsh 3	Flint Creek	Pirkey
Regional Haze	Wet FGD	$290 (2022)			
	Low Nox Burners			$16-$39 (2018)	
Ozone NAAQS	SCR	$164 (2018-2020)	$164 (2018-2020)		
CCR	Coal waste mitigation	$50-$100 (2019)		$50-$100 (2019)	$50-$100 (2019)
ELG	Water treatment	$12-$60 (2018-2023)		$12-$60 (2018-2023)	$12-$60 (2018-2023)
Total		**$485-$534**	**$195-$244**	**$78-$199**	**$62-$160**

[44] 80 Fed. Reg. 65292 (Oct. 26, 2015).

[45] Texas Commission on Environmental Quality, 2015 Ozone NAAQS Designation for the State of Texas, Docket No. 2016-0399-SIP (July 15, 2016), <https://www.tceq.texas.gov/assets/public/comm_exec/agendas/comm/backup/Agendas/2016/08-03-2016/0399SIP.pdf>.

[46] Synapse Energy Economics, Inc., Coal Asset Valuation Tool (CAVT) Version 6.0, available at <www.synapse-energy.com>.

For plants with an installed wet FGD—Pirkey and likely Welsh 1—costs for CCR and ELG compliance would likely be at the higher end of this range.

Q. Why is important that Welsh 1 and 3 be evaluated separately?

A. Welsh 1 and 3 are different units, and it may be more economic to retrofit one than the other. Evaluating them together obscures this possibility. Welsh 1 is a BART-eligible unit under the Regional Haze Rule, for example, and would require additional controls in the form of a wet FGD under the proposed emissions limitation for SO_2 at Welsh 1 of 0.04 lb/MMBtu under the Texas Regional Haze FIP.[47] Welsh 3 has no such requirement.

Welsh 1 and 3 are 528 MW each, and retiring them together would lead to a capacity loss for SWEPCO of 1,056 MW. This is costlier for the Company than retiring a single 528 MW unit because it would require them to build or acquire more replacement capacity to meet the SPP reserve margin.

In his Direct Testimony, Mr. Mark A. Becker does not present any results from any analysis of the retirement of Welsh 1 and 3 on an individual basis; however, SWEPCO did examine this scenario in Spring 2012. Under the Low Band scenario, the workpapers presented in response to OPUC 1-8 show a reduction in the costs associated with retirement when Welsh 1 is retired and Welsh 3 continues to operate.[48] Those results are shown in Table 3, below. In the May 2011 analysis, when both Units were retired, SWEPCO found a cost over retrofits of $522 million. In Spring 2012, using a new gas price forecast, (though still not one that adequately reflected the changing outlook for natural gas) the cost of retirement for both units when compared to retrofits dropped to $365 million. When Welsh 1 was retired and Welsh 3 was retrofit, the cost of retirement

[47] Direct Testimony of John C. Hendricks at 10: 6-9.

[48] SWEPCO Response to OPUC RFI 1-8, Attachment 134. (Mar. 2, 2017)

dropped again, to $198 million. There is clearly a net benefit to evaluating the units separately.

Table 3. Cost of retirement over retrofit, Low Band Scenario, Welsh 1 and 3 (2011-2040 CPWRR $Million)

Analysis Date	Cost of Retirement ($M)
May 2011 - Welsh 1 and 3 retire	($522)
Spring 2012 - Welsh 1 and 3 retire	($365)
Spring 2012 - Welsh 1 retires, Welsh 3 retrofits	($198)

Under an updated, contemporary natural gas price forecast like the one described above, the $198 million in retirement cost for Welsh would likely have been eliminated, and SWEPCO's analysis instead would have shown a net benefit to retirement. Additionally, applying reasonable, non-zero compliance cost assumptions for the pending and imminent environmental regulations identified in Table 2, could have also eliminated the benefit of the MATS retrofits at the Welsh units, and could have demonstrated a net loss relative to retirement.

Q. Did SWEPCO consider appropriate options for replacement capacity in the cases that evaluate the retirement of Welsh 1 and 3?

A. No. In the cases in which Welsh 1 and 3 were retired, SWEPCO replaced those units with new 385 MW combined-cycle generating units.[49] This is an appropriate replacement option, but it is just one of the appropriate replacement options that should have been considered by SWEPCO. New fossil-fueled replacement capacity is likely to be the most expensive replacement option, and restricting the types of available resource alternatives to new natural gas-fired resources is unreasonable.

[49]Direct Testimony of Mark A. Becker at 12:16-17.

SWEPCO should have, at a minimum, also modeled a "Market Purchase" replacement option, where the Company purchases needed capacity and energy on the market. SPP's 2011 *State of the Market* report stated that the region's reserve margin in 2011 was just over 24 percent,[50] which is well above the required 12 percent. In 2012, the reserve margin had increased to 36 percent,[51] and increased again in 2013 to 47 percent.[52] Given the amount of excess capacity in the region, a replacement option that evaluated market purchases may have been more economic than replacement with new NGCC capacity.

The Company should have also examined replacement with a set of renewable resources, combined with natural gas generation or with market purchases, as necessary. Prices for renewable energy have fallen significantly in the previous decade, and while wind or solar may not be able to replace a coal-fired generating unit on a per MW basis at a reasonable cost, the combination of renewables with smaller amounts of gas-fired resources would provide enough energy and capacity to meet customer demand, perhaps at a reduced cost.

Finally, SWEPCO may have also been able to purchase an existing unit as replacement capacity for one or both of Welsh Units 1 and 3. SWEPCO's Response to OPUC RFI 3-14 details the number of generating units available for purchase during the time period in question, any one of which might have provided replacement capacity at a lower cost. These options should have been evaluated in SWEPCO's analysis.

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[50] SPP Marking Monitoring Unit, *2011 State of the Market* (July 9, 2012), p. 9 <https://www.spp.org/documents/17582/2011-state-of-the-market-report.pdf>

[51] SPP Marking Monitoring Unit, *2012 State of the Market* (May 17, 2013), p. 8 <https://www.spp.org/documents/22328/2012%20state%20of%20the%20market%20report.pdf>

[52] SPP Marking Monitoring Unit, *2013 State of the Market* (May 19, 2014), p. 8 <https://www.spp.org/documents/22573/2013%20spp%20state%20of%20the%20market%20report.pdf>

II. Pirkey

Q. Which of the environmental rules described in Section 3 led to SWEPCO emission investments at Pirkey?

A. Pirkey was subject to the CSAPR and MATS rules.

Q. Which emission controls did SWEPCO install at Pirkey to bring the unit into compliance with these rules?

A. SWEPCO installed an ACI system, a calcium bromide injection system, and upgrades to the existing electrostatic precipitator in order to meet MATS requirements. SWEPCO's share of the capital cost of these controls is $37 million.

Q. What were the errors contained in SWEPCO's analysis of the costs impacts of the environmental retrofits at Pirkey?

A. SWEPCO made the same errors in its analysis of the Pirkey unit that it did in the analysis of the Welsh units: (1) the natural gas price forecast used in the retrofit/retirement analysis was two to three years out of date; (2) natural gas prices were improperly correlated with coal prices, so it was impossible to analyze a low natural gas price without also analyzing a low coal price; (3) costs to comply with environmental rules that were still in the proposed phase were not included; and (4) the only replacement option evaluated by SWEPCO was a new NGCC plant, not other options as well.

Q. How should SWEPCO have corrected these errors in its analysis?

A. SWEPCO should have done several things. First, the Company should have used a contemporaneous forecast of natural gas prices in its analyses between 2011 and 2015. Second, it should have forecast coal and natural gas prices independently. Third, it should have included costs to comply with environmental regulations that were still in the proposed phase, which I estimate are anywhere from an additional $62-$160 million. Finally, the Company should have evaluated a variety of capacity replacement options, instead of limiting its analysis to an NGCC replacement.

III. Flint Creek

Q. Which of the environmental rules described in Section 3 led to SWEPCO emission investments at Flint Creek?

A. Flint Creek was subject to the CSAPR and MATS rules, as well as Regional Haze regulation.

Q. Which emission controls did SWEPCO install at Flint Creek to bring the unit into compliance with these rules?

A. SWEPCO installed ACI and dry FGD systems at the unit in order to comply with MATS. The Company's share of the capital cost for these retrofits was $212.9 million.

Q. What were the errors contained in SWEPCO's analysis of the costs impacts of the environmental retrofits at Pirkey?

A. SWEPCO made some of the same errors in its analysis of the Flint Creek unit that it did in the analysis of the Welsh and Pirkey units: (1) the natural gas price forecast used in the retrofit/retirement analysis was two to three years out of date; (2) natural gas prices were improperly correlated with coal prices, so it was impossible to analyze a low natural gas price without also analyzing a low coal price; (3) costs to comply with environmental rules that were still in the proposed phase were not included; and (4) the only replacement options evaluated by SWEPCO were a new NGCC plant or gas conversion.[53]

Q. How should SWEPCO have corrected these errors in its analysis?

A. SWEPCO should have done several things. First, the Company should have used a contemporaneous forecast of natural gas prices in its analyses between 2011 and 2015. Second, it should have forecast coal and natural gas prices independently. Third, it should have included costs to comply with environmental regulations that were still in the proposed phase, which I estimate are anywhere from an

[53] Direct Testimony of Mark A. Becker at 16:19-22.

additional $62-$160 million.[54] Finally, the Company should have evaluated a variety of capacity replacement options, instead of limiting its analysis to an NGCC replacement or gas conversion.

Flint Creek showed the lowest net benefit of retrofits in Mr. Becker's analysis, with a net benefit of retrofit of only $15 million in the Low Band Scenario in the May 2011 analysis[55], and a net benefit of retrofit of $100 million in the Fall 2011 analysis[56]. These analyses relied on the natural gas price forecast found in Exhibit MAB-2, developed by AEP in 2010. Use of a 2011-vintage natural gas price forecast would have likely eroded these benefits, and favored retirement of the unit.

Q. Did another state utility commission review SWEPCO's analysis of the Flint Creek units?

A. Yes, the Arkansas Public Service Commission ("APSC") reviewed SWEPCO's application for a Declaratory Order in APSC Docket 12-008-U. The APSC granted that request.

Q. What is your understanding of the APSC's reason for granting that Order?

A. It is my understanding that the APSC's decision was driven largely by reliability concerns. In Phase One of that proceeding, "all non-applicant parties opposed the declaratory order requested by SWEPCO."[57] Of the non-applicants, the Attorney General believed that there was not enough information offered by SWEPCO to make a decision, intervenor Sierra Club asserted that SWEPCO had not demonstrated that retrofits were in the public interest, and Commission Staff

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[54] This does not include the costs associated with Low NOx burners necessary to comply with Regional Haze in 2018, which were included in SWEPCO's analysis.

[55] Direct Testimony of Mark A. Becker at 18: Tbl. 9.

[56] Direct Testimony of Mark A. Becker at 25: Tbl. 15.

[57] Direct Testimony of Venita McCellon-Allen, Exhibit VMA-3 at 13.

found that there were two options that represented a better outcome than installation of retrofits at Flint Creek.[58]

Following Phase Two of the proceeding and with consideration of additional evidence presented by SWEPCO witnesses, the Attorney General and Commission Staff changed their recommendation based largely on concerns regarding reliability, though they noted that reliability concerns would also exist if Flint Creek received retrofits, and that the time frame for MATS compliance constrained the viability of potential alternatives. Staff recommended that SWEPCO be directed to perform a study examining the solutions to the reliability issues that would still exist with the installation of retrofits at Flint Creek.

Q. How do these proceedings speak to the prudence of SWEPCO's analysis?

A. First, SWEPCO relied on the Fall 2011 analysis as the basis for its application filed with the APSC on February 8, 2012. Once again, SWEPCO relied on an analysis that was more than a year old, and was based on assumptions and forecast data that was more than two years old. Second, if reliability was truly a concern in this docket, SWEPCO's analysis should have monetized those impacts and included them in its analysis of the retrofits versus retirement, including any mitigation options that might have been considered in the case of unit retirement. SWEPCO's analysis was both out of date and incomplete from a risk perspective.

Q. Did the APSC's Declaratory Order satisfy SWEPCO's requirement for prudence with respect to the Flint Creek retrofits?

No. The granting of the Declaratory Order did not cause SWEPCO's prudence requirement to be met. Indeed, in most jurisdictions, utilities have a "continuing" prudence obligation, which requires them to reevaluate significant capital investments in response to changing circumstances. SWEPCO acted imprudently

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[58] Direct Testimony of Venita McCellon-Allen, Exhibit VMA-3 at 13.

by failing to conduct any such evaluation despite significant economic and industry changes in the nearly three years—from Fall 2011 to Summer 2014—that elapsed between their flawed analysis and the beginning of construction.

IV. <u>Dolet Hills</u>

Q. What was the basis for SWEPCO's decision to proceed with the installation of environmental retrofits at Dolet Hills?

A. With regard to Dolet Hills, uniquely, SWEPCO seemed to rely solely on the recommendation from Cleco, the co-owner and operator of the facility.

Q. Did SWEPCO conduct any of its own analysis on the economics of the Dolet Hills emission control retrofits?

A. I have not seen any independent analysis from SWEPCO on the economics of the Dolet Hills retrofits: as of the date of this testimony, I have discerned none in SWEPCO's application and supporting record in this docket, and the Company has indicated in responses to discovery requests that it either does not possess or will not provide any.

SWEPCO has stated that it was "well aware of the economic development benefits and customer fuel cost savings expected to result from its purchase of the Oxbow Mine" and that it was "legitimately and reasonably concerned that retirement of the plant could result in closing of or reduced operations at the mine."[59] The Oxbow Mine is a source of lignite for the Dolet Hills plant, and the Dolet Hills plant is the mine's only customer.

Q. Were you able to review Cleco's analysis of the Dolet Hills retrofits?

A. No. Sierra Club requested the analysis and underlying workpapers that were submitted by Cleco in the Louisiana docket, which SWEPCO did not put into the

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[59] SWEPCO Response to Sierra Club RFI 1-2.a.*x* (Mar. 20, 2017).

record in this docket for the Commission's consideration. The Company has declined, to date, to provide responsive documents.

I was able to review public versions of testimony on behalf of both Cleco and intervenors, and it is important to note that intervenors brought up a number of important issues in Cleco's analysis. Those include:

- Failure by Cleco to model a 1:1 capacity replacement. Cleco examined an NGCC unit replacement for Dolet Hills that was 52% larger than the retiring unit, resulting in excess capacity at a higher cost than was necessary, and biasing the analysis in favor of the retrofits.[60]
- Cleco's 2012 analysis did not include any costs to comply with any additional future environmental regulations, which I discuss below.
- The absence of a CO_2 allowance price in Cleco's 2012 Reference Case, as is standard AEP planning practice. In 2011 and beyond, AEP companies have been including a price on CO_2 emissions as part of their Reference Case in their resource planning documents, which include Integrated Resource Plans ("IRPs") and analyses of emission control investments. For example, in its application for preapproval of environmental controls at Big Sandy Unit 2 in Kentucky in 2011, Kentucky Power included a CO_2 price in its Base Band forecast.[61] AEP companies still assume a price on CO_2, as seen in the most recent application in Indiana for preapproval of an SCR at Rockport Unit 2 by

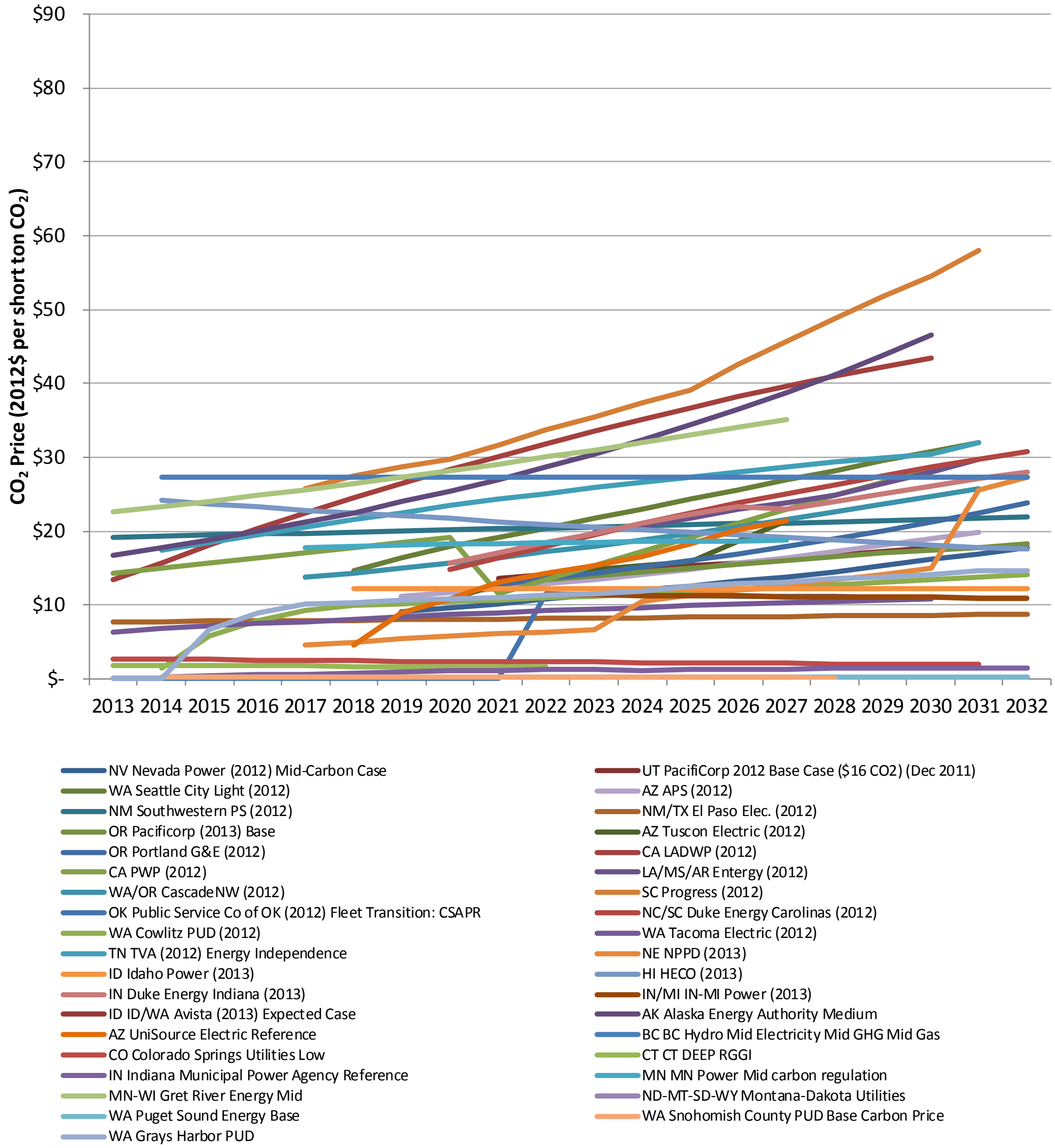
[60] Louisiana Public Service Commission. *Application of Cleco Power LLC For: (I) Authorization To Install Emissions Control Equipment, et al.*, Docket No. U-32507. Direct Testimony of Jeremy I. Fisher, at 16:18-25 (Nov. 8, 2013), available at <http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=00350e6e-78ac-473a-b11e-268c66157bfd> ("Fisher Testimony").

[61] Kentucky Public Service Commission, *In the Matter of Application of Kentucky Power Company for Approval of its 2011 Environmental Compliance Plan, et al.*, Case No. 2011-00401, Application of Kentucky Power Company, Direct Testimony of Scott C. Weaver, at 30: 2-14 (Dec. 5, 2011), available at <http://psc.ky.gov/PSCSCF/2011%20cases/2011-00401/20111205_Kentucky_Power_Application.pdf>.

Indiana Michigan Power Company.[62] When Cleco does include a price on CO_2 as a sensitivity scenario, the Company incorrectly adds that price post-unit dispatch rather than including it as a variable cost of generation that influences unit dispatch. If CO_2 were included as a variable cost, it would raise Dolet Hills' cost of production and would cause the unit to generate fewer hours of the year, thus inaccurately biasing the analysis in favor of the retrofit option. In 2011-2013, the bulk of electric utilities were including CO_2 costs in their Reference Case forecasts. Synapse has collected those forecasts and presented them in Figure 3, below.

[62] *See* Indiana Utility Regulatory Commission. *Verified Petition of Indiana Michigan Power Company (I&M) for Approval of a Clean Energy Project et al.*, Cause No. 44871, Direct Testimony of Scott C. Weaver, at 36: Tbl. 4 (Oct. 21, 2016). The relevant except of that testimony is attached as Exhibit RSW-4 hereto.

Figure 3. Utility Reference Case CO_2 forecasts



Q **Did SWEPCO evaluate environmental regulations impacting Dolet Hills?**

A No, as noted above, it does not appear that SWEPCO conducted any independent analysis of environmental compliance costs at Dolet Hills, but instead relied solely on analysis conducted by Cleco.

Q. Was that analysis complete?

A No. Based on my review of publicly available testimony in Cleco's MATS retrofit docket, Louisiana Public Service Commission ("LPSC") Docket No. U-32507, it appears that Cleco ignored the impacts of rules governing air quality, water quality, and coal combustion residual disposal, which are all expected to impose moderate to significant costs at existing coal-fired facilities.[63] Most significantly, as with the Welsh units, Cleco appears to have ignored the potential environmental compliance risks associated with the SO_2 NAAQS, the CCR rule, and the proposed ELGs for scrubber and ash handling wastewater at steam electric generating units.

A What are the implications of these regulations on SWEPCO's Dolet Hills facility?

Although it may have been difficult to establish the risk associated with each regulation with absolute certainty, as Dr. Jeremy Fisher testified in the LPSC docket, SWEPCO and Cleco could have, and should have, evaluated proxy costs for reasonable bounding cases—lenient or strict implementation of the rules. Instead, SWEPCO evaluated nothing at all. Using Dr. Fisher's assumptions, it appears that the risk associated with the continued operation of the Dolet Hills unit could be significant. Indeed, using a publicly available costing mechanism from EPA (designed by Sargent & Lundy),[64] the capital cost of a full wet FGD system at Dolet Hills could be $341 million.

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[63] *See* Fisher Testimony, *supra* n.60.

[64] *See* EPA, *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model* (Nov. 2013), at 5-4 through 5-7, available at < https://www.epa.gov/sites/production/files/2015-07/documents/documentation_for_epa_base_case_v.5.13_using_the_integrated_planning_model.pdf >, attached hereto as Exhibit RSW-5.

For the CCR rule, Dr. Fisher estimated, based on publicly available estimates from the Electrical Power Research Institute ("EPRI")[65] and by a consultancy working for Edison Electric Institute ("EEI"),[66] that the additional costs of compliance for Dolet Hills could be as much as $104 million.

For ELGs, EPA ultimately required closed-loop or dry bottom ash handling systems, and dry fly ash handling systems. These systems impose both capital costs for new treatment facilities, and higher operational costs. Based on modeling parameters available in EPA's regulatory impact assessment of the ELGs,[67] the Dolet Hills facility would require as much as $49 million in additional capital costs to comply with the rule, and an additional annual fixed O&M costs of $7.0 million. Those costs are presented in Table 4, excerpted from Dr. Fisher's testimony in the LPSC docket.

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[65] Fisher Testimony, *supra* n.60; *see* EPRI, *Engineering and Cost Assessment of Listed Special Waste Designation of Coal Combustion Residuals Under Subtitle C of the Resource Conservation and Recovery Act* (2010).

[66] Fisher Testimony, *supra* n.60; *see* EOP Group, Inc, *Cost Estimates for the Mandatory Closure of Surface Impoundments Used for the Management of Coal Combustion Byproducts at Coal-Fired Electric Utilities* (2009).

[67] *See* EPA, *Regulatory Impact Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (2015), < https://www.epa.gov/sites/production/files/2015-11/documents/steam-electric_regulatory-impact-analysis_09-29-2015.pdf>; EPA, *Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (2015), < https://www.epa.gov/sites/production/files/2015-10/documents/steam-electric-tdd_10-21-15.pdf>.

Table 4. Environmental compliance capital costs for Dolet Hills under strict and lenient interpretations of environmental regulations.[68]

		Dolet Hills	
Technology	**Applicable rule(s)**	**Strict**	**Lenient**
Flue gas desulfurization (FGD)	SO_2 NAAQS CSAPR 2.0	$**341** (2016)	-
Selective Catalytic Reduction	$PM_{2.5}$ NAAQS Ozone NAAQS CSAPR 2.0	$**145** (2018)	$**145** (2021)
Water treatment	ELG	$**49** (2017)	$**6** (2022)
Coal waste mitigation	CCR	$**104** (2019)	$**91** (2021)
Total		**$642**	**$301**

These costs are not engineering estimates; rather they serve as proxy costs in place of the zero costs contemplated by the utility.

Q. What about SWEPCO's Dolet Hills analysis (or lack thereof) do you believe to be imprudent?

A. As a part owner of the Dolet Hills unit, SWEPCO has several obligations to its ratepayers when faced with the decision to retrofit or retire. First, SWEPCO must ensure that Cleco's input assumptions and methodologies are consistent with SWEPCO's (and AEP's) policies and practices. Second, the Company is obligated to ensure that Cleco's analysis of emission controls will comply with environmental regulations. Finally, SWEPCO must confirm that the decision to install emission controls is the least-cost option for compliance for ratepayers.

SWEPCO has not provided any evidence that it did any of those things in a meaningful way. Indeed, Mr. Paul Franklin states in his Direct Testimony that he reviewed the Sargent & Lundy study that evaluated the MATS compliance options for Dolet Hills, and that he agrees that Cleco's retrofit decision was

[68] *See* Fisher Testimony, *supra* n.63.

prudent.[69] Deferring to another utility's work and conclusion—in another case and in another state—is not, in my experience, sufficient for a determination of prudence. The Company's refusal to disclose the Dolet Hills analyses prevents the Commission from fulfilling its obligation to fully evaluate the prudence of SWEPCO's investment decisions, and to ensure that SWEPCO's investment decisions are in the public interest.

Given what SWEPCO's management knew or should have known about the risk of additional environmental compliance costs, the Company's failure to independently evaluate the Dolet Hills effectively commits SWEPCO's ratepayers to significant stranded costs (in the event of retirement), or a long future of mounting capital and operational costs. By deferring to Cleco's piecemeal approach to environmental compliance—requesting cost recovery for a single upcoming cost (i.e., MATS) rather than considering the full costs to ratepayers of continuing to operate—the Company has deprived its own ratepayers as well as this Texas Commission of the benefit of a comprehensive review and prudence determination. The scope of the Commission's consideration of the Company's proposal should reflect a multi-pollutant approach to evaluating the known and likely costs of continued operation and retrofit, rather than considering one regulation at a time—let alone simply deferring to another company's and another state decisionmaker's determinations.

<u>6.</u> <u>PRUDENCE CONCLUSIONS AND RECOMMENDATIONS</u>

Q. What are your conclusions regarding the prudence of SWEPCO's investments in emission controls at Pirkey, Flint Creek, and Welsh 1 and 3?

A. The evidence in this docket seems to indicate that the Company failed to base its decision to invest in emission controls at Pirkey, Flint Creek, and Welsh 1 and 3

[69] Direct Testimony of Paul W. Franklin at 15:15-19.

on a robust analysis that examines detailed costs associated with a carefully selected suite of environmental controls, and compares those costs to a number of reasonable alternatives for replacement capacity.

Glaringly, SWEPCO's analyses failed to utilize contemporaneous forecasts of key commodity price inputs. The Company ignored all evidence of falling natural gas prices, and continued using gas price forecasts that were two to three years out of date, which significantly skewed the outcome of its comparison between retrofitting its affected coal units and retiring and replacing them with non-coal capacity and energy.

Moreover, SWEPCO did not include costs associated with additional rules environmental rules that were proposed at the time of the Company's analyses, which would lead to increases in the revenue requirements associated with the system costs of the environmental retrofits. I estimate the possible range of costs for each unit as follows:

- Welsh 1: $485-534 million
- Welsh 3: $195-244 million
- Pirkey: $62-160 million
- Flint Creek: $62-160 million

In addition to the almost $700 million for which SWEPCO is seeking cost recovery in this docket, the Company should have known that there was the possibility that another $800 million to $1.1 billion might be required at its coal fleet.

Finally, SWEPCO did not examine replacement options other than new natural gas units, such as market purchases, efficiency or renewable energy sources (which were foreseeably cost-effective and have proven to be so). These failures by SWEPCO lead me to conclude that the Company's decision to install emission controls at its units was not based on prudent analysis.

Q. What are your recommendations with respect to the Pirkey, Flint Creek, and Welsh 1 and 3 investments?

A. I would recommend that the Commission disallow a portion of the costs associated with the environmental controls installed at Pirkey, Flint Creek, and Welsh 1 and 3. The total cost of those retrofits collectively was $694.5 million. Following precedent, discussed below, from Oregon, Washington, and Indiana at the least, I recommend a disallowance of 10 percent of the total cost of the imprudent investments at those units, or $69.4 million.

Q. What are your conclusions regarding the prudence of SWEPCO's investments in emission controls at Dolet Hills?

A. I have not seen any evidence that SWEPCO participated in the decision-making process around the Dolet Hills emissions retrofits in any meaningful way, or that the Company independently assured itself of the prudence of those retrofits. As such, the Company's actions simply cannot be considered to meet the standard for planning prudence. Further, SWEPCO has refused to provide Cleco's analysis of the installed emissions controls at Dolet Hills, thus inhibiting review by this Commission, intervenors in this docket, or the Texas public, of the prudence of the decision to install those controls. The Commission should not allow for any cost recovery associated with the Dolet Hills investments under such conditions.

Q. What is your recommendation with respect to the Dolet Hills investments?

A. I recommend that the Commission fully deny recovery for the $52 million in costs associated with the emissions controls installed to meet MATS standards at Dolet Hills, as well as the $4.2 million in costs associated with the controls required to meet CSAPR's seasonal ozone regulations.

Q. Please describe any precedent for disallowance that the Commission should consider when making its decision.

A. As one example, the Oregon Public Utilities Commission recently found that PacifiCorp (d.b.a. Pacific Power), a large utility serving five Western states, acted imprudently by installing emissions controls without a sufficiently rigorous analysis. The Commission disallowed a portion of the costs associated with all of PacifiCorp's installed emissions controls, finding that:

> Pacific Power failed to perform appropriate analyses to determine the cost-effectiveness of the investments. Pacific Power's contemporaneous cost-effectiveness analyses were demonstrably deficient, and did not demonstrate the rigorous review that a prudent utility should have performed prior to making these significant investments.[70]

Similarly, the Washington Utilities and Transportation Commission found that Pacific Power exposed ratepayers to sizeable risk by failing to re-evaluate its analysis of SCR technologies under changing economic conditions, including updating its modeling analysis over a six-month period. The Commission allowed recovery on the SCR, but disallowed a return on those investments, stating that:

> With regard to the Company's request for full recovery of its selective catalytic reduction (SCR) systems on Units 3 and 4 of Bridger, the Commission finds that Pacific Power failed to produce contemporaneous documentation and demonstrate, from May to December 2013, it re-evaluated its options to comply with the Regional Haze Rule obligations when significant changes were occurring in natural gas pricing and coal costs and before it signed the full notice to proceed with the SCR engineering, procurement,

[70] Oregon Public Utility Commission, *In the Matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision*, Docket No. UE 246, Order 12-493 at 28 (Dec. 20, 2012) <http://apps.puc.state.or.us/orders/2012ords/12-493.pdf>.

> and construction services contract. Thus, the Company failed to meet its burden of proof that the investments were prudent.[71]

And, in another MATS retrofit case, the Indiana Utility Regulatory Commission levied a financial penalty on Indianapolis Power & Light ("IP&L") for poor management and for presenting a case lacking in appropriate rigor. The Commission stated:

> At the outset, we must note that IPL's initial presentation of its cost/benefit study through an overly simplistic analysis was disappointing. This choice represented a poor management decision and demonstrated a lack of due regard for the regulatory process. The proposed MATS Compliance Project is a substantial capital investment, and this Commission expects a petitioning utility to present the best evidence available at the outset of its case, in order to provide the Commission and other parties a reasonable opportunity to fully and fairly evaluate the company's proposal.[72]

Q. How does the case at hand compare against the PacifiCorp and IP&L cases you've noted here?

A. The present case is quite similar in its deficiencies to those cases. In the Oregon PacifiCorp case, the utility had moved to install retrofits well ahead of a regulatory deadline, and in the rush to permit and complete construction, failed to rigorously review if the retrofits made economic sense. A review of relevant case studies might have prevented SWEPCO from making an erroneous choice, since the PacifiCorp decision and others like it came before the Company filed its initial

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[71] Washington Utilities and Transportation Commission. *In the Matter of Pacific Power & Light Company Petition For a Rate Increase Based on a Modified Commission Basis Report, Two-Year Rate Plan, and Decoupling Mechanism*, Docket UE-152253, Order 12 at 3 (Sept. 1, 2016) < https://www.utc.wa.gov/docs/Pages/RecentOrders.aspx>.

[72] Indiana Utility Regulatory Commission, *Verified Petition of IPL for Approval of Clean Energy Projects et al.*, Cause No. 44242, Final Order at 31 (Aug. 14, 2013) <http://www.in.gov/iurc/files/44242order_081413.pdf>.

application in this docket. In the Indiana IP&L case, the modeling presented by the utility contained numerous oversights, including several also found in this case today. However, in that case, IP&L at least reviewed its impending non-MATS environmental compliance obligations. There is such a wealth of literature and analysis on the risks to coal-fired facilities today that it is unacceptable for a utility to fail to review these costs.

7. ANALYSIS OF THE ECONOMICS OF SWEPCO'S UNIT DISPATCH PRACTICES, AND CONCLUSIONS AND RECOMMENDATIONS

Q. Did you review SWEPCO's practices with respect to bidding and dispatch of its coal fleet into the SPP, as a part of this docket?

A. Yes. I have analyzed SWEPCO's market bids into SPP's Integrated Marketplace, and the respective energy revenues and production costs of coal units at Pirkey, Flint Creek, Welsh, Dolet Hills, and Turk, from 2015 and 2016, to assess the economics and reasonableness of SWEPCO's coal unit dispatch practices.

Q. Please describe the data you relied upon in your evaluation, and the way in which you used it to review SWEPCO's bidding and dispatch practices.

A. My analysis relies primarily on data provided by SWEPCO in response to Requests for Information. Specifically, referring to the Direct Testimony of A. Naim Hakimi, who directs activities related to the recovery of SWEPCO's operational costs and the Company's dispatch of its units into SPP, I requested the following information for the Pirkey, Flint Creek, Welsh, Dolet Hills, and Turk coal units:

- Daily submissions of bids into the SPP Marketplace for 2015 and 2016;
- Reasons for dispatch for each hour of 2015 and 2016;
- Variable costs of production at the most temporally granular basis available for 2015 and 2016;
- Locational marginal price of energy on an hourly basis for 2015 and 2016;

- Hourly net output for 2015 and 2016; and
- Hourly energy market revenues received from SPP in 2015 and 2016.

In response to these requests, SWEPCO provided voluminous spreadsheets containing the requested data.[73] Since SWEPCO provided its cost data in terms of dollars per MMBtu, I used unit-specific monthly heat rate data derived from generation and fuel consumption data collected by the EIA to convert SWEPCO's costs into units of dollars per Megawatt-hour.[74] I also used variable cost estimates of environmental control technologies published by the EPA to compare against the cost data provided by SWEPCO (see Exhibit RSW-5 hereto[75]).

SWEPCO provided variable production cost data on a monthly [redacted] and so I conducted my analyses by month and year. I aggregated the hourly data provided by SWEPCO up to month and year by taking an average of bid prices for each MW bidding segment, and summing total generation and energy revenues for the relevant time period. For each unit, I estimated monthly net operational revenues by subtracting from gross energy revenues the product of monthly variable costs (in $/MWh) and monthly net generation (in MWh). [redacted]

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[73] SWEPCO Response to Sierra Club RFI No. 2-1, HIGHLY SENSITIVE Attachments 1 through 8; SWEPCO Response to Sierra Club RFI 1-23, CONFIDENTIAL Attachments 1 and 2.

[74] U.S. Department of Energy, EIA, Form EIA-923 detailed data, available at <https://www.eia.gov/electricity/data/eia923/>.

[75] EPA, *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model* (Nov. 2013), at 5-4 through 5-7, available at < https://www.epa.gov/sites/production/files/2015-07/documents/documentation_for_epa_base_case_v.5.13_using_the_integrated_planning_model.pdf >.

[redacted]

[redacted]

Q. In your opinion, do SWEPCO's market bidding and operating decisions conform to generally accepted practices?

A. [redacted] profit-maximizing voluntary energy market participants bid into the market at their generating facilities' approximate marginal (or variable) cost of production.[77] Generators' respective energy bids for a given timeframe are stacked along a dispatch curve from lowest-price to highest-price, until the volume of energy associated with the bid stack matches the demand for energy over that time interval. The bid price of that last generator needed to meet energy demand becomes the market clearing price. If the market clears below a utility-generator participant's production cost, that participant's generator is not dispatched, and rather the generators whose bids did clear at the prevailing market price would supply power to the customers of the utility whose bid did not clear.[78] Such rational economic decision-making avoids losses to the participant associated with its production costs exceeding the price it receives for energy—losses that, having never being incurred, obviously could never later be imposed on ratepayers—while also promoting systemic cost-efficiency across the region. Conversely, if the energy market clears above the participant's production cost, the participant's generator is dispatched and will earn energy revenues above its production costs.

[redacted]

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[77] This discussion pertains to voluntary bidding and dispatch behavior, such as those of SWEPCO discussed below, not to operation mandated for reliability purposes or otherwise required for reasons beyond the market dynamic discussed herein.

[78] *See generally, e.g.*, *SPP Market Protocols, SPP Integrated Marketplace* (Rev. 43, Mar. 7, 2017) <https://www.spp.org/documents/48699/integrated%20marketplace%20protocols%2043.pdf>.

[redacted]

[79] This analysis is based on SWEPCO's response to Sierra Club RFI 2-1, HIGHLY SENSITIVE Attachments 1 and 5, and SWEPCO Response to Sierra Club RFI 1-23, CONFIDENTIAL Attachment 1.

[redacted]

[80] This analysis is based on SWEPCO Response to Sierra Club RFI 2-1, HIGHLY SENSITIVE Attachments 1 and 5.

[redacted]s[81] [redacted]

[81] This analysis is based on SWEPCO Response to Sierra Club RFI 2-1, HIGHLY SENSITIVE Attachment 5, and SWEPCO's Response to Sierra Club RFI 1-23, CONFIDENTIAL Attachment 1.

[redacted] prices [redacted]

[redacted]

Q. What are the consequences of SWEPCO's bidding strategy?

[redacted]

[redacted]

[redacted]

[redacted]

[82] Analysis based on SWEPCO's response to Sierra Club RFI 2-1, HIGHLY SENSITIVE Attachments 4, 5, 6, and 7.

[redacted] 016 [redacted]

[83] This analysis is based on SWEPCO Response to Sierra Club RFI 2-1, HIGHLY SENSITIVE Attachments 5, 7, and 8.

[redacted].

[redacted]

Q. Are the Company's dispatch practices justified by reliability concerns?

A. [redacted]

[84] This analysis is based on SWEPCO Response to Sierra Club RFI 2-1, HIGHLY SENSITIVE Attachments 5, 7, and 8.

[85] This analysis is based on SWEPCO's response to Sierra Club RFI 2-1, HIGHLY SENSITIVE Attachment 4.

[redacted]

[redacted]

Q. Are the Company's dispatch practices justified by the costs of ramping and cycling coal plants?

[redacted]

[86] This analysis is based on SWEPCO's response to Sierra Club RFI 2-1, HIGHLY SENSITIVE Attachments 4, 5, 6, and 7.

[redacted]

[redacted]

[redacted]

Q Are there other potential impacts of SWEPCO's bidding and dispatch practices?

A [redacted]

Q. Does your assessment of SWEPCO's net operational revenues account for all variable costs of production?

A. [redacted]

[redacted]

[redacted]

[87] EPA, *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model* (Nov. 2013), at 5-4 through 5-7, available at < https://www.epa.gov/sites/production/files/2015-07/documents/documentation_for_epa_base_case_v.5.13_using_the_integrated_planning_model.pdf >, attached hereto as Exhibit RSW-5.

[redacted]

Q. [redacted]

A. [redacted]

Q. What can you conclude based on your analysis of the dispatch of SWEPCO's coal fleet?

A. [redacted] SWEPCO conducted additional unit disposition analyses in the Summer of 2015, shown in Tables 14, 15, and 16 in the

Direct Testimony of Mr. Mark A. Becker. Those analyses show a range of retrofit savings for Welsh 1 and 3 of $245-$1,000 million, for Flint Creek of $60-$265 million, and for Pirkey of $350-$940 million.[88] [redacted]

[redacted]

Q. [redacted] **does your analysis of the uneconomic dispatch of SWEPCO's coal fleet lead you to any further recommendations?**

A. [redacted]

[88] Direct Testimony of Mark A. Becker at 24: Tbl. 14; *id.* at 25: Tbls. 15 & 16.

[redacted]

Q. Does this conclude your direct testimony?

A. Yes.

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

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

AFFIDAVIT OF RACHEL S. WILSON FOR DIRECT TESTIMONY

State of Massachusetts)
County of Middlesex)

Affiant Rachel S. Wilson, being first duly sworn, states the following: I am of legal age and a resident of the State of Massachusetts. I certify that my Direct Testimony and associated exhibits filed herewith on Tuesday, April 25, 2017, on behalf of the Sierra Club and Dr. Lawrence Brough, is true and correct to the best of my knowledge and belief after reasonable inquiry.

Rachel Wilson
Rachel Wilson

SUBSCRIBED AND SWORN to me, Janice Conyers, notary public, on this 25 day of April, 2017.

Notary Public ~~for the~~ State of Massachusetts

My Commission expires: 7/27/18

JANICE CONYERS
Notary Public
Commonwealth of Massachusetts
My Commission Expires
July 27, 2018

EXHIBIT RSW-1

Resume of Rachel S. Wilson

Rachel Wilson, Senior Associate

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rwilson@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate*, 2013 – present, *Associate*, 2010 – June 2013, *Research Associate*, 2008 – 2010.

- Conducts research and writes testimony and reports on a wide range of issues relating to electric utilities, including: integrated resource planning; federal and state clean air policies; emissions from electricity generation; electric system dispatch; and environmental compliance technologies, strategies, and costs.
- Uses optimization and electricity dispatch models, including Strategist, PROMOD, PROSYM/Market Analytics, and PLEXOS to conduct analyses of utility service territories and regional energy markets.

Analysis Group, Inc., Boston, MA.

Associate, Energy Practice, 2007 – 2008.

- Supported an expert witness asked to opine on various topics in the electric industry as they applied to merchant generators and provided incentives for their behavior in the late 1990s and early 2000s.
- Analyzed data related to coal production on Indian land and contractual royalties paid to the tribe over a 25 year period to determine if discrepancies exist between these values for the purposes of potential litigation.
- Examined Canadian policies relating to carbon dioxide, and assisted with research on linkage of international tradable permit systems.
- Managed analysts' work processes and evaluated work products.

Senior Analyst Intern, Energy Practice, 2006 – 2007.

- Supported an expert witness in litigation involving whether a defendant power company could financially absorb a greater investment in pollution control under its debt structure while still offering competitive rates. Analyzed impacts of federal and state clean air laws on energy generators and providers. Built a quantitative model showing the costs of these clean air policies to the defendant over a 30 year period. Built a financial model calculating impacts of various pollution control investment requirements.
- Researched the economics of art; assisted in damage calculations in arbitration between an artist and his publisher.

Yale Center for Environmental Law and Policy, New Haven, CT. *Research Assistant*, 2005 – 2007.

- Gathered and managed data for the Environmental Performance Index, presented at the 2006 World Economic Forum. Interpreted statistical output, wrote critical analyses of results, and edited report drafts.
- Part of the team that produced *Green to Gold*, an award-winning book on corporate environmental management and strategy. Managed data, conducted research, and implemented marketing strategy.

Marsh Risk and Insurance Services, Inc., Los Angeles, CA. *Risk Analyst*, Casualty Department, 2003 – 2005.

- Evaluated Fortune 500 clients' risk management programs/requirements and formulated strategic plans and recommendations for customized risk solutions.
- Supported the placement of $2 million in insurance premiums in the first year and $3 million in the second year.
- Utilized quantitative models to create loss forecasts, cash flow analyses and benchmarking reports.
- Completed a year-long Graduate Training Program in risk management; ranked #1 in the western region of the US and shared #1 national ranking in a class of 200 young professionals.

EDUCATION

Yale School of Forestry & Environmental Studies, New Haven, CT
Masters of Environmental Management, concentration in Law, Economics, and Policy with a focus on energy issues and markets, 2007

Claremont McKenna College, Claremont, California
Bachelor of Arts in Environment, Economics, Politics (EEP), 2003. *Cum laude* and EEP departmental honors.

School for International Training, Quito, Ecuador
Semester abroad studying Comparative Ecology. Microfinance Intern – Viviendas del Hogar de Cristo in Guayaquil, Ecuador, Spring 2002.

ADDITIONAL SKILLS AND ACCOMPLISHMENTS

- Microsoft Office Suite, Lexis-Nexis, Platts Energy Database, Strategist, PROMOD, PROSYM/Market Analytics, and PLEXOS, some SAS and STATA.
- Competent in oral and written Spanish.

- Hold the Associate in Risk Management (ARM) professional designation.

PUBLICATIONS

Wilson, R., S. Fields, P. Knight, E. McGee, W. Ong, N. Santen, T. Vitolo, E. A. Stanton. 2016. *Are the Atlantic Coast Pipeline and the Mountain Valley Pipeline Necessary? An examination of the need for additional pipeline capacity in Virginia and Carolinas.* Synapse Energy Economics for Southern Environmental Law Center and Appalachian Mountain Advocates.

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Kentucky Public Service Commission (Case No. 2011-00161 and Case No. 2011-00162): Direct testimony before the Commission discussing STRATEGIST modeling relating to the applications of Kentucky Utilities Company, and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity, and approval of its 2011 compliance plan for recovery by environmental surcharge. On behalf of Sierra Club and Natural Resources Defense Council (NRDC). September 16, 2011.

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EXHIBIT RSW-2

Timeline of selected regulations

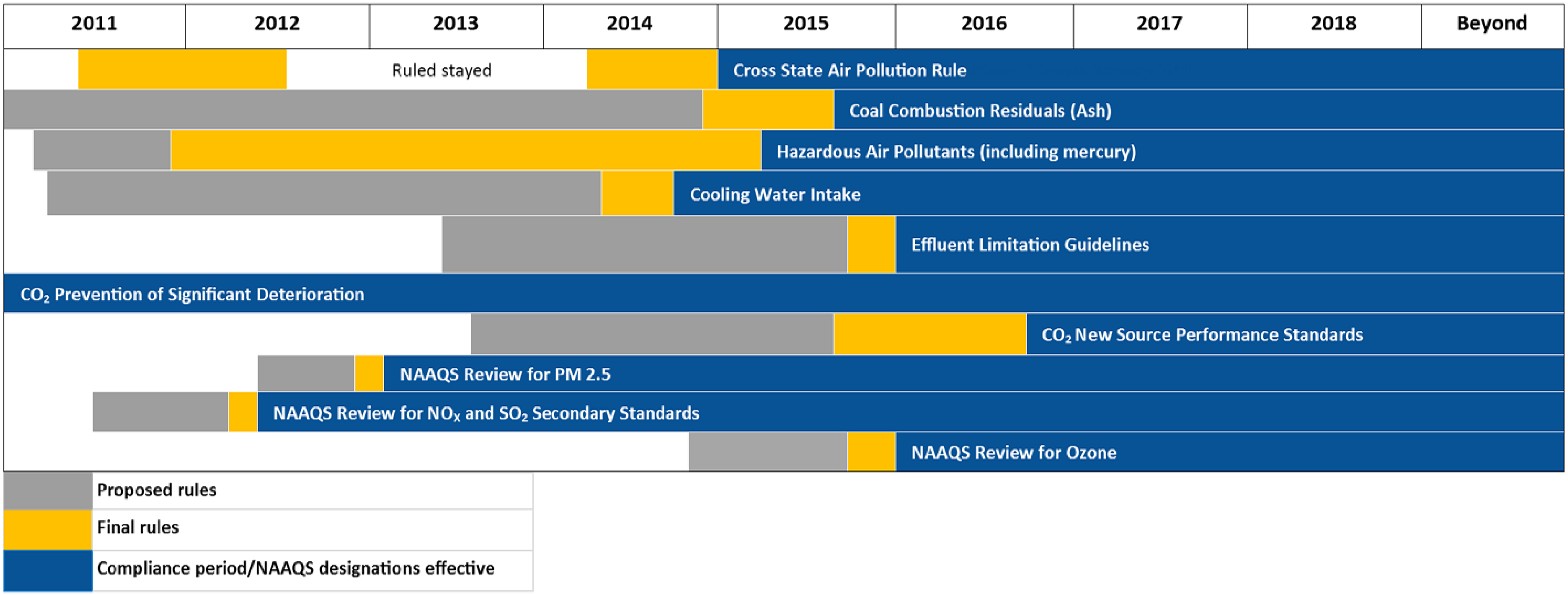
2011
2012
2013
2014
2015
2016
2017
2018
Beyond
Ruled stayed
Cross State Air Pollution Rule
Coal Combustion Residuals (Ash)
Hazardous Air Pollutants (including mercury)
Cooling Water Intake
Effluent Limitation Guidelines
CO_2 Prevention of Significant Deterioration
CO_2 New Source Performance Standards
NAAQS Review for PM 2.5
NAAQS Review for NO_X and SO_2 Secondary Standards
NAAQS Review for Ozone
Proposed rules
Final rules
Compliance period/NAAQS designations effective

EXHIBIT RSW-3

SWEPCO Response to OPUC RFI 1-11

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

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

Question No. 1-11:

Please provide copies of the commodity price forecasts, comparable in detail to those provided in Exhibit MAB-2 to the Direct Testimony of Mark A. Becker, that SWEPCO has used to analyze power purchase and plant investment decisions from 2011 to the present.

Response No. 1-11:

Please see Exhibit MAB-2 for a summary of the commodity price forecasts used in the early 2011 analyses (January 2011 through May 2011). See OPUC 1-11 Attachment 1 for the commodity price forecasts used in Spring 2012, Fall 2012, Summer 2013, Summer 2014 and Summer 2015 to perform the unit disposition plant investment analyses shown in the Direct Testimony of Mark A. Becker.

Prepared By:	Mark Becker	Title:	Resource Planning Mgr
Sponsored By:	Mark Becker	Title:	Resource Planning Mgr

SPP On-Peak Energy ($/MWh)

	Fleet Transition - CSAPR (Base Band)	Fleet Transition - CSAPR (Low Band)	CPP with $15-$25/tonne CO2 Price	CPP with $25-$40/tonne CO2 Price	CPP with No CO2 Price
2012	47.39	44.20			
2013	50.77	45 32			
2014	55.73	47.48			
2015	59.20	52 72	44.52	43.89	48.48
2016	64 97	57.34	48.60	47 60	53.30
2017	65.75	58 54	51.59	50.33	55 46
2018	66.64	59.56	53 61	52 16	57.04
2019	67.85	61.41	55 56	54.69	58.73
2020	66 87	62.52	61.94	69.65	60 81
2021	68.52	64.48	65 65	73.04	63 70
2022	75.69	73.29	67.21	75 00	64.02
2023	76.53	74.03	68.65	76 39	66.00
2024	78.76	75.36	71.64	78 93	68.17
2025	80 50	76.45	74 10	81 63	70 52
2026	81 13	77.12	75.24	83 47	73 23
2027	83 15	78.22	78.20	86.79	75 37
2028	84.15	79.06	81.38	88.68	77.34
2029	85.57	80.45	83.62	91.01	79 83
2030	86.60	81.44	90.66	100.19	81.16
2031	87.88	82 48	93.58	103.83	84.12
2032	89 17	83.53	96.39	107.99	86 83
2033	90 48	84.59	97 68	110 58	89 67
2034	91 82	85.67	99.21	111.39	84 72
2035	93.17	86.76	101.01	112.91	87.97
2036	94.54	87.86	101.70	113.30	89.40
2037	95.94	88.98	102.40	115.77	90 50
2038	97.35	90 11	103.80	116.24	91.25
2039	98.78	91 26	104 42	117.66	91.57
2040	100 24	92 42	105.98	119.07	93.00

SPP Off-Peak Energy ($/MWh)

	Fleet Transition - CSAPR (Base Band)	Fleet Transition - CSAPR (Low Band)	CPP with $15-$25/tonne CO2 Price	CPP with $25-$40/tonne CO2 Price	CPP with No CO2 Price
2012	32.63	30 57			
2013	34.86	31.98			
2014	39.00	33.74			
2015	41 78	36 92	28.12	28 33	32 24
2016	46.15	40.69	30 76	30 88	36.08
2017	47.70	42.41	32.58	32.65	38.53
2018	48.97	42 86	34.11	34.38	40.15
2019	49.75	44 68	36.06	36.33	41 74
2020	48.80	45.35	46.93	55.49	43 58
2021	50 78	47.58	49.15	57 93	45.21
2022	59 13	56.07	50.09	59 06	45.19
2023	60 17	56.36	51 39	60 18	47.12
2024	62.40	58 28	53 27	62.16	49.13
2025	63.83	59.71	55 29	63.87	50.60
2026	64.33	60.67	56.58	65.45	52.31
2027	66.12	61.68	58 67	67.83	54 34
2028	67.56	63.01	60.70	69.87	55 56
2029	69.56	64.32	63.15	71 53	57.73
2030	70 45	64.81	69.78	81.08	59 19
2031	71.86	65.88	72.76	83.80	61 06
2032	73.29	66.97	75.49	87 43	63.98
2033	74.75	68.08	77 11	90.24	66.24
2034	76.25	69.21	79 44	92.66	65.29
2035	77 77	70 35	81.10	94.35	67.74
2036	79.32	71.51	81.75	94.90	69 59
2037	80 91	72.70	83.23	97.02	71 43
2038	82.52	73.90	84.97	98.54	73 02
2039	84.17	75 12	86 63	99.90	74.46
2040	85.85	76.36	87.98	102.30	76 44

Henry Hub Gas Price ($/MMBtu)

	Fleet Transition - CSAPR (Base Band)	Fleet Transition - CSAPR (Low Band)	CPP with $15-$25/tonne CO2 Price	CPP with $25-$40/tonne CO2 Price	CPP with No CO2 Price
2012	4 48	3.94			
2013	4.94	4 35			
2014	5.38	4 73			
2015	5.52	4.86	5.47	5.41	5.45
2016	5.99	5.27	5 83	5.76	5.81
2017	6 13	5.39	6 01	5.93	5.99
2018	6 32	5.56	6.12	6 05	6.10
2019	6 46	5 68	6 19	6 11	6.17
2020	6 52	5.73	6 82	6.66	6.41
2021	6.75	5 94	7 16	6.98	6 62
2022	7.07	6 22	7.54	7.29	6.81
2023	7.26	6 39	7.67	7.42	7.00
2024	7.51	6.61	7.88	7 63	7.19
2025	7.75	6.82	8.13	7.87	7 40
2026	7 85	6.91	8 24	7.99	7.61
2027	8.04	7.08	8 44	8.20	7.80
2028	8.22	7 23	8 63	8.37	7.97
2029	8.41	7.40	8 83	8.56	8.15
2030	8.52	7.50	9 55	9.17	8.27
2031	8.68	7 64	9.78	9.40	8.47
2032	8.85	7.79	10 01	9.63	8.67
2033	9.02	7.94	10 26	9.82	8.89
2034	9 19	8.09	10.52	10.07	9.11
2035	9 37	8 25	10.76	10 29	9.32
2036	9 55	8.41	10.96	10 48	9.55
2037	9 73	8.57	11.15	10 66	9.78
2038	9.92	8.73	11.35	10 86	10.02
2039	10.10	8 90	11.56	11.05	10 26
2040	10.30	9 07	11.77	11 25	10 51

PRB 8800 Btu/lb 0 8 #SO2 (FOB$/Ton)

	Fleet Transition - CSAPR (Base Band)	Fleet Transition - CSAPR (Low Band)	CPP with $15-$25/tonne CO2 Price	CPP with $25-$40/tonne CO2 Price	CPP with No CO2 Price
2012	15 75	14 49			
2013	16 95	15.26			
2014	17.50	15.75			
2015	17.50	15.40	13.50	13.50	13.60
2016	17.40	15 31	13.20	13.20	13 30
2017	17.30	15 22	13.44	13.44	13 54
2018	17.72	15 59	13.68	13 68	13 78
2019	18.14	15 96	14.42	14 42	14 53
2020	18.57	16 34	14.72	15.49	15 61
2021	19 00	16.72	14.67	15 44	15.56
2022	19.07	16.78	15.71	16.36	16.69
2023	19.51	17.17	16.29	16.97	17.31
2024	19.96	17.57	16.06	16.73	17 06
2025	20.42	17 97	16.01	16 68	17.01
2026	20 89	18.38	16.20	16 88	17 22
2027	21 36	18.80	16.45	17 14	17 48
2028	21.84	19.22	16.68	17.38	17.73
2029	22.34	19 66	17.17	17.89	18.25
2030	22 84	20 10	18.69	20.10	20 50
2031	23 36	20.56	20 91	22.48	22 93
2032	23.89	21.02	24.65	26.50	27.03
2033	24.43	21.50	27.95	30.05	30.65
2034	24.98	21 98	31.04	33 38	34 05
2035	25 55	22 48	30.50	32 80	33 46
2036	26 13	22 99	31.14	33 49	36 90
2037	26.72	23 51	31.80	34.19	40.58
2038	27.32	24.05	32.47	34.91	44.02
2039	27.94	24 59	33.15	35.64	47.32
2040	28.57	25.15	33 84	36.39	50.54

Pirkey Lignite ($/MMBtu)

	Fleet Transition - CSAPR (Base Band)	Fleet Transition - CSAPR (Low Band)	CPP with $15-$25/tonne CO2 Price	CPP with $25-$40/tonne CO2 Price	CPP with No CO2 Price
2012	2.72	2.49			
2013	2.74	2 48			
2014	2.92	2.74			
2015	2.82	2.63	3 13	3.13	3.13
2016	2 67	2.48	3.19	3.19	3.19
2017	2 81	2.60	2.90	2 90	2.90
2018	2.37	2 19	3.04	3.04	3 04
2019	2 53	2.30	2.47	2.47	2 47
2020	2 75	2.47	2 80	2.80	2.80
2021	2.70	2 47	2.81	2.81	2 81
2022	2.96	2.71	2 62	2.62	2.62
2023	2.74	2.50	2 64	2.64	2 64
2024	2 79	2.55	2.65	2.65	2.65
2025	3 09	2.83	2.80	2 80	2.80
2026	2 70	2.47	2.86	2.86	2.86
2027	2.52	2.30	2 93	2.93	2 93
2028	2.64	2 42	2.99	2.99	2 99
2029	2.98	2 73	3.06	3 06	3 06
2030	2.82	2.58	3.13	3 13	3.13
2031	2.80	2.56	3 20	3.20	3 20
2032	2.94	2.69	3 27	3.27	3.27
2033	2 92	2.67	3.35	3 35	3.35
2034	3 29	3.01	3.42	3.42	3.42
2035	3 25	2.98	3.50	3 50	3.50
2036	3 25	3.03	3.58	3 58	3.58
2037	3.25	3 09	3.66	3.66	3 66
2038	3.25	3 14	3.74	3.74	3.74
2039	3.25	3 20	3.83	3.83	3 83
2040	3.25	3 25	3.91	3.91	3 91

CO2 Price ($/Metric Tonne)

	Fleet Transition - CSAPR (Base Band)	Fleet Transition - CSAPR (Low Band)	CPP with $15-$25/tonne CO2 Price	CPP with $25-$40/tonne CO2 Price	CPP with No CO2 Price
2012	0 00	0.00			
2013	0.00	0.00			
2014	0.00	0.00			
2015	0.00	0.00	0 00	0.00	0.00
2016	0.00	0 00	0 00	0 00	0.00
2017	0 00	0 00	0.00	0.00	0.00
2018	0 00	0.00	0.00	0.00	0.00
2019	0 00	0 00	0.00	0.00	0.00
2020	0.00	0 00	15.00	25 00	0.00
2021	0 00	0.00	15.29	25.47	0 00
2022	15 08	15 08	15.58	25.96	0.00
2023	15 28	15.28	15.88	26.47	0.00
2024	15.48	15.48	16.19	27.00	0.00
2025	15.67	15.67	16.51	27 52	0.00
2026	15.88	15.88	16.84	28.08	0.00
2027	16 08	16.08	17 17	28.62	0.00
2028	16 29	16.29	17 50	29 18	0.00
2029	16.50	16.50	17.85	29.74	0.00
2030	16.72	16 72	25.00	40 00	0.00
2031	16.94	16 94	25.47	40 76	0.00
2032	17.16	17 16	25.96	41.52	0.00
2033	17.38	17 38	26.44	42.31	0 00
2034	17.61	17 61	26.93	43.09	0 00
2035	17.84	17.84	27.43	43 88	0 00
2036	18.07	18.07	27.93	44 69	0.00
2037	18.31	18.31	28 44	45.50	0 00
2038	18 55	18.55	28 96	46.34	0.00
2039	18 79	18.79	29 50	47.19	0.00
2040	19.04	19.04	30 04	48.06	0.00

EXHIBIT RSW-4

Excerpt: Direct Testimony of Scott C. Weaver (Oct. 21, 2016),

Indiana Utility Regulatory Commission, Cause No. 44871

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY (I&M), AN INDIANA CORPORATION, FOR APPROVAL OF A CLEAN ENERGY PROJECT AND QUALIFIED POLLUTION CONTROL PROPERTY AND FOR ISSUANCE OF CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR USE OF CLEAN COAL TECHNOLOGY; FOR ONGOING REVIEW; FOR APPROVAL OF ACCOUNTING AND RATEMAKING, INCLUDING THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF SUCH PROJECT THROUGH I&M'S CLEAN COAL TECHNOLOGY RIDER; FOR APPROVAL OF DEPRECIATION PROPOSAL FOR SUCH PROJECT; AND FOR AUTHORITY TO DEFER COSTS INCURRED DURING CONSTRUCTION AND OPERATION, INCLUDING CARRYING COSTS, DEPRECIATION, TAXES, OPERATION AND MAINTENANCE AND ALLOCATED COSTS, UNTIL SUCH COSTS ARE REFLECTED IN THE CLEAN COAL TECHNOLOGY RIDER OR OTHERWISE REFLECTED IN I&M'S BASIC RATES AND CHARGES.	)	**CAUSE NO.**

SUBMISSION OF DIRECT TESTIMONY OF
<u>SCOTT C. WEAVER</u>

Indiana Michigan Power Company, by counsel, hereby submits the direct testimony and attachments of Scott C. Weaver.

Q. IS PROJECTED NATURAL GAS PRICING A DRIVER FOR SUCH ANALYTICAL PROCESSES?

A. Yes, it typically is. In the electric utility industry, the natural gas-fired units often serve as the marginal cost, or "price-setting" units based on their relative higher position in a typical regional dispatch stack (relative to lower variable cost hydro, nuclear and coal-fired units). In PJM, that is most typically the case during "on-peak" hours.[30] Therefore, the price of natural gas will not only determine where gas-fueled units may fall in any regional dispatch stack, it will then largely determine the Locational Marginal Price ("LMP") in which energy may clear in any market-based system such as PJM.

Typically, the higher the natural gas price, the higher gas-fired units—such as even thermally-efficient combined cycle units—would climb in PJM's dispatch stack; and then, depending upon contemporaneous load requirements and constraints, the higher the resulting market-based energy price/LMP might be. Based on that, margins or "spreads" available to more efficient coal-fired units could simultaneously be improved.

Conversely, the lower the gas price, the lower these CC units may fall in PJM's market-based dispatch/supply stack, thereby setting a lower clearing price for a greater number of hours/sub-hours. Under this latter outcome, coal units could potentially be called upon to generate less energy at a lower available spread.

Q. PLEASE PROVIDE AN OVERVIEW OF THE FORECASTED FUNDAMENTAL COMMODITY PRICING, INCLUDING NATURAL GAS,

[30] Although the definition varies, typically, on-peak hours represent a 16-hour per-day period M-F, 6AM-10PM, excluding holidays.

THAT WERE USED IN THE ROCKPORT UNIT 2 DISPOSITION ANALYSES?

A. As shown in **TABLE 4** below, an array of five (5) unique, long-term commodity pricing scenarios were utilized in the Rockport Unit 2 disposition analyses, consisting of a "base" view; two "price banding" sensitivity views; and two "CO_2/carbon" views:

TABLE 4

'BASE' Forecast ... *reflecting:*

- Recognition of relatively lower fuel price trending due to proliferation of shale gas, increasing natural gas price elasticity; as well as capturing a likely implementation profile of environmental regulation including CSAPR, MATS Rule and potential CO_2 mitigation via a ~$15/tonne[31] "carbon tax" (beginning in 2022).

Commodity Price Banding Scenarios…

2. "Higher Band"…*same as the BASE case except:*

- Bounds the high-end of the BASE case with plausible fuels, emissions and energy pricing—with appropriate feedback for load response—and with such fuel prices varying by approximately a +1.0 standard deviation.

3. "Lower Band" ... *same as the BASE case except:*

- Likewise, bounds the low-end of the BASE case with plausible fuel, emissions and energy pricing, with such fuels prices varying by approximately a -1.0 standard deviation.

CO_2 Pricing Scenarios…

4. "No Carbon" Price... *same as the BASE case except:*

- Removes the proxy carbon tax from the suite of commodity pricing; while then adjusting for the correlative effects on other commodities associated with that removal.

5. "High Carbon" Price... *same as the BASE case except:*

- Increases the scale of the relative carbon tax by a magnitude of approximately 60% (to ~$25 tonne).

[31] The unit of measure representing a "metric" ton of CO_2 equal to 1,000 kilograms or 2,204 pounds and represented in "real" (2014) dollars.

The "BASE" Forecast" view reflects the full suite of long-term projection of commodity prices—inclusive of natural gas prices—established by the AEP Fundamental Analysis group that were used in this analysis. This forecast was internally published in the mid-2015 timeframe. Selected commodity pricing projections from that suite are reflected in Attachment SCW-2. This BASE Forecast view focused significantly on emerging natural gas pricing dynamics and considered evolving information that would support natural gas supply increases tied to the projected emergence of additional, significant levels of domestic shale gas at very competitive extraction costs.

This long-term view also assumes and embeds a "CO_2 pricing" impact as a result of potential carbon regulation such as the regulation of CO_2 emissions from *existing* fossil-fueled generating sources as recently set forth by the U.S EPA under Section 111(d) of the Clean Air Act via its Clean Power Plan ("CPP"). In conjunction with the final CPP ultimately submitted in August of 2015, the timing of a carbon pricing proxy in these long-term fundamental pricing forecasts was likewise assumed to be the year 2022.[32]

Q. ARE THE LONG-TERM COMMODITY PRICE FORECASTS USED IN THIS ROCKPORT UNIT 2 SCR PROJECT ANALYSIS—SUMMARIZED ON TABLE 4—CONSISTENT WITH THE PRICING FORECASTS USED IN I&M'S RECENT (NOVEMBER 2015) IRP SUBMITTAL?

[32] The Company and AEP's assumption/position around the prospect of a CO_2 carbon tax has been consistently assuming such a value/price in the AEP Fundamental Analysis group's "base" pricing projections since approximately the '2008' vintage forecasts; through the 2015 vintage forecast. The initial *timing* of such CO_2/carbon pricing in those earlier forecasts started around the year 2015, and has gradually migrated to the currently-assumed 2022 effective date.

VERIFICATION

I, Scott C. Weaver, Managing Director – Resource Planning & Operational Analysis of the American Electric Power Service Corporation, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Date: 10/19/16

Scott C. Weaver

EXHIBIT RSW-5

Excerpt: U.S. EPA, *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model* (Nov. 2013)

5. Emission Control Technologies

EPA Base Case v.5.13 includes an update of emission control technology assumptions. EPA contracted with engineering firm Sargent and Lundy to update and add to the retrofit emission control models previously developed for EPA and used in EPA Base Case v.4.10. EPA Base Case v.5.13 thus includes updated assumptions regarding control options for sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury (Hg), and particulate matter (PM). These emission control options are listed in Table 5-1. They are available in EPA Base Case v.5.13 for meeting existing and potential federal, regional, and state emission limits. It is important to note that, besides the emission control options shown in Table 5-1 and described in this chapter, EPA Base Case v.5.13 offers other compliance options for meeting emission limits. These include fuel switching, adjustments in the dispatching of electric generating units, and the option to retire a unit.

Table 5-1 Summary of Emission Control Technology Retrofit Options in EPA Base Case v.5.13

SO_2 and HCl Control Technology Options	NO_x Control Technology Options	Mercury Control Technology Options	Particulate Matter Control Technology Options	CO_2 Control Technology Options
Limestone Forced Oxidation (LSFO) Scrubber	Selective Catalytic Reduction (SCR) System	Activated Carbon Injection (ACI) System	Pulse-Jet Fabric Filter (FF)	CO_2 Capture and Sequestration
Lime Spray Dryer (LSD) Scrubber	Selective Non-Catalytic Reduction (SNCR) System	SO_2 and NO_x Control Technology Removal Co-benefits	Electrostatic Precipitator (ESP) Upgrade Adjustment	Coal-to-Gas Conversion
Dry Sorbent Injection (DSI)	Combustion Controls			Heat Rate Improvement
FGD Upgrade Adjustment				

Detailed reports and example calculation worksheets for Sargent & Lundy retrofit emission control models used by EPA are available in Attachments 5-1 through 5-7 at: www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html.

5.1 Sulfur Dioxide Control Technologies - Scrubbers

Two commercially available Flue Gas Desulfurization (FGD) “scrubber” technology options for removing the SO_2 produced by coal-fired power plants are offered in EPA Base Case v.5.13: Limestone Forced Oxidation (LSFO) — a wet FGD technology and Lime Spray Dryer (LSD) — a semi-dry FGD technology which employs a spray dryer absorber (SDA). In wet FGD systems, the polluted gas stream is brought into contact with a liquid alkaline sorbent (typically limestone) by forcing it through a pool of the liquid slurry or by spraying it with the liquid. In dry FGD systems the polluted gas stream is brought into contact with the alkaline sorbent in a semi-dry state through use of a spray dryer. The removal efficiency for SDA drops steadily for coals whose SO_2 content exceeds 3 lbs SO_2/MMBtu, so this technology is provided only to plants which have the option to burn coals with sulfur content no greater than 3 lbs SO_2/MMBtu. In EPA Base Casev.5.13 when a unit retrofits with an LSD SO_2 scrubber, it loses the option of burning certain high sulfur content coals (see Table 5-2).

In EPA Base Case v.5.13 the LSFO and LSD SO_2 emission control technologies are available to existing "unscrubbed" units. They are also available to existing "scrubbed" units with reported removal efficiencies of less than fifty percent. Such units are considered to have an injection technology and classified as “unscrubbed” for modeling purposes in the NEEDS database of existing units which is used in setting up the EPA base case. The scrubber retrofit costs for these units are the same as regular unscrubbed units retrofitting with a scrubber.

Default SO_2 removal rates for wet and dry FGD were based on data reported in EIA 860 (2010). These default removal rates were the average of all SO_2 removal rates for a dry or wet FGD as reported in EIA 860 (2010) for the FGD installation year.

To reduce the incidence of implausibly high, outlier removal rates, units whose reported EIA Form 860 (2010) SO_2 removal rates are higher than the average of the upper quartile of SO_2 removal rates across all scrubbed units are instead assigned the upper quartile average unless the reported EIA 860 rate was recently confirmed by utility comments. One upper quartile removal rate is calculated across all installation years and replaces any reported removal rate that exceeds it no matter the installation year.

Existing units not reporting FGD removal rates in form EIA 860 (2010) will be assigned the default SO_2 removal rate for a dry or wet FGD for that installation year.

As shown in Table 5-2, for FGD retrofits installed by the model, the assumed SO_2 removal rates will be 96% for wet FGD and 92% for dry FGD. These are the average of the SO_2 removal efficiencies reported in EIA 860 (2008) for dry and wet FGD installed in 2008 or later. These rates have been subjected to numerous reviews from utilities and other stakeholders recently, so they remain unchanged and continue to be used in EPA Base Case v.5.13.

The procedures used to derive the cost of each scrubber type are discussed in detail in the following sections.

Table 5-2 Summary of Retrofit SO_2 Emission Control Performance Assumptions in Base Case v.5.13

Performance Assumptions	Limestone Forced Oxidation (LSFO)	Lime Spray Dryer (LSD)
Percent Removal	96% with a floor of 0.06 lbs/MMBtu	92% with a floor of 0.08 lbs/MMBtu
Capacity Penalty	Calculated based on characteristics of the unit: See Table 5-3	Calculated based on characteristics of the unit: See Table 5-3
Heat Rate Penalty		
Cost (2011$)		
Applicability	Units ≥ 25 MW	Units ≥ 25 MW
Sulfur Content Applicability		Coals ≤ 3 lbs SO_2/MMBtu[1]
Applicable Coal Types	BA, BB, BD, BE, BG, BH, SA, SB, SD, SE, LD, LE, LG, LH, PK and WC	BA, BB, BD, BE, SA, SB, SD, SE, LD, and LE

[1] FBC units burning WC and PK fuels are provided with LSD retrofit options

Potential (new) coal-fired units built by the model are also assumed to be constructed with a scrubber achieving a removal efficiency of 96%. In EPA Base Case v.5.13 the costs of potential new coal units include the cost of scrubbers.

5.1.1 Methodology for Obtaining SO_2 Controls Costs

Sargent and Lundy's updated performance and cost models for wet and dry SO_2 scrubbers are implemented in EPA Base Case v.5.13 to develop the capital, fixed O&M (FOM), and variable O&M (VOM) components of cost. See Attachments 5-1 and 5-2 (www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html).

Capacity and Heat Rate Penalty: In IPM the amount of electrical power required to operate a retrofit emission control device is represented through a reduction in the amount of electricity that is available for sale to the grid. For example, if 1.6% of the unit's electrical generation is needed to operate the scrubber, the generating unit's capacity is reduced by 1.6%. This is the "capacity penalty." At the same time, to capture the total fuel used in generation both for sale to the grid and for internal load (i.e., for operating the control device), the unit's heat rate is scaled up such that a comparable reduction (1.6% in the previous example) in the new higher heat rate yields the original heat rate[24]. The factor used to scale up the original heat rate is called "heat rate penalty." It is a modeling procedure only and does not represent an increase in the unit's actual heat rate (i.e., a decrease in the unit's generation efficiency). In EPA Base Case v.5.13 specific LSFO and LSD heat rate and capacity penalties are calculated for each installation based on equations from the Sargent and Lundy models that take into account the rank of coal burned, its uncontrolled SO_2 rate, and the heat rate of the model plant.

Table 5-3 presents the capital, VOM, and FOM costs as well as the capacity and heat rate penalty for two SO_2 emission control technologies (LSFO and LSD) included in EPA Base Case v.5.13 for an illustrative set of generating units with a representative range of capacities and heat rates.

[24] Mathematically, the relationship of the heat rate and capacity penalties (both expressed as positive percentage values) can be represented as follows:

$$\text{Heat Rate Penalty} = \left(\frac{1}{\left(1 - \frac{\text{Capacity Penalty}}{100}\right)} - 1 \right) \times 100$$

Table 5-3 Illustrative Scrubber Costs (2011$) for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13

					Capacity (MW)											
					50		100		300		500		700		1000	
Scrubber Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
LSFO	9,000	-1.50	1.53	2.03	819	23.7	819	23.7	600	11.2	519	8.3	471	7.7	426	6.4
	10,000	-1.67	1.70	2.26	860	24.2	860	24.2	629	11.5	544	8.6	495	8.0	447	6.6
	11,000	-1.84	1.87	2.49	899	24.6	899	24.6	658	11.8	569	8.9	517	8.2	467	6.8
LSD	9,000	-1.18	1.20	2.51	854	29.1	701	17.3	513	8.6	444	6.5	422	5.7	422	5.3
	10,000	-1.32	1.33	2.79	894	29.6	734	17.7	538	8.9	465	6.8	442	5.9	442	5.5
	11,000	-1.45	1.47	3.07	933	30.0	766	18.0	561	9.1	485	7.0	461	6.1	461	5.7

Note: The above cost estimates assume a boiler burning 3 lb/MMBtu SO_2 Content Bituminous Coal for LSFO and 2 lb/MMBtu SO_2 Content Bituminous Coal for LSD.

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5.2 Nitrogen Oxides Control Technology

The EPA Base Case v.5.13 includes two categories of NO_x reduction technologies: combustion and post-combustion controls. Combustion controls reduce NO_x emissions during the combustion process by regulating flame characteristics such as temperature and fuel-air mixing. Post-combustion controls operate downstream of the combustion process and remove NO_x emissions from the flue gas. All the specific combustion and post-combustion technologies included in EPA Base Case v.5.13 are commercially available and currently in use in numerous power plants.

5.2.1 Combustion Controls

The EPA Base Case v.5.13 representation of combustion controls uses equations that are tailored to the boiler type, coal type, and combustion controls already in place and allow appropriate additional combustion controls to be exogenously applied to generating units based on the NO_x emission limits they face. Characterizations of the emission reductions provided by combustion controls are presented in Table 3-1.3 in Attachment 3-1. The EPA Base Case v.5.13 cost assumptions for NO_x Combustion Controls are summarized in Table 5-4. Table 3-11 provides a mapping of existing coal unit configurations and incremental combustion controls applied in EPA Base Case v.5.13 when units under certain conditions are assumed to achieve a state-of-the-art combustion control configuration.

Table 5-4 Cost (2011$) of NO_x Combustion Controls for Coal Boilers (300 MW Size)

Boiler Type	Technology	Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)
Dry Bottom Wall-Fired	Low NO_x Burner without Overfire Air (LNB without OFA)	48	0.3	0.07
	Low NO_x Burner with Overfire Air (LNB with OFA)	65	0.5	0.09
Tangentially-Fired	Low NO_x Coal-and-Air Nozzles with Close-Coupled Overfire Air (LNC1)	26	0.2	0.00
	Low NO_x Coal-and-Air Nozzles with Separated Overfire Air (LNC2)	35	0.2	0.03
	Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air (LNC3)	41	0.3	0.03
Vertically-Fired	NO_x Combustion Control	31	0.2	0.06

Scaling Factor

The following scaling factor is used to obtain the capital and fixed operating and maintenance costs applicable to the capacity (in MW) of the unit taking on combustion controls. No scaling factor is applied in calculating the variable operating and maintenance cost.

LNB without OFA & LNB with OFA = ($/kW for X MW Unit) = ($/kW for 300 MW Unit) x $(300/X)^{0.359}$

LNC1, LNC2, and LNC3 = ($/kW for X MW Unit) = ($/kW for 300 MW Unit) x $(300/X)^{0.359}$

Vertically-Fired = ($/kW for X MW Unit) = ($/kW for 300 MW Unit) x $(300/X)^{0.553}$

where ($/kW for 300 MW Unit) is a value from the above table and X is the capacity (in MW) of the unit taking on combustion controls.

5.2.2 Post-combustion NO_x Controls

The EPA Base Case v.5.13 includes two post-combustion retrofit NO_x control technologies for existing coal units: Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). In EPA Base Case v.5.13 oil/gas steam units are eligible for SCR only. NO_x reduction in a SCR system takes place by injecting ammonia (NH_3) vapor into the flue gas stream where the NO_x is reduced to nitrogen (N_2) and water (H_2O) abetted by passing over a catalyst bed typically containing titanium, vanadium oxides, molybdenum, and/or tungsten. As its name implies, SNCR operates without a catalyst. In SNCR a nitrogenous reducing agent (reagent), typically urea or ammonia, is injected into, and mixed with, hot flue gas where it reacts with the NO_x in the gas stream reducing it to nitrogen gas and water vapor. Due to the presence of a catalyst, SCR can achieve greater NO_x reductions than SNCR. However, SCR costs are higher than SNCR costs.

Table 5-5 summarizes the performance and applicability assumptions in EPA Base Case v.5.13 for each post-combustion NO_x control technology and provides a cross-reference to information on cost assumptions.

Table 5-5 Summary of Retrofit NO_x Emission Control Performance Assumptions

Control Performance Assumptions	**Selective Catalytic Reduction (SCR)**		**Selective Non-Catalytic Reduction (SNCR)**
Unit Type	Coal	Oil/Gas	Coal
Percent Removal	90%	80%	Pulverized Coal: 25% Fluidized Bed: 50%
Rate Floor	Bituminous: 0.07 lb/MMBtu Subbituminous and Lignite: 0.05 lb/MMBtu	--	Pulverized Coal: 0.1 lb/MMBtu Fluidized Bed: 0.08 lb/MMBtu
Size Applicability	Units ≥ 25 MW	Units ≥ 25 MW	Pulverized Coal: Units ≥ 25 MW and ≤ 100 MW Fluidized Bed: Units ≥ 25 MW
Costs (2011$)	See Table 5-6 Illustrative Post-combustion NOx Control Costs (2011$) for Coal Plants for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13	See Table 5-7	See Table 5-6 Illustrative Post-combustion NOx Control Costs (2011$) for Coal Plants for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13

5.2.3 Methodology for Obtaining SCR Costs for Coal

Sargent and Lundy's updated performance/cost models for SCR and SNCR technologies are implemented in EPA Base Case v.5.13 to develop the capital, fixed O&M (FOM), and variable O&M (VOM) components of cost. See Attachments 5-3 and 5-4 (www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html).

Table 5-6 presents the SCR and SNCR capital, VOM, and FOM costs and capacity and heat rate penalties for an illustrative set of coal generating units with a representative range of capacities and heat rates.

Table 5-6 Illustrative Post-combustion NO_x Control Costs (2011$) for Coal Plants for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13

					Capacity (MW)									
					100		300		500		700		1000	
Control Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
SCR	9,000	-0.54	0.54	1.23	321	1.76	263	0.76	243	0.64	232	0.58	222	0.53
	10,000	-0.56	0.56	1.32	349	1.86	287	0.81	266	0.69	255	0.63	244	0.57
	11,000	-0.58	0.59	1.41	377	1.96	311	0.87	289	0.73	277	0.67	265	0.62
SNCR - Tangential	9,000	-0.05	0.78	1.04	55	0.48	30	0.26	22	0.20	18	0.16	15	0.13
	10,000			1.15	56	0.50	30	0.27	23	0.20	19	0.17	15	0.14
	11,000			1.27	57	0.51	31	0.27	23	0.21	19	0.17	16	0.14
SNCR - Fluidized Bed	9,000	-0.05	0.78	1.04	41	0.36	22	0.20	17	0.15	14	0.12	11	0.10
	10,000			1.15	42	0.37	23	0.20	17	0.15	14	0.12	12	0.10
	11,000			1.27	43	0.38	23	0.21	17	0.15	14	0.13	12	0.10

Note: Assumes a boiler burning bituminous coal with an input NO_x rate of 0.5 lbs/MMBtu. The technology is applied to boilers larger than 25 MW.

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