BEFORE THE
CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA FOR COMMISSION AUTHORIZATION OF A PLAN AND COST RECOVERY OF ACTIONS OF PSO TO BE IN COMPLIANCE WITH CERTAIN ENVIRONMENTAL RULES PROMULGATED BY THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY; SUCH ACTIVITIES TO INCLUDE, BUT NOT BE LIMITED TO, CAPITAL EXPENDITURES FOR EQUIPMENT AND FACILITIES; CONSTRUCTION OR PURCHASE OF AN ELECTRIC GENERATING FACILITY OR ENTER INTO A LONG-TERM PURCHASE POWER CONTRACT (AND POSSIBLE EARNING ON THE CONTRACT); CHANGE IN DEPRECIATION RATES AND/OR ESTABLISHMENT AND RECOVERY OF A REGULATORY ASSET; AND FOR SUCH OTHER RELIEF AS THE COMMISSION DEEMS PSO IS ENTITLED.	Cause No. PUD 201200054

FILED
FEB 11 2013
COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

REBUTTAL TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

THE SIERRA CLUB

Resource Insight, Inc.

FEBRUARY 11, 2013

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I. Introduction

Q: Please state your name, occupation, and business address.

A: My name is Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Are you the same Jonathan Wallach that filed responsive testimony in this proceeding?

A: Yes.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Sierra Club.

Q: What is the purpose of your rebuttal testimony?

A: This rebuttal testimony responds to the responsive testimony by OIEC witness Scott Norwood regarding: (1) the Settlement Agreement between PSO, EPA, ODEQ, the Secretary of the Environment, and the Sierra Club; and (2) the Company's proposed Compliance Plan.

Q: Please summarize your findings and conclusions regarding Mr. Norwood's responsive testimony on the Settlement Agreement.

A: Mr. Norwood believes that the Company acted prematurely in entering into the Settlement Agreement and should not have taken any steps to comply with RHR and MATS until all litigation regarding these regulations had run its course. Mr. Norwood further claims that his wait-and-see approach would likely have reduced compliance costs, whether or not the Company eventually prevailed in the courts. Even if the RHR FIP were eventually upheld, Mr. Norwood asserts that customers would have still saved about $12 million for each month that the RHR compliance deadline was delayed, assuming that PSO would have been granted a stay.

The Commission should reject Mr. Norwood's speculations regarding the prudence of the Company's decision to enter the into the Settlement Agreement. It would have been reckless and contrary to prudent utility practice for the Company to have followed Mr. Norwood's advice to do nothing and hope for the best. In essence, Mr. Norwood suggests that PSO should have gambled ratepayer money on a bet that the courts would vacate the RHR FIP, "reinstate" the RHR SIP, and overturn the MATS regulation.[1] The industry appears to place very long odds on such an outcome, given widespread retirement announcements and decisions to expend vast sums on costly compliance retrofits (including by Oklahoma Gas and Electric for MATS compliance). Moreover, the consequences of being on the wrong side of the bet are much greater than Mr. Norwood conceives. Mr. Norwood's calculation of the savings from delayed implementation is fundamentally flawed and mistakes cost deferrals for cost savings. More critically, Mr. Norwood fails to account for the potentially substantial increase in the cost of RHR FIP compliance measures if, as a result of the implementation delay, those measures were installed after the MATS compliance measures.

Q: Would it be reasonable to judge the prudence of the Settlement Agreement based on the outcome of the RHR FIP and MATS litigation?

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[1] Mr. Norwood refers in his testimony to a "reinstatement" of the Oklahoma SIP, but as he acknowledges in response to Sierra Club to OIEC Data Request 2-4, the Oklahoma SIP was never approved by EPA and so never became effective. He also admits to no personal understanding of whether the Tenth Circuit could, in addition to vacating the RHR FIP, appropriately order EPA to approve the Oklahoma SIP.

A: No. Withholding judgment on the Settlement Agreement until the outcome of the RHR FIP and MATS litigation would constitute hindsight review, and as such would be inconsistent with Commission rules and practice. Instead, the prudence of the Company's decision to enter into the Settlement Agreement should be judged based on information at the time that the Settlement Agreement was negotiated and executed.

Q: Would it be reasonable to judge the prudence of individual provisions of the Settlement Agreement separately from other provisions?

A: No. The various provisions of the Settlement Agreement are inter-dependent and, in total, provide for a comprehensive resolution of a number of overlapping issues.[2] As a result, it would be inappropriate and potentially misleading to judge the reasonableness of any one provision without considering how it relates to other provisions in the Settlement Agreement. Therefore, it would be unreasonable to judge the prudence of the Company's decision to enter into the Settlement Agreement on the basis of the reasonableness of individual provisions in isolation from the rest of the Settlement Agreement.

Q: Please summarize your findings and conclusions regarding Mr. Norwood's responsive testimony on the proposed Compliance Plan.

A: Based on the Company's Strategist analysis of the Option #1A sensitivity case, Mr. Norwood concludes that the proposed Compliance Plan would be more expensive than installing DFGD on both Northeastern units and

[2] For example, only in combination do the various provisions relating to SO_2 emissions (i.e., use of ultra-low-sulfur coal, retirement of Northeastern Unit 4 in 2016, ramp-down of dispatch of Northeastern Unit 3, and retirement of Unit 3 in 2026) satisfy the SO_2 BART requirements for the Northeastern units.

continuing to operate both units for 25 more years. In fact, based on a number of adjustments to the Company's analysis, Mr. Norwood claims that the Company's economic analysis understates the cost advantage of Option #1A by about $616 million (cumulative present worth).[3] Moreover, Mr. Norwood asserts that the proposed Compliance Plan would be more risky than the Option #1A alternative, because there would be less fuel diversity and thus greater exposure to the risk of high gas prices under the proposed Compliance Plan.

The Commission should give no weight to Mr. Norwood's conclusion that it would be cheaper and less risky to retrofit the Northeastern units with DFGD than to implement the Company's proposed Compliance Plan. Mr. Norwood bases his conclusion regarding the cost advantages of DFGD retrofit on the results of a sensitivity case which, as I discussed in my responsive testimony, the Company acknowledges understates the likely cost of continued operation of the Northeastern units following DFGD retrofit. Furthermore, Mr. Norwood's calculations of the adjustments to the results of the Company's analysis of the Option #1A sensitivity case are marred by methodological flaws, unrealistic assumptions, and errors in calculation. Finally, Mr. Norwood's assessment of the impact of the proposed Compliance Plan on fuel diversity fails to account for the potential contribution of energy efficiency and wind resources to the supply mix or for

[3] Throughout his responsive testimony, Mr. Norwood primarily cites costs not in CPW dollars, but in cumulative nominal dollars, perhaps because the larger nominal-dollar figures appear more compelling. However, for the purposes of determining the economic value of compliance options, the only relevant measure is the cumulative present worth of annual costs over the 30-year study period.

the fact that the Company's economic analysis of the proposed Compliance Plan already reflects the risk of high gas prices.

Q: Has Mr. Norwood's responsive testimony caused you to modify any of the findings and conclusions of your assessment of the proposed Compliance Plan?

A: No. I continue to find that the Company has conclusively shown that the proposed Compliance Plan is likely to be the lowest-cost of feasible options for complying with the RHR and MATS and is likely to provide the strongest hedge against potential environmental restrictions over the next two decades. I therefore also continue to conclude that the Company's proposal to upgrade Northeastern Unit 3, retire Unit 4 in 2016, and to retire Unit 3 in 2026 is a reasonable approach for complying with the RHR FIP and MATS and for mitigating the risk of future environmental requirements.

II. The Settlement Agreement

Q: What does Mr. Norwood conclude with respect to the Settlement Agreement?

A: Mr. Norwood asserts that PSO acted prematurely in entering into the Settlement Agreement, because both the RHR FIP and MATS have been appealed and "could ultimately be delayed, modified, or vacated."[4] Mr. Norwood instead believes that the Company should not have taken any compliance action until all appeals relating to the RHR FIP and MATS had been exhausted.

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[4] *Responsive Testimony of Scott Norwood on behalf of Oklahoma Industrial Energy Consumers*, Cause No. PUD 201200054, January 8, 2013, p. 4.

Mr. Norwood further claims that his wait-and-see approach would likely have reduced compliance costs, whether or not the Company eventually prevailed in the courts. Mr. Norwood estimates that enactment of the original Oklahoma SIP instead of the RHR FIP "could save approximately $400 million per year in capital, fuel, and operations and maintenance costs."[5] Even if the RHR FIP were eventually upheld, Mr. Norwood estimates that customers would have still saved about $12 million for each month that the RHR compliance deadline was delayed.

Q: Would it have been reasonable for PSO to do nothing and hope for the best outcome from the RHR and MATS litigation, as Mr. Norwood suggests?

A: No. It would have been contrary to prudent planning practice for PSO to simply await the outcome of litigation before initiating a compliance plan. Doing nothing in the face of an uncertain future is not an option for utilities. Instead, faced with uncertain outcomes, utilities must identify the range of possible outcomes, assess the likelihood of those outcomes, evaluate the risks (i.e., costs and other consequences) of potential outcomes, and then plan accordingly. In this case, the Company apparently determined that the Settlement Agreement was reasonable given the likely outcomes of the RHR FIP and MATS litigation and the risks of future environmental regulations.[6]

More broadly, owners of coal plants across the U.S. (including Oklahoma Gas and Electric) apparently are making decisions today as to how to bring their plants into compliance with MATS rather than wait for the

[5] *Id.*, p. 19.

[6] Apparently, EPA, ODEQ, the Secretary of the Environment, and the Sierra Club also judged the Settlement Agreement to be a reasonable way to resolve the RHR FIP litigation.

outcome of the MATS litigation (or for any greater certainty regarding future environmental regulations.) These owners are choosing to either incur substantial compliance costs or to retire their plants even though the outcome of the MATS litigation and the scope of other rules are uncertain at this time.[7]

Q: If the courts were to vacate the RHR FIP, would it necessarily be replaced by the original Oklahoma SIP?

A: No. Mr. Norwood takes a logical leap in assuming that the original SIP would be enacted if the RHR FIP were to be vacated. As he acknowledges in response to Sierra Club Data Request 2-4, even if the Court remands the RHR FIP to EPA, it is uncertain what instructions the Court would give EPA for its reconsideration.

Q: Will the outcome of Oklahoma Gas and Electric's challenge to the RHR FIP in the Tenth Circuit affect PSO?

A: No. The pending challenge pertains only to the portion of the RHR FIP that affects four coal plants owned Oklahoma Gas and Electric.[8]

Q: Please describe how Mr. Norwood estimates that enactment of the SIP in place of the RHR FIP would save $400 million per year.

A: As indicated in Exhibit SN-12, Mr. Norwood believes that there are two sources of savings contributing to the $400 million total. First, Mr. Norwood estimates that enactment of the SIP (with a more permissive standard for SO_2 emissions than in the RHR FIP) would avoid about $149 million per year for

[7] See Exhibit JFW-6, which updates the list of retirement announcements provided in Exhibit JFW-2 to reflect the announced retirement of eleven additional plants in five states since my responsive testimony was filed.

[8] Order Granting Motion to Stay, *State of Oklahoma v. Jackson*, Nos. 12-9526 & 12-9527 (10th Cir. Jun. 22, 2012). (Provided in Exhibit JFW-7.)

DFGD capital recovery and O&M expenditures.[9] Second, Mr. Norwood estimates that enactment of the SIP would avoid about $256 million per year for replacement of capacity and energy from Northeastern Units 3 and 4 with market purchases.[10]

Q: Has Mr. Norwood reasonably estimated the likely savings from enactment of the original SIP instead of the RHR FIP?

A: No. To the contrary, Mr. Norwood's calculation overstates savings by: (1) incorrectly assuming that enactment of the SIP would avoid replacement power costs; and (2) failing to account for additional spending with enactment of the SIP.

Q: Why is Mr. Norwood incorrect in assuming that replacing the RHR FIP with the original SIP would avoid replacement power costs?

A: Enacting the original SIP in place of the RHR FIP would not avoid replacement power costs, because no such costs would be incurred if the RHR FIP were upheld. Instead, with the RHR FIP in force, the Northeastern units would continue to operate and therefore replacement market purchases would not be necessary. Consequently, Mr. Norwood's calculation overstates savings by at least $256 million.

Q: How does Mr. Norwood's calculation fail to account for additional spending under the SIP?

A: Mr. Norwood's calculation assumes that, relative to the RHR FIP baseline, enacting the SIP would avoid capital expenditures for a DFGD with an

[9] This $149 million figure is the sum of Mr. Norwood's estimates for annual scrubber capital cost recovery ($119 million) and scrubber-related O&M ($30 million).

[10] This $256 million figure is the sum of Mr. Norwood's estimates of the costs to replace both Northeastern units' capacity ($163 million) and energy ($93 million).

integrated fabric filter. However, without DFGD, the Company might have to invest in DSI and a fabric filter (along with ACI) order to comply with MATS. If so, such incremental expenditures would reduce the savings from replacing the RHR FIP with the original SIP.

Q: Please describe how Mr. Norwood estimates the monthly savings from a delay in implementation of the RHR FIP.

A: As indicated in Exhibit SN-11, Mr. Norwood first estimates that the annual cost recovery for scrubber capital and O&M costs would amount to about $149 million per year, or about $12 million per month. Mr. Norwood then posits that each month's delay in implementation of the RHR FIP would avoid the estimated monthly cost recovery of $12 million for scrubber capital and O&M.

Q: Has Mr. Norwood reasonably estimated the cost impact from a delay in implementation of the RHR FIP?

A: No. Mr. Norwood's calculation is conceptually flawed, since it improperly treats a $12 million monthly cost *deferral* as a monthly cost *savings*. In other words, each month's delay in implementation of the RHR FIP would defer by one month the start of cost recovery. However, once cost recovery begins, PSO would recover over time the same amount of scrubber capital and O&M costs in total as would be recovered without a delay in implementation. Thus, contrary to Mr. Norwood's claim, there would be no savings to ratepayers from a delay in implementation of the RHR FIP.

In fact, an implementation delay could increase compliance costs, if it were to preclude installation of the scrubber prior to installation of the other measures required to comply with MATS. According to the Company's response to OIEC Data Request 7-3:

> Utilizing the NID technology allows the lowest-cost one step strategy for environmental compliance. It is estimated that using a two step-approach for installation (To first comply with MATS and then the Regional Haze Rule) of the DFGD would increase the overall capital cost of the project between 20 and 40 percent. Additionally using a two-step approach for compliance would force the use of a SDA type of DFGD, which is a step backwards in terms of innovation of DFGDs. The NID type of DFGD is superior to the SDA by eliminating the lime slurry preparation equipment; the reactor vessel and the high-maintenance reagent spray equipment.

Moreover, even if PSO had not settled and been granted a stay, there is no guarantee that the court, if it ruled against the Company, would have provided for adequate lead time to comply with the RHR FIP. If not, the Company might have been forced to spend more than currently budgeted on labor, equipment, or materials in order to accelerate the construction schedule. More critically, PSO might not have been able meet the court's deadline because of competition for available labor and equipment within SPP.[11] If so, the Company would have needed to keep the Northeastern units out of service for longer than expected and to purchase additional short-term replacement power for the duration.

Q: What do you conclude with regard to Mr. Norwood's responsive testimony on the Settlement Agreement?

A: There is no merit to Mr. Norwood's argument that ratepayers would be better off if the Company had not entered into the Settlement Agreement and instead waited for the outcome of litigation over the RHR FIP and MATS. Given the long odds against winning both cases and the potentially severe

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[11] According to NERC, "In SPP, it is expected that the impact of retrofits will constrain the availability and increase the costs of qualified labor, materials, and heavy equipment." See North American Electric Reliability Corporation, *2012 Long-Term Reliability Assessment*, November, 2012, p. 26. (Available at www.nerc.com/files/2012_LTA_FINAL.pdf.)

consequences from losing either one, it would not have been reasonable for PSO to have followed Mr. Norwood's advice to gamble ratepayer money on a bet that the courts would vacate the RHR FIP, order EPA to approve the RHR SIP in its place, and overturn the MATS regulation.

III. Economic Analysis of the Proposed Compliance Plan

Q: What does Mr. Norwood find with regard to the proposed Compliance Plan?

A: Based on the Company's Strategist analysis of the Option #1A sensitivity case, Mr. Norwood finds that the proposed Compliance Plan would be more expensive than installing DFGD on both Northeastern units and continuing to operate both units for 25 more years. Although the Company's analysis of the Option #1 base case shows that the proposed Compliance Plan would be less expensive than installing DFGD and operating the Northeastern units for 15 more years, Mr. Norwood apparently rejects these results as "primarily based on speculative concerns regarding the potential cost impact of future EPA regulations which may never exist."[12]

Mr. Norwood also finds that the Company's economic analysis suffers from a number of speculative compliance cost assumptions and analytical flaws that render it "unreasonably biased in favor of the Settlement."[13] Based on a number of adjustments to the Company's analysis, Mr. Norwood claims that the Company's economic analysis understates the cost advantage of the Option #1A sensitivity by about $616 million (cumulative present worth).

[12] *Responsive Testimony of Scott Norwood*, p. 5.

[13] *Id*.

Finally, Mr. Norwood asserts that the proposed Compliance Plan would be more risky than the Option #1A sensitivity, because there would be less fuel diversity under the proposed Compliance Plan:

> By requiring the premature retirement of the Northeastern coal units, the proposed EPA Settlement would virtually eliminate the existing fuel diversity on PSO's system, thereby creating significantly higher future cost risk for customers when compared to the Coal Retrofit option.[14]

Mr. Norwood further claims that the hedge value of the additional fuel diversity with continued operation is indicated by the results of the Company's economic analysis using a high gas price forecast. This high gas price forecast increases the cost advantage of the Option #1A sensitivity over the EPA Settlement Option case by about $323 million. Thus, from Mr. Norwood's perspective, continued operation of the Northeastern units provides a hedge against the risk that the cost of the proposed Compliance Plan would be $323 million more than expected due to higher-than-expected gas prices.

Q: Does the Option #1A sensitivity case realistically portray the likely costs to continue operating the Northeastern units for 25 years?

A: No. As I discussed in my responsive testimony, and as PSO acknowledges, the Option #1A sensitivity does not account for the potentially substantial costs to comply with a host of impending environmental regulations. As a result, the Company's economic analysis likely understates the cost advantage of the EPA Settlement Option case relative to the Option #1A sensitivity.

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[14] *Id.*, p. 6.

Q: Do you agree with Mr. Norwood's characterization of the cost impacts from these impending regulations as "speculative"?

A: No, I do not. As shown in my responsive testimony and in Mr. Ground's direct testimony, it is reasonable to expect that the Northeastern units will be subject to a number of new or tighter environmental regulations in the future, and that the Company will incur substantial costs to comply with such regulations.

Likely new or tightened regulations include:

- **Regional Haze**. The BART analysis at issue in the dispute over the RHR FIP is only one aspect of regional haze requirements. The Clean Air Act requires states to develop plans for reasonable progress toward eliminating man-made visibility problems in national parks and wilderness areas through compliance with a Long Term Strategy. (42 U.S.C. § 7491(b)(2)(B).) States have ongoing obligations to both report on their "reasonable progress goals," and devise long term strategy plans with "enforceable emission limitations, compliance schedules, and other measures as necessary to achieve the [reasonable progress goals]."[15] A second regional haze implementation plan is due to EPA in 2018 and every 10 years thereafter.[16] If the state submits an insufficient plan to EPA, EPA may disapprove the plan. (42 U.S.C. §§ 7410(c), 7491(b)(2).)
- **Revised NAAQS for ozone.** As I discussed in my responsive testimony, the EPA is considering revising the 8-hour ozone NAAQS

[15] 40 C.F.R. § 51.308(d)(3), (f), (g) (setting out requirements for long term strategy plans, revisions of implementation plans, and periodic reports).

[16] *Id.* See Exhibit JFW-8 for a graphical depiction of the regional haze timeline.

from 75 ppb down to 60-70 ppb. The EPA has stated that it will propose a rule to revise the ozone NAAQS in 2013 and issue a final rule in 2014.[17]

As I also noted in my responsive testimony, the EPA predicts that Tulsa will be out of attainment in 2020 if the ozone standard is revised to 65 ppb or lower. As Oklahoma Gas and Electric Company has stated to the Commission:

> If an area is redesignated as nonattainment for a NAAQS, existing sources could be required to reduce emissions of NOx, volatile organic compounds and/or SO2. The reductions required for existing facilities could create a need for OG&E to install scrubbers, SCRs and/or baghouses.[18]

- **New One-Hour SO_2 Primary NAAQS.** The new 1-hour SO_2 standard (described in Mr. Ground's direct testimony) poses significant challenges for coal-fired power plants. For example, a study by Burns & McDonnell concluded that "both scrubbed and unscrubbed boilers will have difficulty complying with the new one-hour SO2 NAAQS during short-term high emissions."[19]

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[17] See Memorandum from G. McCarthy, Assistant Administrator, EPA to Air Division Directors, Regions 1-10, September 22, 2011. (Available at http://www.epa.gov/glo/pdfs/OzoneMemo9-22-11.pdf.) Also, see EPA "Regulatory Gateway" database, which projects publication in the Federal Register of a proposed rule by October of 2013. (Available at http://yosemite.epa.gov/opei/RuleGate.nsf/(LookupRIN)/2060-AP38#4.)

[18] Comments of Oklahoma Gas & Electric Company, Cause No. PUD 201100077, filed July 11, 2011, pp. 5-6.

[19] Robynn Andracsek, et al, Burns & McDonnell, "Flue Gas Desulfurization-Equipped Coal-Fired Power Plants: Will They Comply with the 1-Hour National Ambient Air Quality Standard for Sulfur Dioxide?", TECHBriefs 2011 No. 2, p. 2. (Provided in Exhibit JFW-9.)

- **Cross State Air Pollution Rule**. The EPA has a statutory duty to require states to address emissions that "contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to [the NAAQS]."[20] Furthermore, states' obligations with respect to cross-state air pollution are tied to the National Ambient Air Quality Standards.[21] As the NAAQS get tighter, there is greater likelihood that an upwind state will contribute to nonattainment in a downwind state. As a result, although the 2010 version of CSAPR was vacated by the D.C. Circuit, future regulations on interstate air pollution implemented to comply with the D.C. Circuit's opinion could be even stricter. The regulations will have to address lower annual standards for fine particulate matter (PM2.5), which were finalized in January 2013, as well as updated ozone standards, which are expected to be finalized in 2014.[22]
- **Carbon legislation**. The Obama Administration has recently placed a renewed emphasis on addressing climate change, including emissions from fossil-fuel fired power plants, and at least one member of

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[20] See Clean Air Act Section 110(a)(2)(d)(i).

[21] See Clean Air Act Section 110(a)(2)(d)(i).

[22] *National Ambient Air Quality Standards for Particulate Matter; Final Rule,* 78 Fed. Reg. 3086 (Jan. 15, 2013), *available at* http://www.gpo.gov/fdsys/pkg/FR-2013-01-15/pdf/2012-30946.pdf. (At p. 3088: "EPA is revising the annual PM2.5 standard by lowering the level from 15.0 to 12.0 mg/m3 so as to provide increased protection against health effects associated with long-and short-term exposures…. This action provides increased protection for children, older adults, persons with pre-existing heart and lung disease, and other at-risk populations against an array of PM2.5- related adverse health effects that include premature mortality, increased hospital admissions and emergency department visits, and development of chronic respiratory disease.")

Congress has announced plans to introduce legislation. Senator Sanders (I-VT) stated on January 22, 2013, "Next month, I will introduce comprehensive legislation that will charge the fossil fuel corporations a fee for their carbon pollution."[23]

- **Greenhouse Gas New Source Performance Standards (NSPS) for existing units.** The EPA has not indicated a timeline for issuing rules to address greenhouse gases from existing coal-fired power plants. However, EPA's statutory duty to do so will be triggered when it finalizes its proposed regulations for new units, now expected in March 2013.[24] (*See* Clean Air Act, Section 111(d), which requires EPA to prescribe regulations addressing any air pollutant "to which a standard of performance under this section would apply if such existing source were a new source").
- **Coal Combustion Residuals.** The EPA proposed two alternative rules on June 21, 2010, but has not yet finalized either rule. Eleven environmental groups have filed a lawsuit in federal district court claiming that EPA's failure to regulate the storage and disposal of coal ash, which is known to contain highly toxic substances, is a violation of the Resource Conservation and Recovery Act.[25] Briefing has concluded in this proceeding. As noted by Mr. Ground, this litigation could result in a firm deadline for EPA to issue a final CCR Rule.

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[23] http://www.sanders.senate.gov/newsroom/news/?id=D33B9C34-5C41-4A2E-A9A9-4C78626A1655.

[24] Office of Management & Budget, Unified Agenda database, http://www.reginfo.gov/public/do/eAgendaViewRule?pubId=201210&RIN=2060-AQ91.

[25] See *Appalachian Voices v. Jackson* (D.D.C.), Complaint, available at http://earthjustice.org/sites/default/files/Stamped-Complaint_04-05-2012.pdf.

Moreover, the Northeastern facility's coal ash landfill has only an "in-situ clay liner," meaning that the landfill currently does not have a synthetic liner to protect against toxics that may be leaching into groundwater or surface water and causing risks to human health.[26] It is reasonable to conclude that PSO will have to address this issue well prior to 2041, regardless of the details and timing of the CCR Rule.

- **Effluent Limitation Guidelines.** The EPA is bound by consent decree to issue effluent limitations for coal-fired power plants by May of 2014.[27] The EPA is bound to propose the rule by April 19, 2013 and has already begun the interagency review process. The EPA has indicated it will not seek further extensions of the deadline to propose a rule.[28]

Q: Are you aware of any estimates of the costs to comply with these new regulations?

A: Yes. I am aware of a number of studies and utility filings that assume implementation of many of these new regulations and that estimate expected costs to comply with such regulations. For example:

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[26] See PSO Response to Sierra Club DR 2-6. Also, see EPA, *Frequent Questions: Coal Combustion Residues (CCR) - Proposed Rule.* (Available at http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ ccr-rule/ccrfaq.htm#8.) ("EPA's risk assessment suggests, and damage cases confirm, that the management of CCRs in unlined and clay-lined landfills and surface impoundments may present risks to human health and the environment through leaching. For landfills and surface impoundments the primary concern is cancer risk from arsenic in drinking water. Surface impoundments also showed high non-cancer risks from cobalt and nitrate/nitrite in drinking water.")

[27] EPA, Steam Electric Power Generation Effluent Limitation Guidelines webpage, http://water.epa.gov/scitech/wastetech/guide/steam-electric/index.cfm#point7. (See links to Consent Decree, Consent Decree Extensions, and Status Report.)

[28] Steam Electric Power Generation Effluent Limitation Guidelines webpage.

- For its economic analysis of the installation of DFGD at the Flint Creek coal plant in Arkansas, Southwestern Electric Power Company assumed that selective catalytic reduction (SCR) would be required by 2020 in order to comply with "potential (future) requirements for further NO_x reduction under revised National Ambient Air Quality Standards (NAAQS) for NO_x/ozone."[29] Southwestern Electric Power Company further assumed an installed cost for SCR of $130 million for the 528 MW plant, or about $246/kW.[30] Based on this unit-cost estimate, the installed cost for SCR at the both Northeastern units would amount to about $230 million.[31]
- For compliance with CO_2 regulations, there have been numerous forecasts of allowance prices that were either derived from economic analyses of cap-and-trade legislation or developed by electric utilities for planning purposes. For example, a 2012 study by Synapse Energy Economics reports that, in 55 publicly available forecasts of allowance prices by electric utilities, the forecasted price for 2030 ranges from $10/ton (2012$) to $80/ton (2012$).[32] Furthermore, the Company relied on the same forecast of CO_2 prices in this case as its affiliate,

[29] *Direct Testimony of Scott C. Weaver on behalf of Southwestern Electric Power Company*, Arkansas Public Service Commission Docket No. 12-008-U, February 8, 2012, Table 5, p. 24.

[30] *Id.*, Table 6, p. 37.

[31] In its BART evaluation for PSO, the Oklahoma Department of Environmental Quality estimated that the capital cost of installing SCR at the Northeastern units would be $290 million. (See PSO Response to OIEC DR 3-2 (Supplemental Response), "Exhibit C, Final Northeastern BART Determination", Table 5.)

[32] Synapse Energy Economics, Inc., *2012 Carbon Dioxide Price Forecast*, October 4, 2012, p. 22. (Available at http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf.)

Southwestern Electric Power Company, used for its Flint Creek analysis.

- With regard to CCR compliance, generic cost assumptions have been adopted in various studies of the economic and reliability impacts of environmental compliance costs. For example, a 2010 study by the North American Electric Reliability Corporation assumed a cost of $30 million for bottom-ash conversion, or more than 50% greater than the cost assumed by PSO.[33] Likewise, a 2011 study by the Edison Electric Institute assumed a cost of $80 million for wastewater treatment for plants without FGD systems, or more than four times the cost assumed by PSO.[34]

Q: How does Mr. Norwood derive his $616 million adjustment to the Company's estimate of the CPW difference between the EPA Settlement Option and Option #1A case?

A: As indicated in Table 9 of his responsive testimony, Mr. Norwood makes four adjustments to the Company's estimate of a $278 million CPW difference between the EPA Settlement Option and Option #1A cases:

1. **No CO_2 taxes.** Mr. Norwood increases the CPW difference by $251 million based on his estimate of the effect of setting the CO_2 tax to zero. Mr. Norwood eliminates the cost of CO_2 taxes because "there are

[33] North American Electric Reliability Council, *2010 Special Reliability Assessment Scenario: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*, October, 2010, p. 56. (Available at http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf.)

[34] Edison Electric Institute, *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*, January, 2011, p. 37. (Available at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf.)

presently no carbon regulations which apply to existing coal units such as the Northeastern units, and whether there will ever be a carbon tax is pure speculation."[35]

2. **Excess Capacity Value.** Mr. Norwood notes that there is more excess capacity on the PSO system under the Option #1A sensitivity case than under the EPA Settlement Option case (at least in the near term), and that "the Company could sell some or all of the excess capacity and use the revenues to lower production costs of its system under the Coal Retrofit case."[36] Based on the Company's late-2011 economic analysis, Mr. Norwood estimates that explicit valuation of this excess capacity would increase the CPW cost advantage of the Option #1A case over the EPA Settlement Option case by about $93 million.

3. **Incremental O&M.** Based on a comparison with the Company's forecast for the new Turk coal plant, Mr. Norwood claims that the non-fuel O&M costs assumed for the Northeastern coal units in the Company's economic analysis "seem very high."[37] Substituting the Company's forecast of Turk O&M costs for its forecast of Northeastern O&M costs, Mr. Norwood estimates an increase in the CPW cost advantage of the Option #1A case of about $192 million.

4. **2013 NPV / Discount Rate.** Mr. Norwood asserts that the Company should be discounting annual costs back to 2013, rather than back to 2011. In addition, he believes that the Company's discount rate should be based on the currently approved return on equity (ROE) of 10.15%, rather

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[35] *Responsive Testimony of Scott Norwood*, p. 43.

[36] *Id.*, p. 57.

[37] *Id.*, p. 61.

than the 11.15% ROE assumed by the Company. Mr. Norwood estimates that the change in the discount year and rate increases the Option #1A CPW advantage by $80 million.

Q: Does Mr. Norwood offer a valid argument for assuming a zero price for CO_2?

A: No. As discussed above, contrary to Mr. Norwood's assessment of the likelihood of carbon regulation, a substantial number of utilities throughout the U.S. are assuming some form of future regulation for planning purposes. It was therefore reasonable for PSO to assume a carbon tax in its base case analysis.

Q: Has Mr. Norwood reasonably estimated the cost impact of a no-carbon sensitivity?

A: No. Mr. Norwood overstates the cost impact, because he fails to account for the offsetting effect on fuel prices from an assumption of no carbon taxes.

The Company's forecasts of coal and natural gas prices incorporate an estimate of the demand-related price impact from carbon taxes. Specifically, the Company's forecast reduces coal prices to reflect decreased demand with carbon regulation and increases gas prices to reflect increased demand with carbon regulation. Consequently, Mr. Norwood should have assumed higher coal prices and lower natural gas prices than forecast by PSO for the purposes of estimating the cost impact from elimination of carbon taxes. These adjustments to fuel prices would have *reduced* the CPW difference between the EPA Settlement Option and Option #1A cases and thus offset the increase to the CPW difference from elimination of carbon taxes.

As acknowledged in his response to AG / Staff Data Request 1-17, Mr. Norwood did not make any such adjustment to fuel prices for the purposes of estimating the impact from elimination of carbon taxes. As a result, Mr. Norwood overstated the cost adjustment for a no-carbon sensitivity.

Q: Would it be reasonable to include an explicit valuation of excess capacity in the Company's economic analysis?

A: Yes. However, Mr. Norwood has overstated the likely impact of explicit valuation, since his estimate is based on a forecast of capacity prices by PSO that is outdated and does not realistically reflect current market conditions in SPP. In particular, the Company's price forecast appears to assume that there will be surplus capacity in SPP, and that prices will be depressed to reflect such surplus, until around 2019. In contrast, the most recent reliability assessment from NERC indicates that surplus conditions will persist in SPP through at least the middle of the next decade.[38]

By adjusting the Company's capacity price forecast to reflect current forecasts of market surplus, I estimate that the CPW impact from explicit valuation of excess capacity would be about $32 million, or about one-third that estimated by Mr. Norwood.

Q: Is Mr. Norwood's adjustment for incremental O&M costs reasonable?

A: No. Mr. Norwood contends that the forecast of O&M costs for the Northeastern units should be based on that for the Turk coal plant. However, unlike the former, the latter is a brand-new coal plant with modern plant design and systems and integrated environmental controls. There is no reason to believe that O&M spending at the Northeastern units, with late-1970s design and retrofitted emissions controls, would bear any resemblance to that

[38] North American Electric Reliability Council, *2012 Long-Term Reliability Assessment*, November, 2012, p. 234.

forecast for the Turk plant, which began commercial operation in December of 2012.

It would be more reasonable to assume that O&M spending at Northeastern would be comparable to that forecast for the Flint Creek plant, since these plants are of similar vintage. Based on data provided in Mr. Weaver's direct testimony in the Flint Creek proceeding in Arkansas, the Company was forecasting a non-fuel O&M cost in 2016 of about $20 million for Southwestern Electric Power Company's 50% share of Flint Creek, or about $75/kW-yr.[39] At $75/kW-yr, O&M spending in 2016 at the Northeastern units would amount to about $70 million, or about 20% more than assumed for the Northeastern units in the Company's economic analysis in this proceeding. Thus, contrary to Mr. Norwood's finding, the Company's forecast of non-fuel O&M costs appears significantly understated, not "very high."

Q: How does Mr. Norwood derive his $80 million adjustment for the change in discount year and rate?

A: For the change in discount year, Mr. Norwood simply discounts the annual cost difference between the EPA Settlement Option and Option #1A cases back to 2013, rather than to 2011. As a result, the CPW difference increases by about $30 million. In other words, the CPW difference when expressed in 2013 discounted dollars is $30 million greater than when expressed in 2011 discounted dollars.

For the change in discount rate, Mr. Norwood discounts the annual cost difference between the two cases using a discount rate based on the

[39] *Direct Testimony of Scott C. Weaver on behalf of Southwestern Electric Power Company*, Arkansas Public Service Commission Docket No. 12-008-U, February 8, 2012, Exhibit SCW-5.

Company's current ROE.[40] Mr. Norwood estimates that reliance on this alternative discount rate would increase the CPW difference between the two cases by about $50 million.

Q: Is Mr. Norwood's adjustment for the discount year relevant to the economic comparison of the compliance scenarios?

A: No. Mr. Norwood is correct in his contention that changing the discount year from 2011 to 2013 will increase the *absolute* CPW difference between the two cases.[41] However, changing the discount year will have no effect on the *percentage* difference between the two cases' CPW. In other words, changing the discount year from 2011 from 2013 will increase the CPW for each case by the same percentage, such that the percentage difference between the two cases will be invariant with changes in the discount year.[42] Thus, changing the discount year will have no effect on the relative cost of the two cases.

Q: What is the basis for Mr. Norwood's use of the currently approved ROE to set the discount rate?

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[40] The Company sets the discount rate equal to its weighted cost of capital. For the purposes of the economic analysis of compliance options, the Company assumed an ROE of 11.15%, resulting in a discount rate of 8.4%. Using the currently approved ROE of 10.15% yields a discount rate of 7.9%.

[41] In fact, the absolute CPW difference will increase by 8.4% (i.e., by the discount rate) for each year that the discount year is advanced and will decrease by 8.4% for each year that the discount year is moved back.

[42] For example, the Company finds that the annual costs for the EPA Settlement Option case, when discounted to 2011, is 2% greater than the 2011 discounted cost for the Option #1A sensitivity case. If annual costs for each of these cases were discounted to 2013, the percentage difference between the 2013 discounted costs for these two cases would still be 2%.

A: The only reason that Mr. Norwood offers for his use of the current ROE to set the discount rate is that the ROE assumed by the Company "is relatively high" in comparison.[43]

This is not a valid basis for relying on the current ROE to set the discount rate. To the contrary, a higher ROE in the future could be justified, for example, on the basis of the fact that interest rates have been pushed to an extremely low levels by the Federal Reserve. To the extent that interest rates are expected to rise with improving economic conditions, it would be reasonable to assume that the return required by equity investors would also increase.

Q: What are Mr. Norwood's concerns with regard to the impact of the proposed Compliance Plan on fuel diversity?

A: Mr. Norwood has two related concerns regarding the impact of the proposed Compliance Plan on fuel diversity. First, Mr. Norwood is concerned about the drop in the contribution of coal-fired generation to total system requirements, because "at present, coal-fired generation is the only real hedge against rising natural gas prices on PSO's system."[44] Second, because coal is "the only real hedge," Mr. Norwood is concerned that the proposed Compliance Plan will expose ratepayers to a substantial risk from higher-than-expected gas prices. As the basis for this second concern, Mr. Norwood cites the results of a high gas price sensitivity conducted by the Company in response to AG / Staff Data Request 1-4. Mr. Norwood interprets the results of this sensitivity as indicating that the proposed Compliance Plan exposes ratepayers to the risk of an additional $323 million in costs if gas prices are higher than expected.

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[43] *Responsive Testimony of Scott Norwood*, p. 62.

[44] *Id.*, p. 24.

Q: Are Mr. Norwood's concerns justified?

A: No. Mr. Norwood is mistaken when he contends that coal-fired generation is the "only real hedge" against gas price volatility. To the contrary, as I discussed in my responsive testimony, there are large, untapped reserves of both energy-efficiency savings and wind generation in Oklahoma that the Company could rely on to hedge both gas and coal price risk (as well as the risk of future environmental restrictions on the Northeastern units.)[45]

Mr. Norwood's concern that the Company's economic analysis does not capture gas price risk is also unwarranted. In fact, as discussed in my responsive testimony, the Company's economic analysis already incorporates this risk as a certainty by relying on an outdated base-case price forecast that forecasts gas prices well in excess of current market prices. Consequently, the Company's economic analysis of the proposed Compliance Plan already captures the cost impact from higher-than-expected gas prices. In contrast, the results of the high gas price sensitivity would best be interpreted as indicating the consequences of a highly unlikely and extreme price divergence.

Q: What do you conclude with regard to Mr. Norwood's responsive testimony on the Company's economic analysis of the proposed Compliance Plan?

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[45] In my responsive testimony, I estimated the potential for additional energy efficiency if PSO were to ramp up its programs to achieve incremental annual savings of 1.5% of load. By coincidence, the Arkansas Public Service Commission issued an order at the same time as my responsive testimony was filed, which proposed that Arkansas utilities (including Southwestern Electric Power Company) target savings of 1.5% of load by 2016. See Arkansas Public Service Commission, *Order*, Docket No. 13-002-U, January 4, 2013, p. 7.

A: Mr. Norwood does not reasonably support his conclusion that it would be cheaper and less risky to retrofit the Northeastern units with DFGD than to implement the Company's proposed Compliance Plan. Mr. Norwood bases his conclusion regarding the cost advantages of DFGD retrofit on the results of a sensitivity case which, as the Company acknowledges, understates the likely cost of continued operation of the Northeastern units following DFGD retrofit. Furthermore, Mr. Norwood's calculations of the adjustments to the results of the Company's analysis of the Option #1A sensitivity case are marred by methodological flaws, unrealistic assumptions, and errors in calculation. Finally, Mr. Norwood's concerns regarding the impact of the proposed Compliance Plan on fuel diversity are misplaced, since he fails to account for the potential contribution of energy efficiency and wind resources to the Company's supply mix or to account for the fact that the Company's economic analysis of the proposed Compliance Plan already explicitly values the risk of high gas prices.

Q: Does this conclude your rebuttal testimony?

A: Yes.

State	Plant Name	Boiler	Year Operational	Nameplate (MW)	2010 Capacity Factor	Planned Retirement Date	Announcement Date	Announcement Source
AL	Widows Creek	5	1954	141	11%	7/31/2015	4/14/2011	EPA TVA Settlement
AL	Widows Creek	6	1954	141	9%	7/31/2015	4/14/2011	EPA TVA Settlement
AL	Widows Creek	3	1952	141	0%	7/31/2014	4/14/2011	EPA TVA Settlement
AL	Widows Creek	4	1953	141	10%	7/31/2014	4/14/2011	EPA TVA Settlement
AL	Widows Creek	1	1952	141	5%	7/31/2013	4/14/2011	EPA TVA Settlement
AL	Widows Creek	2	1952	141	1%	7/31/2013	4/14/2011	EPA TVA Settlement
AL	E C Gaston	1	1960	272	29%	4/1/2015	4/25/2012	Platts Electric Power Daily
AL	E C Gaston	2	1960	272	38%	4/1/2015	4/25/2012	Platts Electric Power Daily
AL	E C Gaston	3	1961	272	54%	4/1/2015	4/25/2012	Platts Electric Power Daily
AL	E C Gaston	ST4	1962	245	50%	4/1/2015	4/25/2012	Platts Electric Power Daily
AL	Gadsden	1	1949	69	22%	12/31/2014	7/3/2012	The Gadsden Times
AL	Gadsden	2	1949	69	16%	12/31/2014	7/3/2012	The Gadsden Times
AL	Colbert	5	1965	550	38%	12/31/2015	2/1/2013	TVA Consent Decree
CA	ACE Cogeneration Facility	GEN1	1990	108	83%	12/31/2017	12/31/2012	SNL reports planned retirement announcement date
CO	Arapahoe	4	1955	112	44%	12/31/2014	8/1/2008	PUC Docket - Reduction Emission Plan
CO	Arapahoe	3	1951	46	45%	12/31/2013	8/1/2008	PUC Docket - Reduction Emission Plan
CO	Cherokee	3	1962	171	52%	12/31/2011	8/13/2010	PUC Docket - Reduction Emission Plan
CO	Cherokee	4	1968	381	51%	12/31/2017	8/13/2010	PUC Docket - Reduction Emission Plan
CO	Valmont	5	1964	192	65%	12/31/2017	8/13/2010	PUC Docket - Reduction Emission Plan
CO	W N Clark	1	1955	19	61%	12/31/2013	12/16/2010	PUC Compliance with "Clean Air-Clean Jobs" Bill
CO	W N Clark	2	1959	25	72%	12/31/2013	12/16/2010	PUC Compliance with "Clean Air-Clean Jobs" Bill
CT	AES Thames	GEN1	1989	214	74%	4/30/2013	12/12/2011	Canadian Business
DE	Indian River Generating Station	1	1957	82	26%	5/1/2011	7/15/2010	WGMD News Radio
DE	Indian River Generating Station	3	1970	177	36%	12/31/2013	7/15/2010	WGMD News Radio
DE	NRG Energy Center Dover	COG1	1985	18	44%	5/30/2012	8/28/2012	DNREC Public Affairs Office
FL	Central Power & Lime	GEN1	1988	125	55%	12/31/2012	9/23/2011	Application for minor source air construction permit
GA	Harllee Branch	1	1965	299	30%	12/31/2013	3/16/2011	Georgia Power News Release
GA	Harllee Branch	2	1967	359	27%	10/1/2013	3/16/2011	Georgia Power News Release
GA	Harllee Branch	3	1968	544	46%	4/16/2015	1/7/2013	Georgia Power/Southern Company announcement for Harlee Branch
GA	Harllee Branch	4	1969	544	40%	4/16/2015	1/7/2013	Georgia Power/Southern Company announcement for Harlee Branch
GA	Mitchell	3	1964	163	7%	12/31/2012	3/26/2009	Georgia PSC
GA	Yates	1	1950	123	37%	4/16/2015	1/7/2013	Georgia Power/Southern Company announcement for Yates
GA	Yates	2	1950	123	34%	4/16/2015	1/7/2013	Georgia Power/Southern Company announcement for Yates
GA	Yates	3	1952	123	36%	4/16/2015	1/7/2013	Georgia Power/Southern Company announcement for Yates
GA	Yates	4	1957	156	35%	4/16/2015	1/7/2013	Georgia Power/Southern Company announcement for Yates
GA	Yates	5	1958	156	34%	4/16/2015	1/7/2013	Georgia Power/Southern Company announcement for Yates
GA	Yates	6	1974	404	50%	4/16/2015	1/7/2013	Georgia Power/Southern Company announcement for Yates
GA	Yates	7	1974	404	50%	4/16/2015	1/7/2013	Georgia Power/Southern Company announcement for Yates

GA	Kraft	ST1	1958	50	59%	4/16/2016	1/7/2013	Georgia Power/Southern Company announcement for Kraft
GA	Kraft	2	1961	54	56%	4/16/2016	1/7/2013	Georgia Power/Southern Company announcement for Kraft
GA	Kraft	3	1965	104	46%	4/16/2016	1/7/2013	Georgia Power/Southern Company announcement for Kraft
IA	Dubuque	3	1959	29	23%	1/1/2015	11/1/2010	IP&L Docket 08-673
IA	Dubuque	4	1952	38	29%	1/1/2015	11/1/2010	IP&L Docket 08-673
IA	Pella	6	1972	27	14%	12/31/2012	6/16/2011	Missouri River Energy Press Release
IA	Pella	5	1964	12	13%	12/31/2012	6/16/2011	Missouri River Energy Press Release
IA	Sutherland	1	1955	38	47%	1/1/2015	11/1/2010	IP&L Docket 08-673
IA	George Neal North	1	1964	147	71%	4/30/2016	1/22/2013	MidAmerican Consent Decree
IA	George Neal North	2	1972	349	65%	4/30/2016	1/22/2013	MidAmerican Consent Decree
IA	Walter Scott Jr Energy Center (Council B	1	1954	49	69%	4/30/2016	1/22/2013	MidAmerican Consent Decree
IA	Walter Scott Jr Energy Center (Council B	2	1958	82	87%	4/30/2016	1/22/2013	MidAmerican Consent Decree
IA	Riverside	3HS	1949	5	19%	4/30/2016	1/22/2013	MidAmerican Consent Decree
IA	Riverside	5	1961	136	49%	4/30/2016	1/22/2013	MidAmerican Consent Decree
IL	University of Illinois Abbott Power Plt	T10	2004	13	0%	12/31/2017	5/15/2010	IL Climate Action Plan
IL	University of Illinois Abbott Power Plt	T11	2004	13	0%	12/31/2017	5/15/2010	IL Climate Action Plan
IL	University of Illinois Abbott Power Plt	T12	2004	7	47%	12/31/2017	5/15/2010	IL Climate Action Plan
IL	University of Illinois Abbott Power Plt	T6	1959	8	33%	12/31/2017	5/15/2010	IL Climate Action Plan
IL	University of Illinois Abbott Power Plt	T7	1962	8	15%	12/31/2017	5/15/2010	IL Climate Action Plan
IN	CC Perry K	4	1925	15	2%	12/31/2014	11/16/2011	Indianapolis Business Journal
IN	CC Perry K	6	1938	5	10%	12/31/2014	11/16/2011	Indianapolis Business Journal
IN	CC Perry K	7	2009	2	24%	12/31/2014	11/16/2011	Indianapolis Business Journal
IN	CC Perry K	8	2009	2	0%	12/31/2014	11/16/2011	Indianapolis Business Journal
IN	Tanners Creek	1	1951	153	25%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
IN	Tanners Creek	2	1952	153	21%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
IN	Tanners Creek	3	1954	215	25%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
IN	Whitewater Valley	2	1973	61	25%	2/28/2013	8/2/2011	Louisville Platts
IN	Whitewater Valley	1	1955	33	27%	2/28/2013	8/2/2011	Louisville Platts
IN	Frank E Ratts	1	1970	117	75%	12/31/2015	5/9/2012	Power Engineering
IN	Frank E Ratts	2	1970	117	63%	12/31/2015	5/9/2012	Power Engineering
KS	Riverton	7	1950	38	39%	12/31/2015	12/31/2012	SNL reports planned retirement announcement date
KS	Riverton	8	1954	50	74%	12/31/2015	12/31/2012	SNL reports planned retirement announcement date
KY	Big Sandy	1	1963	281	36%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
KY	Cane Run	4	1962	163	65%	5/31/2015	9/15/2011	LG&E Press Release
KY	Cane Run	5	1966	209	61%	5/31/2015	9/15/2011	LG&E Press Release
KY	Cane Run	6	1969	272	51%	5/31/2015	9/15/2011	LG&E Press Release
KY	Green River	3	1954	75	53%	12/31/2015	9/15/2011	LG&E Press Release
KY	Green River	4	1959	114	55%	12/31/2015	9/15/2011	LG&E Press Release
KY	Shawnee	10	1956	175	12%	12/31/2015	4/14/2011	EPA TVA Settlement
KY	Tyrone	3	1953	75	21%	12/31/2015	9/15/2011	LG&E Press Release
KY	Robert A Reid	1	1966	96	1%	1/1/2014	4/2/2012	CPCN application in KY PSC case no. 2012-00063

LA	Big Cajun 2	2	1982	626	70%	4/15/2015	11/21/2012	Consent Decree
MA	Salem Harbor	1	1952	82	42%	6/1/2014	5/12/2011	PR Newswire
MA	Salem Harbor	2	1952	82	37%	6/1/2014	5/12/2011	PR Newswire
MA	Salem Harbor	3	1958	166	47%	6/1/2014	5/12/2011	PR Newswire
MI	B C Cobb	4	1956	156	78%	1/1/2015	12/2/2011	Gongwer News Michigan
MI	B C Cobb	5	1957	156	64%	1/1/2015	12/2/2011	Gongwer News Michigan
MI	Harbor Beach	1	1968	121	16%	12/31/2015	9/30/2011	PSCR Plan
MI	J C Weadock	7	1955	156	67%	1/1/2015	12/2/2011	Gongwer News Michigan
MI	J C Weadock	8	1958	156	60%	1/1/2015	12/2/2011	Gongwer News Michigan
MI	J R Whiting	1	1952	106	61%	1/1/2015	12/2/2011	Gongwer News Michigan
MI	J R Whiting	2	1952	106	66%	1/1/2015	12/2/2011	Gongwer News Michigan
MI	J R Whiting	3	1953	133	68%	1/1/2015	12/2/2011	Gongwer News Michigan
MN	Silver Lake	1	1948	8	-2%	12/31/2015	8/7/2012	RPU Utility Board Decision
MN	Silver Lake	2	1953	12	-1%	12/31/2015	8/7/2012	RPU Utility Board Decision
MN	Silver Lake	3	1962	25	7%	12/31/2015	8/7/2012	RPU Utility Board Decision
MN	Silver Lake	4	1969	54	2%	12/31/2015	8/7/2012	RPU Utility Board Decision
MN	Hoot Lake	2	1959	54	72%	12/31/2020	1/31/2013	Star Tribune
MN	Hoot Lake	3	1964	74	71%	12/31/2020	1/31/2013	Star Tribune
MN	Syl Laskin	1	1953	58	50%	12/31/2015	1/30/2013	Minnesota Power announcement
MN	Syl Laskin	2	1953	58	52%	12/31/2015	1/30/2013	Minnesota Power announcement
MN	Taconite Harbor Energy Center	GEN3	1967	84	57%	12/31/2015	1/30/2015	Minnesota Power announcement
MO	Asbury	2	1986	19	0%	1/31/2014	7/3/2012	Missouri PSC Docket
NC	Buck	5	1953	125	49%	1/1/2015	8/31/2010	Duke Energy Carolinas IRP
NC	Buck	6	1953	125	46%	1/1/2015	8/31/2010	Duke Energy Carolinas IRP
NC	L V Sutton	1	1954	113	41%	12/31/2014	12/1/2009	Progress Energy Retirement Plan
NC	L V Sutton	2	1955	113	44%	12/31/2014	12/1/2009	Progress Energy Retirement Plan
NC	L V Sutton	3	1972	447	45%	12/31/2014	12/1/2009	Progress Energy Retirement Plan
NC	Riverbend	4	1952	100	27%	1/1/2020	8/31/2010	Duke Energy Carolinas IRP
NC	Riverbend	5	1952	100	26%	1/1/2020	8/31/2010	Duke Energy Carolinas IRP
NC	Riverbend	6	1954	133	35%	1/1/2020	8/31/2010	Duke Energy Carolinas IRP
NC	Riverbend	7	1954	133	35%	1/1/2020	8/31/2010	Duke Energy Carolinas IRP
NC	Univ of NC Chapel Hill Cogen Facility	TG3	1991	28	27%	12/31/2020	5/4/2010	UNC News
NC	Lumberton	GEN1	1985	35	0%	4/1/2009	7/10/2012	SELC existing and proposed biomass facilities
NJ	B L England	1	1962	136	9%	10/31/2013	5/1/2012	Press of Atlantic City
NJ	B L England	2	1964	163	33%	5/31/2016	5/1/2012	Reuters
NM	Four Corners	1	1963	190	81%	12/31/2012	11/8/2010	Arizona Public Service Company News Release
NM	Four Corners	2	1963	190	73%	12/31/2012	11/9/2010	Arizona Public Service Company News Release
NM	Four Corners	3	1964	253	75%	12/31/2012	11/10/2010	Arizona Public Service Company News Release
NY	Cornell University Central Heat	TG2	1988	5	0%	6/1/2011	1/10/2010	Ithaca Journal
NY	Cornell University Central Heat	TG1	1988	1	0%	6/1/2011	1/10/2010	Ithaca Journal
NY	Black River Generation	GEN1	1989	56	17%	3/31/2013	8/28/2012	Black River company fuel swtich announcement

NY	Danskammer Generating Station	3	1959	147	52%	12/31/2102	12/10/2012	Dynegy retirement announcement
NY	Danskammer Generating Station	4	1967	239	49%	12/31/2102	12/10/2012	Dynegy retirement announcement
NY	S A Carlson	5	1951	25	1%	1/1/2015	12/31/2012	Jamestown Board of Public Utilities announcement
NY	S A Carlson	6	1968	25	20%	1/1/2015	12/31/2012	Jamestown Board of Public Utilities announcement
OH	Ashtabula	5	1958	256	39%	9/1/2012	1/26/2012	First Energy
OH	Avon Lake	7	1949	86	4%	4/30/2015	2/29/2012	GenOn Planned Retirement Announcement
OH	Avon Lake	12	1970	680	47%	4/30/2015	2/29/2012	GenOn Planned Retirement Announcement
OH	Eastlake	1	1953	123	71%	9/1/2012	1/26/2012	First Energy
OH	Eastlake	2	1953	123	52%	9/1/2012	1/26/2012	First Energy
OH	Eastlake	3	1954	123	47%	9/1/2012	1/26/2012	First Energy
OH	Lake Shore	18	1962	256	34%	9/1/2012	1/26/2012	First Energy
OH	Lausche Heating Plant	OUG1	1994	1	0%	12/31/2015	3/29/2011	Sierra Club - OU Press Release
OH	Miami Fort	6	1960	163	69%	1/1/2015	8/8/2011	Cincinnati.com
OH	Muskingum River	1	1953	220	38%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
OH	Muskingum River	2	1954	220	34%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
OH	Muskingum River	3	1957	238	44%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
OH	Muskingum River	4	1958	238	50%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
OH	Niles	2	1954	133	19%	6/30/2012	2/29/2012	GenOn Planned Retirement Announcement
OH	Picway	5	1955	106	7%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
OH	Shelby Municipal Light Plant	1	1968	13	26%	3/31/2011	10/1/2010	WMFD TV
OH	Shelby Municipal Light Plant	2	1973	13	34%	3/31/2011	10/1/2010	WMFD TV
OH	Shelby Municipal Light Plant	3	1948	5	0%	3/31/2011	10/1/2010	WMFD TV
OH	Shelby Municipal Light Plant	4	1954	7	3%	3/31/2011	10/1/2010	WMFD TV
OH	Walter C Beckjord	1	1952	115	-1%	1/1/2015	7/15/2011	Wall Street Journal
OH	Walter C Beckjord	2	1953	113	0%	1/1/2015	7/15/2011	Wall Street Journal
OH	Walter C Beckjord	3	1954	125	-1%	1/1/2015	7/15/2011	Wall Street Journal
OH	Walter C Beckjord	4	1958	163	39%	1/1/2015	7/15/2011	Wall Street Journal
OH	Walter C Beckjord	5	1962	245	56%	1/1/2015	7/15/2011	Wall Street Journal
OH	Walter C Beckjord	6	1969	461	51%	1/1/2015	7/15/2011	Wall Street Journal
OH	O H Hutchings	1	1948	69	0.05%	6/1/2015	5/10/2012	PJM Reliability Study
OH	O H Hutchings	2	1949	69	0.22%	6/1/2015	5/10/2012	PJM Reliability Study
OH	O H Hutchings	4	1951	69	4%	6/1/2013	6/28/2012	PJM Reliability Study
OH	O H Hutchings	5	1952	69	9%	12/31/2015	4/4/2012	Air Pollution Permit
OH	O H Hutchings	6	1953	69	8%	12/31/2015	4/4/2012	Air Pollution Permit
OK	Northeastern	3	1979	473	78%	12/31/2017	4/24/2012	Sierra Club Press Release
OK	Northeastern	4	1980	473	67%	12/31/2026	4/24/2012	Sierra Club Press Release
OR	Boardman	1	1980	601	78%	12/31/2019	10/27/2011	PUC Docket
PA	Elrama Power Plant	1	1952	100	3%	6/30/2012	2/29/2012	GenOn Planned Retirement Announcement
PA	Elrama Power Plant	2	1953	100	11%	6/30/2012	2/29/2012	GenOn Planned Retirement Announcement
PA	Elrama Power Plant	3	1954	125	7%	6/30/2012	2/29/2012	GenOn Planned Retirement Announcement
PA	Elrama Power Plant	4	1960	185	20%	6/30/2012	2/29/2012	GenOn Planned Retirement Announcement

PA	New Castle Plant	3	1952	98	23%	4/30/2015	2/29/2012	GenOn Planned Retirement Announcement
PA	New Castle Plant	4	1958	114	24%	4/30/2015	2/29/2012	GenOn Planned Retirement Announcement
PA	New Castle Plant	5	1964	136	25%	4/30/2015	2/29/2012	GenOn Planned Retirement Announcement
PA	Portland	1	1958	172	46%	1/31/2015	2/29/2012	GenOn Planned Retirement Announcement
PA	Portland	2	1962	255	45%	1/31/2015	2/29/2012	GenOn Planned Retirement Announcement
PA	Shawville	1	1954	125	46%	4/30/2015	2/29/2012	GenOn Planned Retirement Announcement
PA	Shawville	2	1954	125	44%	4/30/2015	2/29/2012	GenOn Planned Retirement Announcement
PA	Shawville	3	1959	188	46%	4/30/2015	2/29/2012	GenOn Planned Retirement Announcement
PA	Shawville	4	1960	188	51%	4/30/2015	2/29/2012	GenOn Planned Retirement Announcement
PA	Sunbury Generation LP	1	1949	89	56%	12/31/2014	12/28/2011	Centre Daily News
PA	Sunbury Generation LP	2	1949	89	51%	12/31/2014	12/28/2011	Centre Daily News
PA	Sunbury Generation LP	3	1951	104	36%	12/31/2014	12/28/2011	Centre Daily News
PA	Sunbury Generation LP	4	1953	156	40%	12/31/2014	12/28/2011	Centre Daily News
PA	Titus	1	1951	75	38%	4/30/2015	2/29/2012	GenOn Planned Retirement Announcement
PA	Titus	2	1951	75	36%	4/30/2015	2/29/2012	GenOn Planned Retirement Announcement
PA	Titus	3	1953	75	39%	4/30/2015	2/29/2012	GenOn Planned Retirement Announcement
SC	W S Lee	1	1951	90	30%	10/1/2014	8/31/2010	Duke Energy Carolinas IRP
SC	W S Lee	2	1951	90	31%	10/1/2014	8/31/2010	Duke Energy Carolinas IRP
SC	W S Lee	3	1958	175	38%	10/1/2014	8/31/2010	Duke Energy Carolinas IRP
SC	Canadys Steam	1	1962	136	26%	12/31/2012	5/30/2012	SCE&G announces planned retirement per the IRP
SC	Canadys Steam	2	1964	136	34%	12/31/2015	5/30/2012	SCE&G announces planned retirement per the IRP
SC	Canadys Steam	3	1967	218	33%	12/31/2015	5/30/2012	SCE&G announces planned retirement per the IRP
SC	Urquhart	3	1955	100	46%	12/31/2012	5/30/2012	SCE&G announces planned retirement per the IRP
SC	McMeekin	1	1958	147	60%	12/31/2015	5/30/2012	SCE&G announces planned retirement per the IRP
SC	McMeekin	2	1958	147	52%	12/31/2015	5/30/2012	SCE&G announces planned retirement per the IRP
SC	Dolphus M Grainger	1	1966	82	26%	12/31/2015	10/19/2012	Santee Cooper Retirement Announcement
SC	Dolphus M Grainger	2	1966	82	31%	12/31/2015	10/19/2012	Santee Cooper Retirement Announcement
SC	Jefferies	3	1970	173	26%	12/31/2015	10/19/2012	Santee Cooper Retirement Announcement
SC	Jefferies	4	1970	173	17%	12/31/2015	10/19/2012	Santee Cooper Retirement Announcement
SD	Ben French	ST1	1961	25	60%	8/30/2012	8/6/2012	Black Hills Company Announcement
TN	John Sevier	3	1956	200	55%	12/31/2012	4/14/2011	EPA TVA Settlement
TN	John Sevier	4	1957	200	51%	12/31/2012	4/14/2011	EPA TVA Settlement
TN	Johnsonville	1	1951	125	52%	12/31/2015	4/14/2011	EPA TVA Settlement
TN	Johnsonville	2	1951	125	55%	12/31/2015	4/14/2011	EPA TVA Settlement
TN	Johnsonville	3	1952	125	53%	12/31/2015	4/14/2011	EPA TVA Settlement
TN	Johnsonville	4	1952	125	48%	12/31/2015	4/14/2011	EPA TVA Settlement
TN	Johnsonville	5	1952	147	41%	12/31/2015	4/14/2011	EPA TVA Settlement
TN	Johnsonville	6	1953	147	45%	12/31/2015	4/14/2011	EPA TVA Settlement
TN	Johnsonville	7	1958	173	54%	12/31/2017	4/14/2011	EPA TVA Settlement
TN	Johnsonville	8	1959	173	43%	12/31/2017	4/14/2011	EPA TVA Settlement
TN	Johnsonville	9	1959	173	54%	12/31/2017	4/14/2011	EPA TVA Settlement

TN	Johnsonville	10	1959	173	42%	12/31/2017	4/14/2011	EPA TVA Settlement
TX	J T Deely	1	1977	486	59%	12/31/2017	6/20/2011	CPS CEO Announcement
TX	J T Deely	2	1978	446	78%	12/31/2017	6/20/2011	CPS CEO Announcement
TX	Welsh	2	1980	558	75%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
UT	Kennecott Utah Power Plant	3	1946	25	60%	12/31/2013	12/15/2010	Rio Tinto News Release
UT	Kennecott Utah Power Plant	2	1943	25	60%	12/31/2013	12/15/2010	Rio Tinto News Release
UT	Kennecott Utah Power Plant	1	1943	50	46%	12/31/2013	12/15/2010	Rio Tinto News Release
UT	Carbon	1	1954	75	80%	4/30/2015	3/1/2012	Filing of Revised Tariff Schedules
UT	Carbon	2	1957	114	77%	4/30/2015	3/1/2012	Filing of Revised Tariff Schedules
VA	Altavista	1	1992	71	26%	12/31/2012	4/1/2011	Dominion Resources News Release
VA	Bremo Bluff	3	1950	69	38%	12/31/2014	9/1/2010	Dominion Resources IRP
VA	Bremo Bluff	4	1958	185	46%	12/31/2015	9/1/2010	Dominion Resources IRP
VA	Chesapeake	3	1959	185	54%	12/31/2015	9/1/2011	DailyPress
VA	Chesapeake	ST1	1953	113	62%	12/31/2015	9/1/2011	DailyPress
VA	Chesapeake	ST2	1954	113	64%	12/31/2015	9/1/2011	DailyPress
VA	Chesapeake	ST4	1962	239	59%	12/31/2015	9/1/2011	DailyPress
VA	Clinch River	2	1958	238	24%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
VA	Clinch River	1	1958	238	36%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
VA	Clinch River	3	1961	238	12%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
VA	Glen Lyn	5	1944	100	2%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
VA	Glen Lyn	6	1957	238	10%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
VA	Hopewell Power Station	1	1992	71	27%	12/31/2012	4/1/2011	Dominion Resources News Release
VA	Southampton Power Station	1	1992	71	28%	12/31/2012	4/1/2011	Dominion Resources News Release
VA	Yorktown	1	1957	188	42%	12/31/2014	9/1/2011	DailyPress
VA	Yorktown	2	1959	188	52%	12/31/2014	9/1/2011	DailyPress
WA	Transalta Centralia Generation	1	1972	730	70%	12/31/2020	3/5/2011	Washington governor press release
WA	Transalta Centralia Generation	2	1973	730	63%	12/31/2025	3/5/2011	Washington governor press release
WI	Univ of Wisc Madison Charter Sreet Plar	1	1965	10	0%	12/31/2011	2/19/2010	Wisconsin State Journal
WI	Valley	1	1968	136	25%	12/31/2015	5/5/2011	Milwaukee Journal-Sentinel
WI	Valley	2	1969	136	41%	12/31/2015	5/5/2011	Milwaukee Journal-Sentinel
WI	Waupun Correctional Central Heating Pl	1	1951	1	0%	12/31/2011	3/13/2010	Wisconsin State Journal
WI	Waupun Correctional Central Heating Pl	2	1951	1	0%	12/31/2011	3/13/2010	Wisconsin State Journal
WI	Nelson Dewey	1	1959	100	70%	12/31/2015	7/27/2012	Alliant Press Release
WI	Nelson Dewey	2	1962	100	66%	12/31/2015	7/27/2012	Alliant Press Release
WI	Edgewater	3	1951	60	6%	12/31/2015	7/27/2012	Alliant Press Release
WI	Edgewater	4	1969	330	63%	12/31/2018	7/30/2012	Journal Sentinal Online
WI	Pulliam	5	1949	50	32%	12/31/2015	1/4/2013	News release for settlement
WI	Pulliam	6	1951	69	40%	12/31/2015	1/4/2013	News release for settlement
WI	Weston	1	1954	60	47%	12/31/2015	1/4/2013	News release for settlement
WI	Weston	2	1960	82	73%	12/31/2015	1/4/2013	News release for settlement
WV	Kammer	1	1958	238	24%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan

WV	Kammer	2	1958	238	28%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
WV	Kammer	3	1959	238	20%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
WV	Kanawha River	1	1953	220	20%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
WV	Kanawha River	2	1953	220	40%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
WV	North Branch	1	1992	80	0%	12/31/2015	12/3/2010	Wheeling News-Register
WV	Philip Sporn	1	1950	153	50%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
WV	Philip Sporn	2	1950	153	41%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
WV	Philip Sporn	3	1951	153	38%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
WV	Philip Sporn	4	1952	153	39%	12/31/2014	6/9/2011	American Electric Power EPA Regulations Compliance Plan
WV	Philip Sporn	5	1960	496	5%	12/31/2011	10/1/2010	American Electric Power 2010 IRP
WY	Naughton	3	1971	326	89%	12/31/2014	4/9/2012	PSC Testimony
WY	Neil Simpson	5	1969	22	80%	3/31/2014	8/6/2012	Black Hills Company Announcement
WY	Osage	1	1948	12	47%	3/31/2014	8/6/2012	Black Hills Company Announcement
WY	Osage	2	1949	12	47%	3/31/2014	8/6/2012	Black Hills Company Announcement
WY	Osage	3	1952	12	39%	3/31/2014	8/6/2012	Black Hills Company Announcement

FILED
United States Court of Appeals
Tenth Circuit

June 22, 2012

Elisabeth A. Shumaker
Clerk of Court

UNITED STATES COURT OF APPEALS

FOR THE TENTH CIRCUIT

STATE OF OKLAHOMA; OKLAHOMA INDUSTRIAL ENERGY CONSUMERS, an unincorporated association; OKLAHOMA GAS & ELECTRIC COMPANY, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, Respondent. -- SIERRA CLUB, Intervenor-Respondent.	Nos. 12-9526 & 12-9527 (No. EPA-R06-OAR-2010-0190)

ORDER

Before **KELLY** and **HOLMES**, Circuit Judges.

Petitioners, the State of Oklahoma, Oklahoma Industrial Energy Consumers, and the Oklahoma Gas & Electric Company, seek a stay pending review of that portion of the Environmental Protection Agency's final rule requiring the reduction of sulfur dioxide emissions at four electric generating units. We conclude that the stay factors have been met in this case, and we therefore GRANT the motion for stay pending hearing by the merits panel.

Entered for the Court

ELISABETH A. SHUMAKER, Clerk

Regional Haze

Timeline for States to Implement EPA's Rule

1999 — EPA issues final Regional Haze Rule

2001 — PM 2.5 Monitors in place

2003-5 — EPA designates PM 2.5 areas as "nonattainment", "attainment", or "unclassifiable"

2004-6 — Areas designated "Attainment" & "Unclassifiable" - States submit haze plans (establish progress goals and control strategies) 1 year from PM 2.5 designation date

2004-6 — Option- Regional Planning States commit to regional planning and submit haze plans one year after EPA designates first area within State

2006-8 — Areas designated "Nonattainment" - States submit haze plans (establish progress goals and control strategies) 3 years from PM 2.5 designation date

2008 — Option- Regional Planning States submit complete haze control strategy plans (establish progress goals and control strategies)

2011-13 — Option- States complete source-specific Best Available Retro-fit Technology (BART) controls

2013 — States submit progress reports on "reasonable progress" goals and strategies (every 5 years thereafter)

2016-18 — Option- States complete emis-sions trading or alternative con-trol measures

2018 — States com-plete revised haze plans (every 10 years thereafter)

Option for Grand Canyon Visibility Transport Commission (GCVTC) Areas

2000 — States submit annex to original GCVTC report (establish SO2 milestones)

2003 — States submit haze control strategy plans for 16 original areas

2008 — Latest date for States to submit haze control strategy plans for other Class I areas

2018 — States complete revised haze plans (every 10 years thereafter)

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Flue Gas Desulfurization-Equipped Coal-Fired Power Plants

Will They Comply with the 1-Hour National Ambient Air Quality Standard for Sulfur Dioxide?

By Robynn Andracsek, PE, Douglas Randall, PE, and Carl Weilert, PE

The U.S. Environmental Protection Agency (EPA) has promulgated a National Ambient Air Quality Standard (NAAQS) for sulfur dioxide (SO_2) with a one-hour averaging time. This article presents the results of an assessment of the ability of coal-fired energy generating units (EGUs) equipped with modern wet or semi-dry flue gas desulfurization (FGD) systems to achieve compliance with the new standard.

The assessment used air-quality models to predict ground-level SO_2 concentrations resulting from emissions of SO_2 from three configurations of a hypothetical 500-megawatt (MW) EGU: one firing low-sulfur coal and equipped with semi-dry FGD; one firing high-sulfur coal and equipped with wet FGD; and one with no FGD.

Methodology

The top 10 performing semi-dry FGD systems were identified by ranking, from lowest to highest, the EGUs with that FGD type by the average emission rate of pounds SO_2 per million British thermal units (lb SO_2/MMBtu) during 2009. The top 10 performing wet FGD systems on EGUs having estimated FGD inlet SO_2 concentration of greater than 4.0 lb/MMBtu were identified by ranking, from lowest to highest, by the average percent removal during 2009. Percent removal was estimated through the combination of annual average emission rate (lb SO_2/MMBtu) for 2009 as reported to the EPA and the weighted average fuel quality data for each facility obtained from EIA Form 923 for 2009.

For each of those 20 units, the 2009 hourly emission data was evaluated. The only modification performed on the data was to eliminate hours where the heat input (MMBtu/hour) or emission rate (lb/hour) was equal to zero. The average lb/hour emission rates were then determined for all remaining data. Next, the highest one-hour emission rate (lb/hour) in 2009 was determined for each unit using the Microsoft Excel function "Maximum (data set)."

To create a comparable emission factor for units of varying sizes, the highest lb/hour emission rate was normalized for each unit. The highest value for each unit was normalized by dividing the highest lb/hour emission rate by the annual average emission rate (lb/hour) on a unit-by-unit basis. The average, maximum and minimum of the 10 normalized ratios developed from the highest one-hour emission rate for each category are shown in Table 1.

The equivalent emission rates (lb SO_2/MMBtu) for the evaluated uncontrolled facility were determined using 2009 annual emission data from facilities that do not indicate the use of any SO_2 control devices. The maximum uncontrolled emission rate was determined to be 5.9 lb SO_2/MMBtu. The average uncontrolled emission rate was determined to be approximately 1.0 lb SO_2/MMBtu. The minimum

Table 1: Normalized Highest One-Hour Emission Rates

SO_2 Control Type	Wet FGD	Semi-Dry FGD	No FGD
Top 10 average emission rate (lb SO_2/MMBtu)	0.088	0.069	N/A
Average of normalized values	15.4	9.1	1.0 lb SO_2/MMBtu
Maximum of normalized values	30.4	23.6	5.9 lb SO_2/MMBtu
Minimum of normalized values	8.9	2.5	0.35 lb SO_2/MMBtu

Cause No PUD201200054
Exhibit JFW-9

emission rate was assumed to be 0.35 lb SO_2/MMBtu.

The baseline emissions for the theoretical 5,000 MMBtu/hour (representative of a 500-MW) facility modeled for this study are shown in Table 2. The emission rate (lb/MMBtu) is based upon the average emission rate of the annual data for the 10 facilities in each category. The long-term pound-per-hour emission rate is based on the long-term lb/MMBtu emission rate and an assumed heat input of 5,000 MMBtu/hour. The modeled emission rate is determined by multiplying the appropriate normalized emission factor by the pound-per-hour emission rate in Table 2, or, in the case of no FGD, multiplying the lb/MMBtu emission rate by 5,000 MMBtu/hour.

The National Emissions Inventory (NEI) Air Pollutant Emissions Trends Database (http://www.epa.gov/ttnchie1/trends) was used to determine representative stack characteristics (height, temperature, exit velocity and diameter) for a theoretical 5,000 MMBtu/hr unit. (See Table 3.)

Three scenarios were modeled varying whether the unit had a wet flue gas desulfurization (FGD), semi-dry FGD, or no FGD. The exhaust temperature and velocity were varied based on the method of SO_2 control. The same building structure was used for each method of SO_2 control: a building with dimensions of 130 feet by 210 feet and a height of 240 feet. A tall stack height was assumed in order to eliminate the stack height impacts. Shorter stack heights would result in higher ground level concentrations.

AERMOD (v09292) was used to run the dispersion model using regulatory defaults. The model was run for each of the three cases (wet FGD, semi-dry FGD, and no FGD) in three locations (Texas, Wisconsin and South Dakota). The different locations provide variability for the impact of different terrain on the modeling results. The SO_2POST (v1.2) post-processor from Beeline Software was used to determine the three-year average of the 99th percentile of the annual distribution of daily maximum one-hour average concentrations, which is the form of the NAAQS. The five-year average was used in lieu of the three-year average, to provide less conservative (better dispersion) results. A 22 km by 22 km receptor grid was used with elevated terrain. Preprocessed meteorological data was obtained from the state agencies' websites or other public information.

Table 2: Baseline Emissions for Modeled Facility

	Wet FGD	Semi-Dry FGD
Lbs per million Btu	0.088	0.069
Lbs per hour	440	345

Table 3: Stack Characteristics of Modeled Facility

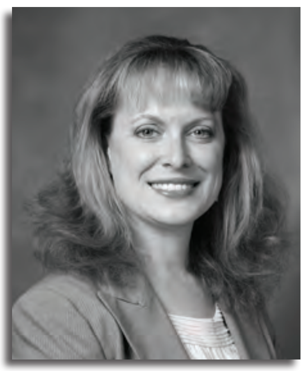
	Wet FGD	Semi-Dry FGD	No FGD
Temperature (°F)	132	157	330
Exit velocity (feet/sec)	60	83	100
Stack height (feet)	600 feet	600 feet	600 feet
Stack diameter (feet)	23 feet	20 feet	20 feet

Background concentrations were added to the results and were determined from existing monitors in each state. The one-hour SO_2 NAAQS is 75 ppb or 196 μg/m^3.

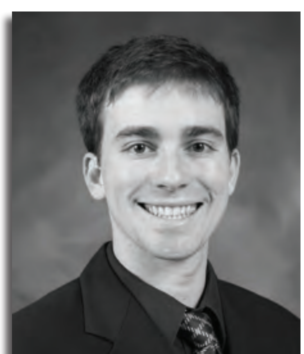
Conclusions

Dispersion modeling using non-conservative (greatest dispersion) assumptions shows that both scrubbed and unscrubbed boilers will have difficulty complying with the new one-hour SO_2 NAAQS during short-term high emissions. (See Table 4.) The reduced dispersion associated with cooler scrubbed gas will magnify the impacts of the upset period. Each facility should model their own emission rates to determine their impact, because compliance is not a given.

Several observations can be made from the results shown in Table 4.



Robynn Andracsek, PE, is an associate environmental engineer specializing in air-quality regulations.



Douglas Randall, PE, is a senior chemical engineer in the Burns & McDonnell Energy Group.

Table 4: Results of Modeling Scenarios

	Emission Rate lb/hour		South Dakota Without background	South Dakota With background of 79.47 µ/m3	Texas Without background	Texas With background of 47.16 µ/m3	Wisconsin Without background	Wisconsin With background of 129 µ/m3
Wet FGD	Maximum	13,366	246.76	326.23	306.13	353.29	383.79	512.79
	Average	6,785	125.25	204.73	155.39	202.55	194.81	323.81
	Minimum	3,900	71.99	151.47	89.32	136.48	111.98	240.98
Semi-Dry FGD	Maximum	8,147	181.43	260.90	234.12	281.28	281.40	410.40
	Average	3,120	69.48	148.95	89.66	136.82	107.77	236.77
	Minimum	851	18.96	98.43	24.47	71.63	29.41	158.41
No FGD	Maximum	41,359	553.71	633.18	530.31	577.47	692.56	821.56
	Average	6,870	91.97	171.45	88.09	135.25	115.04	244.04
	Minimum	2,454	32.85	112.32	31.46	78.62	41.08	170.08

*Blue indicates a modeled exceedance of the 1-hr SO_2 NAAQS

Table 4: Dispersion model results point to compliance difficulties for both scrubbed and non-scrubbed boilers.

- The addition of the required background concentration can be the difference between being in or out of compliance. Therefore, it is important to understand how the state agency is calculating the background concentration. For example, the maximum highest monitored value may be too conservative. Additionally, the background concentrations can vary greatly between locations. In this study, the background ranged from 24% to 66% of the standard.

- The standard is one-hour, which is a very short time to recover from process upsets. These facilities would likely have complied with the annual SO_2 NAAQS, which is more forgiving to short-term periods of under-controlled emissions; however, EPA revoked both the annual and 24-hour averages. The three-hour average was retained.

- The presence and type of FGD influences the plume's dispersion. Wet FGD systems have the lowest exit temperatures and velocities, followed by semi-dry FGD and then no FGD. The modeled concentrations are inversely proportional to the initial dispersion provided by temperature (buoyancy flux) and velocity (momentum flux). As the exhaust temperature and velocity increase, modeled concentration decreases (if everything else is held constant). However, due to the varying emission rates, the extent to which the change in modeled concentrations is due to dispersion characteristics cannot be discerned.

- Comparing the results for the different locations modeled shows the impact of terrain and meteorological data on the ground level concentration. The Wisconsin location had the most exceedances, likely due to its presence next to a bluff. The South Dakota and Texas sites were relatively flat. Texas had the next highest modeled concentrations, likely due to the fact that the wind direction had little variance.

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